STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative:
Mr. Steven F. Gilliland, Senior Vice President

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Air Permit No. PSD-FL-302
New Gas Turbine Peaking Plant

Enclosed is Final Air Permit No. PSD-FL-302 (Project No. 1110100-001-AC). This permit authorizes the construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. As noted in the Final Determination (attached), minor changes to the draft permit were made by the Department, mostly at the request of the applicant. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., 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 6/18/01 to the person(s) listed:

Mr. Steven F. Gilliland, Duke Energy*
Mr. Nathan K. Plagens, Duke Energy
Mr. George Howroyd, CH2MHILL
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Chair, St. Lucie Board of County Commissioners

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.

Charlotte J. Hayes (Clerk) 6/18/01 (Date)

FINAL DETERMINATION

PERMITTEE

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

PERMITTING AUTHORITY

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

PROJECT

Site Name: Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Air Permit No. PSD-FL-302

This permit authorizes the construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The plant will consist of eight simple cycle gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. The project is subject to PSD preconstruction review.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on May 1, 2001. The applicant published the "Public Notice of Intent to Issue" in The Tribune (St. Lucie County, Florida) on May 10, 2001. The Department received the proof of publication on June 12, 2001. No requests for administrative hearings were filed.

No comments on the Draft Permit were received from the public, the Department's Southeast District Office, or the National Park Service. The following section summarizes the Department's response to the applicant's comments and resulting revisions.

APPLICANT'S COMMENTS AND REQUESTS

After receiving the initial "Intent to Issue Permit" package, the applicant's consultant noted that the description of the project location was incorrect. The correct project description is "located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road". This was corrected prior to the publishing the Public Notice and changed throughout the remaining documents.

EPA COMMENTS

On May 23, 2001, the Department received written comments from EPA Region 4 regarding the Draft Permit. The following summarizes each comment and the Department's response:

1. *Comment*: In addition to the Department's short-term NOx limit (12 ppmvd based on a 3-hour rolling average), EPA Region 4 recommended a long-term NOx standard with an average of 9 ppmvd for "the life of the facility". *Response*: For simple cycle projects, the Department considers whether or not distillate oil will be fired as a backup fuel because NOx emissions are at least 3.5 times more than when firing natural gas. Emissions of particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds also increase with oil firing. For example, simple cycle projects with NOx emissions standards of 15 ppmvd may not be authorized for any oil firing while projects with standards of 9 ppmvd are typically allowed

approximately 750 hours of oil firing. In addition to providing some ability to negotiate projects with lower potential emissions, this strategy is useful in accommodating a variety of manufacturers. For the proposed project, the applicant withdrew the initial request to fire up to 1000 hours of distillate oil per year with the understanding that a slightly higher NOx standard could be accommodated. The Department's Technical Evaluation and Preliminary Determination included a review of fourteen simple cycle projects with Draft Permits issued since July 1999 that featured the General Electric Model 7EA gas turbine. Nine of the projects specified NOx standards from 12 to 15 ppmvd based on 1-hour averages, monthly averages and annual averages. Also, two of the five projects with standards of 9 ppmvd were issued in Florida and were based on the considerations given above. The Department believes the permit is consistent with other recent permits for similarly sized units.

2. *Comment*: EPA Region 4 suggests that definitions of startup and shutdown be included within the permit condition defining excess emissions. *Response*: "Startup" and "shutdown" are specific terms that are defined in Rule 62-210.200 (Definitions), F.A.C. To satisfy EPA's request, the Department added these definitions to Condition No. 20.b in Section II of the permit.

OTHER CHANGES

In Appendix BD of Section IV, the following corrections were made: "sulfuric acid mist (SAM)" was added to the requirements for SO_2 in both tables; "initial test" was added to the compliance method for VOC in both tables (consistent with the permit); the estimated VOC emissions in both tables were corrected to "29 tons per year"; and the estimated particulate matter emissions were corrected to "10 lb/hour".

CONCLUSION

The above minor revisions were made as well as corrections of typographical errors. The final action of the Department is to issue the permit with the changes described above.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative:
Mr. Steven F. Gilliland, Senior Vice President

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Air Permit No. PSD-FL-302
Facility ID No. 1110100
SIC No. 4911
Expires: December 1, 2002

PROJECT AND LOCATION

This permit authorizes the construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The plant will consist of eight simple cycle gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. The UTM coordinates are Zone 17, 561.6 km East, and 3029.0 km North.

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.) and 40 CFR 52.21. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	-	Terminology
Appendix BD	-	BACT Determinations and Emissions Standards Summary
Appendix GC	-	General Conditions
Appendix GG	-	NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	-	CEMS Excess Emissions and Data Exclusion Report

Howard L. Rhodes 6/15/01

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The new 640 MW electrical generating plant will consist of eight new 80 MW simple cycle gas turbine-electrical generator sets, evaporative inlet air foggers, continuous monitoring equipment, exhaust stacks, and associated support equipment.

NEW EMISSIONS UNITS

This permit authorizes construction of the following new emissions units.

ID No.	Common Emission Unit Description
001 to 008	**Simple Cycle Unit Nos. 1 - 8**: Each simple cycle unit is a General Electric Model PG7121(EA) gas turbine-electrical generator set designed to produce a nominal 80 MW of electrical power fired primarily with natural gas and with very low sulfur distillate oil as a backup fuel.
009	**Distillate Oil Storage Tanks**

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new facility is subject to the acid rain provisions of the Clean Air Act.

Title V: The new facility is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year. 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: Emissions of at least one regulated pollutant from the new facility will be greater than 250 tons per year. The project is located in an area designated as in attainment or unclassifiable for each pollutant subject to a National Ambient Air Quality Standard. Therefore, the project is subject to new source preconstruction review in accordance with Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: New units subject to the New Source Performance Standards of 40 CFR 60 include the gas turbines (Subpart GG) and the fuel storage tanks (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 10/05/00 and all related correspondence.
- Intent to Issue Permit package mailed May 1, 2001.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authorities: All documents related to compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, P.O. Box 15425, West Palm Beach, Florida 33401. The phone number is 561/681-6600 and the fax number is 561/681-6790.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. Definitions of common terms are listed in Rule 62-210.200, F.A.C. Appendix A explains the format used to cite rules and regulations in this permit.

4. General Conditions: The permittee is subject to, and 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.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, 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.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if 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. [40 CFR 52.21(r)(2)]

7. Permit Expiration: 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, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

9. 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.]

10. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. 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 Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. 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 ninety 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, and copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, F.A.C. and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

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

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

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

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

TESTING REQUIREMENTS

17. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

18. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

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

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

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

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

20. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C.; 40 CFR 60.7 and 60.8]

21. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

22. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

RECORDS AND REPORTS

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

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

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

A. GAS TURBINES

This section of the permit addresses the following new emissions units.

Emissions Unit ID Nos. 001 – 008: Simple Cycle Unit Nos. 1 - 8
Each simple cycle unit consists of a General Electric Model PG7121(EA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 93 feet tall and 15 feet in diameter, and associated support equipment. Each unit is fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology when firing natural gas and wet injection when firing distillate oil. The automated gas turbine control system modulates critical parameters of the dry low-NOx combustors to achieve a lean, pre-mix steady state operation.
At a compressor inlet air temperature of 59° F, operating at 100% load, and firing 977 mmBTU (HHV) per hour of natural gas, each unit produces approximately 84 MW. Exhaust gases exit the stack at 970° F with a volumetric flow rate of approximately 1,570,000 acfm.
At a compressor inlet air temperature of 59° F, operating at 100% load, and firing 1007 mmBTU (HHV) per hour of distillate oil, each unit produces approximately 87 MW. Exhaust gases exit the stack at 994° F with a volumetric flow rate of approximately 1,604,000 acfm.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2). See Appendix BD for the BACT determinations and a summary of the emissions standards. [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: Each gas turbine shall comply with the following applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A, General Provisions,* including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. *Subpart GG, Standards of Performance for Stationary Gas Turbines* as specified in Appendix GG of this permit.

EQUIPMENT

3. Simple Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain eight new General Electric Model PG7121(EA) gas turbines with electrical generator sets. Each unit shall be designed and installed as a simple cycle system to include an automated gas turbine control system, General Electric's latest dry low-NOx combustion system, an inlet air filtration system, a compressor inlet air evaporative cooling system, a single exhaust stack that is 93 feet tall and 15.0 feet in diameter, and associated support equipment. Prior to the initial emissions performance tests, each gas turbine and control system shall be tuned to optimize the reduction of NOx emissions. Thereafter, each unit shall be maintained and tuned in accordance with the manufacturer's recommendations. The permittee shall provide at least 7 days advance notice prior to any regularly scheduled tuning performed by the manufacturer. [Applicant Request; Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Permitted Capacity: The maximum heat input rates to each gas turbine shall not exceed 977 mmBTU per hour when firing natural gas and 1007 mmBTU per hour when firing distillate oil. The maximum heat-input rates are based on 100% load, a compressor inlet air temperature of 59° F, and the higher heating values (HHV) of each fuel. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the 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. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Fuel Specifications: Each gas turbine shall fire pipeline-quality natural gas as the primary fuel with a maximum of 2 grains of sulfur per 100 SCF of natural gas. As restricted by this permit, No. 2 distillate oil (or a superior grade) may be fired as backup fuel with a maximum of 0.05% sulfur by weight. [Project Design; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

6. Restricted Operation: No individual gas turbine shall operate more than 5000 hours during any consecutive 12-month period. All eight gas turbines (combined) shall not operate more than an average of 2500 hours per installed unit during any consecutive 12-month period. No individual gas turbine shall fire distillate oil for more than 12 hours during any calendar day. No individual gas turbine shall fire distillate oil for more than 1000 hours during any consecutive 12-month period. All eight gas turbines (combined) shall not fire distillate oil for more than an average of 500 hours per installed unit during any consecutive 12-month period. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

7. Simple Cycle Operation Only: Each gas turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the justification for the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to restricted operation. Future conversion of any unit to combined cycle operation or a relaxation in the hours of operation will invoke the source obligation requirements of Rule 62-212.400(2)(g), F.A.C. Such requests will be reviewed as if the simple cycle units had never been constructed with a new determination of the Best Available Control Technology for each significant pollutant. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the simple cycle gas turbines and pollution control systems in accordance with the guidelines and procedures established by the 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.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to each simple cycle gas turbine. The mass emission limits are based a compressor inlet temperature of 59° F and 100% load. For comparison to the standard, actual measured mass emissions shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

9. Carbon Monoxide (CO)

   a. *First 12 Months*: When firing natural gas, CO emissions from each gas turbine shall not exceed 52.0 pounds per hour nor 25.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, CO emissions from each gas turbine shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 10 and apply during the initial performance tests and during the 12 month period following the initial performance tests.

   b. *After First 12 Months*: When firing natural gas or low sulfur distillate oil, CO emissions from each gas turbine shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen, as determined by EPA Method 10. These standards are based on 3-hour test averages conducted at base load and apply after the 12 month period following the initial performance tests.

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

10. Nitrogen Oxides (NOx)

    a. *Initial Performance Test*: When firing natural gas, NOx emissions from each gas turbine (new and clean) shall not exceed 32.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions from each gas turbine shall not exceed 167.0 pounds per hour nor 42.0 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 7E or 20 and apply during the initial performance tests.

    b. *CEMS*: When firing natural gas, NOx emissions shall not exceed 10.5 ppmvd corrected to 15% oxygen based on a 3-hour rolling average. When firing low sulfur distillate oil, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average. These standards are based on valid data collected from the certified NOx CEMS and apply at all times.

    NOx emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

11. Particulate Matter (PM/PM_{10}): The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) for particulate matter emissions from each gas turbine. Compliance with the fuel specifications and the CO emissions standards of this section shall serve as indicators of good combustion. The following visible emissions limit is established as a work-practice standard for particulate matter emissions. Visible emissions from each gas turbine shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. {Permitting Note: As determined by EPA Method 5 (front-half catch only), particulate matter emissions from each unit are expected to be less than 5/10 pounds per hour when firing natural gas/low sulfur distillate oil.} [Rule 62-212.400(BACT), F.A.C.]

12. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel specifications of Condition No. 5 in this section represent the Best Available Control Technology (BACT) for SAM and SO_2 emissions from each gas turbine and effectively limit potential emissions. Compliance with the fuel specifications shall be determined by Condition No. 21 of this section. [Rules 62-204.800(7) and 62-212.400(BACT), F.A.C.]

13. Volatile Organic Compounds (VOC)

    a. *Initial Performance Test*: When firing natural gas, VOC emissions from each gas turbine shall not exceed 2.5 pounds per hour nor 2.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, VOC emissions from each gas turbine shall not exceed 4.5 pounds per hour nor 3.5 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 25A. Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. VOC emissions shall be expressed in terms of methane. [Design; Rule 62-4.070, F.A.C.; To Avoid Rule 62-212.400(BACT), F.A.C.]

b. *After Initial Performance Test*: The efficient combustion design, use of clean fuels, and good operating practices minimize VOC emissions from each gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. After the initial performance tests, subsequent tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C. [Design; Rule 62-4.070, F.A.C.]

EXCESS EMISSIONS

14. 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 emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

15. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

    a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

    b. Except for startup and shutdown, operation below 50% base load is prohibited.

    c. In accordance with Condition No. 20 of this section, certain data collected by each CEMS during startup, shutdown, malfunction, and tuning may be excluded from the NOx compliance averaging periods. If a CEMS reports emissions in excess of a 3-hour rolling average emissions standard, the permittee shall notify the Compliance Authority within one (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    [Design; Rules 62-210.700, 62-4.130, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

16. Initial Tests Required: Each gas turbine shall be tested initially for each fuel to demonstrate compliance with the emission standards for CO, NOx, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each unit. Tests for CO and VOC emissions shall be conducted concurrently. Valid NOx emissions data collected by the certified CEMS during each CO test run shall be included in the test report. [Rules 62-297.310(7)(a)1. and 62-212.400(BACT), F.A.C.]

17. Continuous Compliance: Each gas turbine shall demonstrate continuous compliance with the 3-hour rolling average NOx emissions standards as determined by valid data collected from the certified CEMS specified in Condition No. 20 of this section. [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Performance Tests: Each gas turbine shall be tested annually to demonstrate compliance with the emission standards for CO and visible emissions. Annual tests shall be conducted at least once during each federal fiscal year (October 1st to September 30th). Valid NOx emissions data collected by the certified CEMS during each CO test run shall be included in the test report. If less than 400 hours of oil is fired in a gas turbine during a federal fiscal year, the annual CO test is waived. [Rule 62-297.310(7)(a)4., F.A.C.]

19. Test Methods: As required, tests shall be performed in accordance with the following reference methods.

EPA Method	Description of Method and Comments
5	Determination of Particulate Matter Emissions from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • Optionally, 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 Volatile Organic Concentrations

The above reference methods are specified in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used to demonstrate compliance unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

CONTINUOUS MONITORING REQUIREMENTS

20. NOx CEMS: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the emissions of NOx from each gas turbine in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The oxygen content or the carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NOx is monitored to correct the measured NOx emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards for NOx specified in this permit.

   a. *Data Collection.* Compliance with the CEMS emission standards for NOx shall be based on a 3-hour rolling average. The 3-hour rolling average shall be calculated from three successive hourly average emission rate values. Each hourly 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). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. 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). Final results of the CEMS shall be expressed as "ppmvd corrected to 15% oxygen". Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of Subpart GG in 40 CFR 60.

b. *Data Exclusion.* Data for NOx emissions and oxygen (or CO_2) content shall be recorded by the CEMS during all episodes of startup, shutdown and malfunction. Individual hourly NOx emission rate values recorded during these episodes may be excluded from the continuous NOx compliance determination. No more than three (3) hourly average emission rate values shall be excluded in any 24-hour block period due to all gas turbine startups, shutdowns, and documented unavoidable malfunctions. If an hourly average emission rate value is excluded, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour average. Startup means the commencement of operation of any emissions unit that has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. Shutdown means the cessation of the operation of an emissions unit for any purpose. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

   The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

c. *NOx Monitor Certification.* The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEM emission standards of this permit, missing data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The monitor shall be a dual range monitor with a lower span no greater than 30 ppm and an upper span no greater than 125 ppm.

d. *Oxygen (or CO_2) Monitor Certification.* The oxygen (or CO_2) monitor shall be certified and operated in accordance with 40 CFR 60, Appendix B, Performance Specification 3. 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 quarterly to each Compliance

Authority. The RATA tests required for the oxygen (or CO_2) monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the 3-hour average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEMS during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than quarterly, including quarterly periods in which no data is excluded or no instances of missing data occur.

f. *Availability.* NOx monitor availability shall not be less than 95% in any calendar quarter. The report required in Appendix XS 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.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEMS 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 Part 51, Appendix P; 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.]

RECORDS

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

a. *Natural Gas*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the 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 the most recent versions.

b. *Distillate Oil*: Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling and analyzing 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 distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the vendor. 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.]

22. Monitoring of Operations: To demonstrate compliance with the capacity requirements, the permittee shall monitor and record the operating rate of each simple cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above,

or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

23. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following information in a written or electronic log.

- Hours of operation for each gas turbine for the previous month and 12 months of operation;
- Average hours operation per installed gas turbine for the previous 12 months of operation;
- Hours of distillate oil firing for each gas turbine for the previous month and 12 months of operation;
- Average hours of distillate oil firing per installed gas turbine for the previous 12 months of operation;
- For any gas turbine firing distillate oil for more than 12 hours in a calendar day, indicate the date and hours of oil firing;

Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request from the Department or a Compliance Authority. [Rules 62-4.160(15) and 62-4.070(3), F.A.C.]

REPORTS

24. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and NOx monitor availability for the previous calendar quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. DISTILLATE OIL STORAGE TANKS

This section of the permit addresses the following emissions unit.

Emissions Unit No. 009: Distillate Oil Storage Tanks
Four storage tanks supply low sulfur distillate oil as a backup fuel to the gas turbines.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]
2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE REQUIREMENTS

3. Equipment: The distillate oil tanks shall provide storage for the very low sulfur distillate oil used as backup fuel for the gas turbines. [Applicant Request]
4. Hours of Operation: Operation of the distillate oil storage tank is not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

RECORDS

5. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual throughput of distillate oil through each storage tank. [Rule 62-210.370(3), F.A.C.]
6. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the tank. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

TERMINOLOGY

Abbreviations and Acronyms

CEM	-	Continuous Emissions Monitor
CT	-	Combustion Turbine
DARM	-	Division of Air Resource Management
DEP	-	State of Florida, Department of Environmental Protection
DLN	-	Dry Low-NOx Combustion Technology
EPA	-	United States Environmental Protection Agency
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
GT	-	Gas Turbine
HRSG	-	Heat Recovery Steam Generator
OC	-	Oxidation Catalyst Technology for CO Control
ppmvd	-	Parts per million by volume on a dry basis
SOA	-	Specific Operating Agreement
SCR	-	Selective Catalytic Reduction
UTM	-	Universal Transverse Mercator

Rule Citations

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.):

Example: [Rule 62-213.205, F.A.C.]

Where:	62	-	identifies the specific Title of the F.A.C.
	62-213	-	identifies the specific Chapter of the F.A.C.
	62-213.205	-	identifies the specific Rule of the F.A.C.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001

Where:	099	-	identifies the specific county location
	0221	-	identifies the specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV

Where:	AC	-	identifies the permit as an Air Construction Permit
	AV	-	identifies the permit as a Title V Major Source Air Operation Permit
	099	-	identifies the specific county that project is located in
	2222	-	identifies the specific facility
	001	-	identifies the specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456

Where:	AC	-	identifies the permit as an Air Construction Permit
	AO	-	identifies the permit as an Air Operation Permit
	123456	-	identifies the specific permit project

BACT DETERMINATIONS AND EMISSIONS STANDARDS SUMMARY

The following tables summarize the final Best Available Control Technology determinations for this project and the corresponding standards for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

Table B-1. EU-001 through 008: Eight 80 MW Simple Cycle Gas Turbines – Natural Gas Firing

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: Pipeline-quality natural gas with 2 grains of sulfur per 100 SCF of gas, max.	ASTM Methods D4084-82, D3246-81 or more recent versions with monthly vendor analysis.
CO	*BACT Control*: Efficient combustion design, good operating practices	Emissions Performance Tests
	BACT Standards, First Year: 25.0 ppmvd @ 15% oxygen (52.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for initial tests
	BACT Standards, Thereafter: 20.0 ppmvd @ 15% oxygen (43.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for annual tests
NOx	*BACT Control*: Dry low-NOx combustion design	Certified CEMS data.
	BACT Standard: 9.0 ppmvd @ 15% oxygen (32.0 lb/hour), 3-hour test avg.	EPA Method 7E (or 20) at base load for initial tests "new and clean"
	BACT Standard: 10.5 ppmvd @ 15% O_2, 3-hour rolling CEMS avg.	Certified CEM data for continuous compliance demonstration
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	EPA Method 9 for initial and annual tests
	Comment: Particulate matter emissions are expected to be less than 5 lb/hour.	EPA Method 5 (front-half catch only); no test required
SAM/SO_2	*BACT Control*: Fuel specifications (low sulfur)	See compliance methods for fuel specifications.
	BACT Standard: Potential SAM and SO_2 emissions are effectively limited by the fuel specifications.	See compliance methods for fuel specifications.
VOC	*Control*: Efficient combustion of clean fuels, good operating practices	Initial test and compliance with fuel specifications and CO standards
	Standard: 2.0 ppmvd @ 15% oxygen (2.5 lb/hr), 3-hour test avg.	EPA Method 25A with emissions measured and reported as methane; (Optionally, EPA Method 18 may be conducted concurrently to deduct methane and ethane emissions.)
	Comment: Total potential VOC emissions from all eight gas turbines are estimated to be 29 tons per year. The project is not subject to PSD for VOC emissions.*	

Note: Mass emissions standards are based on the following conditions: 100% load (approximately 83 MW), 977 mmBTU per hour of heat input (HHV) from firing natural gas, and a compressor inlet air temperature of 59° F.

Table B-2. EU-001 through 008: Eight 80 MW Simple Cycle Gas Turbines – Distillate Oil Firing

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: No. 2 distillate oil with 0.05% sulfur by weight, maximum	ASTM D 2880-71 (equivalent) with vendor analysis
CO	*BACT Control*: Efficient combustion design, good operating practices	Emissions performance tests
	BACT Standards: 20.0 ppmvd @ 15% oxygen (43.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for initial and annual tests
NOx	*BACT Control*: Dry low-NOx combustion design	Certified CEMS data.
	BACT Standard: 42.0 ppmvd @ 15% oxygen (167.0 lb/hour), 3-hour test avg.	EPA Method 7E (or 20) at base load for initial tests "new and clean"
	BACT Standard: 42.0 ppmvd @ 15% O_2, 3-hour rolling CEMS avg.	Certified CEM data for continuous compliance demonstration
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	EPA Method 9 for initial and annual tests
	Comment: Particulate matter emissions are expected to be less than 10 lb/hour.	EPA Method 5 (front-half catch only); no test required
SAM/SO_2	*BACT Control*: Fuel specifications (low sulfur)	See compliance methods for fuel specifications.
	BACT Standard: Potential SAM/SO_2 emissions are effectively limited by the fuel specifications.	See compliance methods for fuel specifications.
VOC	*Control*: Efficient combustion of clean fuels, good operating practices	Initial tests and compliance with fuel specifications and CO standards
	Standard: 3.5 ppmvd @ 15% oxygen (4.5 lb/hr), 3-hour test avg.	EPA Method 25A with emissions measured and reported as methane; (Optionally, EPA Method 18 may be conducted concurrently to deduct methane and ethane emissions.)
	Comment: *Total potential VOC emissions from all eight gas turbines are estimated to be 29 tons per year. The project is not subject to PSD for VOC emissions.*	

Note: Mass emissions standards are based on the following conditions: 100% load (approximately 83 MW), 977 mmBTU per hour of heat input (HHV) from firing natural gas, and a compressor inlet air temperature of 59° F.

BACT DETERMINATIONS

As summarized in the previous table, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for carbon monoxide, particulate matter, nitrogen oxides, sulfuric acid mist and sulfur dioxide. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:

J. F. Koerner   6-12-01

J. F. Koerner, P.E., Project Engineer   (Date)
New Source Review Section

Recommended By:

CH Fancy   6/15/01

C. H. Fancy, Chief   (Date)
Bureau of Air Regulation

Approved By:

Howard L. Rhodes   6/15/01

Howard L. Rhodes, Director   (Date)
Division of Air Resources Management

SECTION IV. APPENDIX GC

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

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

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

{Note: The new gas turbines are subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. 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 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.}

11. Pursuant to 40 CFR 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:

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

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 de-fined in paragraph (a)(3) of this section.

(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)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

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

Department requirement: "F" is zero because the fuel bound nitrogen content is negligible.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. Based on the manufacturer's heat rates (LHV) of 10,510 BTU/kW-hr and 10,960, the "Y" values are approximately 11.3 for natural gas and 11.7 for distillate oil, respectively. The equivalent emission standards are approximately 96 and 92 ppmvd at 15% oxygen, respectively. The standards of this permit are much 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.

12. Pursuant to 40 CFR 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:

(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.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

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

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

Department requirement: Very low sulfur No. 2 distillate oil will be stored in four tanks. Compliance with the fuel sulfur limit may be satisfied by a certified fuel vendor analysis for each delivery. The requirement to monitor the nitrogen content of distillate oil is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit.

(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 pipeline quality natural gas 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 permittee shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with the 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 § 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 § 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: The NOx monitor availability threshold shall not be less than 95% in any calendar quarter. The report required in Appendix XS shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the owner or operator 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.

[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.

14. Pursuant to 40 CFR 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 percent 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 permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee 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.

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

<u>Department requirement</u>: **The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system 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 the permit shall be used instead of that specified in paragraph (c)(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.

<u>Department requirement</u>: **The permit specifies sulfur testing methods and allows 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 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 the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

CEMS EXCESS EMISSIONS AND DATA EXCLUSION REPORT

Figure 1 – Quarterly Performance Summary Report
Gaseous Excess Emission and Monitoring System

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

Pollutant: Nitrogen Oxides (NOx)

Reporting period dates: From ____________________ to ____________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ____________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: ________________________

Emission data summary [a]		CMS performance summary [a]	
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] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For gases, record all times in hours.

[b] 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 last quarter in CMS, process or controls.*

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

____
(Company Name)

____
(Name and Title)

____ ____________________
(Signature) *(Date)*

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. Steven F. Gilliland
Duke Energy North America
5400 Westheimer Court
Houston, FL 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6 25 01

C. Signature
X Helen Butler

☐ Agent
☐ Addressee

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 *(Copy from service label)*
7000 0600 0026 4129 8504

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7000 0600 0026 4129 8504

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

Postmark
Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland

Street, Apt. No.; or PO Box No.
5400 Westheimer Court

City, State, ZIP+4
Houston, FL 77056-5310

PS Form 3800, February 2000 See Reverse for Instructions

Memorandum

Florida Department of
Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: June 12, 2001

SUBJECT: Final Air Permit No. PSD-FL-302
Project No. 1110100-001-AC
Duke Energy Fort Pierce, LLC
New 640 MW Gas Turbine Peaking Plant

The Final Permit for this project is attached for your approval and signature. The permit authorizes the construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The plant will consist of eight simple cycle gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. BACT determinations were made for significant emissions increases of carbon monoxide, nitrogen oxides, particulate matter, sulfuric acid mist, and sulfur dioxide.

The Department distributed an "Intent to Issue Permit" package on May 1, 2001. The applicant published the "Public Notice of Intent to Issue" in The Tribune (St. Lucie County, Florida) on May 10, 2001. The Department received the proof of publication on June 12, 2001. No requests for administrative hearings were filed.

Day 90 is July 15, 2001. I recommend your approval and signature.

Attachments

CHF/jfk

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 28, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Duke Energy Fort Pierce, LLC
Extension of Air Construction Permit No. PSD–FL-302
Initial Project No. 1110100-001-AC

Dear Mr. Gilliland:

On October 15, 2002, the Department received your request with sufficient fee for an extension of the authority to begin physical construction and the expiration date of Air Permit No. PSD-FL-302 for the proposed new simple cycle gas turbine peaking plant to be located in Fort Pierce, Florida. The Department approves your request subject to the following changes.

The authority to begin physical construction of the project is extended to May 1, 2004. The permit expiration date is hereby extended from **December 1, 2002** to **November 1, 2004** to provide the necessary time to conduct testing and submit a complete application for a Title V air operation permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes. A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3), F.S., must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 of the Florida Administrative Code (F.A.C.)

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

Mediation is not available in this proceeding.

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this action will not be effective until further order of the

Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for Howard L. Rhodes, Director
Division of Air Resources Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/28/02 to the persons listed:

Mr. Steven F. Gilliland, Duke Energy*
Mr. Nathan K. Plagens, Duke Energy
Mr. George Howroyd, CH2MHILL
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Chair, St. Lucie Board of County Commissioners

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.

Victoria Gibson October 28, 2002
(Clerk) (Date)

Memorandum

Florida Department of Environmental Protection

TO: ~~Howard Rhodes~~

THRU: Al Linero aal 10/28

FROM: Jeff Koerner JK

DATE: October 24, 2002

SUBJECT: Duke Energy Fort Pierce, LLC
Extension of Air Construction Permit
Air Permit No. PSD-FL-302
Initial Project No. 1110100-001-AC

Attached for your approval and signature is a permit modification that extends the authority to begin physical construction and the permit expiration date for the above referenced project. Day 74 is December 27, 2002. I recommend your approval and signature.

Attachments

AAL/jfk

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:

Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J. C. Martinez

B. Date of Delivery 103/02

C. Signature

X

☐ Agent
☐ Addressee

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. Art 7001 0320 0001 3692 7751

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

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

OFFICIAL USE

7001 0320 0001 3692 7751

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

Postmark Here

Sent To Steven F. Gilliland

Street, Apt. No.; or PO Box No. 5400 Westheimer Court

City, State, ZIP+4 Houston, TX 77056-5310

PS Form 3800, January 2001 See Reverse for Instructions

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Extension of Air Permit No. PSD-FL-302
Initial Project No. 1110100-001-AC
Duke Energy Fort Pierce, LLC
ARMS Facility ID No. 1110100
640 MW Electrical Generation Peaking Plant

COUNTY

St. Lucie County

APPLICANT

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

October 24, 2002

{Filename: Duke Fort Pierce Extension TEPD.doc}

1. GENERAL PROJECT INFORMATION

Applicant Name and Address

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative: Mr. Steven F. Gilliland, Senior Vice President

Processing Schedule

10/14/02 Received application for an extension of the time to construct.

10/15/02 Received sufficient processing fee.

Facility Description and Location

Duke Energy Fort Pierce, LLC is a permitted, proposed new 640 MW electrical generating plant to be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS).

Standard Industrial Classification Code (SIC)

SIC No. 4911 – Electrical Services

Regulatory Categories

Title III: The new facility will be a potential major source of hazardous air pollutants (HAP).

Title IV: The new facility will operate units subject to the acid rain provisions of the Clean Air Act.

Title V: The new facility will be a Title V major source of air pollution.

PSD: The new facility will be a PSD-major source of air pollution.

NSPS: The new facility will operate units subject to a New Source Performance Standard (40 CFR 60).

Project Description

On June 15, 2001, the Department issued a PSD permit to Duke Energy Fort Pierce, LLC (DEFP) to construct new 640 MW electrical generating plant to be located in St. Lucie County, Florida. The plant will consist of eight simple cycle gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. The permit authorized construction of the plant with an expiration date of December 1, 2002. Due to the significant economic downturn and poor financial markets, DEFP has been forced to delay construction of this project. However, DEFP does intend to begin construction as early as January 2003 and requests that the authority to construct be extended to May 1, 2004.

2. PROJECT REVIEW

In support of this request, DEFP provided information regarding the adequacy of the initial BACT determination based on recent determinations for similar projects involving the General Electric 7EA gas turbine. This information is based on EPA Region 4's "National Combustion Turbine Spreadsheet", attached, which is a compilation of determinations for gas turbine projects across the United States. The following summarizes the Department's review of the adequacy of the initial BACT determinations for the DEFP project compared to similar simple cycle General Electric 7EA gas turbine projects permitted in 2000 or after for peaking operation (< 4000 hours/year).

NOx Emissions

Based on recent similar projects, NOx BACT standards for gas firing range from 9 ppmvd (24-hour average) up to 15 ppmvd (annual average). The "9 ppmvd" limits are typically for initial startup or are based on a 30-day or annual average. The current project limits for gas-firing limits are 9 ppmvd (initial performance test) and 10.5 ppmvd (3-hour CEMS average). Based on recent similar projects, the NOx BACT standard for oil firing is 42 ppmvd (1-hour to 24-hour average) with oil firing restricted to less than 1000 hours per year. The current project limit for oil-firing limit is 42 ppmvd (3-hour CEMS average) with oil firing limited to no more than an average of 500 hours per year for all eight units. The Department concludes that the existing BACT limits are within the current range of recent BACT determinations for similar 7EA simple cycle gas turbine peaking projects.

CO Emissions

Based on recent similar projects, CO BACT standards for gas and oil firing range from 20-25 ppmvd O_2. It is assumed that the averaging period is based on three test runs. The current project limits for gas firing are 25 ppmvd for the first year and 20 ppmvd O_2 thereafter. The current project limit for oil firing is 20 ppmvd. Compliance is based on initial and annual performance tests. The Department concludes that the existing BACT limits are within the current range of recent similar BACT determinations for 7EA simple cycle gas turbine peaking projects.

PM and VOC Emissions

For these pollutants, nearly all recent BACT determinations are based on good combustion design with the firing of clean fuels. The current project limits visible emissions to ≤ 10% opacity as a work practice standard for particulate matter. It also establishes VOC standards of 2/3.5 ppmvd for gas/oil firing based on initial performance tests. Natural gas (primary fuel) and distillate oil (alternate restricted fuel) are readily combusted and contain negligible amounts of ash. The Department concludes that the existing BACT limits are within the current range of recent BACT determinations for similar 7EA simple cycle gas turbine peaking projects.

SAM and SO_2 Emissions

For these pollutants, nearly all recent BACT determinations are based on the firing of very low sulfur fuels. The current project limits the fuel sulfur contents to 2 grains of sulfur per 100 SCF of natural gas and to 0.05% sulfur by weight for distillate oil. The Department concludes that the existing BACT limits are within the current range of recent BACT determinations for similar 7EA simple cycle gas turbine peaking projects.

3. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. The authority to begin physical construction shall be extended to May 1, 2004 as requested. The permit expiration date shall be extended to November 1, 2004 to provide sufficient time to file a complete application for a Title V air operation permit.

This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the current PSD air construction permit. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

EPA National Permit Listing - GE 7EAs

National Combustion Turbine List

Lasted updated 10/11/02

Source: www.epa.gov/region4/air/permits/index.htm

10/10/02

State	Facility	# of New MW	Application Date	Final Permit Issued	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NJ	PSEG Fossil LLC - Linden	170	12/15/00	2/10/00	Delegated	2	0	GE 7EA	NG; FO	SC	8,760	12 ppm NG; 42 ppm FO	DLN	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD. Unit started operation in April, 2000.
NJ	PSEG Fossil LLC - Burlington	340	pending	applic. under review	Delegated	4	0	GE 7EA	NG; FO	SC	8,760	9 ppm NG; 42 ppm FO	DLN	1 hour		CatOx	1 hour	Application under review.
AL	Alabama Power - Olin Cogeneration	137	7/31/97	Dec-97	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	15 ppm	DLN		0.07 lb/MMBtu	GCP		Power Augmentation
AL	Alabama Power - GE Plastics Cogeneration	100	10/1/97	May-98	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	9 ppm; 0.20 lb/MMBtu (DB)	DLN		0.08 lb/MMBtu (combined)	GCP		
AL	Duke Energy - Alexander City	1,260	7/13/00	2-01	SIP Approved	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
AL	Kinder Morgan Alabama LLC	7				7	7	LM 6000 & GE 7EA		CC	5750; 8760							
FL	Hardee Power Partners (TECO)	75	6/29/99	10-99	SIP Approved (1)	1	0	GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Florida Power Corp., Intercession City	261	6/1/99	12-99	SIP Approved (1)	3	0	GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Gainesville Regional Utilities, Kelly Generating Station	133	9/8/99	2-00	SIP Approved (1)	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NOx
FL	Duke Energy - Ft. Pierce	640	10/11/00	6/18/01	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI	3-hr rolling	25 ppm NG; 20 ppm FO	GCP	3-hr test	SCR - $50,602/ton NOx; CatOx - $21,832/ton CO&VOC
FL	Duke Energy Lake	640	12/5/00	7/18/01	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG	SC	2,500	12 ppm (9 ppm initial test)	DLN; WI	3-hr rolling	20 ppm (25 ppm first year)	GCP	3-hr test	SCR - $15,000/ton NOx; CatOx - $5,563/ton CO
GA	Georgia Power, Jackson County	1,216	2/11/99	8-99	SIP Approved	16	0	GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO	GCP		
GA	Duke Energy Sandersville, LLC	640	10/25/00	11/9/01	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	10 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		Hot SCR - $36,520/ton NOx; CatOx - $8,330/ton CO
GA	Kinder Morgan Georgia, LLC - Tift Power	560	7/30/01	applic. under review	SIP Approved	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	158.5 lb/hr & 141.0 lb/hr	GCP		
GA	Duke Energy Baker, LLC	640	8/17/01	applic. under review	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2500; 500 FO	12 ppm NG (9 ppm annual); 42 ppm FO	DLN; WI		24.7 ppm NG; 18.4 ppm FO	GCP		Hot SCR - $36,497/ton NOx; CatOx - $9,210/ton CO
KY	Duke Energy - Marshall Co.	640	2/8/00	draft permit	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr/an	20 ppm NG; 25 ppm FO	GCP		
KY	Duke Energy Metcalfe	640	9/1/00	draft permit	SIP Approved	8	0	GE 7EA (80 MW)	NG	SC	2,500	12/9 ppm	DLN	1-hr/an	25 ppm	GCP	1-hr	
KY	East Kentucky Power Cooperative, Inc.	240	3/1/00	7/27/01	SIP Approved	3	0	GE 7EA (80 MW)	NG; FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		CatOx - $8,000/ton CO
MS	Duke Energy Southaven	640	12/17/99	8-00	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	Warren Power LLC (revision)	320	3/23/01	draft permit	SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	2,000	12 ppm (9 ppm annual)	DLN	24-hr	25 ppm	GCP	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
MS	Duke Energy Enterprise	160	5/30/00	draft permit	SIP Approved	2	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	MEP Clarksdale Power	320	10/16/00	draft permit	SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
MS	TVA - Kemper CT Plant	440	1/25/01	draft permit	SIP Approved	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
MS	South Mississippi Electric Power Association	250	11/16/01	applic. under review	SIP Approved	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN	24-hr	25 ppm	GCP		
NC	Duke Energy - Buck Steam Station	640	11/16/00	11/20/01	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI	24-hr	20 ppm NG; 25 ppm FO	GCP	3-hr	CatOx - $11,976/ton CO
SC	Duke Power - Mill Creek (f/k/a/ RIPP)	654	2/28/01	11/8/01	SIP Approved	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI	24-hr	25 ppm NG; 20 ppm FO	GCP	24-hr	

State	Facility	# of New MW	Application Date	Final Permit Issued	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TN	TVA, Johnsonville Fossil Plant	340	12/8/98	7-99	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Gallatin Fossil Plant	340	12/2/98	7-99	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Lagoon Creek Plant	1,760	11/30/99	4-00	SIP Approved	16	0	GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI	30/15day	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
IN	Vermillion Generating Station	640	12/18/98	6/1/00	Delegated	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	annual	25 ppm NG; 20 ppm FO	GEP	1-hr > 50% load	BACT; Usage limit of 20,336 MMCF NG-12 consec. months. Also 2 Emergency Generators; 1 Emergency Diesel Fire Pump; 4 Diesel Storage Tanks; SCR @ $19,309/ton (avg.); Ox Cat @ 90% Control, rejected at $8,977/ton
IN	Indianapolis Power and Light	191		8/17/99	Delegated	1		GE 7121EA (95.7 MW)	NG; FO	SC	peaking	25 ppm NG; 42 ppm FO	WI					Synth Minor
IN	Indianapolis Power and Light	265		9/17/99	Delegated	3		GE (88.4 MW each)	NG	SC	peaking	25 ppm NG; 42 ppm FO	DLN	an/hr	25 ppm NG; 20 ppm FO	GCP		Synth Minor
IN	DeSoto Generating Station	?		applic. under review	Delegated	8		GE 7EA (80 MW each)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	25 ppm NG; 20 ppm FO	GCP		BACT
MI	KM Power Co	550	application received 3/00	6/26/00	Delegated	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	9 ppm and 22 ppm	DLN	30 day	79 lb/hr and 132 lb/hr	GCP	1 hr	BACT
MI	Detroit Edison Co	250	application received 7/00	application under review	Delegated	3		GE PG7121(EA)										
MN	Lakefield Junction	552		draft permit	Delegated	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	25 ppm NG; 20 ppm FO	GCP	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
OH	Duke Energy Madison LLC	640	12/21/98	7/1/99	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN	1 hr (ann.)	25 NG 20 FO	GCP	hr/an	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
OH	Duke Energy Madison II, LLC	640	?	-	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,000 NG; 500 FO							PSD
WI	Wisconsin Public Service	360		7/1/99	SIP Approved	1		GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN	hr, nat gas, FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $13,866/ton; Ox Cat rejected at $6053/ton incremental cost
WI	Wisconsin Electric	85		draft permit	SIP Approved	1		GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug.	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	DLN	24-hr, 1 hr FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
TX	SEI - Texas, LLC	650	2/11/99	3/21/00	SIP Approved	4		2 GE 7FA (170 MW) / 2 GE 7EA (82 MW)		SC		9/9 ppm	DLN		9/25 ppm			
TX	City of Garland	85	3/9/99	2/23/00	SIP Approved	1		GE 7EA (85 WM)		SC	.	9 ppm	DLN		25 ppm			
KS	Western Resources	380	11/20/98	6/11/99	SIP Approved	3	0	2 - GE-7EA (100 MW each); 1 GE-7FA (180 MW)	NG; FO	SC		15 ppm NG; 42 ppm FO	DLN; WI	802				NOx limits are for > 70% load. NSPS limits will apply at < 70 % Load
KS	Great Plains Power, Paola	320	6/6/01	Presently Under	SIP Approved	4	0	4 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	402	30-day rolling	25 ppm	CC	
KS	Great Plains Power, Gardner	640	6/6/01	Presently Under	SIP Approved	8	0	8 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	804	30-day rolling	25 ppm	CC	
MO	Kansas City Power & Light Hawthorn Units 7 & 8	150	2/29/99	8/18/99	SIP Approved	2	0	GE 7EA (75 MW, each)	NG	SC		9 ppm	DLN	337		25 ppm	GCP	
MO	Duke Energy - Audrain	640	4/11/00	5/9/00	SIP Approved	8	0	GE 7EA (80 MW, each)	NG; FO	SC	2,500; 500 FO	NOx: (NG) 12 ppm, 1-hr, NOx: (NG) 9 ppm, annual, NOx: (Oil) 42 ppm	DLN; WI	646		20 ppm NG; 25 ppm FO	GCP	

State	Facility	# of New MW	Application Date	Final Permit Issued	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
MO	Duke Energy - Bollinger	640	8/17/00	9/22/00	SIP Approved	8	0	GE 7EA (80 MW, each)	NG	SC	2,500	NOx: (NG) 12 ppm, 1-hr, NOx: (NG) 9 ppm, annual	DLN	430		20 ppm	GCP	PM-10: 0.016#/mmBtu, Formaldehyde: <10 TPY. Each turbine limited to 2,500 hours on NG-only (annual rolling), with entire plant limited to 4,000 hours per year
MO	Kinder Morgan, LLC	530	Permit Tentatively Denied	Permit Tentatively Denied	SIP Approved	7	7	8 GE-LM6000 (50MW, each); 1 GE-7EA (110 MW), plus 120 MW supplemental	NG	CC	8,760			705				
CO	Platte River Power Authority/Rawhide (82 MW)	82	3/00	12/00	SIP Approved	1	none	GE Frame 7EA	NG	SC	8,760	9 ppm	DLN					plan startup 5/2002; CO PTE below significance level so didn't do BACT; characterized as peaking plant, but not restricted in operating hours
CO	TriState Generation & Transmission/Limon Station (164 MW)	164	7/00	1/01	SIP Approved	2	none	GEF7EA, or equiv	NG, FO (1000 hr, each turbine, limit on FO)	SC	8,760	9 ppm (42 ppm on FO)	DLN (plus WI on FO)	1-hr	25 ppm	GCP		
WA, PSD 91-04	Tenaska Ferndale	248		5/29/92	Joint Issuance: EPA & Ecology	2	2	GE Frame 7EA	NG;FO	CC	8,760	7.0 / 12 ppmdv gas / oil @15% O2	DLN, SCR	24-hr	20.0 ppmdv	GCP	1-hr	Operating, www.tenaska.com, 1/19/00 permit revision, permit revision needed to allow installation of fogger to increase output 20 MW
WA, PSD-X80-02	Whitehorn (Puget Sound Energy)	187		12/19/79	EPA	4	0	2 Pratt & Whitney, 2 GE Frame 7E	NG;FO	CC	8,760	NSPS GG	WI			GCP		Operating

CH2MHILL

RECEIVED

OCT 15 2002

BUREAU OF AIR REGULATION

CH2M HILL
115 Perimeter Center Place NE
Suite 700
Atlanta, GA
30346-1278
Tel 770.604.9095
Fax 770.604.9183

October 14, 2002

154648

Mr. Jeff Koerner
Permit Engineer
Florida Department of Environmental Regulation
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Submittal of $50 Processing Fee
Request for Extension of PSD Air Construction Permit
Duke Energy Fort Pierce, LLC
Air Permit No. PSD-FL-302

Dear Mr. Koerner:

As requested, we are submitting a check in the amount of $50.00 payable to Florida Department of Environmental Regulation for the Processing of the above-referenced Request for Extension. This payment is being submitted on behalf of our client, Duke Energy North America.

If you should have any questions concerning any aspect of this submittal, please contact Bill Collins, Duke Energy's Manager, Environmental Licensing at 713-627-5370 (e-mail: wgcollins@duke-energy.com), or Dr. George Howroyd at CH2M HILL, Duke Energy's Environmental Consultant at 770-604-9182, ext 355 (e-mail: ghowroyd@ch2m.com).

Sincerely,

CH2M HILL

George C. Howroyd

George C. Howroyd, Ph.D., P.E.
Principal Engineer

154648 Duke Energy\PSD Permit\Submittal of PSD Extension Processing Fee.doc

c: Dan Runyan/DENA Houston
William Collins/DENA Houston

Duke Energy North America
A Duke Energy Company

Duke Energy
North America, LLC
5400 Westheimer Court
Houston, TX 77056-5310
P.O. Box 1642
Houston, TX 77251-1642

RECEIVED

OCT 14 2002

BUREAU OF AIR REGULATION

October 11, 2002

Mr. Jeff Koerner
Permit Engineer
Florida Department of Environmental Regulation
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Request for Extension of PSD Air Construction Permit
Duke Energy Fort Pierce, LLC
St. Lucie County, Florida
Air Permit No. PSD-FL-302

Dear Mr. Koerner:

This letter is written to request an extension of the expiration date for the above-referenced permit for the proposed Duke Energy Fort Pierce, LLC ("DEFP") generating station. The current permit, which was issued on June 18, 2001, states in Proviso No. 6 of Section II, that the permit will expire if construction is not commenced within 18 months of the date of issuance, or December 18, 2002. The front page of the permit states that it will expire on December 1, 2002. Proviso No. 7 of Section II states that the permittee may, for good cause, request that the permit be extended. This letter contains information that supports the basis for our request, our revised construction schedule, and a review of best available control technology (BACT) determinations made since the permit was issued.

Basis for Duke Energy's Request for Extension

As you are aware, the national power market has experienced a significant economic downturn and there has been an associated reduction in the development of new power projects across the country. Many projects that were under development (and even under construction) have been postponed or cancelled. DEFP does not believe that these conditions will persist and we are therefore requesting that our Permit to Construct the DEFP generating station be extended.

Duke Energy's Proposed Schedule for Construction and Operation

DEFP's original proposed construction schedule was based on a commercial operation by June of 2002; however, the temporary lull in customer demand and dramatic change in the financial markets has forced us to delay construction. Anticipated construction could start as early as January 2003 or as late as May 2004. Therefore, we are requesting that the start of construction be extended by 18 months to May 1, 2004.

Review of BACT Determinations for Recent Permits for Similar Facilities

In order to ensure that the project's current permit conditions for emissions and emission controls are still representative of BACT, we have compared the current permit limits and associated emission control requirements with current determinations for best available control technology (BACT) for similar facilities. We have discussed this issue with representatives of EPA Region IV and obtained a current listing of BACT determinations that have been made for General Electric 7EA gas turbine generators operating in simple cycle mode from EPA's web site , located at:

www.epa.gov/region4/air/permits/index.htm)

A copy of the list identifying the permits for GE 7EA gas turbine projects that have been issued, or are under review, is attached to this letter.

NOx Emissions

For permits issued after the DEFP permit was issued, permitted (or proposed) NOx emission limits for gas-fired operation are seen to range from 9 to 12 ppm, based on the use of dry low NOx (DLN) technology, for several different scenarios:

9 ppm long-term (annual) limit; 12 ppm short-term limit
9 ppm; unrestricted operation (8760 hours/yr)
9 ppm; >2500 hrs/yr operation

Several permits were also issued with NOx limits of 9 ppm at startup and 10.0 or 10.5 ppm. These limits are equivalent or similar to the current limits for the DEFP project.

NOx emission limits for oil-fired operation for permitted or proposed facilities are 42 ppm @ 15% O_2, based on the use of water injection and good combustion practices as control technology. This is equivalent to the current permit limits for the DEFP project for oil firing.

The DEFP emission limits for NOx are based on less than 2500 hours per year average annual operation (less than 500 annual average hours and no more than 12 hours/day for oil-fired operation), DLN technology, and good combustion practices, as follows:

NOx	9.0 ppm @ 15% O_2 (gas) – *initial performance test*
	10.5 ppm @ 15% O_2 (gas) – *routine operation as measured by CEMs*
	42.0 ppm @ 15% O_2 (oil)

Based on our review of recent permit determinations and discussions with EPA Region IV staff, DEFP believes that the NOx emission limits in the current permit are still representative of BACT. DEFP therefore requests that the permit limits for NOx remain unchanged.

CO Emissions

Permitted or proposed CO emission limits for GE 7EA turbines are generally in the range of 20 to 25 ppm for gas and oil-fired units.

The DEFP emission limits for CO are based on less than 2500 hours per year average annual operation (less than 500 annual average hours and no more than 12 hours/day for oil-fired operation) and good combustion practices, as follows:

CO	25.0 ppm @ 15% O_2 (gas) - *first 12 months of operation*
	20.0 ppm @ 15% O_2 (gas) - *after first 12 months of operation*
	20.0 ppm @ 15% O_2 (oil)

Based on our review of recent permit determinations and discussions with EPA Region IV staff, DEFP believes that the CO emission limits in the current permit are still representative of BACT. DEFP therefore requests that the permit limits for CO remain unchanged.

PM, SO_2, VOC, and H_2SO_4 Emissions

Emissions from these pollutants are inherently very low for this type of facility and the emission limits specified in the current permit are still consistent with the BACT determinations conducted for recent permits. DEFP proposes that the current permit limits are still representative of BACT and requests that the permit limits for these pollutants remain unchanged.

If you should have any questions concerning any aspect of this request, please contact Bill Collins, Duke Energy's Manager, Environmental Licensing at 713-627-5370 (e-mail: wgcollins@duke-energy.com), or Dr. George Howroyd at CH2M HILL, Duke Energy's Environmental Consultant at 770-604-9182, ext 355 (e-mail: ghowroyd@ch2m.com).

Sincerely,

Duke Energy North America

Steven F. Gilliland
Senior Vice President

Attachment: National Combustion Turbine List

c: Dan Runyan/DENA Houston
William Collins/DENA Houston
George Howroyd/CH2M HILL Atlanta

State	Facility	# of New MW	Application Date	Final Permit Issued	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NJ	PSEG Fossil LLC - Linden	170	12/15/00	2/10/00	Delegated	2	0	GE 7EA	NG; FO	SC	8,760	12 ppm NG; 42 ppm FO	DLN	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD. Unit started operation in April, 2000.
NJ	PSEG Fossil LLC - Burlington	340	*pending*	applic. under review	*Delegated*	4	0	GE 7EA	NG; FO	SC	8,760	9 ppm NG; 42 ppm FO	DLN	*1 hour*		CatOx	*1 hour*	*Application under review.*
AL	Alabama Power - Olin Cogeneration	137	7/31/97	Dec-97	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	15 ppm	DLN		0.07 lb/MMBtu	GCP		Power Augmentation
AL	Alabama Power - GE Plastics Cogeneration	100	10/1/97	May-98	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	9 ppm; 0.20 lb/MMBtu (DB)	DLN		0.08 lb/MMBtu (combined)	GCP		
AL	Duke Energy - Alexander City	1,260	7/13/00	2-01	SIP Approved	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
AL	Kinder Morgan Alabama LLC	7				7	7	LM 6000 & GE 7EA		CC	5750; 8760							
FL	Hardee Power Partners (TECO)	75	6/29/99	10-99	SIP Approved (1)	1	0	GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Florida Power Corp., Intercession City	261	6/1/99	12-99	SIP Approved (1)	3	0	GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Gainesville Regional Utilities, Kelly Generating Station	133	9/8/99	2-00	SIP Approved (1)	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NOx
FL	Duke Energy - Ft. Pierce	640	10/11/00	6/18/01	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI	3-hr rolling	25 ppm NG; 20 ppm FO	GCP	3-hr test	SCR - $50,602/ton NOx; CatOx - $21,832/ton CO&VOC
FL	Duke Energy Lake	640	12/5/00	7/18/01	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG	SC	2,500	12 ppm (9 ppm initial test)	DLN; WI	3-hr rolling	20 ppm (25 ppm first year)	GCP	3-hr test	SCR - $15,000/ton NOx; CatOx - $5,563/ton CO
GA	Georgia Power, Jackson County	1,216	2/11/99	8-99	SIP Approved	16	0	GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO	GCP		
GA	Duke Energy Sandersville, LLC	640	10/25/00	11/9/01	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	10 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		Hot SCR - $36,520/ton NOx; CatOx - $8,330/ton CO
GA	Kinder Morgan Georgia, LLC - Tift Power	560	7/30/01	applic. under review	SIP Approved	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8,760; 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	158.5 lb/hr & 141.0 lb/hr	GCP		
GA	Duke Energy Baker, LLC	640	8/17/01	applic. under review	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2500; 500 FO	12 ppm NG (9 ppm annual); 42 ppm FO	DLN; WI		24.7 ppm NG; 18.4 ppm FO	GCP	.	Hot SCR - $36,497/ton NOx; CatOx - $9,210/ton CO
KY	Duke Energy - Marshall Co.	640	2/8/00	draft permit	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr/an	20 ppm NG; 25 ppm FO	GCP		
KY	Duke Energy Metcalfe	640	9/1/00	draft permit	SIP Approved	8	0	GE 7EA (80 MW)	NG	SC	2,500	12/9 ppm	DLN	1-hr/an	25 ppm	GCP	1-hr	
KY	East Kentucky Power Cooperative, Inc.	240	3/1/00	7/27/01	SIP Approved	3	0	GE 7EA (80 MW)	NG; FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		CatOx - $8,000/ton CO
MS	Duke Energy Southaven	640	12/17/99	8-00	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	Warren Power LLC (revision)	320	3/23/01	draft permit	SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	2,000	12 ppm (9 ppm annual)	DLN	24-hr	25 ppm	GCP	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
MS	Duke Energy Enterprise	160	5/30/00	draft permit	SIP Approved	2	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	MEP Clarksdale Power	320	10/16/00	draft permit	SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
MS	TVA - Kemper CT Plant	440	1/25/01	draft permit	SIP Approved	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
MS	South Mississippi Electric Power Association	250	11/16/01	applic. under review	SIP Approved	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN	24-hr	25 ppm	GCP		
NC	Duke Energy - Buck Steam Station	640	11/16/00	11/20/01	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI	24-hr	20 ppm NG; 25 ppm FO	GCP	3-hr	CatOx - $11,976/ton CO
SC	Duke Power - Mill Creek (*f/k/a* RIPP)	654	2/28/01	11/8/01	SIP Approved	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI	24-hr	25 ppm NG; 20 ppm FO	GCP	24-hr	

State	Facility	# of New MW	Application Date	Final Permit Issued	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TN	TVA, Johnsonville Fossil Plant	340	12/8/98	7-99	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Gallatin Fossil Plant	340	12/2/98	7-99	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Lagoon Creek Plant	1,760	11/30/99	4-00	SIP Approved	16	0	GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI	30/15day	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
IN	Vermillion Generating Station	640	12/18/98	6/1/00	Delegated	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	annual	25 ppm NG; 20 ppm FO	GEP	1-hr > 50% load	BACT; Usage limit of 20,336 MMCF NG-12 consec. months. Also 2 Emergency Generators; 1 Emergency Diesel Fire Pump; 4 Diesel Storage Tanks; SCR @ $19,309/ton (avg.); Ox Cat @ 90% Control, rejected at $8,977/ton
IN	Indianapolis Power and Light	191		8/17/99	Delegated	1		GE 7121EA (95.7 MW)	NG; FO	SC	peaking	25 ppm NG; 42 ppm FO	WI					Synth Minor
IN	Indianapolis Power and Light	265		9/17/99	Delegated	3		GE (88.4 MW each)	NG	SC	peaking	25 ppm NG; 42 ppm FO	DLN	an/hr	25 ppm NG; 20 ppm FO	GCP		Synth Minor
IN	DeSoto Generating Station	?		applic. under review	Delegated	8		GE 7EA (80 MW each)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	25 ppm NG; 20 ppm FO	GCP		BACT
MI	KM Power Co	550	application received 3/00	6/26/00	Delegated	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	9 ppm and 22 ppm	DLN	30 day	79 lb/hr and 132 lb/hr	GCP	1 hr	BACT
MI	Detroit Edison Co	250	application received 7/00	application under review	Delegated	3		GE PG7121(EA)										
MN	Lakefield Junction	552		draft permit	Delegated	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	25 ppm NG; 20 ppm FO	GCP	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
OH	Duke Energy Madison LLC	640	12/21/98	7/1/99	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN	1 hr (ann.)	25 NG 20 FO	GCP	hr/an	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
OH	Duke Energy Madison II, LLC	640	?	-	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,000 NG; 500 FO							PSD
WI	Wisconsin Public Service	360		7/1/99	SIP Approved	1		GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN	hr, nat gas, FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $13,866/ton; Ox Cat rejected at $6053/ton incremental cost
WI	Wisconsin Electric	85		draft permit	SIP Approved	1		GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug.	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	DLN	24-hr, 1 hr FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
TX	SEI - Texas, LLC	650	2/11/99	3/21/00	SIP Approved	4		2 GE 7FA (170 MW) / 2 GE 7EA (82 MW)		SC		9/9 ppm	DLN		9/25 ppm			
TX	City of Garland	85	3/9/99	2/23/00	SIP Approved	1		GE 7EA (85 WM)		SC		9 ppm	DLN		25 ppm			
KS	Western Resources	380	11/20/98	6/11/99	SIP Approved	3	0	2 - GE-7EA (100 MW each); 1 GE-7FA (180 MW)	NG; FO	SC		15 ppm NG; 42 ppm FO	DLN; WI	802				NOx limits are for > 70% load. NSPS limits will apply at < 70 % Load
KS	Great Plains Power, Paola	320	6/6/01	Presently Under	SIP Approved	4	0	4 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	402	30-day rolling	25 ppm	CC	
KS	Great Plains Power, Gardner	640	6/6/01	Presently Under	SIP Approved	8	0	8 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN	804	30-day rolling	25 ppm	CC	
MO	Kansas City Power & Light Hawthorn Units 7 & 8	150	2/29/99	8/18/99	SIP Approved	2	0	GE 7EA (75 MW, each)	NG	SC		9 ppm	DLN	337		25 ppm	GCP	
MO	Duke Energy - Audrain	640	4/11/00	5/9/00	SIP Approved	8	0	GE 7EA (80 MW, each)	NG; FO	SC	2,500; 500 FO	NOx: (NG) 12 ppm, 1-hr, NOx: (NG) 9 ppm, annual, NOx: (Oil) 42 ppm	DLN; WI	646		20 ppm NG; 25 ppm FO	GCP	

State	Facility	# of New MW	Application Date	Final Permit Issued	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
MO	Duke Energy - Bollinger	640	8/17/00	9/22/00	SIP Approved	8	0	GE 7EA (80 MW, each)	NG	SC	2,500	NOx: (NG) 12 ppm, 1-hr, NOx: (NG) 9 ppm, annual	DLN	430		20 ppm	GCP	PM-10: 0.016#/mmBtu, Formaldehyde: <10 TPY. Each turbine limited to 2,500 hours on NG-only (annual rolling), with entire plant limited to 4,000 hours per year
MO	Kinder Morgan, LLC	530	Permit Tentatively Denied	Permit Tentatively Denied	SIP Approved	7	7	~~6 GE-~~ LM6000 (50MW, each); 1 GE-7EA (110 MW), plus 120 MW supplemental	NG	CC	8,760			705				
CO	Platte River Power Authority/Rawhide (82 MW)	82	3/00	12/00	SIP Approved	1	none	GE Frame 7EA	NG	SC	8,760	9 ppm	DLN					plan startup 5/2002; CO PTE below significance level so didn't do BACT; characterized as peaking plant, but not restricted in operating hours
CO	TriState Generation & Transmission/Limon Station (164 MW)	164	7/00	1/01	SIP Approved	2	none	GEF7EA, or equiv	NG, FO (1000 hr, each turbine, limit on FO)	SC	8,760	9 ppm (42 ppm on FO).	DLN (plus WI on FO)	1-hr	25 ppm	GCP		
WA, PSD 91-04	Tenaska Ferndale	248		5/29/92	Joint Issuance: EPA & Ecology	2	2	GE Frame 7EA	NG;FO	CC	8,760	7.0 / 12 ppmdv gas / oil @15% O2	DLN, SCR	24-hr	20.0 ppmdv	GCP	1-hr	Operating, www.tenaske.com, 1/19/00 permit revision, permit revision needed to allow installation of fogger to increase output 20 MW
WA, PSD-X80-02	Whitehorn (Puget Sound Energy)	187		12/19/79	EPA	4	0	2 Pratt & Whitney, 2 GE Frame 7E	NG;FO	CC	8,760	NSPS GG	WI			GCP		Operating

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:

Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* J. Martinez

B. Date of Delivery 10/3/01

C. Signature
X
☐ Agent
☐ Addressee

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 7001 0320 0001 3692 7751

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

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

7001 0320 0001 3692 7751

OFFICIAL USE

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

Postmark Here

Sent To Steven F. Gilliland
Street, Apt. No.; or PO Box No. 5400 Westheimer Court
City, State, ZIP+4 Houston, TX 77056-5310

PS Form 3800, January 2001 See Reverse for Instructions

BEST AVAILABLE COPY

SCRIPPS HOWARD

THE TRIBUNE

ST. LUCIE COUNTY, FLORIDA

P.O. Box 69, Fort Pierce, FL 34954-0069

RECEIVED

JUN 12 2001

BUREAU OF AIR REGULATION

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Lynn Ferraro, General Manager; Kathy LeClair, Business Manager or Dorothy Dicks, Advertising Manager of The Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida; that the attached copy of advertisement was published in The Tribune in the following issues below. Affiant further says that the said Tribune is a newspaper published at Fort Pierce in said St. Lucie County, Florida and that the said newspaper has heretofore been continuously published in said St. Lucie County, Florida daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of attached copy of advertisement; and affiant further says that he/she 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. The Tribune has been entered as second class matter at the Post Office in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Name	Date	Price Per Day	PO #
2146609	CH2M HILL	05/10/2001	$390.04	
		Total	$390.04	

Subscribed and sworn to me before this date:

06/05/2001

Cathy LeClair

Kathy Lee

Notary Public

KATHY LEE
My Comm Exp. 7/30/2002
No. CC 763706
[X] Personally Known [ ] Other I.D.

NOTARY PUBLIC

cc: J. Koerner
C. Holladay
J. Goldman, SED
B. Worley, EPA
J. Bunyak, NPS

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Project No. 1110100-001-AC
Draft Permit PSD-FL-302
Duke Energy Fort Pierce, LLC
Proposed 640 MW Simple Cycle Gas Turbine Plant
Emissions Units 001 - 009

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Duke Energy Fort Pierce, LLC to construct a nominal 640 MW simple cycle gas turbine plant. The proposed plant will be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The applicant plans to install eight new simple cycle gas turbine-electrical generator sets with inlet air fogging systems and necessary support equipment. Each unit is a General Electric Model PG7121(EA) gas turbine with a nominal generating capacity of 80 MW. The applicant's authorized representative is Mr. Steven F. Gilliland, Senior Vice President of Duke Energy North America. The applicant's mailing address is 5400 Westheimer Court, Houston, TX 77056-5310.

Each simple cycle gas turbine will be fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Operation is restricted to an average of 2500 hours per gas turbine per year with an average of no more than 500 hours of oil firing per gas turbine per year. When firing natural gas, nitrogen oxide emissions will be minimized with dry low-NOx combustion technology. When firing very low sulfur distillate oil, nitrogen oxide emissions will be minimized with wet injection and restricted operation. Emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of these clean fuels.

The potential emissions from this project are shown in the following table.

Pollutant	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	540	100	Yes	Yes
NOx	632	40	Yes	Yes
PM/PM10	60	25/15	Yes	Yes
SAM	17	7	Yes	Yes
SO2	147	40	Yes	Yes
VOC	29	40	No	No

As indicated, a determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM) and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

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

Florida Department of Environmental Protection	Florida Department of Environmental Protection
Bureau of Air Regulation	Southeast District Office - Air Resources
(111 S. Magnolia Drive, Suite 4)	(400 NORTH CONGRESS AVENUE)
2600 Blair Stone Road, MS #5505	P.O. BOX 15425
Tallahassee, Florida, 32399-2400	West Palm Beach, Florida 33401
Telephone: 850/488-0114	Telephone: 561/681-6600
Fax: 850/922-6979	Fax: 561/681-6790

Publish: May 10, 2001

2146806

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED
MAY 23 2001
BUREAU OF AIR REGULATION

MAY 21 2001

4APT-ARB

Mr. A. A. Linero, P.E.
Division of Air Resources Management
FL Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit dated May 1, 2001, for the Duke Energy Fort Pierce, LLC project (PSD-FL-302) located in St. Lucie County, Florida. The preliminary determination is for the proposed construction and operation of a power project consisting of eight (GE 7EA) simple cycle gas combustion turbines (CTs) with a nominal generating capacity of 80 MW each. The CTs will combust pipeline quality natural gas and No. 2 distillate oil. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM).

Based on our review of the preliminary determination and draft permit, we have the following comments:

1. The Florida Department of Environmental Protection (FDEP) proposes a NO_x emission rate of 10.5 ppmvd as best available control technology (BACT) for the combustion turbines after passing an initial "new and clean" performance test at 9 ppmvd. We recommend that FDEP consider establishing a short-term NO_x limit of 10.5 ppmvd and a long-term limit of 9 ppmvd for the life of the facility. If the Duke Energy Lake project is significantly different from other GE 7EA combustion turbine projects burning natural gas, Duke should provide clarification of why a 9 ppmvd NO_x limit can not be achieved at this facility on a long-term average basis. For your information, Duke Energy has proposed this exact same configuration (8 simple cycle GE 7EA combustion turbines) in several other states and has typically accepted a long-term limit of 9 ppmvd.

2. The draft permit provides certain exemptions during periods of startup and shutdown. The final permit should include a definition of the words startup and shutdown in terms of the observable operating conditions that indicate a period of startup and a period of shutdown.

Thank you for the opportunity to comment on the Duke Energy Fort Pierce, LLC facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to César Zapata at (404) 562-9139.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Koerner
C. Holladay
L. Kaldman, SED
J. Bunyak, NPS
T. Davis, ECT

ECT
Environmental Consulting & Technology, Inc.

RECEIVED
MAY 22 2001
BUREAU OF AIR REGULATION

May 21, 2001

Mr. Cleve Holladay
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

5/24
FYI - Please return for file

Re: Fort Pierce Repowering Project
Revised Dispersion Modeling Results

Dear Mr. Holladay:

Fort Pierce Repowering Project, LLC (FPRP) is planning to construct, own, and operate a new electric power generating facility to be located at the existing Fort Pierce Utilities Authority's (FPUA) H.D. King Electric Generating Plant in Fort Pierce, St. Lucie County, Florida. The new electric generating facility is designated as FPRP CTG-1.

A Prevention of Significant Deterioration (PSD) Air Construction Permit Application for the FPRP CTG-1 project was submitted to the Department in April 2001. This application included an assessment of air quality impacts resulting from the operation of the proposed FPRP CTG-1. As previously advised, the dimensions of the building that will house FPRP CTG-1 have recently been revised. In response to your request, the dispersion modeling analysis was repeated using the revised building dimensions to assess sulfur dioxide (SO_2) impacts. Additional modeling for SO_2 was requested since prior modeling had shown project impacts to be well below the significant impact levels for the remaining pollutants.

Revised Table 7-1 (screening mode input and results), Table 7-3 (project maximum annual SO_2 impacts), Table 7-5 (project maximum 3-hour SO_2 impacts), Table 7-6 (project maximum 24-hour SO_2 impacts), Table 7-11 (highest, seconding highest 3-hour SO_2 AAQS impacts), Table 7-12 (highest, seconding highest 24-hour SO_2 AAQS impacts), Table 7-13 (highest, seconding highest 3-hour SO_2 PSD Class II impacts), and Table 7-14 (highest, seconding highest 24-hour SO_2 PSD Class II impacts) are attached for your review. The screening and refined dispersion model input and output files have been sent to you via e-mail. The additional dispersion modeling demonstrates that the changes to the FPRP CTG-1 building dimensions will result in maximum air quality impacts that are essentially the same as previously determined.

3701 Northwest 98TH Street
Gainesville, FL 32606

(352) 332-0444

FAX (352) 332-6722

FPRP has also removed simple cycle mode operation as an alternative operating scenario for the FPRP CTG-1 project. Revisions to the emission rate calculations (previously provided in Appendix C of the permit application) reflecting this change, as well as minor revisions to fuel heating values, are also attached.

Your continued expeditious review of the FPRP air permit application will be appreciated. Please contact me at 352/332-6230, Ext. 351 if there are any questions regarding this material.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

cc: Mr. Scott Churbock, FPRP
Mr. Jeffery Koerner, FDEP
I. Goldman

Enclosures
B. Worley, EPA
J. Bunyak, NPS

REVISED DISPERSION MODELING RESULTS

Case	Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (μg/m^3)	NO_2 Emission Rate[(a)] (g/sec)	NO_2 Emission Rate Ratio	NO_2 Maximum 1-Hr Impact (μg/m^3)	SO_2 Emission Rate (g/sec)	SO_2 Emission Rate Ratio	SO_2 Maximum 1-Hr Impact (μg/m^3)
SS 15	Oil, 32 °F, 100% Load	1.00	3.548	3.64	3.64	12.9	12.25	12.25	43.5
SS 13	Oil, 32 °F, 100% Load, DB	1.00	3.287	3.64	3.64	12.0	12.52	12.52	41.2
SS 17	Oil, 32 °F, 75% Load	1.00	4.750	3.64	3.64	17.3	9.84	9.84	**46.8**
SS 9	Gas, 32 °F, 50% Load	1.00	4.761	3.64	3.64	17.4	0.82	0.82	3.9
SS 16	Oil, 59/74/95 °F, 100% Load, IAC	1.00	3.654	3.64	3.64	13.3	11.87	11.87	43.4
SS 14	Oil, 59/74/95 °F, 100% Load, IAC, DB	1.00	3.375	3.64	3.64	12.3	12.14	12.14	41.0
SS 18	Oil, 59 °F, 75% Load	1.00	4.951	3.64	3.64	18.0	9.25	9.25	45.8
SS 10	Gas, 59 °F, 50% Load	1.00	4.907	3.64	3.64	17.9	0.79	0.79	3.9
SS 19	Oil, 74 °F, 75% Load	1.00	5.070	3.64	3.64	18.5	8.95	8.95	45.4
SS 11	Gas, 74 °F, 50% Load	1.00	4.997	3.64	3.64	18.2	0.77	0.77	3.8
SS 20	Oil, 95 °F, 75% Load	1.00	5.224	3.64	3.64	**19.0**	8.54	8.54	44.6
SS 12	Gas, 95 °F, 50% Load	1.00	5.120	3.64	3.64	18.7	0.74	0.74	3.8
	Maximums					**19.0**			**46.8**

(a) Annualized emission rate for Annual Profile B.

Case	Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (µg/m^3)	PM/PM_{10} Emission Rate (g/sec)	PM/PM_{10} Emission Rate Ratio	PM/PM_{10} Maximum 1-Hr Impact (µg/m^3)	CO Emission Rate (g/sec)	CO Emission Rate Ratio	CO Maximum 1-Hr Impact (µg/m^3)
SS 15	Oil, 32 °F, 100% Load	1.00	3.548	4.410	4.41	15.6	4.131	4.13	14.7
SS 13	Oil, 32 °F, 100% Load, DB	1.00	3.287	5.355	5.36	17.6	4.997	5.00	**16.4**
SS 17	Oil, 32 °F, 75% Load	1.00	4.750	3.465	3.47	16.5	3.305	3.30	15.7
SS 9	Gas, 32 °F, 50% Load	1.00	4.761	1.386	1.39	6.6	2.520	2.52	12.0
SS 16	Oil, 59/74/95 °F, 100% Load, IAC	1.00	3.654	4.410	4.41	16.1	4.131	4.13	15.1
SS 14	Oil, 59/74/95 °F, 100% Load, IAC, DB	1.00	3.375	5.355	5.36	18.1	4.779	4.78	16.1
SS 18	Oil, 59 °F, 75% Load	1.00	4.951	3.465	3.47	17.2	3.098	3.10	15.3
SS 10	Gas, 59 °F, 50% Load	1.00	4.907	1.260	1.26	6.2	2.142	2.14	10.5
SS 19	Oil, 74 °F, 75% Load	1.00	5.070	3.465	3.47	17.6	3.150	3.15	16.0
SS 11	Gas, 74 °F, 50% Load	1.00	4.997	1.260	1.26	6.3	2.142	2.14	10.7
SS 20	Oil, 95 °F, 75% Load	1.00	5.224	3.465	3.47	**18.1**	2.940	2.94	15.4
SS 12	Gas, 95 °F, 50% Load	1.00	5.120	1.260	1.26	6.5	2.016	2.02	10.3
	Maximums					**18.1**			**16.4**

Notes: IAC = inlet air chilling.
DB = duct burner firing.

Source: ECT, 2001.

Table 7-3. ISCST3 Model Results - Maximum Annual Average SO_2 Impacts

Revised May 2001

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact ($\mu g/m^3$)	0.402	0.325	0.261	**0.464**	0.290
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	40.2	32.5	26.1	**46.4**	29.0
Receptor UTM Easting (m)	566,553.1	566,553.1	566,553.1	**566,553.1**	566,553.1
Receptor UTM Northing (m)	3,036,276.3	3,036,276.3	3,036,276.3	**3,036,276.3**	3,036,276.3
Distance From CT (m)	229	229	229	**229**	229
Direction From CT (Vector °)	273	273	273	**273**	273

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Table 7-5. ISCST3 Model Results - Maximum 3-Hour Average SO_2 Impacts

Revised May 2001

Maximum 3-Hour Impacts	1987	**1988**	1989	1990	1991
ISCST3 Impact ($\mu g/m^3$)	19.28	**26.61**	15.12	17.71	20.37
PSD Significant Impact ($\mu g/m^3$)	25.0	**25.0**	25.0	25.0	25.0
Exceed PSD Significant Impact (Y/N)	N	**Y**	N	N	N
Percent of PSD Significant Impact (%)	77.1	**106.4**	60.5	70.8	81.5
Receptor UTM Easting (m)	566,553.1	**566,553.1**	566,553.1	566,553.1	566,553.1
Receptor UTM Northing (m)	3,036,276.3	**3,036,276.3**	3,036,276.3	3,036,276.3	3,036,276.3
Distance From CT (m)	229	**229**	229	229	229
Direction From CT (Vector °)	273	**273**	273	273	273
Date of Maximum Impact	11/16/87	**1/31/88**	1/25/89	12/27/87	12/20/91
Julian Date of Maximum Impact	320	**31**	25	361	354
Ending Hour of Maximum Impact	0900	**0300**	1500	0900	2100

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Maximum 24-Hour Impacts	**1987**	1988	1989	1990	1991
ISCST3 Impact (μg/m³)	**11.68**	6.22	5.28	5.31	5.76
PSD Significant Impact (μg/m³)	**5.0**	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	**Y**	Y	Y	Y	Y
Percent of PSD Significant Impact (%)	**233.6**	124.5	105.7	106.3	115.3
PSD *de minimis* Ambient Impact Threshold (μg/m³)	**13.0**	13.0	13.0	13.0	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	**N**	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	**89.9**	47.9	40.6	40.9	44.3
Receptor UTM Easting (m)	**566,553.1**	566,553.1	566,553.1	566,553.1	566,553.1
Receptor UTM Northing (m)	**3,036,276.3**	3,036,276.3	3,036,276.3	3,036,276.3	3,036,276.3
Distance From CT (m)	**229**	229	229	229	229
Direction From CT (Vector °)	**273**	273	273	273	273
Date of Maximum Impact	**11/16/87**	1/31/88	11/25/89	4/9/90	4/4/91
Julian Date of Maximum Impact	**320**	31	329	99	94

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Table 7-11. ISCST3 Model Results - High, Second Highest 3-Hour Average SO_2 Impacts; NAAQS Analysis

High, Second Highest 3-Hour Impacts	**1987**	1988	1989	1990	1991
All Source ISCST3 Impact ($\mu g/m^3$)	**81.0**	79.5	75.2	65.1	80.8
Background ($\mu g/m^3$)	**178.0**	178.0	178.0	178.0	178.0
Total Impact ($\mu g/m^3$)	**259.0**	257.5	253.2	243.1	258.8
NAAQS ($\mu g/m^3$)	**1,300.0**	1,300.0	1,300.0	1,300.0	1,300.0
Exceed NAAQS (Y/N)	**N**	N	N	N	N
Percent of NAAQS (%)	**19.9**	19.8	19.5	18.7	19.9
Receptor UTM Easting (m)	**566,653.1**	566,653.1	566,653.1	566,653.1	566,653.1
Receptor UTM Northing (m)	**3,036,276.3**	3,036,276.3	3,036,276.3	3,036,276.3	3,036,276.3
Distance From CT (m)	**129**	129	129	129	129
Direction From CT (Vector ^{o})	**275**	275	275	275	275
Date of Maximum Impact	**7/13/87**	4/16/88	5/11/89	7/30/90	7/12/91
Julian Date of Maximum Impact	**194**	107	131	211	193
Ending Hour of Maximum Impact	**1800**	1200	1200	1200	1200

Note: Maximum impact shown in bold.

Source: ECT, 2001.

Table 7-12. ISCST3 Model Results - High, Second Highest 24-Hour Average SO_2 Impacts; NAAQS Analysis

High, Second Highest 24-Hour Impacts	1987	1988	1989	1990	**1991**
All Source ISCST3 Impact (µg/m^3)	21.1	18.8	14.0	14.6	**29.9**
Background (µg/m^3)	34.0	34.0	34.0	34.0	**34.0**
Total Impact (µg/m^3)	55.1	52.8	48.0	48.6	**63.9**
NAAQS (µg/m^3)	260.0	260.0	260.0	260.0	**260.0**
Exceed NAAQS (Y/N)	N	N	N	N	**N**
Percent of NAAQS (%)	21.2	20.3	18.5	18.7	**24.6**
Receptor UTM Easting (m)	566,653.1	566,653.1	566,653.1	566,653.1	**566,653.1**
Receptor UTM Northing (m)	3,036,276.3	3,036,276.3	3,036,276.3	3,036,276.3	**3,036,276.3**
Distance From CT (m)	129	129	129	129	**129**
Direction From CT (Vector ^{o})	275	275	275	275	**275**
Date of Maximum Impact	8/14/87	1/10/88	12/22/89	8/4/90	**2/15/91**
Julian Date of Maximum Impact	226	10	356	216	**46**

Note: Maximum impact shown in bold.

Source: ECT, 2001.

Table 7-13. ISCST3 Model Results - High, Second Highest 3-Hour Average SO_2 Impacts; PSD Class II Analysis

High, Second Highest 3-Hour Impacts	**1987**	1988	1989	1990	1991
All Source ISCST3 Impact ($\mu g/m^3$)	**81.0**	79.5	75.2	65.1	80.8
PSD Class II Increment ($\mu g/m^3$)	**512.0**	512.0	512.0	512.0	512.0
Exceed PSD Class II Increment (Y/N)	**N**	N	N	N	N
Percent of PSD Class II Increment (%)	**15.8**	15.5	14.7	12.7	15.8
Receptor UTM Easting (m)	**566,653.1**	566,653.1	566,653.1	566,653.1	566,653.1
Receptor UTM Northing (m)	**566,653.1**	566,653.1	566,653.1	566,653.1	566,653.1
Distance From CT (m)	**2,469,612**	2,469,612	2,469,612	2,469,612	2,469,612
Direction From CT (Vector °)	**180**	180	180	180	180
Date of Maximum Impact	**7/13/87**	4/16/88	5/11/89	7/30/90	7/12/91
Julian Date of Maximum Impact	**194**	107	131	211	193
Ending Hour of Maximum Impact	**1800**	1200	1200	1200	1200

Note: Maximum impact shown in bold.

Source: ECT, 2001.

Table 7-14. ISCST3 Model Results - High, Second Highest 24-Hour Average SO_2 Impacts; PSD Class II Increment Analysis Revised May 2001

High, Second Highest 24-Hour Impacts	1987	1988	1989	1990	**1991**
All Source ISCST3 Impact ($\mu g/m^3$)	21.1	18.8	14.0	14.6	**29.9**
PSD Class II Increment ($\mu g/m^3$)	91.0	91.0	91.0	91.0	**91.0**
Exceed PSD Class II Increment (Y/N)	N	N	N	N	**N**
Percent of PSD Class II Increment (%)	23.2	20.7	15.4	16.0	**32.9**
Receptor UTM Easting (m)	566,653.1	566,653.1	566,653.1	566,653.1	**566,653.1**
Receptor UTM Northing (m)	3,036,276.3	3,036,276.3	3,036,276.3	3,036,276.3	**3,036,276.3**
Distance From CT (m)	129	129	129	129	**129**
Direction From CT (Vector °)	275	275	275	275	**275**
Date of Maximum Impact	8/14/87	1/10/88	12/22/89	8/4/90	**2/15/91**
Julian Date of Maximum Impact	226	10	356	216	**46**

Note: Maximum impact shown in bold.

Source: ECT, 2001.

APPENDIX C

EMISSION RATE CALCULATIONS

Table C-1. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
CTG Operating Scenarios - MHI 501F

Gas/Oil Case No.	Ambient Temperature (°F)	CTG Inlet Air Temperature (°F)	Load (%)	Steam Sales Mode	Annual Profile A (hr/yr)	Annual Profile B (hr/yr)	Inlet Air Chilling	Duct Burner Firing	Gas-Firing	Oil-Firing
	Winter									
SS 3/15	32.0	32.0	100	X					X	X
SS 1/13	32.0	32.0	100	X				X	X	X
SS 5/17	32.0	32.0	75	X					X	X
SS 9	32.0	32.0	50	X					X	
	ISO									
SS 4/16	59.0	45.0	100	X			X		X	X
SS 2/14	59.0	45.0	100	X	8,760 (G)	7,760 (G), 1,000 (O)	X	X	X	X
SS 6/18	59.0	59.0	75	X					X	X
SS 10	59.0	59.0	50	X					X	
	Annual Average									
SS 4/16	74.0	45.0	100	X			X		X	X
SS 2/14	74.0	45.0	100	X			X	X	X	X
SS 7/19	74.0	74.0	75	X					X	X
SS 11	74.0	74.0	50	X					X	
	Summer									
SS 4/16	95.0	45.0	100	X			X		X	X
SS 2/14	95.0	45.0	100	X			X	X	X	X
SS 8/20	95.0	95.0	75	X					X	X
SS 12	95.0	95.0	50	X					X	

Source: FPRP, 2001.

Table C-2B. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F CTG; Steam Sales; Hourly Emission Rates - Natural Gas-Firing

Temp. (°F)	Case No.	Load (%)	PM/PM$_{10}$[(a)] (lb/hr)	PM/PM$_{10}$[(a)] (g/sec)	SO_2[(b)] (lb/hr)	SO_2[(b)] (g/sec)	H_2SO_4[(c)] (lb/hr)	H_2SO_4[(c)] (g/sec)	Lead[(d)] (lb/hr)	Lead[(d)] (g/sec)
32	SS 3	100	14.0	1.76	10.9	1.37	2.0	0.25	0.0305	0.00384
	SS 1	100	17.0	2.14	13.0	1.64	2.4	0.30	0.0364	0.00458
	SS 5	75	11.0	1.39	8.7	1.09	1.6	0.20	0.0243	0.00306
	SS 9	50	11.0	1.39	6.5	0.82	1.2	0.15	0.0181	0.00228
59	SS 4	100	14.0	1.76	10.9	1.37	2.0	0.25	0.0305	0.00385
	SS 2	100	17.0	2.14	13.0	1.64	2.4	0.30	0.0364	0.00459
	SS 6	75	11.0	1.39	8.3	1.05	1.5	0.19	0.0233	0.00294
	SS 10	50	10.0	1.26	6.3	0.79	1.2	0.15	0.0176	0.00222
74	SS 4	100	14.0	1.76	10.9	1.37	2.0	0.25	0.0305	0.00385
	SS 2	100	17.0	2.14	13.0	1.64	2.4	0.30	0.0364	0.00459
	SS 7	75	11.0	1.39	8.1	1.01	1.5	0.19	0.0225	0.00284
	SS 11	50	10.0	1.26	6.1	0.77	1.1	0.14	0.0171	0.00216
95	SS 4	100	14.0	1.76	10.9	1.37	2.0	0.25	0.0305	0.00385
	SS 2	100	17.0	2.14	13.0	1.64	2.4	0.30	0.0364	0.00459
	SS 8	75	11.0	1.39	7.7	0.97	1.4	0.18	0.0215	0.00271
	SS 12	50	10.0	1.26	5.9	0.74	1.1	0.14	0.0165	0.00207
		Maximums	17.0	2.14	13.0	1.64	2.4	0.30	0.0364	0.00459

Temp. (°F)	Case No.	Load (%)	NO_x (ppmvd)[(e)]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[(e)]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[(e)(f)]	VOC (lb/hr)[(f)]	VOC (g/sec)
32	SS 3	100	3.5	20.0	2.52	3.5	13.5	1.70	2.2	3.7	0.46
	SS 1	100	3.5	23.0	2.90	3.5	14.4	1.82	2.2	5.5	0.69
	SS 5	75	3.5	16.0	2.02	3.5	9.2	1.16	2.2	3.7	0.46
	SS 9	50	3.5	11.0	1.39	10.6	20.0	2.52	22.3	24.0	3.02
59	SS 4	100	3.5	20.0	2.52	3.5	11.7	1.47	2.2	3.7	0.46
	SS 2	100	3.5	23.0	2.90	3.5	13.1	1.65	2.2	5.5	0.69
	SS 6	75	3.5	15.0	1.89	3.5	9.7	1.23	2.2	3.7	0.46
	SS 10	50	3.5	11.0	1.39	9.2	17.0	2.14	19.0	20.0	2.52
74	SS 4	100	3.5	20.0	2.52	3.5	11.7	1.47	2.2	3.7	0.46
	SS 2	100	3.5	23.0	2.90	3.5	13.1	1.65	2.2	5.5	0.69
	SS 7	75	3.5	15.0	1.89	3.5	9.7	1.23	2.2	3.7	0.46
	SS 11	50	3.5	10.0	1.26	9.2	17.0	2.14	18.9	19.0	2.39
95	SS 4	100	3.5	20.0	2.52	3.5	11.7	1.47	2.2	3.7	0.46
	SS 2	100	3.5	23.0	2.90	3.5	13.1	1.65	2.2	6.0	0.76
	SS 8	75	3.5	14.0	1.76	3.5	9.7	1.23	2.2	3.7	0.46
	SS 12	50	3.5	10.0	1.26	9.2	16.0	2.02	18.7	19.0	2.39
		Maximums	3.5	23.0	2.90	10.6	20.0	2.52	22.3	24.0	3.02

(a) As measured by EPA Reference Methods 5 or 17.
(b) Based on natural gas sulfur content of 2.0 gr/100 ft^3.
(c) Based on 8.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
(d) AP-42, EPA, May 1998 - Draft.
(e) Corrected to 15% O_2.
(f) Expressed as methane.

Sources: ECT, 2001.
FPRP, 2001.

Revised May 2001

Table C-2D. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F CTG; Steam Sales; Hourly Emission Rates - Distillate Fuel Oil-Firing

Temp. (^oF)	Case No.	Load (%)	PM/PM_{10} [a] (lb/hr)	PM/PM_{10} [a] (g/sec)	SO_2 [b] (lb/hr)	SO_2 [b] (g/sec)	H_2SO_4 [c] (lb/hr)	H_2SO_4 [c] (g/sec)	Lead [d] (lb/hr)	Lead [d] (g/sec)
32	SS 15	100	35.0	4.41	97.3	12.25	14.9	1.88	0.025	0.0032
	SS 13	100	42.5	5.36	99.4	12.52	15.2	1.92	0.025	0.0032
	SS 17	75	27.5	3.47	78.1	9.84	12.0	1.51	0.020	0.0026
59	SS 16	100	35.0	4.41	94.2	11.87	14.4	1.82	0.025	0.0031
	SS 14	100	42.5	5.36	96.3	12.14	14.7	1.86	0.025	0.0031
	SS 18	75	27.5	3.47	73.4	9.25	11.2	1.42	0.019	0.0024
74	SS 16	100	35.0	4.41	94.2	11.87	14.4	1.82	0.025	0.0031
	SS 14	100	42.5	5.36	96.3	12.14	14.7	1.86	0.025	0.0031
	SS 19	75	27.5	3.47	71.0	8.95	10.9	1.37	0.019	0.0023
95	SS 16	100	35.0	4.41	94.2	11.87	14.4	1.82	0.025	0.0031
	SS 14	100	42.5	5.36	96.3	12.14	14.7	1.86	0.025	0.0031
	SS 20	75	27.5	3.47	67.8	8.54	10.4	1.31	0.018	0.0022
		Maximums	42.5	5.36	99.4	12.52	15.2	1.92	0.025	0.0032

Temp. (^oF)	Case No.	Load (%)	NO_x (ppmvd) [e]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [e]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd) [e][f]	VOC (lb/hr) [f]	VOC (g/sec)
32	SS 15	100	12.0	66.0	8.32	10.0	32.8	4.13	10.0	19.3	2.43
	SS 13	100	12.0	78.0	9.83	10.0	39.7	5.00	10.0	22.0	2.77
	SS 17	75	12.0	53.0	6.68	10.0	26.2	3.30	10.0	14.9	1.88
59	SS 16	100	12.0	64.0	8.06	10.0	32.8	4.13	10.0	18.4	2.32
	SS 14	100	12.0	75.0	9.45	10.0	37.9	4.78	10.0	22.2	2.80
	SS 18	75	12.0	50.0	6.30	10.0	24.6	3.10	10.0	14.9	1.88
74	SS 16	100	12.0	64.0	8.06	10.0	32.8	4.13	10.0	18.4	2.32
	SS 14	100	12.0	75.0	9.45	10.0	37.9	4.78	10.0	22.2	2.80
	SS 19	75	12.0	49.0	6.17	10.0	25.0	3.15	10.0	13.8	1.74
95	SS 16	100	12.0	64.0	8.06	10.0	32.8	4.13	10.0	18.4	2.32
	SS 14	100	12.0	75.0	9.45	10.0	37.9	4.78	10.0	22.2	2.80
	SS 20	75	12.0	47.0	5.92	10.0	23.3	2.94	10.0	14.0	1.76
		Maximums	12.0	78.0	9.83	10.0	39.7	5.00	10.0	22.2	2.80

(a) As measured by EPA Reference Methods 5 or 17.
(b) Based on distillate fuel oil sulfur content of 0.05-percent by weight.
(c) Based on 6.0% conversion of fuel S to SO_3 (CT), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
(d) Table 3.1-5., AP-42, EPA, April 2000.
(e) Corrected to 15% O_2.
(f) Expressed as methane.

Sources: ECT, 2001.
FPRP, 2001.

Table C-3A4. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F CTG; Hazardous Air Pollutants - Annual Profile B, Natural Gas

Parameter	Units	Case		
		SC 4	SS 2	
Maximum Hourly Fuel Flow:	10^6 Btu/hr (HHV)	0.0	1,999.2	
Maximum Annual Hours:	hrs/yr	0	7,760	

Pollutant	Emission Factor [(a)(b)] ($lb/10^6$ Btu)	Emission Rates			
		SC 4 (lb/hr)	SS 2 (lb/hr)		Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.00000	0.00012		0.00047
Acetaldehyde	4.31E-05	0.000	0.086		0.33
Acrolein	5.60E-06	0.000	0.011		0.043
Arsenic	N/A	N/A	N/A		N/A
Benzene	1.83E-05	0.000	0.037		0.14
Beryllium	N/A	N/A	N/A		N/A
Cadmium	N/A	N/A	N/A		N/A
Chromium	N/A	N/A	N/A		N/A
Ethylbenzene	2.28E-05	0.000	0.046		0.18
Formaldehyde	1.14E-04	0.000	0.228		0.88
Lead	1.69E-05	0.000	0.034		0.13
Manganese	N/A	N/A	N/A		N/A
Mercury	7.80E-10	0.0000000	0.0000016		0.0000061
Naphthalene	6.33E-07	0.0000	0.0013		0.0049
Nickel	N/A	N/A	N/A		N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.00000	0.00094		0.0037
Propylene Oxide	2.86E-05	0.000	0.057		0.222
Selenium	N/A	N/A	N/A		N/A
Toluene	6.80E-05	0.000	0.136		0.53
Xylene	6.51E-05	0.000	0.130		0.50
Maximum Individual HAP		0.000	0.228		0.884
Total HAPs		0.000	0.767		2.975

[(a)] - Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
[(b)] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Source: ECT, 2001.

Table C-3A6. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F CTG; Hazardous Air Pollutants - Annual Profile B, Oil

Parameter	Units	Case		
		SC 16	SS 14	
Maximum Hourly Fuel Flow:	10^6 Btu/hr (HHV)	0.0	1,764.0	
Maximum Annual Hours:	hrs/yr	0	1,000	

Pollutant	Emission Factor [(a)] (lb/10^6 Btu)	Emission Rates			
		SC 16 (lb/hr)	SS 14 (lb/hr)		Annual (ton/yr)
1,3-Butadiene	1.60E-05	0.000	0.028		0.014
Acetaldehyde	N/A	N/A	N/A		N/A
Acrolein	N/A	N/A	N/A		N/A
Arsenic	1.10E-05	0.000	0.019		0.010
Benzene	5.50E-05	0.000	0.097		0.049
Beryllium	3.10E-07	0.00000	0.00055		0.00027
Cadmium	4.80E-06	0.000	0.008		0.0042
Chromium	1.10E-05	0.000	0.019		0.010
Ethylbenzene	N/A	N/A	N/A		N/A
Formaldehyde	2.80E-04	0.000	0.494		0.25
Lead	1.40E-05	0.000	0.025		0.012
Manganese	7.90E-04	0.000	1.394		0.70
Mercury	1.20E-06	0.0000	0.0021		0.0011
Naphthalene	3.50E-05	0.000	0.062		0.031
Nickel	4.60E-06	0.0000	0.0081		0.0041
Polycyclic Aromatic Hydrocarbons	4.00E-05	0.000	0.071		0.035
Propylene Oxide	N/A	N/A	N/A		N/A
Selenium	2.50E-05	0.000	0.044		0.022
Toluene	N/A	N/A	N/A		N/A
Xylene	N/A	N/A	N/A		N/A
Maximum Individual HAP		0.000	1.394		0.697
Total HAPs		0.000	2.272		1.136

[(a)] - Tables 3.1-4. and 3.1-5, EPA AP-42, April 2000.

Source: ECT, 2001.

Table C-3A7. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
Profile B - Annual Hazardous Air Pollutants Emission Rates

Pollutant	CTG Emissions (ton/yr)
1,3-Butadiene	0.015
Acetaldehyde	0.33
Acrolein	0.043
Arsenic	0.010
Benzene	0.19
Beryllium	0.00029
Cadmium	0.0060
Chromium	0.012
Dichlorobenzene	0.0019
Ethylbenzene	0.18
Formaldehyde	1.25
Hexane	2.89
Lead	0.14
Manganese	0.70
Mercury	0.0015
Naphthalene	0.037
Nickel	0.0074
Polycyclic Aromatic Hydrocarbons	0.039
Propylene Oxide	0.22
Selenium	0.022
Toluene	0.53
Xylene	0.50
Maximum Individual HAP	2.890
Total HAPs	7.143

Source: ECT, 2001.

Table C-3A8. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project Annual Hazardous Air Pollutants Emission Rates Summary

Pollutant	Profile A (ton/yr)	Profile B (ton/yr)	Maximum (ton/yr)
1,3-Butadiene	0.00053	0.015	0.015
Acetaldehyde	0.38	0.33	0.38
Acrolein	0.049	0.043	0.049
Arsenic	0.00032	0.010	0.010
Benzene	0.16	0.19	0.19
Beryllium	0.000019	0.00029	0.00029
Cadmium	0.0018	0.0060	0.0060
Chromium	0.0022	0.012	0.012
Dichlorobenzene	0.0019	0.0019	0.0019
Ethylbenzene	0.20	0.18	0.20
Formaldehyde	1.12	1.25	1.25
Hexane	2.89	2.89	2.89
Lead	0.15	0.14	0.15
Manganese	0.00061	0.70	0.70
Mercury	0.00042	0.0015	0.0015
Naphthalene	0.0065	0.037	0.037
Nickel	0.0034	0.0074	0.0074
Polycyclic Aromatic Hydrocarbons	0.0043	0.039	0.039
Propylene Oxide	0.25	0.22	0.250
Selenium	0.000039	0.022	0.022
Toluene	0.60	0.53	0.60
Xylene	0.57	0.50	0.57
Maximum Individual HAP	2.890	2.890	2.890
Total HAPs	6.390	7.143	7.381

Source: ECT, 2001.

Table C-4A1. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project MHI 501F CTG/HRSG Annual Emission Rates - Profile A Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case No.	Fuel Type	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG	SS 2	Natural Gas	8,760	23.0	100.7	13.1	57.5	5.5	24.1
		Totals	**8,760**	**N/A**	**100.7**	**N/A**	**57.5**	**N/A**	**24.1**

Source	Case No.	Fuel Type	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG	SS 2	Natural Gas	8,760	17.0	74.5	13.0	56.9	0.036	0.16	2.4	10.5
		Totals	**8,760**	**N/A**	**74.5**	**N/A**	**56.9**	**N/A**	**0.16**	**N/A**	**10.46**

Sources: ECT, 2001.
FPRP, 2001.

Table C-4A2. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F CTG Annual Emission Rates - Profile B
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case No.	Fuel Type	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG	SC 4	Natural Gas	0	173.0	0.0	42.0	0.0	8.4	0.0
CTG	SC 16	Distillate Oil	0	272.0	0.0	197.0	0.0	34.0	0.0
CTG/HRSG	SS 2	Natural Gas	7,760	23.0	89.2	13.1	50.9	5.5	21.3
CTG/HRSG	SS 14	Distillate Oil	1,000	75.0	37.5	37.9	19.0	22.2	11.1
		Totals	**8,760**	**N/A**	**126.7**	**N/A**	**69.9**	**N/A**	**32.5**

Source	Case No.	Fuel Type	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG	SC 4	Natural Gas	0	14.0	0.0	10.9	0.0	0.031	0.00	1.3	0.0
CTG	SC 16	Distillate Oil	0	35.0	0.0	94.5	0.0	0.025	0.00	8.7	0.0
CTG/HRSG	SS 2	Natural Gas	7,760	17.0	66.0	13.0	50.4	0.036	0.14	2.4	9.3
CTG/HRSG	SS 14	Distillate Oil	1,000	42.5	21.3	96.3	48.2	0.025	0.01	14.7	7.4
		Totals	**8,760**	**N/A**	**87.2**	**N/A**	**98.6**	**N/A**	**0.15**	**N/A**	**16.6**

Sources: ECT, 2001.
FPRP, 2001.

Table C-4A3. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project
MHI 501F Annual Emission Rate Summary
Criteria Air Pollutants and Sulfuric Acid Mist

Annual Profile	Annual Emissions (ton/yr)						
	NO_x	CO	VOC	PM/PM_{10}	SO_2	Pb	H_2SO_4
A	100.7	57.5	24.1	74.5	56.9	0.16	10.5
B	126.7	69.9	32.5	87.2	98.6	0.15	16.6
Maximums	126.7	69.9	32.5	87.2	98.6	0.16	16.6

Sources: ECT, 2001.
FPRP, 2001.

Table C-7B. Ft. Pierce Utilities Authority H.D. King Plant Repowering Project Fuel Flow Data - MHI 501 F CTG; Steam Sales

A. Natural Gas-Firing

	100 % Load								75 % Load			
	32 °F	32 °F	59 °F	59 °F	74 °F	74 °F	95 °F	95 °F	32 °F	59 °F	74 °F	95 °F
Case	SS 3	SS 1	SS 4	SS 2	SS 4	SS 2	SS 4	SS 2	SS 5	SS 6	SS 7	SS 8
Heat Input - LHV[1] (MMBtu/hr)	1,802.9	1,802.9	1,803.8	1,803.8	1,803.8	1,803.8	1,803.8	1,803.8	1,433.4	1,379.4	1,332.0	1,271.4
Heat Input - HHV[2] (MMBtu/hr)	1,998.2	1,998.2	1,999.2	1,999.2	1,999.2	1,999.2	1,999.2	1,999.2	1,588.7	1,528.8	1,476.3	1,409.1
Fuel Rate[3] (lb/hr)	86,285	86,285	86,330	86,330	86,330	86,330	86,330	86,330	68,602	66,017	63,750	60,848
Fuel Rate[4] (10^6 ft^3/hr)	1.907	1.907	1.908	1.908	1.908	1.908	1.908	1.908	1.516	1.459	1.409	1.345
Fuel Rate (lb/sec)	23.968	23.968	23.981	23.981	23.981	23.981	23.981	23.981	19.056	18.338	17.708	16.902

B. Distillate Fuel Oil-Firing

	100 % Load								75 % Load			
	32 °F	32 °F	59 °F	59 °F	74 °F	74 °F	95 °F	95 °F	32 °F	59 °F	74 °F	95 °F
Case	SS 15	SS 13	SS 16	SS 14	SS 16	SS 14	SS 16	SS 14	SS 17	SS 18	SS 19	SS 20
Heat Input - LHV[2] (MMBtu/hr)	1,698.2	1,698.2	1,645.3	1,645.3	1,645.3	1,645.3	1,645.3	1,645.3	1,364.2	1,281.9	1,239.8	1,183.0
Heat Input - HHV[5] (MMBtu/hr)	1,820.7	1,820.7	1,764.0	1,764.0	1,764.0	1,764.0	1,764.0	1,764.0	1,462.7	1,374.5	1,329.3	1,268.4
Fuel Rate[6] (lb/hr)	97,260	97,260	94,231	94,231	94,231	94,231	94,231	94,231	78,133	73,421	71,010	67,756
Fuel Rate[7] (10^3 gal/hr)	13.508	13.508	13.088	13.088	13.088	13.088	13.088	13.088	10.852	10.197	9.862	9.411
Fuel Rate (lb/sec)	27.017	27.017	26.175	26.175	26.175	26.175	26.175	26.175	21.704	20.395	19.725	18.821

[1] Natural gas HHV/LHV ratio of 1.10830.
[2] Includes 5% margin.
[3] Natural gas heat content of 23,158 Btu/lb (HHV).
[4] Natural gas density of 0.0452 lb/ft^3.
[5] Distillate fuel oil HHV/LHV ratio of 1.07216.
[6] Distillate fuel oil heat content of 18,720 Btu/lb (HHV).
[7] Distillate fuel oil density of 7.20 lb/gal.

Sources: ECT, 2001.
FPRP, 2001.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 8, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Project No. 1110100-001-AC
Draft Air Permit No. PSD-FL-302
Duke Energy Fort Pierce, LLC
Correction to Location Description

Dear Mr. Gilliland:

Enclosed is one copy of the corrected Public Notice document for Duke Energy's project to construct a new 640 MW electrical generating plant located in St. Lucie County, Florida. Your engineering consultant indicated that the description of the project location in the application was in error. The correct description is "located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road". This is noted for the Department's public file and corrected in the attached Public Notice. In addition, the text "average of" was inserted to clarify that oil firing is limited to *an average of* 500 hours per gas turbine per year.

If you have any, please contact Jeff Koerner at 850/921-9536.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, Project Engineer
New Source Review Section

AAl/jfk

Enclosures

Mr. Steven F. Gilliland, Duke Energy
Mr. Nathan K. Plagens, Duke Energy
Mr. George Howroyd, CH2MHILL
Chair, St. Lucie Board of County Commissioners
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 1110100-001-AC
Draft Permit PSD-FL-302

Duke Energy Fort Pierce, LLC
Proposed 640 MW Simple Cycle Gas Turbine Plant
Emissions Units 001 - 009

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Duke Energy Fort Pierce, LLC to construct a nominal 640 MW simple cycle gas turbine plant. The proposed plant will be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The applicant plans to install eight new simple cycle gas turbine-electrical generator sets with inlet air fogging systems and necessary support equipment. Each unit is a General Electric Model PG7121(EA) gas turbine with a nominal generating capacity of 80 MW. The applicant's authorized representative is Mr. Steven F. Gilliland, Senior Vice President of Duke Energy North America. The applicant's mailing address is 5400 Westheimer Court, Houston, TX 77056-5310.

Each simple cycle gas turbine will be fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Operation is restricted to an average of 2500 hours per gas turbine per year with no more than an average of 500 hours of oil firing per gas turbine per year. When firing natural gas, nitrogen oxide emissions will be minimized with dry low-NOx combustion technology. When firing very low sulfur distillate oil, nitrogen oxide emissions will be minimized with wet injection and restricted operation. Emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of these clean fuels.

The potential emissions from this project are shown in the following table.

Pollutant	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	540	100	Yes	Yes
NOx	632	40	Yes	Yes
PM/PM_{10}	60	25/15	Yes	Yes
SAM	17	7	Yes	Yes
SO_2	147	40	Yes	Yes
VOC	29	40	No	No

As indicated, a determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

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

Florida Department of Environmental Protection
Bureau of Air Regulation
(111 S. Magnolia Drive, Suite 4)
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Florida Department of Environmental Protection
Southeast District Office – Air Resources
(400 North Congress Avenue)
P.O. Box 15425
West Palm Beach, Florida 33401
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Trevor Woodruff

B. Date of Delivery 5/4/01

C. Signature
X Trevor Woodruff ☐ Agent ☐ Addressee

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 *(Copy from service label)*
7099 3400 0000 1453 1996

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 1996

Article Sent To:

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

Postmark Here

Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Steven F. Gilliland
Street, Apt. No.; or PO Box No.
5400 Westheimer Ct.
City, State, ZIP+4
Houston, TX 77056-5310

PS Form 3800, July 1999 See Reverse for Instructions

DRAFT PERMIT

PERMITTEE:

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative:
Mr. Steven F. Gilliland, Senior Vice President

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Air Permit No. PSD-FL-302
Facility ID No. 1110100
SIC No. 4911
Expires: December 1, 2002

PROJECT AND LOCATION

This permit authorizes the construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The plant will consist of eight simple cycle gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. The UTM coordinates are Zone 17, 561.6 km East, and 3029.0 km North.

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.) and 40 CFR 52.21. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A	-	Terminology
Appendix BD	-	BACT Determinations and Emissions Standards Summary
Appendix GC	-	General Conditions
Appendix GG	-	NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	-	CEMS Excess Emissions and Data Exclusion Report

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The new 640 MW electrical generating plant will consist of eight new 80 MW simple cycle gas turbine-electrical generator sets, evaporative inlet air foggers, continuous monitoring equipment, exhaust stacks, and associated support equipment.

NEW EMISSIONS UNITS

This permit authorizes construction of the following new emissions units.

ID No.	Common Emission Unit Description
001 to 008	**Simple Cycle Unit Nos. 1 - 8**: Each simple cycle unit is a General Electric Model PG7121(EA) gas turbine-electrical generator set designed to produce a nominal 80 MW of electrical power fired primarily with natural gas and with very low sulfur distillate oil as a backup fuel.
009	**Distillate Oil Storage Tanks**

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new facility is subject to the acid rain provisions of the Clean Air Act.

Title V: The new facility is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year. 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: Emissions of at least one regulated pollutant from the new facility will be greater than 250 tons per year. The project is located in an area designated as in attainment or unclassifiable for each pollutant subject to a National Ambient Air Quality Standard. Therefore, the project is subject to new source preconstruction review in accordance with Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: New units subject to the New Source Performance Standards of 40 CFR 60 include the gas turbines (Subpart GG) and the fuel storage tanks (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 10/05/00 and all related correspondence.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authorities: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, P.O. Box 15425, West Palm Beach, Florida 33401. The phone number is 561/681-6600 and the fax number is 561/681-6790.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. Appendix A lists frequently used abbreviations and explains the format used to cite rules and regulations in this permit.

4. General Conditions: The permittee is subject to, and 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.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, 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.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if 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. [40 CFR 52.21(r)(2)]

7. Permit Expiration: 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, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

9. 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.]

10. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. 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 Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. 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 ninety 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, and copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, F.A.C. and Chapter 62-213, F.A.C.]

EMISSIONS AND CONTROLS

13. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]
14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

TESTING REQUIREMENTS

17. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.
18. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]
19. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

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

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

20. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C.; 40 CFR 60.7 and 60.8]

21. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

22. Determination of Process Variables

a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

RECORDS AND REPORTS

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

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

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

This section of the permit addresses the following new emissions units.

Emissions Unit ID Nos. 001 – 008: Simple Cycle Unit Nos. 1 - 8
Each simple cycle unit consists of a General Electric Model PG7121(EA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 93 feet tall and 15 feet in diameter, and associated support equipment. Each unit is fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology when firing natural gas and wet injection when firing distillate oil. The automated gas turbine control system modulates critical parameters of the dry low-NOx combustors to achieve a lean, pre-mix steady state operation. At a compressor inlet air temperature of 59° F, operating at 100% load, and firing 977 mmBTU (HHV) per hour of natural gas, each unit produces approximately 84 MW. Exhaust gases exit the stack at 970° F with a volumetric flow rate of approximately 1,570,000 acfm. At a compressor inlet air temperature of 59° F, operating at 100% load, and firing 1007 mmBTU (HHV) per hour of distillate oil, each unit produces approximately 87 MW. Exhaust gases exit the stack at 994° F with a volumetric flow rate of approximately 1,604,000 acfm.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2). See Appendix BD for the BACT determinations and a summary of the emissions standards. [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: Each gas turbine shall comply with the following applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A, General Provisions*, including: 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements).

   b. *Subpart GG, Standards of Performance for Stationary Gas Turbines* as specified in Appendix GG of this permit.

EQUIPMENT

3. Simple Cycle Gas Turbines: The permittee is authorized to install, tune, operate and maintain eight new General Electric Model PG7121(EA) gas turbines with electrical generator sets. Each unit shall be designed and installed as a simple cycle system to include an automated gas turbine control system, General Electric's latest dry low-NOx combustion system, an inlet air filtration system, a compressor inlet air evaporative cooling system, a single exhaust stack that is 93 feet tall and 15.0 feet in diameter, and associated support equipment. Prior to the initial emissions performance tests, each gas turbine and control system shall be tuned to optimize the reduction of NOx emissions. Thereafter, each unit shall be maintained and tuned in accordance with the manufacturer's recommendations. The permittee shall provide at least 7 days advance notice prior to any regularly scheduled tuning performed by the manufacturer. [Applicant Request; Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Permitted Capacity: The maximum heat input rates to each gas turbine shall not exceed 977 mmBTU per hour when firing natural gas and 1007 mmBTU per hour when firing distillate oil. The maximum heat-input rates are based on 100% load, a compressor inlet air temperature of 59° F, and the higher heating values (HHV) of each fuel. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, and evaporative cooling. The permittee shall provide the 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. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Fuel Specifications: Each gas turbine shall fire pipeline-quality natural gas as the primary fuel with a maximum of 2 grains of sulfur per 100 SCF of natural gas. As restricted by this permit, No. 2 distillate oil (or a superior grade) may be fired as backup fuel with a maximum of 0.05% sulfur by weight. [Project Design; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

6. Restricted Operation: No individual gas turbine shall operate more than 5000 hours during any consecutive 12-month period. All eight gas turbines (combined) shall not operate more than an average of 2500 hours per installed unit during any consecutive 12-month period. No individual gas turbine shall fire distillate oil for more than 12 hours during any calendar day. No individual gas turbine shall fire distillate oil for more than 1000 hours during any consecutive 12-month period. All eight gas turbines (combined) shall not fire distillate oil for more than an average of 500 hours per installed unit during any consecutive 12-month period. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

7. Simple Cycle Operation Only: Each gas turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the justification for the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to restricted operation. Future conversion of any unit to combined cycle operation or a relaxation in the hours of operation will invoke the source obligation requirements of Rule 62-212.400(2)(g), F.A.C. Such requests will be reviewed as if the simple cycle units had never been constructed with a new determination of the Best Available Control Technology for each significant pollutant. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the simple cycle gas turbines and pollution control systems in accordance with the guidelines and procedures established by the 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.]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to each simple cycle gas turbine. The mass emission limits are based a compressor inlet temperature of 59° F and 100% load. For comparison to the standard, actual measured mass emissions shall be corrected to this compressor inlet temperature with manufacturer's data on file with the Department. Emissions standards with continuous monitoring requirements apply at all loads. Appendix BD provides a summary of the emissions standards of this permit.}

9. Carbon Monoxide (CO)

   a. *First 12 Months*: When firing natural gas, CO emissions from each gas turbine shall not exceed 52.0 pounds per hour nor 25.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, CO emissions from each gas turbine shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 10 and apply during the initial performance tests and during the 12 month period following the initial performance tests.

   b. *After First 12 Months*: When firing natural gas or low sulfur distillate oil, CO emissions from each gas turbine shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen, as determined by EPA Method 10. These standards are based on 3-hour test averages conducted at base load and apply after the 12 month period following the initial performance tests.

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

10. Nitrogen Oxides (NOx)

    a. *Initial Performance Test*: When firing natural gas, NOx emissions from each gas turbine (new and clean) shall not exceed 32.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions from each gas turbine shall not exceed 167.0 pounds per hour nor 42.0 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 7E or 20 and apply during the initial performance tests.

    b. *CEMS*: When firing natural gas, NOx emissions shall not exceed 10.5 ppmvd corrected to 15% oxygen based on a 3-hour rolling average. When firing low sulfur distillate oil, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average. These standards are based on valid data collected from the certified NOx CEMS and apply at all times.

    NOx emissions are defined as oxides of nitrogen expressed as NO_2. [Rule 62-212.400(BACT), F.A.C.]

11. Particulate Matter (PM/PM_{10}): The efficient combustion of clean fuels represents the Best Available Control Technology (BACT) for particulate matter emissions from each gas turbine. Compliance with the fuel specifications and the CO emissions standards of this section shall serve as indicators of good combustion. The following visible emissions limit is established as a work-practice standard for particulate matter emissions. Visible emissions from each gas turbine shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. {Permitting Note: As determined by EPA Method 5 (front-half catch only), particulate matter emissions from each unit are expected to be less than 5/10 pounds per hour when firing natural gas/low sulfur distillate oil.} [Rule 62-212.400(BACT), F.A.C.]

12. Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2): The fuel specifications of Condition No. 5 in this section represent the Best Available Control Technology (BACT) for SAM and SO_2 emissions from each gas turbine and effectively limit potential emissions. Compliance with the fuel specifications shall be determined by Condition No. 21 of this section. [Rules 62-204.800(7) and 62-212.400(BACT), F.A.C.]

13. Volatile Organic Compounds (VOC)

    a. *Initial Performance Test*: When firing natural gas, VOC emissions from each gas turbine shall not exceed 2.5 pounds per hour nor 2.0 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, VOC emissions from each gas turbine shall not exceed 4.5 pounds per hour nor 3.5 ppmvd corrected to 15% oxygen. These standards are based on 3-hour test averages conducted at base load as determined by EPA Method 25A. Optionally, EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. VOC emissions shall be expressed in terms of methane. [Design; Rule 62-4.070, F.A.C.; To Avoid Rule 62-212.400(BACT), F.A.C.]

b. *After Initial Performance Test*: The efficient combustion design, use of clean fuels, and good operating practices minimize VOC emissions from each gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. After the initial performance tests, subsequent tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C. [Design; Rule 62-4.070, F.A.C.]

EXCESS EMISSIONS

14. 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 emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

15. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

    a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

    b. Except for startup and shutdown, operation below 50% base load is prohibited.

    c. In accordance with Condition No. 20 of this section, certain data collected by each CEMS during startup, shutdown, malfunction, and tuning may be excluded from the NOx compliance averaging periods. If a CEMS reports emissions in excess of a 3-hour rolling average emissions standard, the permittee shall notify the Compliance Authority within one (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    [Design; Rules 62-210.700, 62-4.130, and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

16. Initial Tests Required: Each gas turbine shall be tested initially for each fuel to demonstrate compliance with the emission standards for CO, NOx, VOC and visible emissions. The initial tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later than 180 days after initial operation of each unit. Tests for CO and VOC emissions shall be conducted concurrently. Valid NOx emissions data collected by the certified CEMS during each CO test run shall be included in the test report. [Rules 62-297.310(7)(a)1. and 62-212.400(BACT), F.A.C.]

17. Continuous Compliance: Each gas turbine shall demonstrate continuous compliance with the 3-hour rolling average NOx emissions standards as determined by valid data collected from the certified CEMS specified in Condition No. 20 of this section. [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Performance Tests: Each gas turbine shall be tested annually to demonstrate compliance with the emission standards for CO and visible emissions. Annual tests shall be conducted at least once during each federal fiscal year (October 1st to September 30th). Valid NOx emissions data collected by the certified CEMS during each CO test run shall be included in the test report. If less than 400 hours of oil is fired in a gas turbine during a federal fiscal year, the annual CO test is waived. [Rule 62-297.310(7)(a)4., F.A.C.]

19. Test Methods: As required, tests shall be performed in accordance with the following reference methods.

EPA Method	Description of Method and Comments
5	Determination of Particulate Matter Emissions from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • The method shall be based on a continuous sampling train. • The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography • Optionally, 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 Volatile Organic Concentrations

The above reference methods are specified in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used to demonstrate compliance unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

CONTINUOUS MONITORING REQUIREMENTS

20. NOx CEMS: The permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the emissions of NOx from each gas turbine in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit. The oxygen content or the carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where NOx is monitored to correct the measured NOx emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards for NOx specified in this permit.

a. *Data Collection.* Compliance with the CEMS emission standards for NOx shall be based on a 3-hour rolling average. The 3-hour rolling average shall be calculated from three successive hourly average emission rate values. Each hourly 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). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour. 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). Final results of the CEMS shall be expressed as "ppmvd corrected to 15% oxygen". Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of Subpart GG in 40 CFR 60.

b. *Data Exclusion.* Data for NOx emissions and oxygen (or CO_2) content shall be recorded by the CEMS during all episodes of startup, shutdown and malfunction. Individual hourly NOx emission rate values recorded during these episodes may be excluded from the continuous NOx compliance determination. No more than three (3) hourly average emission rate values shall be excluded in any 24-hour block period due to all gas turbine startups, shutdowns, and documented unavoidable malfunctions. If an hourly average emission rate value is excluded, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour average. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

   The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

c. *NOx Monitor Certification.* The NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the CEM emission standards of this permit, missing data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour average. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The monitor shall be a dual range monitor with a lower span no greater than 30 ppm and an upper span no greater than 125 ppm.

d. *Oxygen (or CO_2) Monitor Certification.* The oxygen (or CO_2) monitor shall be certified and operated in accordance with 40 CFR 60, Appendix B, Performance Specification 3. 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 quarterly to each Compliance Authority. The RATA tests required for the oxygen (or CO_2) monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the 3-hour average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEMS during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than quarterly, including quarterly periods in which no data is excluded or no instances of missing data occur.

f. *Availability*. NOx monitor availability shall not be less than 95% in any calendar quarter. The report required in Appendix XS 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.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEMS 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 Part 51, Appendix P; 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.]

RECORDS

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

a. *Natural Gas*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the 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 the most recent versions.

b. *Distillate Oil*: Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling and analyzing 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 distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the vendor. 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.]

22. Monitoring of Operations: To demonstrate compliance with the capacity requirements, the permittee shall monitor and record the operating rate of each simple cycle gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEMS required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

23. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following information in a written or electronic log.

- Hours of operation for each gas turbine for the previous month and 12 months of operation;
- Average hours operation per installed gas turbine for the previous 12 months of operation;
- Hours of distillate oil firing for each gas turbine for the previous month and 12 months of operation;
- Average hours of distillate oil firing per installed gas turbine for the previous 12 months of operation;
- For any gas turbine firing distillate oil for more than 12 hours in a calendar day, indicate the date and hours of oil firing;

Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request from the Department or a Compliance Authority. [Rules 62-4.160(15) and 62-4.070(3), F.A.C.]

REPORTS

24. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and NOx monitor availability for the previous calendar quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. DISTILLATE OIL STORAGE TANKS

This section of the permit addresses the following emissions unit.

Emissions Unit No. 009: Distillate Oil Storage Tanks
Four storage tanks supply low sulfur distillate oil as a backup fuel to the gas turbines.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE REQUIREMENTS

3. Equipment: The distillate oil tanks shall provide storage for the very low sulfur distillate oil used as backup fuel for the gas turbines. [Applicant Request]

4. Hours of Operation: Operation of the distillate oil storage tank is not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

RECORDS

5. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual throughput of distillate oil through each storage tank. [Rule 62-210.370(3), F.A.C.]

6. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the tank. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

TERMINOLOGY

Abbreviations and Acronyms

CEM	-	Continuous Emissions Monitor
CT	-	Combustion Turbine
DARM	-	Division of Air Resource Management
DEP	-	State of Florida, Department of Environmental Protection
DLN	-	Dry Low-NOx Combustion Technology
EPA	-	United States Environmental Protection Agency
°F	-	Degrees Fahrenheit
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
GT	-	Gas Turbine
HRSG	-	Heat Recovery Steam Generator
OC	-	Oxidation Catalyst Technology for CO Control
ppmvd	-	Parts per million by volume on a dry basis
SOA	-	Specific Operating Agreement
SCR	-	Selective Catalytic Reduction
UTM	-	Universal Transverse Mercator

Rule Citations

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

<u>Florida Administrative Code (F.A.C.)</u>:

Example:	[Rule 62-213.205, F.A.C.]		
Where:	62	-	identifies the specific Title of the F.A.C.
	62-213	-	identifies the specific Chapter of the F.A.C.
	62-213.205	-	identifies the specific Rule of the F.A.C.

<u>Facility Identification (ID) Number</u>:

Example:	Facility ID No. 099-0001		
Where:	099	-	identifies the specific county location
	0221	-	identifies the specific facility

<u>New Permit Numbers</u>:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV		
Where:	AC	-	identifies the permit as an Air Construction Permit
	AV	-	identifies the permit as a Title V Major Source Air Operation Permit
	099	-	identifies the specific county that project is located in
	2222	-	identifies the specific facility
	001	-	identifies the specific permit project

<u>Old Permit Numbers</u>:

Example:	Permit No. AC50-123456 or AO50-123456		
Where:	AC	-	identifies the permit as an Air Construction Permit
	AO	-	identifies the permit as an Air Operation Permit
	123456	-	identifies the specific permit project

BACT DETERMINATIONS AND EMISSIONS STANDARDS SUMMARY

The following tables summarize the final Best Available Control Technology determinations for this project and the corresponding emissions standards. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

Table B-1. EU-001 through 008: Eight 80 MW Simple Cycle Gas Turbines – Natural Gas Firing

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: Pipeline-quality natural gas with 2 grains of sulfur per 100 SCF of gas, max.	ASTM Methods D4084-82, D3246-81 or more recent versions with monthly vendor analysis.
CO	*BACT Control*: Efficient combustion design, good operating practices	Emissions Performance Tests
	BACT Standards, First Year: 25.0 ppmvd @ 15% oxygen (52.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for initial tests
	BACT Standards, Thereafter: 20.0 ppmvd @ 15% oxygen (43.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for annual tests
NOx	*BACT Control*: Dry low-NOx combustion design	Certified CEMS data.
	BACT Standard: 9.0 ppmvd @ 15% oxygen (32.0 lb/hour), 3-hour test avg.	EPA Method 7E (or 20) at base load for initial tests "new and clean"
	BACT Standard: 10.5 ppmvd @ 15% O_2, 3-hour rolling CEMS avg.	Certified CEM data for continuous compliance demonstration
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	EPA Method 9 for initial/annual tests
	Comment: Particulate matter emissions are expected to be less than 5.0 lb/hour.	EPA Method 5 (front-half catch only); no test required
SO_2	*BACT Control*: Fuel specifications (low sulfur)	See compliance methods for fuel specifications.
	BACT Standard: Potential SO_2 emissions are effectively limited by the fuel specifications.	See compliance methods for fuel specifications.
VOC	*Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	Standard: 2.0 ppmvd @ 15% oxygen (2.5 lb/hr), 3-hour test avg.	EPA Method 25A with emissions measured and reported as methane; (Optionally, EPA Method 18 may be conducted concurrently to deduct methane and ethane emissions.)
	Comment: *Total potential VOC emissions from all eight gas turbines are estimated to be 26 tons per year. The project is not subject to PSD for VOC emissions.*	

Note: Mass emissions standards are based on the following conditions: 100% load (approximately 83 MW), 977 mmBTU per hour of heat input (HHV) from firing natural gas, and a compressor inlet air temperature of 59° F.

Table B-2. EU-001 through 008: Eight 80 MW Simple Cycle Gas Turbines – Distillate Oil Firing

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: No. 2 Distillate oil with 0.05% sulfur by weight, maximum	ASTM D 2880-71 (equivalent) with vendor analysis
CO	*BACT Control*: Efficient combustion design, good operating practices	Emissions performance tests
	BACT Standards: 20.0 ppmvd @ 15% oxygen (43.0 lb/hour), 3-hour test avg.	EPA Method 10 at base load for annual tests
NOx	*BACT Control*: Dry low-NOx combustion design	Certified CEMS data.
	BACT Standard: 42.0 ppmvd @ 15% oxygen (167.0 lb/hour), 3-hour test avg.	EPA Method 7E (or 20) at base load for initial tests "new and clean"
	BACT Standard: 42.0 ppmvd @ 15% O_2, 3-hour rolling CEMS avg.	Certified CEM data for continuous compliance demonstration
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	EPA Method 9 for initial/annual tests
	Comment: Particulate matter emissions are expected to be less than 5.0 lb/hour.	EPA Method 5 (front-half catch only); no test required
SO_2	*BACT Control*: Fuel specifications (low sulfur)	See compliance methods for fuel specifications.
	BACT Standard: Potential SO_2 emissions are effectively limited by the fuel specifications.	See compliance methods for fuel specifications.
VOC	*Control*: Efficient combustion of clean fuels, good operating practices	Compliance with fuel specifications and CO standards
	Standard: 3.5 ppmvd @ 15% oxygen (4.5 lb/hr), 3-hour test avg.	EPA Method 25A with emissions measured and reported as methane; (Optionally, EPA Method 18 may be conducted concurrently to deduct methane and ethane emissions.)
	Comment: *Total potential VOC emissions from all eight gas turbines are estimated to be 31 tons per year. The project is not subject to PSD for VOC emissions.*	

Note: Mass emissions standards are based on the following conditions: 100% load (approximately 83 MW), 977 mmBTU per hour of heat input (HHV) from firing natural gas, and a compressor inlet air temperature of 59° F.

BACT DETERMINATIONS

As summarized in the previous table, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for carbon monoxide, particulate matter, nitrogen oxides, and sulfur dioxide. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

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

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

{Note: The new gas turbines are subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. 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 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.}

11. Pursuant to 40 CFR 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:

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

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 de-fined in paragraph (a)(3) of this section.

(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≤0.015	0
0.015<N≤0.1	0.04(N)
0.1<N≤0.25	0.004+0.0067(N–0.1)
N>0.25	0.005

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

Department requirement: "F" is zero because the fuel bound nitrogen content is negligible.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. Based on the manufacturer's heat rates (LHV) of 10,510 BTU/kW-hr and 10,960, the "Y" values are approximately 11.3 for natural gas and 11.7 for distillate oil, respectively. The equivalent emission standards are approximately 96 and 92 ppmvd at 15% oxygen, respectively. The standards of this permit are much 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.

12. Pursuant to 40 CFR 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:

(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.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

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

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

Department requirement: **Very low sulfur No. 2 distillate oil will be stored in four tanks. Compliance with the fuel sulfur limit may be satisfied by a certified fuel vendor analysis for each delivery. The requirement to monitor the nitrogen content of distillate oil is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit.**

(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 pipeline quality natural gas 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 permittee shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.**

[Note: This is consistent with the 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 § 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 § 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: **The NOx monitor availability threshold shall not be less than 95% in any calendar quarter. The report required in Appendix XS shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the owner or operator 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.**

[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.

14. Pursuant to 40 CFR 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 percent 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 permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee 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 permittee 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 permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system 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 the permit shall be used instead of that specified in paragraph (c)(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: The permit specifies sulfur testing methods and allows 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 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 the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

CEMS EXCESS EMISSIONS AND DATA EXCLUSION REPORT

Figure 1 – Quarterly Performance Summary Report
Gaseous Excess Emission and Monitoring System

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

Pollutant: Nitrogen Oxides (NOx)

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: _____________________________________

Date of Latest CMS Certification or Audit: ____________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: _________________________

Emission data summary [a]		CMS performance summary [a]	
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] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For gases, record all times in hours.

[b] 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 last quarter in CMS, process or controls.

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

____
(Company Name)

____
(Name and Title)

____ ____________________
(Signature) *(Date)*

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief, BAR

THROUGH: Al Linero, Administrator - New Source Review Section *aay 4/30*

FROM: Jeff Koerner, New Source Review Section *JK*

DATE: April 25, 2001

SUBJECT: Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC
New 640 MW Gas Turbine Peaking Plant, St. Lucie County
(Eight 80 MW Simple Cycle Gas Turbines)

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- PE Certification

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, and BACT determinations. The P.E. certification briefly summarizes the proposed project and BACT determinations. Note that this project is nearly identical to the recently issued draft for Duke's Lake County project except it allows low sulfur distillate oil as a backup fuel for up to 500 hours per year per gas turbine. Day #74 is May 11, 2001. I recommend your approval of the attached Draft Permit for this project.

CHF/AAL/jfk

Attachments

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

P.E. CERTIFICATION STATEMENT

PERMITTEE

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Draft Permit No. PSD-FL-302
SIC No. 4911

PROJECT DESCRIPTION

The applicant proposes construction of a new 640 MW electrical generating plant (Duke Energy Fort Pierce, LLC) to be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The plant will consist of eight gas turbine-electrical generator sets, each with a nominal generating capacity of 80 MW. The primary fuel will be pipeline-quality natural gas with very low sulfur distillate oil as a backup fuel. Operation of the simple cycle peaking plant is limited to an average of 2500 hours per gas turbine per year with no more than 500 hours of oil firing per gas turbine per year. The new plant is not subject to the requirements of the Power Plant Siting Act because it does not produce steam-generated electrical power.

Emissions from the proposed project exceed the PSD Significant Emission Rates for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2). The Department establishes the efficient combustion of natural gas and very low sulfur distillate oil as the Best Available Control Technology (BACT) for emissions of CO, PM/PM_{10}, and SO_2. This technique also reduces the emissions of volatile organic compounds (VOC) below the PSD Significant Emission Rate of 40 tons per year. For the firing of natural gas, the Department establishes the dry low-NOx combustion technology of the General Electric Model PG7121(EA) gas turbine as BACT for emissions of NOx. For the firing of low sulfur distillate oil, the Department establishes wet injection and restricted operation as BACT for emissions of NOx. The specified technologies utilize clean fuels and are consistent with recent determinations in other states. The emissions standards and compliance requirements based on the Department's BACT determinations are summarized in Appendix BD of the Draft Air Permit.

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

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
Registration Number: 49441

04-25-01
(Date)

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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X [illegible signature]

☒ Agent
☐ Addressee

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 *(Copy from service label)*
7000 0600 0026 4129 9426

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

7000 0600 0026 4129 9426

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

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

Duke Energy
Postmark Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland
Street, Apt. No.; or PO Box No.
5400 Westheimer Court
City, State, ZIP+4
Houston, Tx 77056-5310

PS Form 3800, February 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

May 1, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Project No. 1110100-001-AC
Draft Air Permit No. PSD-FL-302
Duke Energy Fort Pierce, LLC
Proposed New 640 MW Gas Turbine Peaking Plant

Dear Mr. Gilliland:

Enclosed is one copy of the Draft Permit to construct a new 640 MW electrical generating plant located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Within seven days of publication, the proof of publication (i.e., newspaper affidavit) must be provided to the Department's Bureau of Air Regulation. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/AAL/jfk

Enclosures

In the Matter of an
Application for Air Permit by:

Mr. Steven F. Gilliland, Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Duke Energy Fort Pierce, LLC
Project No. 1110100-001-AC
Draft Permit No. PSD-FL-302
Emission Units 001 – 009
St. Lucie County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Duke Energy North America, applied on October 5, 2000 to the Department for an air construction permit to construct a new 640 MW electrical generating plant located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The Draft Permit authorizes the construction of eight General Electric Model PG7121(EA) combustion turbine-electrical generator sets, each having a nominal generating capacity of 80 MW.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

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

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/1/01 to the person(s) listed:

Mr. Steven F. Gilliland, Duke Energy*
Mr. Nathan K. Plagens, Duke Energy
Mr. George Howroyd, CH2MHILL
Chair, St. Lucie Board of County Commissioners
Mr. Isidore Goldman, SED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Charlotte J Hayes (Clerk) 5/1/01 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 1110100-001-AC
Draft Permit PSD-FL-302

Duke Energy Fort Pierce, LLC
Proposed 640 MW Simple Cycle Gas Turbine Plant
Emissions Units 001 - 009

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Duke Energy Fort Pierce, LLC to construct a nominal 640 MW simple cycle gas turbine plant. The proposed plant will be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. The applicant plans to install eight new simple cycle gas turbine-electrical generator sets with inlet air fogging systems and necessary support equipment. Each unit is a General Electric Model PG7121(EA) gas turbine with a nominal generating capacity of 80 MW. The applicant's authorized representative is Mr. Steven F. Gilliland, Senior Vice President of Duke Energy North America. The applicant's mailing address is 5400 Westheimer Court, Houston, TX 77056-5310.

Each simple cycle gas turbine will be fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Operation is restricted to an average of 2500 hours per gas turbine per year with no more than 500 hours of oil firing per gas turbine per year. When firing natural gas, nitrogen oxide emissions will be minimized with dry low-NOx combustion technology. When firing very low sulfur distillate oil, nitrogen oxide emissions will be minimized with wet injection and restricted operation. Emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of these clean fuels.

The potential emissions from this project are shown in the following table.

Pollutant	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	540	100	Yes	Yes
NOx	632	40	Yes	Yes
PM/PM_{10}	60	25/15	Yes	Yes
SAM	17	7	Yes	Yes
SO_2	147	40	Yes	Yes
VOC	29	40	No	No

As indicated, a determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM) and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

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

Florida Department of Environmental Protection
Bureau of Air Regulation
(111 S. Magnolia Drive, Suite 4)
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Florida Department of Environmental Protection
Southeast District Office – Air Resources
(400 North Congress Avenue)
P.O. Box 15425
West Palm Beach, Florida 33401
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project for additional information at the address and phone numbers listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION
(Including Draft BACT Determinations)

Duke Energy Fort Pierce, LLC

New 640 MW Simple Cycle Gas Turbine Peaking Plant

St. Lucie County

Project No. 1110100-001-AC

Draft Permit No. PSD-FL-302

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

April 25, 2001

{Filename: 302 BACT and TEPD.DOC}

This document describes the overall project, rule applicability, draft determination of Best Available Control Technology, analysis of air quality impacts, and makes a preliminary determination. It is organized in the following sections:

1. GENERAL PROJECT INFORMATION

1.1 Applicant Name and Address

Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Authorized Representative:
Mr. Steven F. Gilliland, Senior Vice President

1.2 Processing Schedule

10/05/00	Department received the application for a PSD air pollution construction permit.
10/11/00	Department mailed copies to EPA Region 4 and the National Park Service.
10/26/00	Department requested additional information.
12/14/01	Department received additional information.
01/08/01	Department requested additional information
02/27/01	Department received additional information; application complete.

1.3 Facility Description and Location

The applicant proposes to construct a new 640 MW electrical generating plant consisting of eight 80 MW simple cycle gas turbines. The planned project will be located approximately one-half mile east of the Florida Turnpike and one mile north of Midway Road in St. Lucie County, Florida. This is an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates are Zone 17, 561.6 km East, and 3029.0 km North. This location is approximately 190 km from the nearest Class I area, the Everglades National Park.

1.4 Standard Industrial Classification Code (SIC)

Industry Group No. 49, Electric, Gas, and Sanitary Services

Industry No. 4911, Electric Services

1.5 Regulatory Categories

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbines are subject to the acid rain provisions of the Clean Air Act.

Title V: The new facility is a Title V major source of air pollution because potential emissions of at least one regulated pollutant exceed 100 tons per year. 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: Emissions of at least one regulated pollutant from the new facility will be greater than 250 tons per year. The project is located in an area designated as in attainment or unclassifiable for each pollutant subject to a National Ambient Air Quality Standard. Therefore, the project is subject to new source preconstruction review in accordance with Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS: New units are subject to the New Source Performance Standards of 40 CFR 60 include the gas turbines (Subpart GG) and the fuel storage tanks (Subpart Kb).

1.6 Project Description

The applicant proposes construction of a new 640 MW electrical generating plant in St. Lucie County comprised of eight simple cycle gas turbines. Each gas turbine consists of a General Electric Model PG7121(EA) gas turbine-electrical generator, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 93 feet tall and 15 feet in diameter. Each unit is designed to produce a nominal 80 MW of electrical power. The applicant proposes to limit operation of each gas turbine to an average of no more than 2500 hours per year. To control nitrogen oxide emissions, the applicant proposes dry low-NOx (DLN) combustion technology when firing natural gas and wet injection with restricted operation when firing low sulfur distillate oil as a backup fuel.

1.7 Potential Emissions

Table 1A. This table summarizes potential project emissions and the resulting PSD applicability.

Pollutant	PTE As Proposed [a] (Tons Per Year)	PTE Draft Permit [b] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	520	540/432	100	Yes	Yes
Lead	Negligible	Negligible	0.60	No	No
NOx	646	632	40	Yes	Yes
PM/PM_{10}	138	60	25/15	Yes	Yes
SAM	17	17	7	Yes	Yes
SO_2	148	147	40	Yes	Yes
VOC	20	29	40	No	No

[a] The applicant's potential emissions were based on eight gas turbines, each with 2000 hours per year of gas firing and 500 hours per year of oil firing. Operation was assumed to be 100% load with a compressor inlet temperature of approximately 75° F.

[b] The Department's potential emissions were based on eight gas turbines, each with 2000 hours per year of gas firing and 500 hours per year of oil firing. In addition to the permit limits, operation was assumed to be 100% load with a compressor inlet temperature of approximately 59° F. CO emissions assumed to be 25 ppmvd for first year and then 20 ppmvd thereafter. Also, the "back half condensables" were not included for PM/PM_{10} emissions. VOC emissions were assumed to be 2 ppmvd to remain "minor" with respect to PSD applicability.

2. APPLICABLE REGULATIONS

2.1 State Regulations

This 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 applicable rules and regulations defined in the following Chapters of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

2.2 Federal Regulations

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

Title 40, CFR	Description
Section 51.166	Requirements for State Implementation Plans, Prevention of Significant Deterioration
Section 52.21	Approval of State Implementation Plans, Prevention of Significant Deterioration
Part 60	Subpart A - General Provisions for NSPS Sources
	NSPS Subpart GG - Stationary Gas Turbines
	NSPS Subpart Kb - Fuel Storage Tanks
	Applicable Appendices
Part 72	Acid Rain Permits
Part 73	Allowances
Part 75	Monitoring
Part 77	Acid Rain Program - Excess Emissions

2.3 General PSD Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required only in areas currently in attainment with the National Ambient Air Quality Standard (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it 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 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants

2.4 PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to predict ambient impacts from the project; a comparison of predicted ambient impacts from the project with National Ambient Air Quality Standards and PSD Increments; an evaluation of the air quality impacts from the project upon soils, vegetation, wildlife, and visibility; and an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The purpose of the Air Quality Analysis is to determine whether or not the proposed project will have a significant impact on Class I and Class II Areas and determine whether or not emissions from the project contribute significantly to, or cause a violation of, any state or federal ambient air quality standards.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

2.5 PSD Applicability for Project

The proposed new plant will be located in St. Lucie County, Florida, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). As shown in Table 1A, the new plant is considered a PSD-major source because potential emissions of at least one regulated pollutant exceed 250 tons per year. Emissions of CO, NOx, PM/PM_{10}, SAM and SO_2 are significant and the Department is required to make determinations of the Best Available Control Technology (BACT) for these pollutants and review the applicant's air quality impact analysis.

3. DRAFT BACT DETERMINATIONS

3.1 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make these determinations:

- Informal comments received from the National Park Service;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical documents regarding DLN emissions and the gas turbine control system;
- Equipment costs for an oxidation catalyst (CO) and "hot" selective catalytic reduction system (NOx);
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation; Prepared for the U.S. Department of Energy (November 5, 1999);

- Proposed AP-42 changes to Section 3.1 for gas turbines (April 2000);
- Recently issued Department permits for the General Electric Model PG7121(EA) gas turbine;
- CO/NOx performance curves for the General Electric Model PG7121(EA) gas turbine;
- Emissions test data for a new GE Model PG7121(EA) gas turbine (Hardee Power Station Unit 2B);
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. A list of recent determinations regarding similar projects in the United States is provided in the following table.

Table 3A. Summary of Recent CO and NOx BACT Standards 80 MW Simple Cycle Gas Turbines (Gas Firing)

Project Location	Nominal Unit MW	Date	Controls	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	Operation hr/yr	Oil hr/yr
PSEG Fossil LLC Linden (NJ)	80	02/00	GE DLN	NA	12	NA	(authorized)
Hardee Power Partners (FL)	80	10/99	GE DLN	25, 1st year 20, after 1st year	9, 24-hr (CEMS)	8760	876
FPC Intercession City (FL)	80	12/99	GE DLN	25, 1st year 20, after 1st year	9, initial test 10, 3-hr (CEMS)	3390	833
Georgia Power Jackson Co. (GA)	80	08/99	GE DLN	45	12	4000	1000
Duke Energy Marshall Co. (KY)	80	Draft	GE DLN	20	12, 1-hr 9	2500	500
TVA Johnsonville Fossil Plant (TN)	80	07/99	GE DLN	25	15	2628	876
TVA Gallatin Fossil Plant (TN)	80	07/99	GE DLN	25	15	2628	876
Enron, Des Plaines Greenland (IL)	80	09/99	GE DLN	25	12, monthly 15, 1-hr	3250	0
Enron Kendall New Century (IL)	80	01/00	GE DLN	25	12, monthly 15, 1-hr	3300	0
Duke Energy (IL)	80	Draft	GE DLN	NA	12, annual 15, 1-hr	2000	500
Vermillion Generating Station (IN)	80	07/99	GE DLN	25	12, annual 15, 1-hr	2500	NA
Duke Energy Madison (OH)	80	07/99	GE DLN	25	12, annual 15, 1-hr	2500	500
Wisconsin Public Service (WI)	80	07/99	GE DLN	25	9, 24-hr	4000	2000
Wisconsin Electric (WI)	80	Draft	GE DLN	25	9, 24-hr	2000	NA

Table Notes:

- All data presented is for the General Electric Model 7EA gas turbine firing natural gas. The above information includes only units with a draft or final permit.
- "GE DLN" means General Electric's dry low-NOx combustion technology.

- "CEMS" means continuous emissions monitoring system. These projects should all be subject to Title IV, which requires a NOx CEMS.
- Some units have other modes of operation such as steam injection for power augmentation or high temperature peaking, which is not listed in the above table.

3.2 Nitrogen Oxides (NOx)

Discussion of Emissions

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd corrected to 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd corrected to 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Many new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure, which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

Description of Available Controls

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd corrected to 15% oxygen.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature (1100° F) is above the design temperature range for this technology.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1100° F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature (1100°F) is below the design limit (1600° F) for this technology.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines with variable control efficiencies. This control alternative is not feasible for simple cycle projects because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design level for this technology.

SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and distributed by ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which requires a heat recovery steam generator for use with a combined cycle gas turbine. SCONOx™ can achieve control efficiencies in the 90% to 98% range. This control alternative is not feasible for simple cycle projects because the gas turbine exhaust temperature of 1100°F is above the design limit for this technology.

XONON™: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range. This emerging technology is model-specific and not yet commercially available for the General Electric Model PG7121(EA).

Cannon Technology's Low Temperature Oxidation (LTO): This technology involves injecting ozone into a gas stream (approximately 300° F) to oxidize CO, NOx, and SO_2 to carbonates, nitrates, and sulfates, which are then absorbed by a dilute nitric acid solution in a scrubber. The system was developed for steam boilers and test results show NOx emissions below 4 ppmvd at 3% oxygen for gas firing. However, only very small units (< 20 mmBTU per hour) have been tested. It is unknown as to whether this technology could be adapted to gas turbines exhausts. Therefore, LTO is not yet demonstrated or commercially available for gas turbines.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided funding to several gas turbine manufacturers to aid in the development of inherently lower pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. For the 7EA Frame units, this occurs in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The lean premix mode of operation occurs at 50% to 100% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the automated gas turbine control system becomes a critical component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues. Dry low-NOx combustion technology is an integral component of the General Electric PG7121(EA) gas turbine.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, 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. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies. Because dry low-NOx combustion technology does not yet achieve low NOx emissions when firing oil, wet injection remains a viable control technique for oil firing.

Applicant's Proposed NOx Controls

The applicant recognized "hot" selective catalytic reduction with dry low-NOx (DLN) combustion technology as the top control option followed by DLN combustion technology alone and wet injection. Although identified as potentially feasible, the applicant does not believe hot SCR has been successfully demonstrated for this size unit. The applicant also makes the following claims regarding additional adverse impacts of hot SCR.

Energy Impacts: Due to a pressure drop across the catalyst, hot SCR would result in a loss of 612,500 kWh per gas turbine.

Environmental Impacts: The applicant mentions that hot SCR could result in ammonia emissions either as unreacted ammonia "slipping" past the catalyst or as an accidental release. Also, additional fine particulate matter (PM_{10}) could be emitted as ammonium bisulfate and ammonium sulfate.

Economic Impacts: The applicant performed a revised cost analysis for the addition of hot SCR based on the firing natural gas for 2500 hours per year in each unit. The applicant's revised estimate indicated that installation of hot SCR (per gas turbine) would result in a capital investment of $4,141,000 and total annualized costs of $1,282,000 per year. The Department notes that the applicant did not necessarily agree with the Department's request for revised items in this estimate. Based on a reduction of approximately 36 tons of NOx per year with hot SCR for gas firing, the incremental cost effectiveness was estimated to be approximately $35,000 per ton of NOx removed.

Applicant's Proposal: Based on the estimated high capital and operating costs associated with this add on control system, the applicant rejected hot SCR and proposed the following NOx standards based on DLN combustion when firing natural gas as the primary and wet injection with restricted distillate oil firing as a backup fuel

Gas: 12.0 ppmvd @ 5% oxygen, short-term basis (or 10.5 ppmvd @ 15% oxygen, long-term basis)

Oil: 42.0 ppmvd @ 15% oxygen, short-term basis

Department's Draft NOx BACT Determination

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone and wet injection. However, the Department notes that General Electric is able to guarantee NOx emissions of 9 ppmvd corrected to 15% oxygen for base-loaded units firing natural gas with the DLN technology of the Model PG7121(EA). The Department has the following comments regarding the applicant's discussion of additional adverse impacts.

Energy Impacts: Installation of hot SCR would result in a small energy penalty of approximately 0.3% per inch of pressure drop across the catalyst bed.

Environmental Impacts: Hot SCR would result in some ammonia "slip" and perhaps small amounts of fine particulate matter (PM_{10}). However, a properly designed SCR system and the firing of very low sulfur fuels (such as natural gas as the primary fuel) can reduce emissions of both pollutants.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7121(EA) is not cost effective. However, the Department does not endorse the applicant's estimate, but predicts the cost effectiveness of hot SCR for this project to be approximately $20,000 per ton of NOx removed, as limited to 2500 hours per year. Even assuming operation of 5000 hours per year, the cost effectiveness would be more than $10,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation (average of 2500 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7121(EA) gas turbine. Should the applicant later request operation of these gas turbines as base load units, conversion to combined cycle operation, the substitution of another gas turbine model, or the firing of an alternative fuel, the NOx BACT determination must be reevaluated as if the project had never been constructed, pursuant to Rule 62-212.400(2)(g), F.A.C.

Draft NOx BACT Determination: At this time, the Department rejects hot SCR as not cost effective for this simple cycle project based on the restricted level of operation requested by the applicant. Therefore, the Department determines BACT for NOx emissions to be the dry low-NOx combustion technology when firing natural gas as primary fuel and wet injection with restricted hours when firing low sulfur distillate oil as a backup fuel. This determination is consistent with recent BACT determinations for simple cycle units made in Florida and other states. The Department establishes the following NOx standards as BACT for this project.

Gas: 9.0 ppmvd @ 15% oxygen, initial 3-hour test average at base load "new and clean"

10.5 ppmvd @ 15% oxygen, 3-hour rolling CEMS average

Oil: 42.0 ppmvd @ 15% oxygen, initial 3-hour test average and 3-hour rolling CEMS average

Also, distillate oil firing will be limited to no more than an average of 500 hours per year per installed gas turbine. Corresponding mass emission limits will also be established in the draft permit with compliance demonstrated by an initial performance test. In making this determination, the Department gave consideration to the applicant's request to fire natural gas as the primary fuel with restricted firing of very low sulfur distillate oil. Natural gas is a clean fuel containing little contaminants that takes full advantage of

DLN the combustion technology of the Model PG7121(EA) gas turbine. The 3-hour average was specified due to General Electric's guarantee and because peaking units typically operate only a portion of the day.

The draft BACT standards are much more stringent than the NSPS standard in Subpart GG in 40 CFR 60. The "new and clean" emissions standard ensures that the installed units are capable of achieving the manufacturer's guaranteed emission rate. Compliance with the "new and clean" BACT standard shall be demonstrated by conducting initial performance tests in accordance with EPA Method 7E or 20. The permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the 3-hour rolling BACT limit. The draft permit also includes the following restrictions:

- Each gas turbine shall operate in simple cycle mode only;
- No gas turbine shall operate more than 5000 hours per year;
- Operation of all installed gas turbines shall not exceed an average of 2500 hours per gas turbine per year;
- No gas turbine shall fire low sulfur distillate oil for more than 1000 hours per year;
- The firing of low sulfur distillate oil for all installed gas turbines shall not exceed an average of 500 hours per gas turbine year;
- Except for startup and shutdown, each gas turbine shall not operate below 50% of base load.

3.3 Carbon Monoxide CO

Discussion

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion. In general, CO emissions are inversely proportional to NOx emissions from gas turbines. However, new advanced combustor designs have also been able to greatly reduce CO emissions concurrently with lower NOx emissions.

Applicant's Proposed CO Controls

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and the inherently low CO emissions of General Electric's dry low-NOx combustion design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst would promote oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1000°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty of approximately 0.2% per inch of pressure drop across the catalyst.

Environmental Impacts: The oxidation catalyst could generate additional PM_{10} and SAM emissions due to the oxidation of ammonia and sulfur in the exhaust gas. An oxidation catalyst would result only in minimal air quality improvements. Spent catalyst may require disposal as a hazardous waste.

Economic Impacts: The applicant's revised estimate indicates that installation of an oxidation catalyst (per gas turbine) would result in a capital investment of $2,419,775 with a total annualized cost of $902,925. It was assumed that the catalytic system could remove an additional 59 tons of CO per year (90% control efficiency). This results in an incremental cost effectiveness for the oxidation catalyst of approximately $15,000 per ton of CO removed. The Department notes that the applicant did not necessarily agree with the Department's request for revised items in this estimate.

Applicant's Proposal: The applicant rejected the oxidation catalyst as not cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following CO standards based on the combustion design of the Model PG7121(EA).

Gas: 25.0 ppmvd @ 15% oxygen, first 12 months

20.0 ppmvd @ 15% oxygen, after first 12 months

Oil: 20.0 ppmvd @ 15% oxygen

Department's Draft CO BACT Determination

The Department also recognizes an oxidation catalyst as the top control for CO emissions. It is noted that the Department has issued permits for the Model PG7121(EA) with a CO emission standard of 20.0 ppmvd for both gas and oil firing. The Department has the following comments regarding the applicant's discussion of additional adverse impacts.

Energy Impacts: The Department agrees that installation of an oxidation catalyst would result in a small energy penalty.

Environmental Impacts: Any additional PM_{10} or SAM emissions would be minimized because of the exceptionally low sulfur content of natural gas as well as the proposed distillate oil. The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in making the BACT determination. The purpose of the PSD program is to prevent the significant deterioration of air quality *before* such problems develop. The Department also notes that an oxidation catalyst may reduce emissions of hazardous air pollutants, such as formaldehyde. Most catalyst manufacturers have a program to take back the spent catalyst for regeneration, recycling and disposal.

Economic Impacts: In general, the Department agrees that the addition of an oxidation catalyst would not be cost effective for a simple cycle gas turbine with restricted operation. The Department does not endorse the applicant's estimate, but predicts the cost effectiveness to be approximately $6000 per ton of CO removed for the project, as limited to 2500 hours per year. Even assuming an operation of 5000 hours per year, the cost effectiveness would be $3000 per ton of CO removed. The high costs are partially the result of substantial expenses related to additional equipment, installation, catalyst replacement, and energy consumption. However, similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operational restrictions.

Draft CO BACT Determination: The Department rejects the addition of an oxidation catalyst as not cost effective for the project based on the restricted level of operation requested by the applicant. The efficient combustion design of the General Electric Model PG7121(EA) is determined to represent BACT for CO emissions from this project. Therefore, the Department establishes the following CO standard as BACT for this project.

Gas: 25.0 ppmvd @ 15% oxygen (first 12 months), 3-hour test average

20.0 ppmvd @ 15% oxygen (after first 12 months), 3-hour test average

Oil: 20.0 ppmvd @ 15% oxygen, 3-hour test average

Corresponding mass emission limits will also be established in the draft permit. Compliance with the BACT emissions standard shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 10 at base load. The draft permit will include the limiting conditions identified in the NOx BACT determination to ensure that BACT is reevaluated for CO and NOx if the applicant later requests a switch to based loaded units, conversion to combined cycle operation, or substitution of gas turbine models. The NOx BACT determination must be reevaluated as if the project had never been constructed, pursuant to Rule 62-212.400(2)(g), F.A.C.

Note: A slightly higher first-year emission rate is allowed to mitigate the applicant's concerns regarding high initial CO emissions for recent startup of similar units in Indiana. The determination is also consistent with two recent simple cycle projects in Florida featuring the General Electric Model 7EA units (Hardee Power Station and FPC Intercession City). General Electric estimates maximum CO emissions to be "25 ppmvd" at base load with an exhaust gas concentration of 13.86% by volume. This is equivalent to 21 ppmvd corrected to 15% oxygen. Test data for a 7EA unit at the Hardee Power Station operating at approximately 98% load indicated actual CO emissions of 8.5 ppmvd corrected to 15% oxygen while NOx emissions were approximately 6.5 ppmvd corrected to 15% oxygen. The Department believes that CO emission levels much lower than the manufacturer's guarantee are achievable once the units are properly installed and tuned.

3.4 Particulate Matter (PM/PM_{10}), Sulfuric Acid Mist (SAM), and Sulfur Dioxide (SO_2)

Discussion

Emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2) will result from the combustion of natural gas. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfuric acid mist and sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas contains little ash, sulfur, or other contaminants.

Applicant's Proposed Controls for PM/PM_{10}, SAM, and SO_2

The applicant indicates that post-control devices have never been applied to gas turbines because of the large volumetric flow rates, low particulate concentrations, low sulfur dioxide concentrations, and excessive back pressure that would be caused by such add-on devices. In addition, clean fuels are required to prevent damage to turbine blades and other high-precision turbine components.

Applicant's Proposal (Fuel Specifications)

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

Department's Draft PM/PM_{10}, SAM, and SO_2 BACT Determinations

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. However, particulate emissions are estimated to be much less than 0.01 grains per dscf of exhaust gas, which is approximately the level of controlled emissions from a baghouse. Similarly, there is acid gas scrubbing equipment available to further reduce SAM and SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel with very low sulfur distillate oil as a backup fuel. The Department agrees that further control of particulate matter, sulfuric acid mist, and sulfur dioxide emissions with any of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case.

Draft PM/PM_{10}, SAM, and SO_2 BACT Determinations: The Department establishes the following fuel specifications and opacity standard as BACT for PM/PM_{10}, SAM, and SO_2.

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

Gas or Oil: Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Compliance with the fuel sulfur limits shall be demonstrated by maintaining the fuel quality records. Limiting the fuel sulfur content also effectively limits the potential emissions of SAM and SO_2, so that additional emissions standards are unnecessary. In conjunction with the fuel specifications, the above opacity standard is specified in lieu of an emission standard due to the difficulty of conducting an isokinetic performance test for particulate matter at very high volumetric flow rates with exhaust temperatures near 1000° F. In addition, the collected sample is expected to be within the level of detection of the method. Note: The maximum estimated emissions of particulate matter are 5/10 pounds per hour for gas/oil firing, as determined by EPA Method 5 (front-half catch only). This is approximately 7.5 tons per year per gas turbine.

3.5 PSD-Synthetic Minor Limits for Volatile Organic Compounds (VOC)

VOC emissions result from incomplete combustion when firing natural gas. Large combustion turbines offer high temperatures with efficient combustion resulting in low levels of volatile organic compounds. Based on the applicant's request, the Department establishes the following standards as PSD-synthetic minor limits for VOC.

Gas: 2.5 pounds per hour (2.0 ppmvd corrected to 15% oxygen) based on a 3-hour test average

Oil: 4.5 pounds per hour (3.5 ppmvd corrected to 15% oxygen) based on a 3-hour test average

The above standards apply during the initial performance tests conducted at base load, measured and reported in terms of methane, as determined by EPA Method 25A. Optionally, EPA Method 18 may also be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane. The efficient combustion design, use of clean fuels and good operating practices minimize VOC emissions from each gas turbine. Compliance with the fuel specifications and CO standards of this section shall serve as indicators of good combustion. The initial tests shall demonstrate compliance with the standards and validate the maximum emissions rates. Subsequent VOC emissions performance tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C.

Note: The emissions limit proposed by the applicant was 1.8 pounds per hour (1.4 ppmvd corrected to 15% oxygen). The draft limit is slightly higher because the detectable limit of the test method is approximately 1 ppm. The draft limit establishes potential VOC emissions at 29 tons per year, which is well below the significant emissions rate.

3.6 Excess Emissions

Based on the design of the gas turbines and Rules 62-210.700 and 62-4.130, F.A.C., the following conditions will be included in the permit to address periods of excess emissions.

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 emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard.

Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of each gas turbine, the following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of operation. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such incidents.

a. During startup and shutdown, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during any calendar day, which shall not exceed 20% opacity. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

b. Except for startup and shutdown, operation below 50% base load is prohibited.

c. Data for NOx emissions and oxygen (or CO_2) content shall be recorded by the CEM system during all episodes of startup, shutdown and malfunction. Individual hourly average NOx emission rate values recorded during such episodes may be excluded from the continuous NOx compliance determination. No more than three (3) hourly average emission rate values shall be excluded in any 24-hour block period due to gas turbine startup, shutdown, or documented unavoidable malfunction. A documented unavoidable malfunction is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

4. Air Quality Impact Analysis

4.1 Summary

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NOx, SO_2, and SAM. PM_{10}, SO_2 and NOx are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments, AAQS or de minimis monitoring levels for SAM; the BACT determination will limit maximum potential SAM emissions.

The applicant's initial PM/PM_{10}, CO, NOx, and SO_2 air quality impact analyses for this project predicted no significant impacts in the Class II area in the vicinity of the project. Therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required in the Class II area. The nearest PSD Class I area is the Everglades National Park (ENP) located about 180 km to the south and southwest. The applicant's PSD Class I air quality analysis showed no significant impacts due to the project. Therefore, a cumulative PSD Class I increment analysis was not required for these pollutants. Also, the maximum predicted impacts for all pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_2 in the surrounding Class II Area;
- A significant impact analysis for PM_{10}, SO_2, and NO_2 in the ENP;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on the required analyses, 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. However, the following EPA-directed stack height language is included: "In approving this permit, 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 vs. 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.

4.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. When available, the use of existing representative monitoring data may satisfy the monitoring requirement. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. The table below shows that predicted ambient impacts from the power plant are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Predicted Maximum Air Quality Impacts from the Project Compared to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	1	10	No
NO_2	Annual	0.1	14	No
SO_2	24-hour	2	13	No
CO	8-hour	10	575	No

4.3 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 National Weather Service (NWS) station at West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. This NWS 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.

PSD Class I Area

Since the PSD Class I ENP is approximately 180 to 284 km from the proposed facility at its closest and farthest points, 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 two Air Quality Related Values (AQRVs), regional haze and deposition of sulfur and nitrogen compounds. 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.

CALPUFF was first run in screen mode using ISCST3 meteorological input data consisting of 5 years of surface and upper air data from West Palm Beach. The 5-year period of meteorological data was from 1986 to 1990. The base ISCST3 data was supplemented with precipitation, solar radiation, and relative humidity data from the same station. The supplemental meteorological data was obtained from the National Climatic Data Center (NCDC) Hourly United States Weather Observations (HUSWO) and Solar and Meteorological

Surface Observation Network (SAMSON) compact discs. Solar radiation data, which is needed for the CALPUFF chemical transformation algorithms, is not available from NCDC after 1990; therefore data from 1986 to 1990 were used to fulfill the 5-year modeling requirement for running CALPUFF in the screen mode.

4.4 Significant Impact Analysis

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 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 II Areas. If this modeling at worst-case load conditions shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 100-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced receptors at 100 meters apart starting at 100 meters and extending to 3,000 meters from the stacks. Beyond 3000 meters, a spacing of 250 meters was used out to 6,000 meters from the facility. From 6 to 12 kilometers, a spacing of 0.5 kilometers was used. Between 12 and 20 kilometers, a spacing of 1 kilometer was used. The modeling approach was based on the assumption that a refined receptor grid (minimum 100 meter spacing) would be used as necessary in order to determine maximum predicted concentrations in various areas of the initial grid.

For the Class I screening analysis two rings of receptors were centered on the Duke Energy facility at distances bracketing the ENP. These distances represent the nearest boundary of 180 kilometers and the farthest boundary of 284 kilometers with respect to the proposed project. Receptors were placed at one-degree intervals over a 360-degree arc along each ring. The tables below show the results of the significant impact modeling for the Class II and Class I areas.

Predicted Maximum Air Quality Impacts from the Project Compared to the PSD Class II Significant Impact Levels in the Vicinity of the Project

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Class II Significant Impact Levels (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	No
	24-hour	2	5	No
	3-hour	14	25	No
PM_{10}	Annual	0.1	1	No
	24-hour	1	5	No
CO	8-hour	10	500	No
	1-hour	50	2000	No
NO_2	Annual	0.1	1	No

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project in the vicinity of the facility; therefore, no further modeling was required in the Class II area.

Predicted Maximum Air Quality Impacts from Project Compared to the EPA Proposed PSD Class I Significant Impact Levels (ENP)

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	No
	24-hour	0.1	0.3	No
NO_2	Annual	0.005	0.1	No
SO_2	Annual	0.002	0.1	No
	24-hour	0.2	0.2	No
	3-hour	0.7	1	No

The results of the significant impact modeling for the ENP show that there are no significant impacts predicted due to PM_{10} and NO_2 emissions from this project; therefore, no further modeling was required in the Class I area for these pollutants. However, impacts equal to the proposed significant impact level for the 24-hour averaging time were predicted. These significant impact levels are only proposed guideline values at this time; the Federal Land Manager (FLM) may make the determination that no adverse impact on the increments is expected and exempt the project from further PSD multi-source increment modeling. Based on the fairly large distance of the project from the ENP and the relatively low SO_2 emissions expected from it, the FLM determined that no further modeling was necessary. In addition, Duke Energy is limiting fuel oil firing to a maximum of 12 hours in any 24-hour period.

4.5 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas and oil-fired combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. An analysis of sulfur and nitrogen deposition impacts in the ENP was done. Based on FLM criteria, no adverse impacts were predicted. 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 considerably less than the respective AAQS. The project impacts are less than the significant impact levels, 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.

Impact On Visibility and Regional Haze

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_x and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal. A regional haze analysis for the ENP was submitted by the applicant. Based on FLM criteria, no adverse impacts were predicted.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area. The proposed project has a small overall physical "footprint" and among the lowest air emissions per unit of electric power generating capacity for peaking operation.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the Air Quality Analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

CH2M HILL
115 Perimeter Center Place NE
Suite 700
Atlanta, GA
30346-1278
Tel 770.604.9095
Fax 770.604.9183

CH2MHILL

February 26, 2001

154648

RECEIVED
MAR 12 2001
BUREAU OF AIR REGULATION

Mr. Jeff Koerner
Florida Department of Environmental Regulation
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Class I Area Impact Analysis
Everglades National Park
Duke Energy Fort Pierce, LLC
Fort Pierce, FL

Dear Mr. Koerner:

Enclosed please a brief report entitled *Dispersion Modeling Assessment – Everglades National Park,* which summarizes the results of a dispersion modeling analysis of Duke Energy's proposed Fort Pierce power generating facility. This analysis was requested by your office and the National Park Service as a means of quantifying potential impacts attributable to the the operation of the Duke facility in the Everglades National Park. This report is intended to supplement the previously submitted application for a Permit to Construct the facility and is being submitted on behalf of our client, Duke Energy Fort Pierce, LLC. We are also sending you under separate cover two copies of a CD-ROM containing all modeling related files that were used in the analysis.

If you should have any questions concerning any aspect of this report, please do not hesitate to call Nathan Plagens of Duke Energy North America at 713-627-5985, or the undersigned at 770-604-9182, ext 355.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\154648\Class I Analysis Subnittal Letter 2-26-01.doc

c: Nathan Plagens/Duke Energy
C. Holladay
NPS (2nd Ex)

Dispersion Modeling Assessment
Everglades National Park

Prepared for

Duke Energy Fort Pierce, LLC
Fort Pierce, Florida,

Prepared by

CH2M HILL, Inc.
Montgomery, Alabama

February 20, 2001
154648.01.PD

Contents

Tables

Dispersion Modeling Assessment
Everglades National Park
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Introduction

Duke Energy Fort Pierce, LLC (Duke), recently submitted a prevention of significant deterioration (PSD) permit application to the Florida Department of Environmental Protection (FDEP) for a proposed 640-megawatt (MW) power generating facility to be located near Fort Pierce, Florida, in St. Lucie County. The National Park Service has requested that ambient air quality, visibility, and total sulfur and nitrogen deposition screening analyses be performed to evaluate the effects of the proposed facility in the Everglades National Park, which is located approximately 180 kilometers (km) south-southwest of the project site.

As provided in Duke's permit application to FDEP dated September 2000, the proposed facility will have the following characteristics:

- 640-MW simple cycle power generating plant (8 GE 7EA turbines)
- Facility located near Fort Pierce, Florida, in St. Lucie County, north-northeast of the Everglades National Park
- Natural gas is the primary fuel, to be used up to 2,500 hours per year (per turbine)
- Low sulfur fuel oil (less than 0.05 percent) will be used only for back-up when natural gas is unavailable. Fuel oil use will be limited to 12 hours/day and 500 hours/year per turbine
- PSD Class II impact analyses demonstrated insignificant impacts for all pollutants at all locations
- Distance to nearest Class I area is approximately 180 km (Everglades National Park)

Maximum potential facility emissions (all turbines in operation) are as follows:

Pollutant	Oil Firing (lbs/hr)	Gas Firing (lbs/hr)
NOx	1,272	328
SO2	400	48
PM-10	200	88
VOC	36	11
CO	336	416

Class I Area Dispersion Modeling Methodology

Modeling Options and Assumptions

Class I Area Modeling Protocol

The Class I Area impact analysis for the Duke Energy Fort Pierce facility followed the methodology given in the 1996 *Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (U.S. Environmental Protection Agency [EPA]-454/R-98-019) (IWAQM2). The approach used the CALPUFF model in a screening mode, as described in Section 2.1 of IWAQM2.

The Class I Area impact analysis included the calculation of concentrations of sulfur dioxide (SO_2), particulate matter (PM_{10}), and nitrogen dioxide (NO_2) for comparison to the EPA proposed Class I significance levels (Table 1); calculation of the percent change in extinction; and total sulfur and nitrogen deposition.

TABLE 1
EPA Proposed Class I Area Significance Levels
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Pollutant	Averaging Time	Concentration (µg/m3)
Sulfur Dioxide	Annual	0.1
	24-hour	0.2
	3-hour	1.0
Particulate Matter	Annual	0.2
	24-hour	0.3
Nitrogen Dioxide	Annual	0.1

Modeling Methodology. Table 2 summarizes the modeling methodology that was followed.

Meteorology. The air quality dispersion modeling analysis was performed using 5 years of meteorological data from West Palm Beach for the years 1986 through 1990. The meteorological data were of the augmented ISC3-type. Specifically, the meteorological data contained the basic ISC3 data (hourly values of the vector flow direction, wind speed, temperature, stability class, and mixing height) augmented by data needed by CALPUFF to implement chemical transformation and deposition (e.g., precipitation type code, precipitation rate, and relative humidity).

TABLE 2
Modeling Methodology
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Meteorology	Use 5 years of data processed using PCRAMMET (extended output needed for deposition).
Receptors	Receptors at every one degree on two rings that encircle source and bound the Class I area of interest at the closest and farthest points.
Dispersion	1. Use ISC2PUF to convert an ISC3 control input file for use by CALPUFF 2. Edit control file to use MESOPUFF II chemistry; use wet and dry deposition (use default setups for these). 3. Run CALPUFF using ISC meteorology option; horizontal domain extending 50 to 80 kilometers beyond outer receptor ring.
Processing	**For Class I Significance Levels:** Use maximum 3-hour, 24-hour, and annual SO_2; maximum 24-hour and annual PM_{10}; and maximum annual NO_2 for comparison with EPA proposed levels. **For haze:** Use maximum 24-hour sulfate, nitrate, and particulate concentrations. Calculate the percent change in extinction using the FLM supplied background extinction. **For total S and N deposition:** Convert deposition flux to kg/(hectare year) using maximum values of annual SO_2, $SO_4^=$, NO_3^-, HNO_3, and NO_2.

Modeling Domain. So that the CALPUFF screening analysis addressed the potential effects at the Everglades National Park, which is between approximately 180 and 284 km from the source at its closest and farthest points, the modeling domain used for the analysis was in the shape of a square extending 334.2 km in the east-west (x) direction and 334.2 km in the north-south (y) direction. The center of the modeling domain is approximately 27.47 degrees N latitude and 80.35 degrees W longitude. The southwestern corner of the square, the origin of the modeling domain, was located at approximately 227.4 km UTMX and 2,694.8 km UTMY (UTM Zone 17). Because the CALPUFF screening analysis only uses single-station meteorological data (rather than the full three-dimensional wind field and temperature data and two-dimensional fields of mixing heights and other meteorological variables generated by CALMET), only two grid cells in the x-direction and two grid cells in the y-direction are needed to fully represent the resulting spatially uniform gridded field.

Receptor Locations. Discrete receptors were spaced every degree on two rings centered on the Duke Energy Fort Pierce facility and bounding the Everglades National Park Class I area. The rings are representative of the nearest and furthest distances from the facility to the Class I area. The two rings have radii of 180 and 284.2 km.

Emission Rates. Because oil-firing is constrained to a maximum of 12 hours in any 24-hour period, diurnally varying emission rates were used in the analysis for the 3-hour and 24-hour time averaging results. For the 3-hour and 24-hour time averaging results, base emission rates were set to those for oil firing. These were then adjusted by means of scaling factors for hours during which gas firing occurred (see Table 3).

TABLE 3
Scaling Factors for Diurnal Variation in Emission Factors for CALPUFF modeling
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Pollutant	Oil Firing (lb/hr)	Gas Firing (lb/hr)	Factor (Gas/Oil)
SO_2	400	48	0.120
NO_x	1272	328	0.258
PM_{10}	200	88	0.440

For the purpose of this analysis, the diurnal variation in emissions associated with fuel oil firing was assessed by assuming that fuel oil would most likely be burned during the 12-hr period from 8 a.m. to 8 p.m. The modeling analysis was therefore based on modeling gas-fired emissions for hours 1 to 8, oil-fired emissions for hours 9 to 20, and gas-fired emissions for hours 21 to 24. All modeling was performed using the CALPUFF Screening methodology. The diurnal variation in emissions was accomplished by using the CALPUFF variable IVARY and the scaling factors given in Table 3. Base emission rates were set to those for oil firing. For hours 9 to 20 (oil firing) a scaling factor of 1 was used. For hours 1 to 8 and 21 to 24 the scaling factors in Table 10 were used. It is noted that Duke will not be restricting the hours of firing to any particular time period during the day, rather it will be resticted from firing oil for more than 12 hours in any given calendar day. The diurnal analysis performed here was based on a time period when the facility might reasonably be expected to operate on oil.

Because the facility will operate up to 2,500 hours per year (500 hours of which could be on back-up fuel oil), emission rates for the annual averaging period were conservatively derived by the following:

- Multiplying the oil-firing hourly rates listed above by 500
- Multiplying the gas-firing hourly rates by 2,000
- Summing the two results
- Dividing the sum by 8,760 (i.e., the number of hours in a year)

Specifically, the rates used for the annual averaging period were SO_2–33.79 lbs/hr, NO_X–147.5 lbs/hr, and PM_{10}–31.51 lbs/hr.

CALPUFF Settings. The CALPUFF settings used in the CALPUFF control file follow those given in Appendix B of IWAQM2. The CALPUFF control files used from the analyses are attached. The main values are summarized in Table 4.

TABLE 4
CALPUFF Settings Used in the Analysis
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_X, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme with CALPUFF default
Deposition	Include both dry and wet deposition, plume
Meteorological	ISCMET.DAT (extended ISC3)
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	PG/MG coefficients,
Output	Create binary file
Model Processing	Highest concentration predicted
Background Values	Ozone: 28 ppb[1]; Ammonia: 10 ppb[2]
Variable Emissions Data for Point Source	Diurnal cycle (24 scaling factors: hours 1-24)

Notes:
[1] Provided by John Notar/NPS
[2] CALPUFF default value

CALPOST Settings. ***Visibility.*** The CALPOST control files from the analyses are attached. The main values for a visibility calculation are summarized in Table 5.

TABLE 5
CALPOST Settings Used for Visibility Calculation
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Parameter	Setting
Species to process	ASPEC = VISIB
Maximum relatively humidity	RHMAX = 95%[1]
Fine Particulates included	LVPMF = T
Modeled PM10 used as Fine Particulates	SPECPMF = PM10
Method used for background light extinction	MVISBK = 2
Background sulfate concentration	BKSO4 = 1.86 $\mu g/m^3$
Background soil concentration	BKSOIL = 14.91 $\mu g/m^3$
Extinction due to Rayleigh Scattering	BEXTRAY = 10 (1/Mm)
Averaging Time	L24HR = T

Note:
[1] Provided by John Notar/NPS

Total Sulfur and Nitrogen Deposition

The total depositions of sulfur and nitrogen were calculated in km per hectare per year. These values were derived from the annual wet and dry fluxes of SO_2, $SO_4^{=}$, NO_X, HNO_3, and NO_3^- that are available as output from CALPOST. Per direction from John Notar of the National Park Service, the fluxes were converted to sulfur and nitrogen deposited by the use of the multipliers given in Section 3.3 of IWAQM2.

Source Description

The proposed 640-MW simple cycle power generating plant (with eight GE 7EA turbines) was modeled as a single source. Table 6 summarizes the emissions source as used in the model.

Visibility

Following the IWAQM2 guidance for a screening analysis, the regional haze analysis for visibility impacts uses the maximum 24-hour sulfate, nitrate, and particulate concentrations to calculate the percent change in extinction using the FLM supplied background extinction. Table 7 summarizes the background visibility values for the Everglades National Park Class I area as provided by John Notar of the National Park Service.

TABLE 6
640-MW Simple Cycle Powering Generating Plant Source Characteristics
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Description	X UTM (km)	Y UTM (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temperature (k)
Power Plant	561.591	3028.9629	28.35	0.0	4.572	41.85	813.7

TABLE 7
Background Visibility Values for Everglades National Park
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Area	Hygro (1/Mm)	Non-Hygro (1/Mm)	Rayleigh (1/Mm)	f(RH)
Everglades NP	5.59	14.91	10	3.85

Results

The results of the ambient air, visibility, and deposition analyses are presented in Tables 8, 9, and 10, respectively. Table 8 shows that modeled concentrations are all less than the EPA proposed Class I area significance levels. Table 9 shows that modeled percent changes in extinction are all less than 10 percent, with only a few days per year greater than 5 percent. In general, with only two exceptions, predicted extinction values are only marginally greater than 5 percent. Table 10 shows that the maximum modeled nitrogen deposition for all years is less than or equal to 0.003 km per hectare per year, and that the maximum modeled sulfur deposited for all years is less than or equal to 0.0025 km per hectare per year.

TABLE 8
Ambient Air Quality Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	SO_2 Annual (μg/m3)	SO_2 24-hour (μg/m3)	SO_2 3-hour (μg/m3)	PM_{10} Annual (μg/m3)	PM_{10} 24-hour (μg/m3)	NO_X Annual (μg/m3)
1986	0.0013	0.1156	0.3669	0.0015	0.0850	0.0030
1987	0.0012	0.1207	0.4540	0.0014	0.0799	0.0028
1988	0.0011	0.1239	0.3859	0.0013	0.0880	0.0027
1989	0.0013	0.1743	0.4730	0.0015	0.1100	0.0027
1990	0.0011	0.1563	0.4762	0.0013	0.1017	0.0027
Class I Significance Level	**0.1**	**0.2**	**1.0**	**0.2**	**0.3**	**0.1**

TABLE 9
Visibility Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	Number of Days with Extinction Change > 5%	Days with Extinction Change ≥ 5%	Extinction Change (%)
1986	2	Day 3	5.29
		Day 51	9.00
1987	2	Day 30	5.41
		Day 51	5.74
1988	3	Day 43	5.00
		Day 44	5.06
		Day 235	5.44
1989	1	Day 356	6.89
1990	2	Day 13	5.54
		Day 355	5.06

TABLE 10
Deposition Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	Total N (kg/(ha*yr))	Total S (kg/(ha*yr))
1986	0.0019	0.0014
1987	0.0016	0.0011
1988	0.0016	0.0011
1989	0.0016	0.0012
1990	0.0016	0.0013

CH2M HILL
115 Perimeter Center Place NE
Suite 700
Atlanta, GA
30346-1278
Tel 770.604.9095
Fax 770.604.9183

CH2MHILL

February 26, 2001

154648

RECEIVED
FEB 27 2001
BUREAU OF AIR REGULATION

Mr. Jeff Koerner
Florida Department of Environmental Regulation
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Class I Area Impact Analysis
Everglades National Park
Duke Energy Fort Pierce, LLC
Fort Pierce, FL

Dear Mr. Koerner:

Enclosed please a brief report entitled *Dispersion Modeling Assessment – Everglades National Park,* which summarizes the results of a dispersion modeling analysis of Duke Energy's proposed Fort Pierce power generating facility. This analysis was requested by your office and the National Park Service as a means of quantifying potential impacts attributable to the the operation of the Duke facility in the Everglades National Park. This report is intended to supplement the previously submitted application for a Permit to Construct the facility and is being submitted on behalf of our client, Duke Energy Fort Pierce, LLC. We are also sending you under separate cover two copies of a CD-ROM containing all modeling related files that were used in the analysis.

If you should have any questions concerning any aspect of this report, please do not hesitate to call Nathan Plagens of Duke Energy North America at 713-627-5985, or the undersigned at 770-604-9182, ext 355.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\154648\Class I Analysis Subnittal Letter 2-26-01.doc

c: Nathan Plagens/Duke Energy
D. Goldman
EPA
NPS

Dispersion Modeling Assessment
Everglades National Park

Prepared for

Duke Energy Fort Pierce, LLC
Fort Pierce, Florida,

Prepared by

CH2M HILL, Inc.
Montgomery, Alabama

February 20, 2001
154648.01.PD

Contents

Tables

Dispersion Modeling Assessment Everglades National Park Duke Energy Fort Pierce, LLC Fort Pierce, Florida

Introduction

Duke Energy Fort Pierce, LLC (Duke), recently submitted a prevention of significant deterioration (PSD) permit application to the Florida Department of Environmental Protection (FDEP) for a proposed 640-megawatt (MW) power generating facility to be located near Fort Pierce, Florida, in St. Lucie County. The National Park Service has requested that ambient air quality, visibility, and total sulfur and nitrogen deposition screening analyses be performed to evaluate the effects of the proposed facility in the Everglades National Park, which is located approximately 180 kilometers (km) south-southwest of the project site.

As provided in Duke's permit application to FDEP dated September 2000, the proposed facility will have the following characteristics:

- 640-MW simple cycle power generating plant (8 GE 7EA turbines)
- Facility located near Fort Pierce, Florida, in St. Lucie County, north-northeast of the Everglades National Park
- Natural gas is the primary fuel, to be used up to 2,500 hours per year (per turbine)
- Low sulfur fuel oil (less than 0.05 percent) will be used only for back-up when natural gas is unavailable. Fuel oil use will be limited to 12 hours/day and 500 hours/year per turbine
- PSD Class II impact analyses demonstrated insignificant impacts for all pollutants at all locations
- Distance to nearest Class I area is approximately 180 km (Everglades National Park)

Maximum potential facility emissions (all turbines in operation) are as follows:

Pollutant	Oil Firing (lbs/hr)	Gas Firing (lbs/hr)
NOx	1,272	328
SO2	400	48
PM-10	200	88
VOC	36	11
CO	336	416

Class I Area Dispersion Modeling Methodology

Modeling Options and Assumptions

Class I Area Modeling Protocol

The Class I Area impact analysis for the Duke Energy Fort Pierce facility followed the methodology given in the 1996 *Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (U.S. Environmental Protection Agency [EPA]-454/R-98-019) (IWAQM2). The approach used the CALPUFF model in a screening mode, as described in Section 2.1 of IWAQM2.

The Class I Area impact analysis included the calculation of concentrations of sulfur dioxide (SO_2), particulate matter (PM_{10}), and nitrogen dioxide (NO_2) for comparison to the EPA proposed Class I significance levels (Table 1); calculation of the percent change in extinction; and total sulfur and nitrogen deposition.

TABLE 1
EPA Proposed Class I Area Significance Levels
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Pollutant	Averaging Time	Concentration (µg/m3)
Sulfur Dioxide	Annual	0.1
	24-hour	0.2
	3-hour	1.0
Particulate Matter	Annual	0.2
	24-hour	0.3
Nitrogen Dioxide	Annual	0.1

Modeling Methodology. Table 2 summarizes the modeling methodology that was followed.

Meteorology. The air quality dispersion modeling analysis was performed using 5 years of meteorological data from West Palm Beach for the years 1986 through 1990. The meteorological data were of the augmented ISC3-type. Specifically, the meteorological data contained the basic ISC3 data (hourly values of the vector flow direction, wind speed, temperature, stability class, and mixing height) augmented by data needed by CALPUFF to implement chemical transformation and deposition (e.g., precipitation type code, precipitation rate, and relative humidity).

TABLE 2
Modeling Methodology
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Meteorology	Use 5 years of data processed using PCRAMMET (extended output needed for deposition).
Receptors	Receptors at every one degree on two rings that encircle source and bound the Class I area of interest at the closest and farthest points.
Dispersion	1. Use ISC2PUF to convert an ISC3 control input file for use by CALPUFF 2. Edit control file to use MESOPUFF II chemistry; use wet and dry deposition (use default setups for these). 3. Run CALPUFF using ISC meteorology option; horizontal domain extending 50 to 80 kilometers beyond outer receptor ring.
Processing	**For Class I Significance Levels:** Use maximum 3-hour, 24-hour, and annual SO_2; maximum 24-hour and annual PM_{10}; and maximum annual NO_2 for comparison with EPA proposed levels. **For haze:** Use maximum 24-hour sulfate, nitrate, and particulate concentrations. Calculate the percent change in extinction using the FLM supplied background extinction. **For total S and N deposition:** Convert deposition flux to kg/(hectare year) using maximum values of annual SO_2, $SO_4^=$, NO_3^-, HNO_3, and NO_2.

Modeling Domain. So that the CALPUFF screening analysis addressed the potential effects at the Everglades National Park, which is between approximately 180 and 284 km from the source at its closest and farthest points, the modeling domain used for the analysis was in the shape of a square extending 334.2 km in the east-west (x) direction and 334.2 km in the north-south (y) direction. The center of the modeling domain is approximately 27.47 degrees N latitude and 80.35 degrees W longitude. The southwestern corner of the square, the origin of the modeling domain, was located at approximately 227.4 km UTMX and 2,694.8 km UTMY (UTM Zone 17). Because the CALPUFF screening analysis only uses single-station meteorological data (rather than the full three-dimensional wind field and temperature data and two-dimensional fields of mixing heights and other meteorological variables generated by CALMET), only two grid cells in the x-direction and two grid cells in the y-direction are needed to fully represent the resulting spatially uniform gridded field.

Receptor Locations. Discrete receptors were spaced every degree on two rings centered on the Duke Energy Fort Pierce facility and bounding the Everglades National Park Class I area. The rings are representative of the nearest and furthest distances from the facility to the Class I area. The two rings have radii of 180 and 284.2 km.

Emission Rates. Because oil-firing is constrained to a maximum of 12 hours in any 24-hour period, diurnally varying emission rates were used in the analysis for the 3-hour and 24-hour time averaging results. For the 3-hour and 24-hour time averaging results, base emission rates were set to those for oil firing. These were then adjusted by means of scaling factors for hours during which gas firing occurred (see Table 3).

TABLE 3
Scaling Factors for Diurnal Variation in Emission Factors for CALPUFF modeling
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Pollutant	Oil Firing (lb/hr)	Gas Firing (lb/hr)	Factor (Gas/Oil)
SO_2	400	48	0.120
NO_x	1272	328	0.258
PM_{10}	200	88	0.440

For the purpose of this analysis, the diurnal variation in emissions associated with fuel oil firing was assessed by assuming that fuel oil would most likely be burned during the 12-hr period from 8 a.m. to 8 p.m. The modeling analysis was therefore based on modeling gas-fired emissions for hours 1 to 8, oil-fired emissions for hours 9 to 20, and gas-fired emissions for hours 21 to 24. All modeling was performed using the CALPUFF Screening methodology. The diurnal variation in emissions was accomplished by using the CALPUFF variable IVARY and the scaling factors given in Table 3. Base emission rates were set to those for oil firing. For hours 9 to 20 (oil firing) a scaling factor of 1 was used. For hours 1 to 8 and 21 to 24 the scaling factors in Table 10 were used. It is noted that Duke will not be restricting the hours of firing to any particular time period during the day, rather it will be resticted from firing oil for more than 12 hours in any given calendar day. The diurnal analysis performed here was based on a time period when the facility might reasonably be expected to operate on oil.

Because the facility will operate up to 2,500 hours per year (500 hours of which could be on back-up fuel oil), emission rates for the annual averaging period were conservatively derived by the following:

- Multiplying the oil-firing hourly rates listed above by 500
- Multiplying the gas-firing hourly rates by 2,000
- Summing the two results
- Dividing the sum by 8,760 (i.e., the number of hours in a year)

Specifically, the rates used for the annual averaging period were SO_2–33.79 lbs/hr, NO_X–147.5 lbs/hr, and PM_{10}–31.51 lbs/hr.

CALPUFF Settings. The CALPUFF settings used in the CALPUFF control file follow those given in Appendix B of IWAQM2. The CALPUFF control files used from the analyses are attached. The main values are summarized in Table 4.

TABLE 4
CALPUFF Settings Used in the Analysis
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_X, HNO_3, NO_3, PM_{10}
Chemical Transformation	MESOPUFF II scheme with CALPUFF default
Deposition	Include both dry and wet deposition, plume
Meteorological	ISCMET.DAT (extended ISC3)
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	PG/MG coefficients,
Output	Create binary file
Model Processing	Highest concentration predicted
Background Values	Ozone: 28 ppb[1]; Ammonia: 10 ppb[2]
Variable Emissions Data for Point Source	Diurnal cycle (24 scaling factors: hours 1-24)

Notes:
[1] Provided by John Notar/NPS
[2] CALPUFF default value

CALPOST Settings. ***Visibility.*** The CALPOST control files from the analyses are attached. The main values for a visibility calculation are summarized in Table 5.

TABLE 5
CALPOST Settings Used for Visibility Calculation
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Parameter	Setting
Species to process	ASPEC = VISIB
Maximum relatively humidity	RHMAX = 95%[1]
Fine Particulates included	LVPMF = T
Modeled PM10 used as Fine Particulates	SPECPMF = PM10
Method used for background light extinction	MVISBK = 2
Background sulfate concentration	BKSO4 = 1.86 $\mu g/m^3$
Background soil concentration	BKSOIL = 14.91 $\mu g/m^3$
Extinction due to Rayleigh Scattering	BEXTRAY = 10 (1/Mm)
Averaging Time	L24HR = T

Note:
[1] Provided by John Notar/NPS

Total Sulfur and Nitrogen Deposition

The total depositions of sulfur and nitrogen were calculated in km per hectare per year. These values were derived from the annual wet and dry fluxes of SO_2, $SO_4^{=}$, NO_x, HNO_3, and NO_3^- that are available as output from CALPOST. Per direction from John Notar of the National Park Service, the fluxes were converted to sulfur and nitrogen deposited by the use of the multipliers given in Section 3.3 of IWAQM2.

Source Description

The proposed 640-MW simple cycle power generating plant (with eight GE 7EA turbines) was modeled as a single source. Table 6 summarizes the emissions source as used in the model.

Visibility

Following the IWAQM2 guidance for a screening analysis, the regional haze analysis for visibility impacts uses the maximum 24-hour sulfate, nitrate, and particulate concentrations to calculate the percent change in extinction using the FLM supplied background extinction. Table 7 summarizes the background visibility values for the Everglades National Park Class I area as provided by John Notar of the National Park Service.

TABLE 6
640-MW Simple Cycle Powering Generating Plant Source Characteristics
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Description	X UTM (km)	Y UTM (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temperature (k)
Power Plant	561.591	3028.9629	28.35	0.0	4.572	41.85	813.7

TABLE 7
Background Visibility Values for Everglades National Park
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Area	Hygro (1/Mm)	Non-Hygro (1/Mm)	Rayleigh (1/Mm)	f(RH)
Everglades NP	5.59	14.91	10	3.85

Results

The results of the ambient air, visibility, and deposition analyses are presented in Tables 8, 9, and 10, respectively. Table 8 shows that modeled concentrations are all less than the EPA proposed Class I area significance levels. Table 9 shows that modeled percent changes in extinction are all less than 10 percent, with only a few days per year greater than 5 percent. In general, with only two exceptions, predicted extinction values are only marginally greater than 5 percent. Table 10 shows that the maximum modeled nitrogen deposition for all years is less than or equal to 0.003 km per hectare per year, and that the maximum modeled sulfur deposited for all years is less than or equal to 0.0025 km per hectare per year.

TABLE 8
Ambient Air Quality Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	SO_2 Annual (µg/m3)	SO_2 24-hour (µg/m3)	SO_2 3-hour (µg/m3)	PM_{10} Annual (µg/m3)	PM_{10} 24-hour (µg/m3)	NO_x Annual (µg/m3)
1986	0.0013	0.1156	0.3669	0.0015	0.0850	0.0030
1987	0.0012	0.1207	0.4540	0.0014	0.0799	0.0028
1988	0.0011	0.1239	0.3859	0.0013	0.0880	0.0027
1989	0.0013	0.1743	0.4730	0.0015	0.1100	0.0027
1990	0.0011	0.1563	0.4762	0.0013	0.1017	0.0027
Class I Significance Level	**0.1**	**0.2**	**1.0**	**0.2**	**0.3**	**0.1**

TABLE 9
Visibility Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	Number of Days with Extinction Change > 5%	Days with Extinction Change ≥ 5%	Extinction Change (%)
1986	2	Day 3	5.29
		Day 51	9.00
1987	2	Day 30	5.41
		Day 51	5.74
1988	3	Day 43	5.00
		Day 44	5.06
		Day 235	5.44
1989	1	Day 356	6.89
1990	2	Day 13	5.54
		Day 355	5.06

TABLE 10
Deposition Results
Proposed Power Generating Facility, Duke Energy Fort Pierce, LLC

Year	Total N (kg/(ha*yr))	Total S (kg/(ha*yr))
1986	0.0019	0.0014
1987	0.0016	0.0011
1988	0.0016	0.0011
1989	0.0016	0.0012
1990	0.0016	0.0013

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 8, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Sr. Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Request for Additional Information No. 2
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Gilliland:

On December 14, 2000, the Department received additional information with regard to the Duke Energy application for a PSD air permit to construct a new 640 MW electrical generating station located approximately ½ mile east of the Florida Turnpike and 1 mile north of Midway Road in St. Lucie County, Florida. The application remains incomplete. To continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. PSD Class I Impact Analysis: The additional information included a report entitled, "CALPUFF Results Report Proposed Power Generating Facility" which is based on the CALPUFF Lite screening model. The Department has concerns with the following ambient impacts summarized in the report:

   - There are several occasions when the ambient SO_2 concentrations in the Everglades National Park are predicted to exceed the Class I Significant Impact Level for the 24-hour averaging period due to the proposed project.
   - There are several incidents predicted to exceed the "5% Change in Extinction Level" in the Everglades National Park due to haze from the proposed project.

   The Department discussed the modeling results with the National Park Service (NPS) on January 5th. NPS is concerned with the number of days the project is predicted to adversely impact the Everglades National Park as well as the levels of impact. As a result, please revise the modeling analysis to include a refined version of the CALPUFF model (utilizing the CALMET meteorological model) be used to evaluate the impacts on the Everglades National Park from the proposed project. Please refer the 1996 EPA report entitled, "Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts", for more information on the required procedures for this modeling exercise. Other items for consideration include reducing the sulfur content of the backup distillate oil, reducing the hours of distillate oil firing during any 24-hour period, or switching the project back to firing only natural gas.

The Department will resume processing your application after receipt of the requested information. 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. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Cleve Holladay, at 850/921-8986.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

cc:

Mr. Nathan L. Plagens, Duke Energy North America
Ms. Pamela A. Lehr, CH2M HILL
Mr. Isidore Goldman, SED
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4

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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-6310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1-12-01

C. Signature

X H Herrick

☐ Agent
☐ Addressee

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 *(Copy from service label)*

~~7099 3400 0000 1453 2801~~

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 2801

Article Sent To:

Mr. Steven F. Gilliland

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

Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland

Street, Apt. No.; or PO Box No.
5400 Westheimer Ct.

City, State, ZIP+4
Houston, TX 77056-5310

PS Form 3800, July 1999 See Reverse for Instructions

CH2M HILL
115 Perimeter Center Place NE
Suite 700
Atlanta, GA
30346-1278
Tel 770.604.9095
Fax 770.604.9183

CH2MHILL

RECEIVED
DEC 15 2000
BUREAU OF AIR REGULATION

Proud Sponsor of
National Engineers Week 2000

December 14, 2000

154648

Mr. Jeffrey F. Koerner, P.E.
Florida Department of Environmental Protection
Division of Air Resources Management
111 South Magnolia Street, Suite 4
Tallahassee, FL 32301

Subject: Request for Additional Information
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Koerner:

This letter is written in response to your October 26, 2000 letter summarizing FDEP's comments regarding Duke Energy's September 2000 permit application for a proposed power generating facility to be located near Fort Pierce, Florida in St. Lucie County. Our response to your comments are provided below:

FDEP Comment No. 1: Simple Cycle Operation - The application requests simple cycle operation only. Does Duke Energy plan to convert these units in the future to combined cycle operation? Do the engineering plans include any provisions for accommodating the future installation of heat recovery steam generators (HRSGs)? The Department intends to limit operation to simple cycle only. Any future request to add combined cycle operation will require a permit modification and PSD review for CO and NOx. Please plan accordingly.

Response: Duke Energy Fort Pierce currently has no plans to convert the proposed simple cycle units to combined cycle operation and there are no provisions in the current design to accommodate the future installation of HRSG's. Duke understands that the Facility will be limited to simple cycle operation and any conversion to combined cycle operation would require a permit modification.

FDEP Comment No. 2: Combustors and Control System - Please identify the model of dry low-NOx combustors that will be included with each unit. Please identify the model and describe the automated gas turbine control system that will be installed with each unit.

Response: The combustors for the GE 7121 EA turbines will be 9/42 DLN 1.0 Combustors. The GE gas turbines and generators are controlled by the Mark VI control system. It is a fully programmable control, protection and monitoring system, which was designed by GE turbine and control engineers. The Mark VI allows for the integration of all power island and balance-of-plant controls and is the product of more than 30 years experience.

The heart of the control system is the control module, which receives input through termination boards. The control module contains an "internal" communication card and a main processor card. The "internal" communication card is used to communicate between: I/O cards that are contained within its card rack; I/O cards that may be contained in expansion I/O racks called Interface Modules; I/O in backup Protection Modules; I/O in other Control Modules used in triple redundant configurations; and the main processor card. The main processor card executes the bulk of the application software.

The Mark VI also has an operator interface referred to as the HMI (Human Machine Interface). It is a PC running Microsoft Windows NT with a graphics display system, a Control System Toolbox for maintenance, and a software interface for the Mark VI and other control systems on the network. The HMI can be used as the primary operator interface for one or multiple units; a backup operator interface to the plant DCS operator interface; a gateway for communication links to other control systems; a permanent or temporary maintenance station; and/or an engineer's workstation.

FDEP Comment No. 3: Inlet Air-Cooling System - Please describe and detail the "air-cooled" auxiliary inlet air cooling system (page 2-5). The application also mentions an inlet fogging system to enhance power output during the summer months. Is this a high-pressure, direct water spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

Response: The air-cooled auxiliary cooling system described on page 2-5 is not for cooling inlet air, but for auxiliary plant equipment, primarily the combustion turbine lubricating system. This system will utilize a closed loop non-contact auxiliary cooling water system that will use a water/glycol mixture as the cooling medium and will include an expansion tank, pumps, and water-to-air fin fan heat exchangers. There will not be any air emissions associated with the operation of this system.

Each CTG will be equipped with an inlet fogging system (high pressure, direct water spray) to enhance the power produced from the generator. When the CTGs are burning fuel gas at 100% load, and ambient temperatures exceed 59 °F, the inlet fogging system will be implemented. While in operation, the fogging system pumps demineralized water (up to 38 gpm per turbine) from on-site storage tanks into the inlet air duct between the inlet filter and the compressor section of the CTG at a pressure of up to 2000 psi. The demineralized water mixes with the inlet air as a very fine mist, and causes the inlet air to approach its wet bulb temperature (up to 33 °F of cooling). The fogging systems are typically model number FPS-3850-6-11, supplied by Mee Industries Inc.

FDEP Comment No. 4: Fuel Tanks - What is the size (gallons) of each of the four fuel oil tanks to be installed?

Response: The four fuel oil storage tanks will be identical in size and will each be capable of storing approximately 1 million gallons of oil. Each storage tank will have a 67-foot diameter and be 48 feet tall. Maximum liquid height in the storage tanks will not exceed 46 feet, therefore, the total storage capacity of all four tanks will be approximately 4.8 million gallons.

FDEP Comment No. 5: CO Emissions Standards - Although the application requests a CO standard for gas firing of 25.0 ppmvd, the Department is aware of actual field data showing CO emissions to be less than 10 ppmvd, particularly at typical stack test conditions near 100% base load. The Department has recently permitted GE 7EA units with the following CO emissions standards for gas firing:

- 25.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, first year of operation
- 20.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, after first year of operation

Table 3-3 indicates CO emissions of 42.0 ppmvd (58.0 lb/hour) at 60% of base load and an inlet temperature of 101° F. Is this correct? Please comment on these items.

Response: Duke has experienced difficulty during warm weather conditions in achieving sustained CO emissions from GE 7FA turbines below 20 to 25 ppmvd. As a result of their operational experience, Duke would prefer to limit CO emissions to a minimum of 20 ppm and is agreeable to the Department's recent permit limits for other 7EA units (i.e., 25 ppmvd during first year and 20 ppmvd thereafter). The CO emission limit of 42 ppmvd shown in Table 3-3 is correct as stated, and is based on the best information available to Duke at this time. At relatively low load levels (i.e., approaching 50 – 60 percent), emissions of CO have been observed in practice to vary significantly. The 42 ppmvd emission rate shown is for an extreme summer temperature condition and should not necessarily be considered reliable, however it represents the best information available to us at this time. It should be noted that Duke does not intend to operate the proposed units at load levels as low as 60% on a consistent basis, but it is possible that they could be operated at these levels for several hours at a time.

FDEP Comment No. 6: NOx Emissions Standards - The application requests a NOx emission standard for gas firing of 12.0 ppmvd corrected to 15% oxygen for the General Electric 7EA gas turbine. The Department has emissions performance data from General Electric that indicates NOx emissions for this unit will be 9.0 ppmvd corrected to 15% oxygen. The Department has recently permitted GE 7EA units with the following NOx emissions standards:

- 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and 9.0 ppmvd @ 15% oxygen based on a 24-hour block CEMS average of available operating hours
- 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and 10.0 ppmvd @ 15% oxygen based on a 3-hour rolling CEMS average

Please comment.

Response: Duke recognizes that General Electric performance data indicates that 7EA units are capable of achieving a NOx emission rate of 9 ppmvd at 15% oxygen during steady state operating conditions. Steady state operating conditions are defined as the condition of the turbine where the rotor is in thermal equilibrium and the load on the unit is not changing by greater than 0.5%. Rotor thermal equilibrium is defined as less than a 5 degree F change in wheel spacings in any 15 minute interval. The unit load change is defined as less than a 0.5% change in fuel flow of the unit within 2 minutes prior to emissions sampling and one minute after sampling. Duke's experience with operational equipment is such that the ability to achieve 9 ppmvd is feasible only during steady state operating conditions and 12 ppmvd is a more feasible emission limit on a *short-term* basis (i.e., 1 to 3 hour average). If the Department does not feel that a 12 ppmvd limit is appropriate (for all averaging periods), Duke would like to request that its NOx emissions for the 7EA units be limited to 10.5 ppmvd (during gas-fired operation) on a continuous basis, with compliance to be assessed on a *long-term* basis. Oil-fired operation will continue to be limited to 1000 hours per year per turbine, with a NOx emission limit of 42 ppmvd.

FDEP Comment No. 7: SAM Emissions - Page 5-21 states that approximately 10% of the SO_2 emissions are oxidized to SO_3, eventually forming sulfuric acid mist (H_2SO_4, SAM). Based on the application, the project would result in 27.4 tons of SAM per year. Table 62-212.400-2, F.A.C. identifies "7.0 tons per year" as the PSD Significant Emission Rate for SAM. Please provide a BACT analysis for SAM emissions.

Response: The statement on page 5-21 is intended to reflect the understanding that only a very small amount of SO_2 emissions from the Facility would be oxidized to SO_3, only some of which in turn could eventually form H_2SO_4 under favorable atmospheric conditions. FDEP's estimate of 27.4 tons of SAM would therefore be a very high (and unlikely) estimate of the amount of SAM resulting from the project. The methods for controlling SAM emissions/formation would be the same as the methods used to control SO_2 emissions. SO_2/SAM control strategies can generally be classified into five categories: fuel/material sulfur content limitation, absorption by a solution (wet scrubbing), 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 illustrates that the exclusive use of low sulfur fuels constitutes the top level of of control for SO_2. For this project, Duke proposes as BACT the use of pipeline natural gas and 0.05% sulfur oil as a backup fuel. This BACT proposal is consistent with other recent determinations for similar facilities in Florida and elsewhere in the country.

Additionally, Duke believes that the formation of SAM will be well below the conservative estimate of 27.4 tons per year because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grains of sulfur per 100 standard cubic feet (gr S/100 scf). This value is well below the "default" maximum value of 20 gr S/100 scf, but high enough to require a BACT determination.

FDEP Comment No. 8: VOC Standard - Please correct the VOC emissions rate from "ppmvw" to "ppmvd corrected to 15% oxygen".

Response: The requested information is provided in Attachment 1.

FDEP Comment No. 9: SCR and CO Oxidation Catalyst Cost Analyses - The application indicates an incremental cost effectiveness of $50,602 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $21,832 per ton of CO removed for the installation of an oxidation catalyst. After reviewing information for similar projects, the Department believes these estimates are inaccurate. In fact, a similar Duke Energy project in Madison, Ohio involved the General Electric Model 7EA with annual operation of 2500 hour of gas firing and 500 hours of oil firing. The agency's permit documentation (July 1999) indicates an incremental cost effectiveness of $19,000 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $9000 per ton of CO removed for the installation of an oxidation catalyst. Other projects in the United States have estimated the cost effectiveness of each of these technologies to be much lower than presented in this application.

Response: Tables 5-2 (Combustion Turbine NOx BACT Analysis) and 5-5 (Combustion Turbine CO and VOC BACT Analysis) have been revised to reflect the Department's comments and are provided as an attachment to this letter. While the cost effectiveness calculations indicate higher than average costs ($/ton) for the control technologies in question, we attribute this to the lower than average emission rates associated with the GE 7EA turbines.

Responses to each of DEP's specific comments are provided below.

For projects requesting operating limits on "groups" of gas turbines instead of individual units, EPA requires calculating the "cost effectiveness" based on the maximum operation for a given unit. For example, based on the application provided, this would be 7760 hours per year of gas firing and 1000 hours per year of oil firing. This would result in annual NOx emissions of 239 tons per year and a potential NOx reduction from SCR of 167 tons per year based on 71% control efficiency. Please base the NOx and CO cost effectiveness calculations ($/ton pollutant removed) on the worst case requested. If the worst case is for oil firing, then include emissions from oil firing based on the same control efficiency. The worst case may be different for the SCR analysis and oxidation catalyst analysis. Note: In addition to the caps requested on total operation of the 8 gas turbines, the Department is considering an operating limit of 5000 hours per year for each turbine.

Response: Duke's application requested a 2,500 hour individual and 20,000 aggregate hourly limit for the 8 simple cycle units, with the intent that individual units could operate up to about 2,500 hours (+/-). It is understood that the Department is considering limiting operation to 5,000 hours per unit. For the purpose of this application, the worst case scenario should be considered to be 2,500 hours operation per unit, of which up to 1,000 hours could be on backup fuel oil. Since NOx control by SCR is not considered to be feasible during fuel oil firing, the worst case BACT analysis for NOx emissions is therefore based on 2,500 hours per turbine per year, with all 8 turbines running simultaneously. Since CO emission rates during natural gas firing are greater than during fuel oil firing (i.e., 52 lb/hr vs. 42 lb/hr per unit at full load), the worst case BACT analysis for CO emissions is therefore based on 2,500 hours per turbine per year. Although VOC emissions are slightly greater during fuel oil firing than during natural gas firing (i.e., 4.5 lb/hr vs. 1.8 lb/hr per unit at full load), the BACT economic analysis of an oxidation catalyst for CO and VOC control is dominated by the much larger reduction of CO emissions that are predicted to occur through the catalyst unit. Therefore, the worst case BACT scenario (for all pollutants) is based on 2,500 hours per turbine per year, with all 8 units operating simultaneously.

a. Please provide the actual vendor's quotes (with equipment listed) for the SCR system and for the oxidation catalyst system.

Response: The cost information for the hot SCR and CO Catalyst systems were obtained from a recent similar project being developed by Duke in Mississippi (i.e., the Southaven Energy Facility). Quotes for capital equipment costs were obtained from Engelhard, a copy of which is attached to this letter as Attachment 2. Engelhard's quote of $3,600,000 is for a complete system including instrumentation assuming 3,500 hours of operation, and this estimate was proportioned among various equipment. To replicate this figure, add $2,037,250 (hot SCR from Table 5-2), $203,700 (instrumentation for SCR from Table 5-2), $1,241,875 (Oxidation Catalyst from Table 5-5), and $124,200 (instrumentation from Table 5-5). Note that there are approximation variances attributable to proportioning the costs between the two systems, which are combined in practice. Instrumentation and freight costs were estimated using EPA's OAQPS Control Cost Guidance Manual, which estimates 10% of capital for instrumentation and 5% of capital for freight.

b. Please describe the "instrumentation" that would be provided for the SCR system ($203,700) and for the oxidation catalyst system ($124,200). Is this instrumentation already included in the vendor quotes? If no instrumentation is proposed, please remove these costs.

Response: The instrumentation associated with the hot SCR system are integrated into Engelhard's quote for the capital cost of the equipment that is discussed in the previous comment and response. The OAQPS guidance was used to isolate a figure for the instrumentation. At this stage of the design, the details on instrumentation are not fully defined, but the estimated cost of 10% of capital is not inconsistent with Duke's experience at other facilities. Instrumentation will consist primarily of control systems for monitoring system performance and the general operation of the system.

c. Please revise the SCR cost analysis and the oxidation catalyst cost analysis for the following items:

Capital Cost Items

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased equipment;

Response: The state sales tax in Tables 5-2 and 5-5 has been revised to 6%. It is assumed that a sales tax will be assessed on purchased equipment. There is no information available at this time to indicate that sales tax will not be assessed on purchased equipment.

- Revise the "contingency" factor under indirect capital costs for hot SCR from 0.20 to 0.10; and

Response: The "contingency factor in Tables 5-2 and 5-5 has been revised to 0.10.

- Remove the cost for "simple interest during construction";

Response: The cost for "simple interest during construction" has been removed from Tables 5-2 and 5-5.

Annual Cost Items

- Revise the cost for "power loss due to pressure drop across the catalyst" based on $0.04 / kWh or provide supporting documentation for $0.065 / kWh;

Response: The cost for "power loss due to pressure drop across the catalyst" has been revised in Tables 5-2 and 5-5, and is now based on $0.04/kWh.

- Revise the cost for "operating labor" based on 625 hours of labor per year (2500 hr/yr* / 12 hr/shift x 3 hr labor/shift);

Response: The cost for "operating labor" has been revised in Tables 5-2 and 5-5 to reflect 625 annual hours (3 hours per shift) for SCR operation, and 208 annual hours (1 hour per shift) for the Oxidation Catalyst.

- Revise cost for "supervisory labor" accordingly;

Response: The cost for "supervisory labor" has been revised in Tables 5-2 and 5-5 to reflect the changes in operating labor described above.

- Revise the cost for "maintenance labor" based on 833 hours of labor per year (2500 hr/yr* / 12 hr/shift x 4 hr labor/shift);

Response: The cost for "maintenance labor" has been revised in Tables 5-2 and 5-5 to reflect 833 annual hours (4 hours per shift) for SCR maintenance, and 208 annual hours (1 hour per shift) for the Oxidation Catalyst.

- Revise the cost for "maintenance materials" accordingly;

Response: The cost for "maintenance materials" has been revised in Tables 5-2 and 5-5 to reflect the changes in maintenance labor described above.

- Remove the cost for "revenue loss during catalyst replacement" (can be scheduled during normal down time);

Response: The cost for "revenue loss during catalyst replacement" has been removed from Table 5-2 and 5-5, to reflect replacement during normal down time.

- Remove the costs for "catalyst cleaning" and "catalyst replacement labor";

Response: Duke notes that the costs associated with catalyst cleaning and catalyst replacement labor are costs that will actually be incurred against the project during its lifetime and they should be included in the analyses; however, at your request we have removed these costs from the analysis in Tables 5-2 and 5-5.

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased catalyst;

Response: The state sales tax in Tables 5-2 and 5-5 has been revised to 6%. It is assumed that a sales tax will be assessed on purchased catalyst. There is no information available at this time to indicate that sales tax will not be assessed on purchased equipment.

- Revise the "overhead" costs based on previous changes; and

Response: The "overhead" costs in Tables 5-2 and 5-5 have been revised based on the previous changes.

- Remove the cost for "property tax" for the control equipment.

Response: The cost for "property tax" has been removed from Table 5-2 and 5-5.

Emissions Reduction

- If the costs are estimated at 8760 hours per year, then the emissions reductions should be based on the same. * If a limit is requested for each simple cycle gas turbine of 5000 hours per year, substitute 5000 for 2500.

Response: The cost in Tables 5-2 and 5-5 have been revised and are based on 2,500 hours per year per turbine. The emissions reductions are based on 2,500 hours per year per turbine.

- Revise the oxidation catalyst control efficiency from 80% to 90% or provide a reference for the assumed 80% control efficiency.

Response: The oxidation catalyst control efficiency in Table 5-5 has been revised to 90% for CO emissions.

FDEP Comment No. 10: PSD Class I Impact Analysis - In July of 2000, representatives for Duke Energy met with representatives of the Department in a pre-application meeting to discuss various issues. During this meeting, Duke Energy questioned whether or not a PSD Class I Ambient Air Quality Impact Analysis for the Everglades National Park was necessary for a combustion turbine project fired completely with natural gas. The Department relayed a response to Duke Energy from the National Park Service that a PSD Class I Ambient Air Quality Impact Analysis was not necessary for the project, as described, fired solely with natural gas. The following table lists the annual emissions given to the Department at that time of the meeting as well as the annual potential emissions as submitted in the application:

Pollutant	Pre-Application TPY	Application TPY
CO	400	580
NOx	225	1010
PM_{10}	120	170
SO_2	100	274

Obviously, Duke Energy now intends to fire low sulfur distillate oil as a backup fuel based on an interruptible gas supply contract (page 2-7) and has requested up to 1000 hours of oil firing per gas turbine. Please submit the required PSD Class I Ambient Air Quality Impact Analysis for this project.

Response: On Duke's behalf, CH2M HILL has discussed the need for a PSD Class I analysis with a representative of the National Park Service (NPS) in Denver. The NPS subsequently requested that a screening analysis be conducted for the oil-fired operating scenario to evaluate potential impacts in the Everglades National Park. CH2M HILL has completed the modeling analysis and has submitted documentation to both NPS and FDEP modeling staff summarizing our modeling procedures and results. A copy of the documentation that was initially submitted to the NPS for review and comment was also provided to Chris Carlson of DEP by e-mail on 10/30/2000. Documentation summarizing the final methodology and results was sent to NPS and FDEP by e-mail on 12/14/2000. Copies of electronic files on CD-ROM are being sent separately to both NPS and FDEP.

FDEP Comment No. 11: Class II Building Downwash Analysis - The modeling files that were submitted with the application modeled all six combustion turbines as a single stack and building. The results were then multiplied by six to obtain the modeled concentration.

This configuration does not adequately address all building downwash concerns. Please resubmit a modeling analysis that models each of the six combustion turbines and their associated buildings explicitly. Also, please submit the input file for the BPIP program.

Response: The modeling analyses were based on conservative and generally accepted assumptions that can be expected to yield higher concentrations than if the stacks and structures would have been modeled at their respective locations. All eight units were modeled at a collocated location and the only significant structures in the vicinity of the stacks (i.e., relatively small inlet air filter housings) were located immediately adjacent to the stacks. In actual fact the inlet air filter housings will be located approximately 75 ft from each respective stack and each stack will be located approximately 75 to 150 ft from each adjacent stack. The separation of the units from one another is such that no more than two of the eight air filter structures are within "5L" of any one stack, where L is the characteristic building dimension provided in DEP and EPA modeling guidance. Since all stacks and structures were modeled at a single collocated location, the predicted concentrations can be expected to be higher than if the stacks and buildings were modeled at separate locations. Inasmuch as the predicted concentrations were determined to be "insignificant" at all locations (even with the conservative assumptions), a more detailed analysis was not justified.

A copy of the input file for the BPIP program are being e-mailed separately to Chris Carlson of DEP's modeling staff.

FDEP Comment No. 12: Modeled Annual NOx Concentrations - Please submit some example calculations that show how the modeled annual NOx concentrations for the oil scenario were derived from the conversion factors presented in Appendix B.

Response: Example Calculations for NOx and PM-10 for the oil-fired scenario are shown in Attachment 3. The information provided with the original application was for the gas-fired scenario. The calculations shown for the oil-fired scenario are consistent with those shown in Appendix B of the original application for the gas-fired case.

FDEP Comment No. 13: NSPS Monitoring - Is Duke Energy proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2? Which proposed emission units would be subject to 40 CFR 60 Subpart Dc requirements as indicated on page 4-6?

Response: As discussed in Section 4.4.2.3 in the Application, Duke would like to utilize a custom fuel monitoring schedule for natural gas in lieu of daily sampling as provided for in the provisions of 40 CFR 60.334(b)(2). Prior to operation, Duke will submit a monitoring plan, which will be certified by Duke's Acid Rain Designated Representative that will commit to using pipeline natural gas as the primary fuel (sulfur content less than 20 gr/100 SCF per 40 CFR 75.11(d)(2) and each unit will be monitored for SO2 using methods consistent with 40 CFR 75. For all bulk fuel oil shipments received at the facility, Duke will obtain copies of vendor analyses showing the sulfur and nitrogen content of the fuel, as well as documentation showing that the analysis methods are in compliance with 40 CFR 60.335(d). The Department should disregard the reference to Subpart Dc fuel monitoring requirements since there will not be any fuel burning sources at the Facility that will be subject to Subpart Dc.

FDEP Comment No. 14: Acid Rain - The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new gas turbines will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

Response: An application for an Acid Rain Permit has not yet been submitted. However, an application and Certificate of Representation is currently being prepared and will be submitted in the near future. Our discussions with EPA Region IV staff indicated that Duke should submit the Certificate of Representation to EPA's Acid Rain Program Office in Washington, DC, and the Acid Rain Application should be submitted to FDEP. Duke requests that DEP confirm that this is correct.

On behalf of Duke Energy, we would like to request that you provide us with a written (or e-mail) acknowledgement that you have received this response, as well as concurrence that the information provided herein adequately addresses the questions and comments contained in your August 4, 2000 e-mail. If you should have any questions regarding the information provided herein or should you require any additional information, please contact me at (770) 604-9182 ext 355, or by e-mail at ghowroyd@ch2m.com, or Nathan Plagens at Duke Energy North America at (713) 627-5985.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\Duke\Response to DEP Comments 10-26-00.doc

c: Nathan Plagens/Duke
Dan Runyan/Duke
Pamela A. Lehr/CH2M HILL
Bill Marsh/CH2M HILL
C. Carlson
I. Goldman, SED
EPA
NPS

Table 5-2 (Revised)
Combustion Turbine NO_x BACT Analysis
71 Percent NO_x Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliaries	As Estimated, A	Vendor Quote	$2,037,250
Instrumentation	0.1 X A	(EPA, 1995a)	$203,700
State Sales Taxes	0.06 X A	State Sales Tax	$122,230
Freight	0.05 X A	(EPA, 1995a)	$101,900
PEC Subtotal (B)			**$2,465,080**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$197,200
Labor	0.14 X B	(EPA, 1990a)	$345,000
Electrical	0.04 X B	(EPA, 1990a)	$98,600
Piping	0.02 X B	(EPA, 1995a)	$49,300
Insulation	0.01 X B	(EPA, 1995a)	$24,700
Painting	0.01 X B	(EPA, 1990a)	$24,700
DIC Subtotal	0.3 X B	(EPA, 1990a)	**$739,500**
Total DIC	PEC+DIC	-	**$3,204,580**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$246,500
Construction Overhead	0.05 X B	(EPA,1990a)	$123,300
Contractor Fees	0.10 X B	(EPA,1990a)	$246,500
Contingencies	0.10 X B	(EPA,1990a)	$246,500
Start-Up	0.02 X B	(EPA,1990a)	$49,300
Performance Testing	0.01 X B	(EPA,1990a)	$24,700
Total IDC		-	**$936,800**
Total Capital Investment (TCI)	**DIC + IDC**		**$4,141,380**

Operating Cost Factors For The SCR

Cost Data

Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***
Catalyst Life	3	0.380
Equipment Life	10	0.1440

Table 5-2 (Revised)
Combustion Turbine NOx BACT Analysis
71 Percent NOx Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Annual Costs, $/Yr			
	FACTOR	**REFERENCE**	**COSTS, $/Yr**
Power Loss Due To Pressure Drop Across Catalyst	0.3% per inch of pressure drop @ $0.04/kWh and 245 KW loss	Vendor	$24,500
Operating Labor	$30/hr @ 3 hr/12-hr shift	Industry Average/Estimate	$18,750
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$2,810
Maintenance Labor	$30/hr @ 4 hr/12-hr shift	Estimate	$25,000
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$25,000
Catalyst Replacement (CR) (A)	$1,077,000 every 3 years including disposal	Vendor Quote	$1,077,000
Sales Tax (B)	6%	State Tax Rate	$64,620
Capital Recovery	[A+B] * CRF	(EPA, 1995a)	$433,816
TOTAL DIRECT ANNUAL COSTS, $/YR			**$529,875**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$31,686
Insurance & Administration	3% of TCI	(EPA,1990a)	$124,241
Capital Recovery	CRF X TCI	N/A	$596,358
			$752,285
Total Annual Costs, $/Yr	**$1,282,160**		
Total Net NOx Reductions (TPY)	36	Natural gas operation, 71% removal, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$35,616**		

Table 5-5 (Revised)
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliary Equipment (A)	As Estimated	Vendor Quote	$1,241,875
Instrumentation	0.1 X A	(EPA, 1995a)	$124,200
State Sales Taxes	0.06 X A	State Sales Tax	$74,500
Freight	0.05 X A	(EPA, 1995a)	$62,100
PEC Subtotal (B)			**$1,502,675**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$120,200
Labor	0.14 X B	(EPA, 1990a)	$210,400
Electrical	0.04 X B	(EPA, 1990a)	$60,100
Piping	0.02 X B	(EPA, 1995a)	$30,100
Insulation	0.01 X B	(EPA, 1995a)	$15,100
Painting	0.01 X B	(EPA, 1990a)	$15,100
DIC Subtotal		(EPA, 1990a)	**$451,000**
Total DIC	PEC+DIC	-	**$1,953,675**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$150,300
Construction Overhead	0.05 X B	(EPA,1990a)	$75,200
Contractor Fees	0.10 X B	(EPA,1990a)	$150,300
Contingencies	0.03 X B	(EPA,1990a)	$45,100
Start-Up	0.02 X B	(EPA,1990a)	$30,100
Performance Testing	0.01 X B	(EPA,1990a)	$15,100
Total IDC		-	**$466,100**
Total Capital Investment (TCI)	**DIC + IDC**		**$2,419,775**

Operating Cost Factors For The Oxidation Catalyst

Cost Data

Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***
Catalyst Life	3	0.38
Equipment Life	10	0.1440

Table 5-5 (Revised)
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Annual Costs, $/Yr			
Power Loss Due To Pressure Drop Across Catalyst	0.1% per inch of pressure drop @ $0.04/kWh and 245 KW loss	Vendor	$24,500
Operating Labor	$30/hr @ 1 hr/12-hr shift	Industry Average/Estimate	$6,250
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$938
Maintenance Labor	$30/hr @ 1 hr/12-hr shift	Estimate	$6,250
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$6,250
Catalyst Replacement (CR) (A)	$1,006,540 every 3 years including disposal	Vendor Quote	$1,006,540
Sales Tax (B)	6%	State Tax Rate	$60,392
Capital Recovery	[A+B] * CRF	(EPA, 1995a)	$405,434
TOTAL DIRECT ANNUAL COSTS, $/YR			**$449,622**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$8,063
Insurance & Administration	3% of TCI	(EPA,1990a)	$72,594
Capital Recovery	CRF X TCI	N/A	$348,448
Property Tax	1% of TCI	Estimate	$24,198
TOTAL INDIRECT ANNUAL COSTS, $/YR			**$453,303**
Total Annual Costs, $/Yr	**$902,925**		
Total Net CO Reductions (TPY)	59	90% Removal Efficiency, 2,500 hours/yr operation	
Total Net VOC Reductions (TPY)	1	45% Removal Efficiency, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$15,048**		

Attachment 1
VOC Emission Rates Corrected to ppmvd at 15% Oxygen

Table 1
Estimated Plant Performance and VOC Emissions Data
Duke Energy Port Pierce Generating Station
Duke Energy Fort Pierce, LLC
Fort Pierce, FL

Combustion turbine load	100%					75%					60%					ISO
Ambient temperature (°F)	**101**	**82**	**74.6**	**66.8**	**27**	**101**	**82**	**74.6**	**66.8**	**27**	**101**	**82**	**74.6**	**66.8**	**27**	**59**
Relative humidity (%)	40	77	72	74	81	40	77	72	74	81	40	77	72	74	81	60
Firing Natural Gas																
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd @ 15% O2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	2.2	1.5	1.5	1.5	1.4	1.5
Firing Distillate Oil																
VOC (ppmvw)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
VOC (ppmvd @ 15% O2)	3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.4	3.3	3.5	3.4	3.4	3.4	3.3	3.4

Attachment 2
Quotes for SCR and Oxidation Catalyst Emission Control Systems

BEST AVAILABLE COPY

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

vember 13, 1998

:
Simple Cycle Turbines
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB98283-Rev. 1

:ar ,

e provide Engelhard Budgetary Proposal for Engelhard Camet® CO Oxidation Catalyst System mponents and NOxCAT ZNX™ High Temperature SCR Catalyst system components for the above projects. This is per your Xes of November 10 and 11, 1998.

ır Budgetary Proposal is based on:

.iven data for GE 7EA, Westinghouse 501D5A, and Westinghouse 501F Gas Turbines operating in simple cycle mode for both 3,500 hours/year and 2,000 hours/year operation;

Oxidation Catalysts for CO reductions as noted;

Catalyst for NOx reductions as noted with ammonia slip of 5 ppmvd@15%O_2;

Delta P through CO and SCR systems of Nominal 4"WG;

Assumed internally insulated ducts with cross sections at the catalyst as illustrated. Note that all transitions are based on assumed turbine discharge cross section of 15 ft. x 15 ft.;

Scope as noted. Please note that we have assumed horizontal gas flow through the CO / SCR reactor and the use of 28% aqueous ammonia. The systems for the GE 7EA and Westinghouse 501F require the use of an ambient air cooling system to reduce the gas temperature to the SCR catalyst.

Three (3) Year Performance Guarantee (expected life five to seven years).

Ve request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Nancy Ellison - Proposal Administrator

T-380 P.003/012 F-841 713-627-5644 From-DUKE ENERGY Nov-09-2000 11:26am

ENGELHARD

BEST AVAILABLE COPY

ENRON
Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB98283-Rev. 1
November 13, 1998

ENGELHARD CORPORATION
CAMET™ CO CATALYST SYSTEM
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

gelhard Corporation ("Engelhard") offers to supply to Buyer the CAMET™ metal substrate CO Catalyst System components ג the NOxCAT ZNX™ ceramic substrate SCR system components summarized herein.

ɔxCAT ZNX™ High Temperature SCR Catalyst System: Scope of Supply

Engelhard CAMET® CO and NOxCAT ZNX™ SCR catalyst in modules;
Internal support structures for catalyst modules (frame);
Internally insulated reactor ductwork - with stainless steel liner sheets - to house CO catalyst modules, AIG, and SCR Catalyst modules;
Inlet and outlet transition duct sections - internally insulated with stainless steel liner - inlet flow straightener in inlet transition section;
Ammonia Injection Grid (AIG);
AIG manifold with flow control valves ;
NH_3/Air dilution skid: Anhydrous Ammonia to skid;
Ambient air cooling system components as required.

JDGET PRICES: Per Turbine- 3,500 hr/yr	GE 7EA	West. 501D5A	West. 501F
ıms 1 - 7 above - complete system	$3,600,000	$6,000,000	$5,500,000
·-·lacement CO Modules	$ 450,000	$ 750,000	$ 500,000 /0.75 = 667,000
cement ZNX Modules	$1,400,000	$2,000,000	$1,800,000
Per Turbine- 2,000 hr/yr	**GE 7EA**	**West. 501D5A**	**West. 501F**
:ms 1 - 7 above - complete system	$3,000,000	$3,600,000	$3,800,000
eplacement CO Modules	$ 360,000	$ 450,000	$ 420,000
eplacement ZNX Modules	$1,000,000	$1,500,000	$1,400,000

'ARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

OCUMENT / MATERIAL DELIVERY SCHEDULE

rawings / Documentation -	6 - 8 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
perating manuals	
laterial Delivery	20 - 24 weeks after approval and release for fabrication

YSTEM DESIGN BASIS:

ias Flow from:	GE Fr7 and Westinghouse 501F - with ambient air cooling
ias Flow from:	Westinghouse 501D5A
ias Flow:	Assumed Horizontal
uel:	Natural Gas
ias Flow Rate (At catalyst face):	See Performance data
emperature (At catalyst face):	See Performance data
·O Concentration (At catalyst face):	See Performance data
Reduction:	See Performance data
ıOx Concentration (At catalyst face):	See Performance data
lOx Reduction:	See Performance data
lH3 Slip:	5 ppmvd@15%O_2
'ressure Drop through SCR	Nom. 4"WG

Simple Cyc. urbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal I
November 13, 1998

Performance Date GE 7EA No. Units - 8 3,600 hr / yr

AMBIENT	69	20	80	90	95	90	90	90	80
LOAD	BASE	BASE	BASE	BASE	BASE	BASE	75%	52%	35%
TURBINE EXHAUST TEMPERATURE, F	969	972	1,012	1,019	1,023	1,019	1,080	1,100	1,064
TURBINE EXHAUST FLOW, lb/hr	2,358,000	2,574,000	2,240,000	2,181,000	2,181,000	2,181,000	1,725,000	1,487,000	1,328,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.68	75.45	74.11	73.63	73.18	73.53	73.45	73.57	73.77
O2	13.65	13.69	13.71	13.69	13.60	13.59	13.36	13.71	14.29
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.19	3.04	2.76
H2O	7.22	6.65	8.18	8.90	9.35	8.90	9.09	8.79	8.27
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.88	0.89	0.69
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0	111,578	120,392	60,909
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,358,000	2,574,000	2,240,000	2,181,000	2,181,000	2,181,000	1,836,578	1,596,392	1,368,909
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	74.66	75.45	74.11	73.63	73.18	73.63	73.91	74.18	74.09
O2	13.66	13.69	13.71	13.59	13.50	13.69	13.70	14.12	14.48
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.00	2.80	2.68
H2O	7.22	6.65	8.18	8.90	9.35	8.90	8.65	8.09	7.91
Ar	0.60	0.91	0.88	0.88	0.88	0.88	0.84	0.82	0.85
CALCULATED AIR + GAS MOL. WT.	28.40	28.54	28.36	28.27	28.22	28.27	28.29	28.32	28.33
GIVEN: TURBINE CO, ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINE CO, lb/hr	63.6	69.0	60.8	49.2	48.4	49.2	35.6	33.1	30.1
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	42.0
CALC.: TURBINE NOx, lb/hr	53.7	59.6	50.6	49.2	48.5	49.2	40.1	32.5	75.0
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	24.7	24.4	24.7	24.7	24.6	24.7	23.3	24.3	27.2
CALC. NOx, ppmvd@15%O2 - AT CATALYST FACE	15.0	15.0	15.0	15.0	15.0	15.0	14.7	14.5	41.2
FLUE GAS TEMP @ SCR CATALYST, F	969	972	1,012	1,019	1,023	1,019	1,026	1,026	1,025
DESIGN REQUIREMENTS									
CO CATALYST CO OUT, ppmvd@15%O2	7.4	7.3	7.4	7.4	7.4	7.4	7.0	7.3	8.2
SCR CATALYST NOx OUT, ppmvd@15%O2	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.									
GUARANTEED PERFORMANCE DATA									
CO CATALYST CO CONVERSION - % Max.	70.0%	75.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
CO OUT, ppmvd@15%O2 - Max.	7.4	6.1	7.4	7.4	7.4	7.4	7.0	7.3	8.2
CO OUT, lb/hr - Max.	16.1	14.6	15.2	14.8	14.6	14.8	11.7	9.9	9.0
CO PRESSURE DROP, 0.8 "WG - Max.									
SCR CATALYST NOx CONVERSION, % - Min.	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
NOx OUT, lb/hr - Max.	16.1	17.9	15.2	14.8	14.6	14.8	12.0	9.7	22.5
NOx OUT, ppmvd@15%O2 - Max.	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	73	81	69	67	66	67	66	46	81
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5

Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal
November 13, 1998

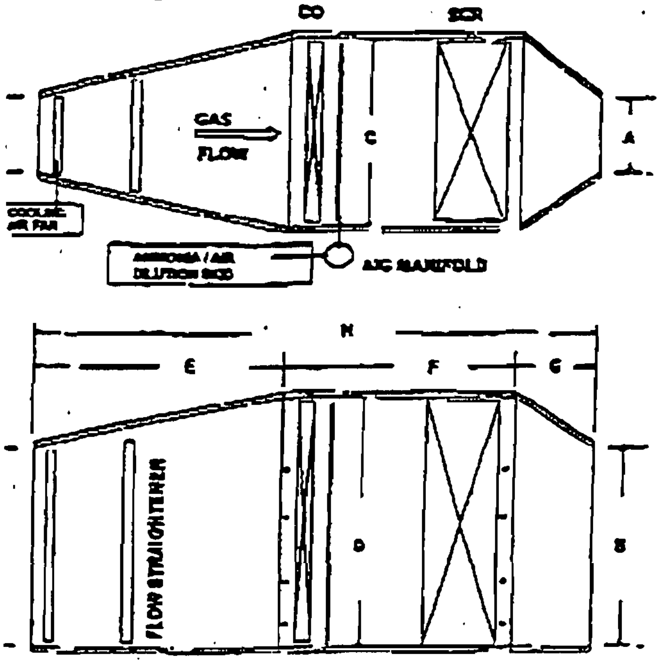
he equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

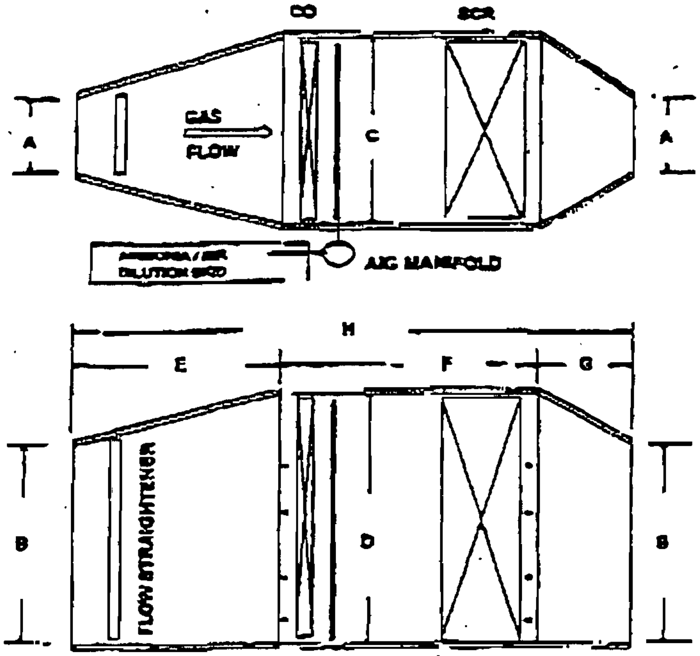
ssumed Dimensions / Sketch:

E7EA 3,500 hr/yr
urbine Discharge Width (A) 15'-0"
urbine Discharge Height (B) 15'-0"
leactor Inside Liner Width (C) 41'-6"
eactor Inside Liner Height (D) 32'-3"
let Transition Length (E) 31'-0"
leactor Depth (F) 15'-0"
utlet Transition Length (G) 13'-3"
otal Depth (H) 59'-3"
stimated Weight 1,100,00 lb.

West. 501D5A 3,500 hr/yr
Turbine Discharge Width (A) 15'-0"
Turbine Discharge Height (B) 15'-0"
Reactor Inside Liner Width (C) 58'-3"
Reactor Inside Liner Height (D) 35'-6"
Inlet Transition Length (E) 38'-6"
Reactor Depth (F) 15'-0"
Outlet Transition Length (G) 21'-6"
Total Depth (H) 75'-0"
Estimated Weight 1,400,000 lb.

Vest. 501F 3,500 hr/yr
urbine Discharge Width (A) 15'-0"
urbine Discharge Height (B) 15'-0"
eactor Inside Liner Width (C) 55'-6"
eactor Inside Liner Height (D) 35'-6"
let Transition Length (E) 36'-3"
eactor Depth (F) 15'-0"
utlet Transition Length (G) 20'-3"
otal Depth (H) 71'-6"
stimated Weight 1,400,000 lb.





Attachment 3
Example Calculations – NOx and PM-10 (Oil-Fired Scenario)

Duke Energy - St. Lucie

100% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0449	0.0459	0.0486	0.0512	**0.0526**
CO - 1-hr. Avg.	10.276	10.013	12.069	13.775	**14.266**
- 8-hr. Avg.	**3.342**	3.055	3.000	2.870	2.870
PM-10 - Annual Avg.	0.067	0.069	0.073	0.077	**0.079**
- 24-hr.	0.811	0.799	0.804	0.837	**0.897**
SO_2 - Annual Avg.	0.124	0.127	0.134	0.141	**0.145**
- 24-hr. Avg.	1.493	1.470	1.479	1.539	**1.651**
- 3-hr. Avg.	6.111	6.172	5.828	5.694	**8.773**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0461	0.0472	0.0499	0.0527	**0.0540**
CO - 1-hr. Avg.	10.978	10.694	12.912	**14.746**	14.390
- 8-hr. Avg.	**3.421**	3.175	3.099	2.964	2.985
PM-10 - Annual Avg.	0.064	0.065	0.069	0.073	**0.074**
- 24-hr.	0.784	0.771	0.776	0.804	**0.842**
SO_2 - Annual Avg.	0.127	0.130	0.138	0.145	**0.149**
- 24-hr. Avg.	1.567	1.542	1.552	1.608	**1.683**
- 3-hr. Avg.	6.386	6.441	6.260	5.942	**9.470**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0484	0.0501	0.0528	0.0549	**0.0565**
CO - 1-hr. Avg.	12.133	11.816	14.308	13.659	**14.606**
- 8-hr. Avg.	**3.539**	3.359	3.259	3.108	3.127
PM-10 - Annual Avg.	0.061	0.063	0.066	0.069	**0.071**
- 24-hr.	0.776	0.757	0.763	0.784	**0.791**
SO_2 - Annual Avg.	0.135	0.140	0.147	0.153	**0.158**
- 24-hr. Avg.	1.731	1.690	1.701	1.748	**1.766**
- 3-hr. Avg.	6.986	7.010	7.144	6.466	**7.156**

Example Calculations

NO_X Annual Average, 1988 Winter Scenario

NO_X (ug/m^3) = (0.0239 ug/m^3)*(1456 lb/hr/79.36508 lb/hr)*(1000 hrs/8760 hrs)

= 0.050 ug/m^3

PM-10 24-hr, 1988 Winter Scenario

PM-10 (ug/m^3) = (0.289 ug/m^3)*(208 lb/hr/79.36508 lb/hr)

= 0.76 ug/m^3

Duke Energy - St. Lucie   100% Oil Load

Summer Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0267	0.0273	0.0289	0.0305	0.0313
24-hr	0.322	0.317	0.319	0.332	0.356
8-hr	0.850	0.777	0.763	0.730	0.730
3-hr	1.318	1.331	1.257	1.228	1.892
1-hr	2.614	2.547	3.070	3.504	3.629

Average Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0252	0.0258	0.0273	0.0288	0.0295
24-hr	0.311	0.306	0.308	0.319	0.334
8-hr	0.808	0.750	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.526	3.050	3.483	3.399

Winter Scenario   Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0231	0.0239	0.0252	0.0262	0.0270
24-hr	0.296	0.289	0.291	0.299	0.302
8-hr	0.747	0.709	0.688	0.656	0.660
3-hr	1.195	1.199	1.222	1.106	1.224
1-hr	2.561	2.494	3.020	2.883	3.083

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 26, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Sr. Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Request for Additional Information
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Gilliland:

On October 5, 2000, the Department received an application with sufficient processing fee from Duke Energy for a PSD air permit to construct eight new 80 MW simple cycle combustion turbine/electrical generator sets. Completion of the project will create a new 640 MW electrical generating station located approximately ½ mile east of the Florida Turnpike and 1 mile north of Midway Road in St. Lucie County, Florida. The application is incomplete. To continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Simple Cycle Operation: The application requests simple cycle operation only. Does Duke Energy plan to convert these units in the future to combined cycle operation? Do the engineering plans include any provisions for accommodating the future installation of heat recovery steam generators (HRSGs)? The Department intends to limit operation to simple cycle only. Any future request to add combined cycle operation will require a permit modification and PSD review for CO and NOx. Please plan accordingly.

2. Combustors and Control System: Please identify the model of dry low-NOx combustors that will be included with each unit. Please identify the model and describe the automated gas turbine control system that will be installed with each unit.

3. Inlet Air-Cooling System: Please describe and detail the "air-cooled" auxiliary inlet air cooling system (page 2-5). The application also mentions an inlet fogging system to enhance power output during the summer months. Is this a high-pressure, direct water spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

4. Fuel Tanks: What is the size (gallons) of each of the four fuel oil tanks to be installed?

5. CO Emissions Standards: Although the application requests a CO standard for gas firing of 25.0 ppmvd, the Department is aware of actual field data showing CO emissions to be less than 10 ppmvd, particularly at typical stack test conditions near 100% base load. The Department has recently permitted GE 7EA units with the following CO emissions standards for gas firing:

   - 25.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, first year of operation
   - 20.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, after first year of operation

Table 3-3 indicates CO emissions of 42.0 ppmvd (58.0 lb/hour) at 60% of base load and an inlet temperature of 101° F. Is this correct? Please comment on these items.

6. NOx Emissions Standards: The application requests a NOx emission standard for gas firing of 12.0 ppmvd corrected to 15% oxygen for the General Electric 7EA gas turbine. The Department has emissions performance data from General Electric that indicates NOx emissions for this unit will be 9.0 ppmvd corrected to 15% oxygen. The Department has recently permitted GE 7EA units with the following NOx emissions standards:

   - 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and
     9.0 ppmvd @ 15% oxygen based on a 24-hour block CEMS average of available operating hours
   - 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and
     10.0 ppmvd @ 15% oxygen based on a 3-hour rolling CEMS average

   Please comment.

7. SAM Emissions: Page 5-21 states that approximately 10% of the SO_2 emissions are oxidized to SO_3, eventually forming sulfuric acid mist (H_2SO_4, SAM). Based on the application, the project would result in 27.4 tons of SAM per year. Table 62-212.400-2, F.A.C. identifies "7.0 tons per year" as the PSD Significant Emission Rate for SAM. Please provide a BACT analysis for SAM emissions.

8. VOC Standard: Please correct the VOC emissions rate from "ppmvw" to "ppmvd corrected to 15% oxygen".

9. SCR and CO Oxidation Catalyst Cost Analyses:

   The application indicates an incremental cost effectiveness of $50,602 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $21,832 per ton of CO removed for the installation of an oxidation catalyst. After reviewing information for similar projects, the Department believes these estimates are inaccurate. In fact, a similar Duke Energy project in Madison, Ohio involved the General Electric Model 7EA with annual operation of 2500 hour of gas firing and 500 hours of oil firing. The agency's permit documentation (July 1999) indicates an incremental cost effectiveness of $19,000 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $9000 per ton of CO removed for the installation of an oxidation catalyst. Other projects in the United States have estimated the cost effectiveness of each of these technologies to be much lower than presented in this application.

   For projects requesting operating limits on "groups" of gas turbines instead of individual units, EPA requires calculating the "cost effectiveness" based on the maximum operation for a given unit. For example, based on the application provided, this would be 7760 hours per year of gas firing and 1000 hours per year of oil firing. This would result in annual NOx emissions of 239 tons per year and a potential NOx reduction from SCR of 167 tons per year based on 71% control efficiency. Please base the NOx and CO cost effectiveness calculations ($/ton pollutant removed) on the worst case requested. If the worst case is for oil firing, then include emissions from oil firing based on the same control efficiency. The worst case may be different for the SCR analysis and oxidation catalyst analysis. Note: In addition to the caps requested on total operation of the 8 gas turbines, the Department is considering an operating limit of 5000 hours per year for each turbine.

   a. Please provide the actual vendor's quotes (with equipment listed) for the SCR system and for the oxidation catalyst system.

   b. Please describe the "instrumentation" that would be provided for the SCR system ($203,700) and for the oxidation catalyst system ($124,200). Is this instrumentation already included in the vendor quotes? If no instrumentation is proposed, please remove these costs.

c. Please revise the SCR cost analysis and the oxidation catalyst cost analysis for the following items:

Capital Cost Items

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased equipment;
- Revise the "contingency" factor under indirect capital costs for hot SCR from 0.20 to 0.10; and
- Remove the cost for "simple interest during construction";

Annual Cost Items

- Revise the cost for "power loss due to pressure drop across the catalyst" based on $0.04 / kWh or provide supporting documentation for $0.065 / kWh;
- Revise the cost for "operating labor" based on 625 hours of labor per year (2500 hr/yr* / 12 hr/shift x 3 hr labor/shift);
- Revise cost for "supervisory labor" accordingly;
- Revise the cost for "maintenance labor" based on 833 hours of labor per year (2500 hr/yr* / 12 hr/shift x 4 hr labor/shift);
- Revise the cost for "maintenance materials" accordingly;
- Remove the cost for "revenue loss during catalyst replacement" (can be scheduled during normal down time);
- Remove the costs for " catalyst cleaning" and "catalyst replacement labor";
- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased catalyst;
- Revise the "overhead" costs based on previous changes; and
- Remove the cost for "property tax" for the control equipment.

Emissions Reduction

- If the costs are estimated at 8760 hours per year, then the emissions reductions should be based on the same. * If a limit is requested for each simple cycle gas turbine of 5000 hours per year, substitute 5000 for 2500.
- Revise the oxidation catalyst control efficiency from 80% to 90% or provide a reference for the assumed 80% control efficiency.

10. <u>PSD Class I Impact Analysis</u>: In July of 2000, representatives for Duke Energy met with representatives of the Department in a pre-application meeting to discuss various issues. During this meeting, Duke Energy questioned whether or not a PSD Class I Ambient Air Quality Impact Analysis for the Everglades National Park was necessary for a combustion turbine project fired completely with natural gas. The Department relayed a response to Duke Energy from the National Park Service that a PSD Class I Ambient Air Quality Impact Analysis was not necessary for the project, as described, fired solely with natural gas. The following table lists the annual emissions given to the Department at that time of the meeting as well as the annual potential emissions as submitted in the application:

Pollutant	Pre-Application TPY	Application TPY
CO	400	580
NOx	225	1010
PM_{10}	120	170
SO_2	100	274

Obviously, Duke Energy now intends to fire low sulfur distillate oil as a backup fuel based on an interruptible gas supply contract (page 2-7) and has requested up to 1000 hours of oil firing per gas turbine. Please submit the required PSD Class I Ambient Air Quality Impact Analysis for this project.

11. Class II Building Downwash Analysis: The modeling files that were submitted with the application modeled all six combustion turbines as a single stack and building. The results were then multiplied by six to obtain the modeled concentration. This configuration does not adequately address all building downwash concerns. Please resubmit a modeling analysis that models each of the six combustion turbines and their associated buildings explicitly. Also, please submit the input file for the BPIP program.

12. Modeled Annual NOx Concentrations: Please submit some example calculations that show how the modeled annual NOx concentrations for the oil scenario were derived from the conversion factors presented in Appendix B.

13. NSPS Monitoring: Is Duke Energy proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2? Which proposed emission units would be subject to 40 CFR 60 Subpart Dc requirements as indicated on page 4-6?

14. Acid Rain: The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new gas turbines will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

The Department will resume processing your application after receipt of the requested information. 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. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Chris Carlson, at 850/921-9537.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

cc:

Mr. Nathan L. Plagens, Duke Energy North America
Ms. Pamela A. Lehr, CH2M HILL
Mr. Isidore Goldman, SED
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4

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. Steven F. Gilliland
Sr. Vice President
Duke Energy North America
5400 Westheimer Ct
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 10-30-00

C. Signature
X H Herrick
☐ Agent
☐ Addressee

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 *(Copy from service label)*
7099 3400 0000 1453 1552

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 1552

Article Sent To:
Mr. Steven F. Gilliland, Sr. VP
Duke Energy No. America

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

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland, SR. VP
Street, Apt. No.; or PO Box No.
5400 Westheimer Ct
City, State, ZIP+4
Houston, TX 77056-5310

PS Form 3800, July 1999 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 11, 2000

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
PSD-FL-302
Facility ID No. 1110100-001-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Duke Energy Fort Pierce, LLC, proposes to construct and operate a power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/jka

Enclosures

cc: Jeff Koerner

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 11, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
PSD-FL-302
Facility ID No. 1110100-001-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Duke Energy Fort Pierce, LLC, proposes to construct and operate a power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact the project engineer, Jeff Koerner at 850/414-7268.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/jka

Enclosures

cc: Jeff Koerner

Duke Energy North America
A Duke Energy Company

Duke Energy
North America, LLC
5400 Westheimer Court
Houston, TX 77056-5310
P.O. Box 1642
Houston, TX 77251-1642
(713) 627-6500

October 3, 2000

Via: FEDERAL EXPRESS

Ms. Patty Adams
Florida Department of Environmental Protection
111 South Magnolia, Suite 4
Tallahassee, Fl 32301

Dear Ms. Adams:

Enclosed please find a check for the Air Permit Application for the Duke Energy Ft. Pierce, LLC Facility.

Please contact me at 713/627-5644 should you have any questions.

Sincerely,

Nathan K. Plagens

Nathan K. Plagens
Manager, Environmental Services

cc: D. Runyan

APPLICATION FOR

Permit to Construct and Operate Air Emissions Equipment

for

Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Prepared for

Duke Energy Fort Pierce, LLC

Prepared by

CH2MHILL

115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346

September 2000

CH2M HILL
115 Perimeter Center Place NE
Suite 700
Atlanta, GA
30346-1278
Tel 770.604.9095
Fax 770.604.9183

Proud Sponsor of
National Engineers Week 2000

CH2MHILL

September 20, 2000

154648

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
Division of Air Resources Management
111 South Magnolia, Suite 4
Tallahassee, FL 32301

Subject: Application for Permit To Construct
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Dear Mr. Linero:

Enclosed please find six copies of the Application for a Permit to Construct the proposed Duke Energy Fort Pierce Generating Station to be located near Fort Pierce, Florida. This application is being submitted on behalf of our client, Duke Energy North America and we ask that your office review this document and initiate the permitting process.

We very much appreciate the cooperation and assistance provided you and your staff at FDEP during the course of the preparation of this application. If you should have any questions regarding this submittal, please do not hesitate to call Nathan Plagans at Duke Energy North America at (713)-627-5985, or the undersigned at (770) 604-9182, ext 355.

Sincerely,

CH2M HILL

George Howroyd

George Howroyd, Ph.D., P.E.
Principal Engineer

ATL\14648 Duke Florida\App Cover Letter.doc
c: Nathan Plagens/DENA

Application for Permit to Construct and Operate Air Emissions Equipment

for

Duke Energy Fort Pierce, LLC
Duke Energy Fort Pierce Generating Station
Fort Pierce, Florida

Prepared for

Duke Energy Fort Pierce, LLC

September 2000

CH2MHILL
115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346

Contents

Tables

Figures

Appendices

Acronyms

ABB	Asea Brown Boveri
BACT	Best Available Control Technology
CARB	California Air Resources Board
CO	Carbon Monoxide
CFR	Code of Federal Regulations
CH_4	Methane
CRF	Capital Recovery Factor
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DLN	Dry Low NO_X
ESP	Electrostatic Precipitator
FAC	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
GE	General Electric
GEP	Good Engineering Practice
HAP	Hazardous Air Pollutant
HRSG	Heat Recovery Steam Generator
ISC	Industrial Source Complex
KW	Kilowatts
KWh	Kilowatt per hour
LAER	Lowest Achievable Emission Rate
LHV	Lower Heating Value
LTO	Low Temperature Oxidation
MACT	Maximum Available Control Technology
MMBtu/hr	Million Btu per hour
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
O_2	Oxygen
OAQPS	Office of Air Quality Planning and Standards
PAH	Polycyclic Aromatic Hydrocarbons

PG&E	Pacific Gas and Electric
PM	Particulate Matter
PM-10	Particulate matter less than 10 micrometers in diameter
Ppmvd	Parts per million based on dry volume
Ppmvw	Parts per million based on wet volume
POM	Polycyclic Organic Matter
PSD	Prevention of Significant Deterioration
Psia	Pounds per square inch absolute
RBLC	RACT/BACT/LAER Clearinghouse
ROI	Radius Of Impact
SARA	Superfund Amendments and Reauthorization Act
SCAQMD	South Coast Air Quality Management District
SCF	Standard Cubic Feet
SDCFH	Standard Dry Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1.0 Introduction

Duke Energy Fort Pierce, LLC (Duke) proposes to construct and operate a power generating facility near the City of Fort Pierce, Florida, in St. Lucie County. The Facility will be known as the Duke Energy Fort Pierce Generating Station, but will be referred to as "The Facility" for the purposes of this report.

The Facility will utilize eight simple cycle generating units to produce up to 640 megawatts (MW) of peak power at its design operating conditions. The primary fuel used by the turbines will be natural gas, with the capability of using low sulfur (0.05 percent) No. 2 distillate fuel oil as a backup fuel in the unlikely event of a natural gas curtailment.

Construction of the Facility is expected to commence in May 2001 with commercial operation expected by June 2002.

This permit application was prepared with the assistance of the consulting firm, CH2M HILL. Questions regarding CH2M HILL's participation can be addressed to the individuals listed below at Duke Energy North America in Houston, Texas, or CH2M HILL in Atlanta, Georgia:

Mr. Nathan K. Plagens
Manager, Environmental Services
Duke Energy North America
5400 Westheimer Court
Houston, Texas 77056-5310
Telephone (713) 627-5985
FAX (713) 627-5644
e-mail: nkplagens@duke-energy.com

Dr. George C. Howroyd, P.E
CH2M HILL
115 Perimeter Center Place, Suite 700
Atlanta, Georgia 30346
Telephone (770) 604-9182, ext. 355
FAX (770) 604-9183

e-mail: ghowroyd@ch2m.com

2.0 Facility Description

2.1 General

Facility Name:	Duke Energy Fort Pierce Generating Station
Owner:	Duke Energy Fort Pierce, LLC
Contact:	Mr. Nathan Plagens Manager, Environmental Services Duke Energy North America 5400 Westheimer Court Houston, Texas 77056-5310 Telephone (713) 627-5985 FAX (713) 627-5644

2.2 Site Description

The proposed Facility will be located on a parcel of land approximately 96-acres in size, and located approximately four miles south southwest of Fort Pierce, St. Lucie County Florida, as shown in Figure 2-1. The proposed plot plan of the facility is illustrated in Figure 2-2. Proposed power train elevations for the simple cycle generating units are illustrated in Figure 2-3.

The Facility will be constructed to generate nominally 640 MW of electricity using eight General Electric Model 7EA combustion turbines (CTs) operating in simple cycle configuration.

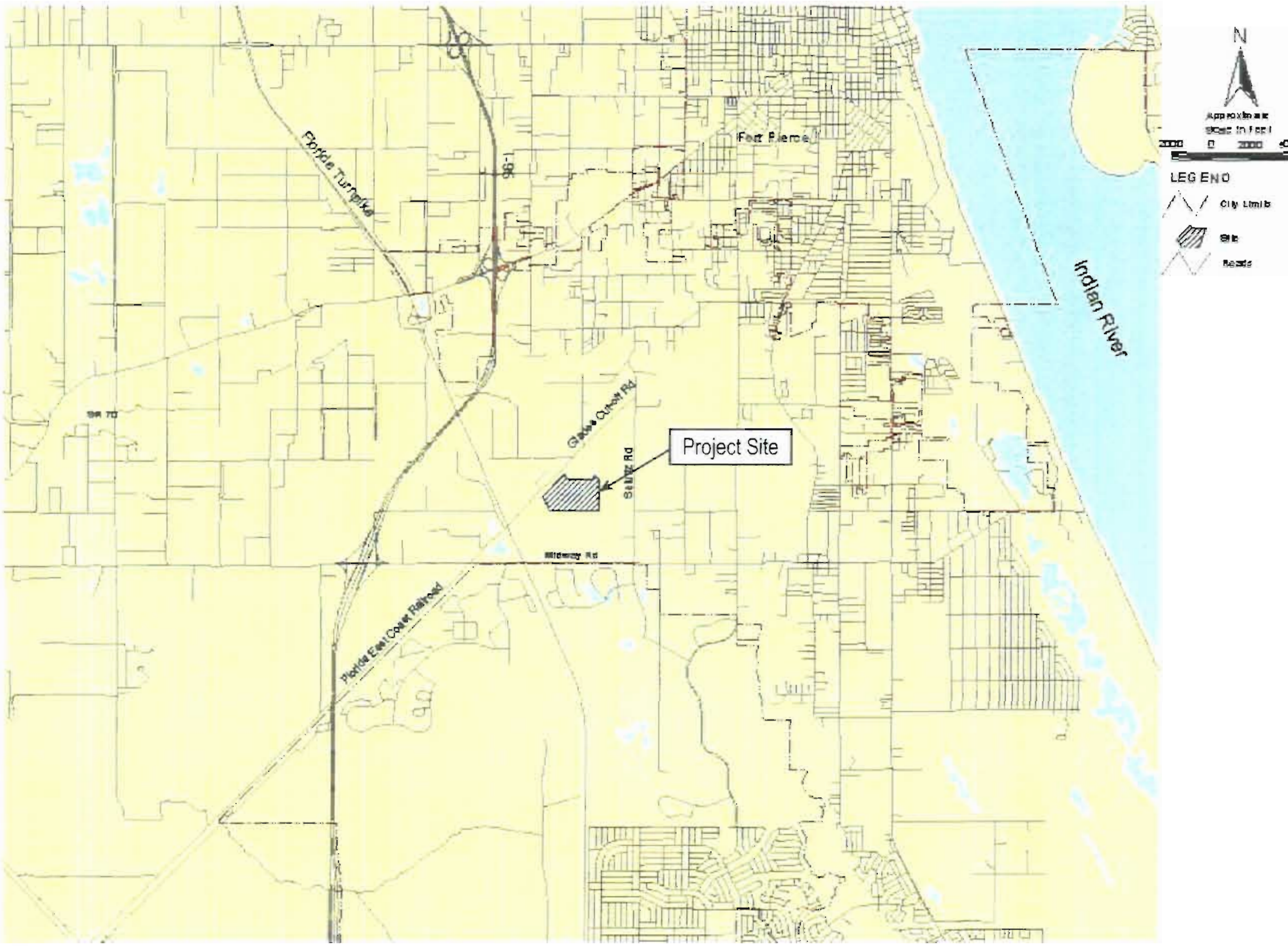
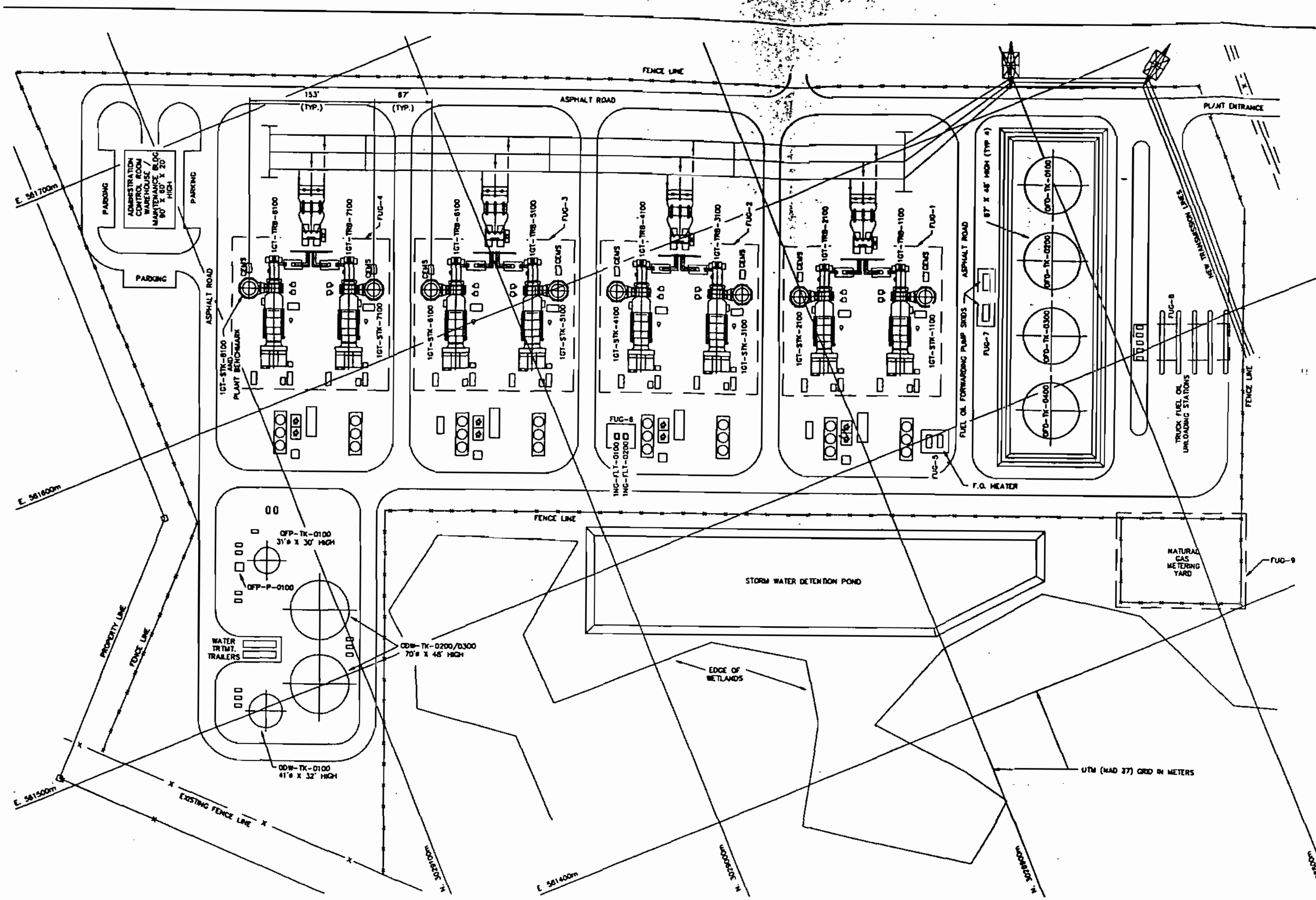


Figure 2-1
Site Location Map
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida



EMISSION POINT COORDINATES

DESCRIPTION	NORTHING	EASTING
OGT-STK-1100	N. 3028859m	E. 561548m
OGT-STK-2100	N. 3028901m	E. 561565m
OGT-STK-3100	N. 3028921m	E. 561573m
OGT-STK-4100	N. 3028963m	E. 561591m
OGT-STK-5100	N. 3028983m	E. 561599m
OGT-STK-6100	N. 3029025m	E. 561616m
OGT-STK-7100	N. 3029045m	E. 561625m
OGT-STK-8100	N. 3029087m	E. 561642m

EQUIPMENT LIST

1GT-TRB-1100 - 8100	COMBUSTION TURBINE GENERATOR
1GT-STK-1100 - 8100	TURBINE EXHAUST STACK
1NG-FLT-0100/0200	FUEL GAS COALESCING FILTERS
ODW-TK-0100	FOGGING WATER STORAGE TANK
ODW-TK-0200/0300	NOx WATER STORAGE TANK
OFP-TK-0100	FIRE WATER/SERVICE WATER TANK
OFP-P-0100	DIESEL FIRE WATER PUMP
OFO-TK-0100 - 0400	FUEL OIL STORAGE TANKS

NOTES:

1. POST-CONSTRUCTION ELEVATION OF SITE = 17' ABOVE MSL.
2. FUG-X DENOTES FUGITIVE EMISSIONS AREAS.
3. ALL COORDINATES SHOWN ARE UTM ZONE 17 GRID, NAD27, AND ARE GIVEN IN METERS.

PRELIMINARY

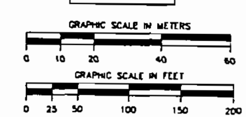
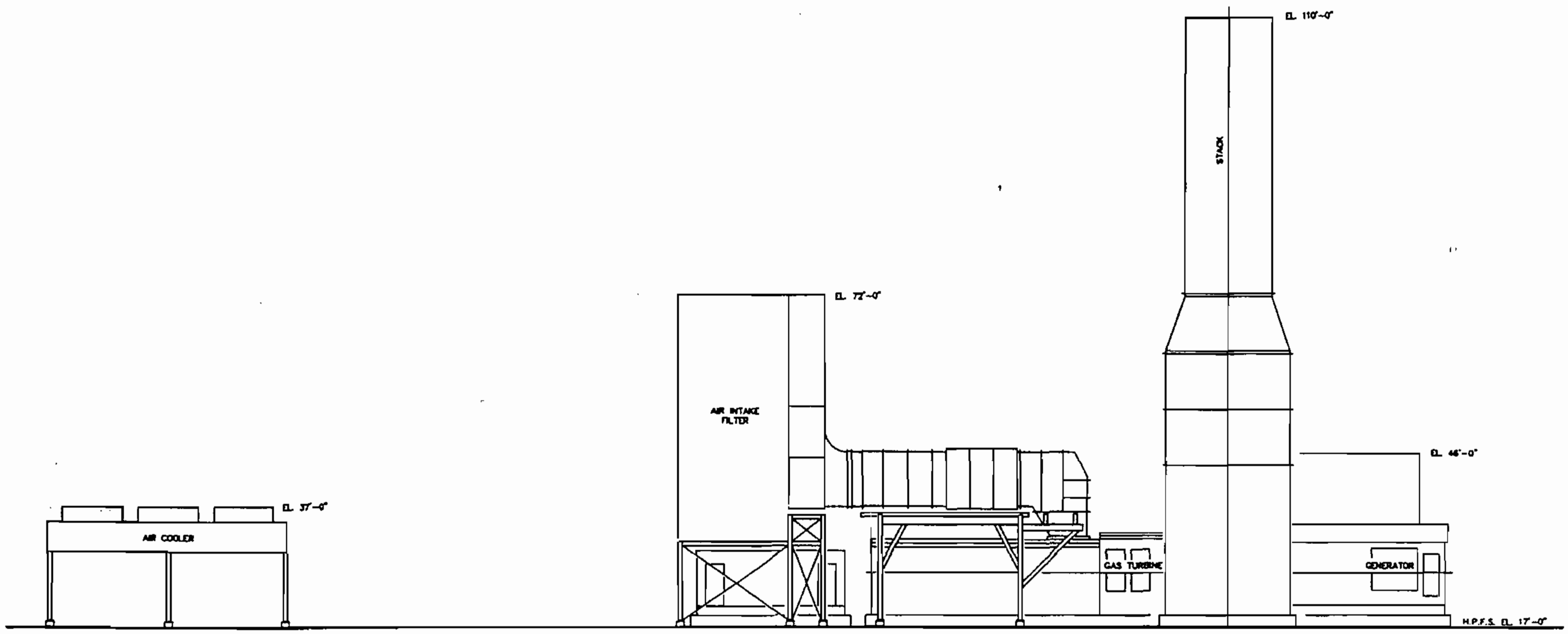


Figure 2-2
Proposed Plot Plan
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

CH2MHILL
E082000002ATL\Duke102.FH8



POWER TRAIN ELEVATION
VIEW LOOKING NORTH

PRELIMINARY

GRAPHIC SCALE IN FEET
0 5 10 15 20 25 30 35 40 45 50

Figure 2-3
Power Train Elevation
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

CH2MHILL
E082000002ATL\Duke101.FH8

The Facility will also be designed to incorporate the following major components:

- Eight 93 foot-exhaust stacks (measured above plant grade), one for each simple-cycle combustion turbine generator (CTG) set;
- Air-cooled auxiliary cooling system;
- Various single-story buildings of approximately 6,000 to 7,000 square feet housing the control room, maintenance shop, and other support facilities;
- Outdoor electrical switchyard, including station step-up transformers, switches, and power metering equipment;
- Underground natural gas transmission line extending from an existing gas transmission line to the Facility;
- Water and wastewater treatment systems and stormwater management facilities. These services will be provided to and from the Facility via underground pipeline;
- Tanks for water and fuel oil storage, etc.;
- Paved roads and parking areas; and
- Diesel firewater pump for emergency use only.

2.3 Facility Description

The simple cycle generating units will be operated as a fully dispatchable peak power generating facility, and may operate up to 24 hours per day and up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). In the event that natural gas is not available, each turbine could operate (on average) up to 1,000 hours per year on backup fuel oil. Exclusive of short-term transient periods (i.e., such as a change in load level and periods of startup and shutdown), nitrogen oxide (NO_X) emissions from the proposed CTG exhaust will be controlled to a level of 12.0 parts per million based on dry volume (ppmvd) (corrected to 15 percent O_2) at full load using dry low-NO_X combustion technology when firing natural gas. During periods of fuel oil firing, NO_X

emissions will be controlled to a level of 42.0 ppmvd (corrected to 15 percent O_2) by using water injection to control flame temperatures in the combustor. These levels of control are consistent with what is currently considered to be Best Available Control Technology (BACT) for the industry.

The combustion turbine is the main component of a simple-cycle power system. First, air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Dry low NO_X combustors are used to minimize NO_X formation during combustion. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine that drives both the air compressor and electric power generator. Exhaust gas exits the power turbine at approximately 1,100°F and 14.69 pounds per square inch absolute (psia).

An inlet air fogging system will be provided to enhance the power output of the combustion turbine generators during the summer months of natural gas operation. The fogging system will consist of two demineralized water storage tanks, pump forwarding/injection skids for each combustion turbine generator unit, and a water treatment system to provide makeup water to the demineralized water storage tanks.

For auxiliary plant equipment, a closed loop auxiliary cooling water system will be utilized. This system will use a water/glycol mixture as the cooling medium and will include an expansion tank, pumps, and water-to-air fin fan heat exchangers.

Table 2-1 summarizes the energy consumption and production capabilities of the CTG for each of the eight CTG trains. The hourly electrical production rate is dependent on operating and ambient conditions such as CTG operating load (percent of maximum load) and ambient temperature. The production rates presented in this Table are based on maximum output of the turbine at the ambient conditions noted (i.e., the approximate mean annual average temperature).

TABLE 2-1
Summary of Energy Production Design Criteria for Simple Cycle Generating Units
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

General Electric Model 7EA Combustion Turbine Generator Sets	
Number of units	8
Fuel[a]	Natural Gas/Fuel Oil
Electrical Capacity (at 74.6°F, 72% RH, 14.69 psia)	
Net Electrical Capacity (one CTG, with Inlet Fogger on)	81,360 kW (Natural Gas)[b]
Net Electrical Capacity (one CTG, Water Injection)	81,910 kW (Fuel Oil)[c]
Total Energy Input, Higher Heating Value (HHV) (One CTG)	975 MMBtu/hr (Natural Gas)[b]
	1,026 MMBtu/hr (Fuel Oil)[c]

Notes:

a Natural gas is primary fuel. Fuel oil used as a backup fuel when natural gas is not available under an interruptible gas supply contract.

b CTG firing natural gas.

c CTG firing fuel oil.

Figure 2-4 provides a simplified process flow schematic of the proposed simple cycle generating units. Each combustion turbine power block will include an advanced firing temperature combustion turbine air compressor section, gas combustion system (dry low NO_X combustors), power turbine, and a generator. Each gas turbine generator set is designed to produce a nominal 81 MW of gross electrical power (at 74.6°F, 72% RH, 14.69 psia).

2.4 Operation

The Facility will be capable of operating up to a maximum of 24 hours and up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). Each turbine will be permitted to operate (on average) up to 1,000 hours per year on backup fuel oil (i.e., 8,000 hours per year for all eight units combined) in the event that natural gas is not available. The CTGs can be operated on a continuous basis with the capability to operate down to load levels as low as 60 percent for maximum flexibility. The facility will employ approximately 10 personnel once fully operational.

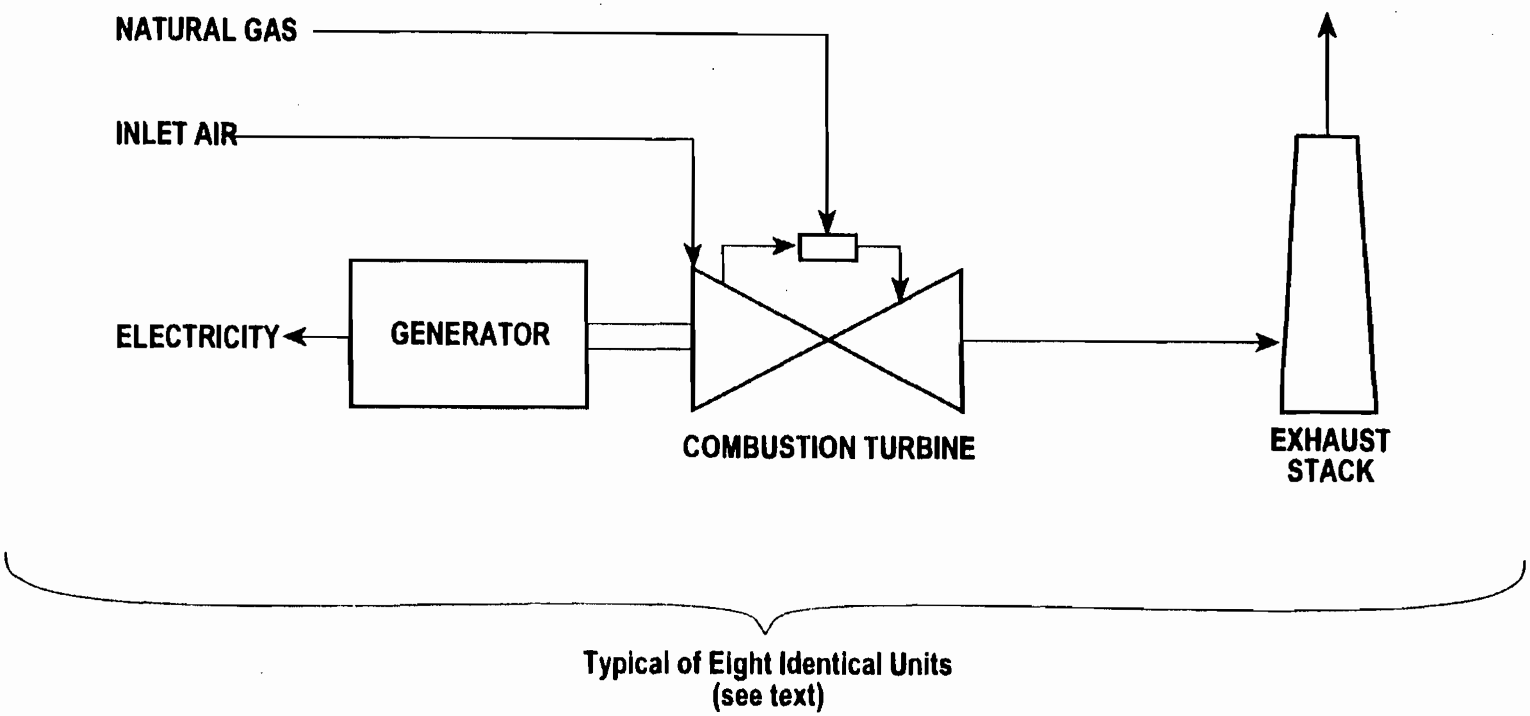


Figure 2-4
Simple Cycle Generating Units
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

3.0 Emission Source Information

3.1 Proposed Facility Emission Sources

3.1.1 Regulated Pollutants

The principal sources of emissions from the proposed Facility will be the eight simple cycle combustion turbines. Summaries of the hourly emissions (ppmvd and lb/hr) for each simple cycle combustion turbine train at maximum and partial load (i.e., 100, 75, and 60 percent) are provided in Tables 3-1 through 3-3 for natural gas fired operation, and in Tables 3-4 through 3-6 for oil fired operation. Due to economic efficiency and equipment control considerations, the turbines will not be operated at partial loads less than the lowest indicated load ratings except during startup and shut down conditions.

The CTG hourly emissions and emission characteristics were calculated at the design ambient temperatures of 101°F (peak summer), 74.6°F (mean annual), and 27°F (minimum winter). This assumption provides a basis for the calculation of emissions over the entire range of conditions under which the turbines may operate. The emission estimates provided in the tables are based on the following assumptions:

- Sulfur content of natural gas is less than 2 grains per 100 standard cubic feet (scf)
- Sulfur content of low sulfur No. 2 distillate fuel oil is 0.05 percent sulfur, by weight
- All particulate emissions are less than or equal to 10 micrometers (PM-10)
- All Volatile Organic Compound (VOC) hourly emissions are represented as methane (CH_4) and result from the combustion of natural gas or fuel oil.

Table 3-1
Summary of Maximum Hourly Emissions and Emission Characteristics (Maximum Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

		Operating Scenario		
Parameter		1	2	3
Load	%	100	100	100
Unit Output Per CTG	kWe	76264	79733	91140
Net Unit Heat Rate (HHV)	Btu/kWh	12131	11984	11677
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	°F	1013	1005	977
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	134.4	137.4	147.4
Stack Emissions Per CTG				
NO_X	ppm_{vd}	12.0	12.0	12.0
	lb/hr	40.0	41.0	47.0
CO	ppm_{vd}	25.0	25.0	25.0
	lb/hr	50.0	52.0	58.0
VOC	ppm_{vw}	1.4	1.4	1.4
	lb/hr	1.8	1.8	2.0
PM-10	lb/MMBtu	0.013	0.013	0.011
	lb/hr	11.0	11.0	11.0
SO_2	lb/MMBtu	0.0071	0.0068	0.0072
	lb/hr	6.0	6.0	7.0

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. NO_X emissions based on GE guarantee of 12 ppm_{vd} @ 15% O_2 at 100% load only
3. CO emissions based on GE guarantee of 25 ppm_{vd} at 100% load only
4. VOC emissions based on GE guarantee of 1.4 ppm_{vw} at 100% load only
5. SO_2 emissions based on sulfur in fuel content of 2 gr/100 SCF
6. All PM emissions assumed to be PM-10
7. Inlet fogging assumed for all temperatures above 59 °F at 100% load

Table 3-2
Summary of Maximum Hourly Emissions and Emission Characteristics (75 Percent Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario 4	5	6
Load	%	75	75	75
Net Unit Output Per CTG	kWe	52553	58210	68146
Net Unit Heat Rate (HHV)	Btu/kWh	13645	13156	12498
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	°F	1094	1064	1017
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	106.5	110.9	118.0
Stack Emissions Per CTG				
NO_X	ppm_{vd}	12.0	12.0	12.0
	lb/hr	31.0	33.0	37.0
CO	ppm_{vd}	25.0	25.0	29.0
	lb/hr	38.0	40.0	52.0
VOC	ppm_{vw}	1.4	1.4	1.4
	lb/hr	1.4	1.4	1.6
PM-10	lb/MMBtu	0.0021	0.0020	0.0020
	lb/hr	11.0	11.0	11.0
SO_2	lb/MMBtu	0.017	0.016	0.014
	lb/hr	5	5	6

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on <2.0 grains S/100 SCF natural gas

Table 3-3
Summary of Maximum Hourly Emissions and Emission Characteristics (60 Percent Load, Natural Gas Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario		
		7	8	9
Load	**%**	60	60	60
Net Unit Output Per CTG	**kWe**	41782	46288	54182
Net Unit Heat Rate (HHV)	**Btu/kWh**	15169	14690	13900
Temperature	**°F**	101	74.6	27
Relative Humidity	**%**	40	72	81
Fuel		Natural Gas	Natural Gas	Natural Gas
Stack Parameters				
Stack Temperature	**°F**	1100	1100	1059
Stack Height	**ft**	93	93	93
Stack Diameter	**ft**	15	15	15
Exit Velocity	**ft/sec**	96.9	100.3	106.3
Stack Emissions Per CTG				
NO_X	**ppm_{vd}**	12.0	12.0	12.0
	lb/hr	28.0	29.0	32.0
CO	**ppm_{vd}**	42.0	25.0	25.0
	lb/hr	58.0	36.0	39.0
VOC	**ppm_{vw}**	2.0	1.4	1.4
	lb/hr	1.8	1.2	1.4
PM-10	**lb/MMBtu**	0.019	0.017	0.016
	lb/hr	11.0	11.0	11.0
SO_2	**lb/MMBtu**	0.0068	0.0079	0.0072
	lb/hr	4	5	5

Notes:
1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on <2.0 grains S/100 SCF natural gas

Table 3-4
Summary of Maximum Hourly Emissions and Emission Characteristics (Maximum Load, Oil Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario 10	Operating Scenario 11	Operating Scenario 12
Load	%	100	100	100
Net Unit Output Per CTG	kWe	72383	80272	94266
Net Unit Heat Rate (HHV)	Btu/kWh	12788	12527	12210
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	°F	1023	1005	971
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	130.2	137.3	149.6
Stack Emissions Per CTG				
NO_X	ppm_{vd}	42.0	42.0	42.0
	lb/hr	146.0	159.0	182.0
CO	ppm_{vd}	20.0	20.0	20.0
	lb/hr	39.0	42.0	47.0
VOC	ppm_{vw}	3.5	3.5	3.5
	lb/hr	4.5	4.5	5.0
PM-10	lb/MMBtu	0.029	0.027	0.025
	lb/hr	25.0	25.0	26.0
SO_2	lb/MMBtu	0.054	0.054	0.055
	lb/hr	46	50	58

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. NO_X emissions based on GE guarantee of 42 ppm_{vd} @ 15% O_2 at 100% load only
3. CO emissions based on GE guarantee of 20 ppm_{vd} at 100% load only
4. VOC emissions based on GE guarantee of 3.5 ppm_{vw} at 100% load only
5. SO_2 emissions based on sulfur in fuel content of 0.05 percent by weight
6. All PM emissions assumed to be PM-10.

Table 3-5
Summary of Maximum Hourly Emissions and Emission Characteristics (75 Percent Load, Oil Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario 13	14	15
Load	%	75	75	75
Net Unit Output Per CTG	kWe	54126	60017	57981
Net Unit Heat Rate (HHV)	Btu/kWh	14077	13610	13009
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	°F	1091	1061	1016
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	107.3	111.9	119.4
Stack Emissions Per CTG				
NO_X	ppm_{vd}	42.0	42.0	42.0
	lb/hr	119.0	128.0	143.0
CO	ppm_{vd}	20.0	20.0	20.0
	lb/hr	31.0	33.0	36.0
VOC	ppm_{vw}	3.5	3.5	3.5
	lb/hr	3.5	3.5	4.0
PM-10	lb/MMBtu	0.034	0.032	0.030
	lb/hr	24.0	24.0	25.0
SO_2	lb/MMBtu	0.054	0.054	0.054
	lb/hr	38	41	46

Notes:
1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on 0.05% Sulfur in fuel oil, by weight

Table 3-6
Summary of Maximum Hourly Emissions and Emission Characteristics (60 Percent Load, Oil Firing)
General Electric Model GE 7EA Simple Cycle Combustion Turbine Generator Set
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

Parameter		Operating Scenario 16	17	18
Load	%	60	60	60
Net Unit Output Per CTG	kWe	43035	47725	56036
Net Unit Heat Rate (HHV)	Btu/kWh	15592	15146	14403
Temperature	°F	101	74.6	27
Relative Humidity	%	40	72	81
Fuel		Distillate Oil	Distillate Oil	Distillate Oil
Stack Parameters				
Stack Temperature	°F	1100	1100	1057
Stack Height	ft	93	93	93
Stack Diameter	ft	15	15	15
Exit Velocity	ft/sec	97.5	101.1	107.4
Stack Emissions Per CTG				
NO_X	ppm_{vd}	42.0	42.0	42.0
	lb/hr	104.0	112.0	126.0
CO	ppm_{vd}	20.0	20.0	20.0
	lb/hr	28.0	29.0	32.0
VOC	ppm_{vw}	3.5	3.5	3.5
	lb/hr	3.0	3.0	3.5
PM-10	lb/MMBtu	0.037	0.036	0.032
	lb/hr	23.0	24.0	24.0
SO_2	lb/MMBtu	0.055	0.054	0.053
	lb/hr	34	36	40

Notes:

1. NO_X concentrations are corrected to 15% O_2
2. SO_2 emissions based on 0.05% Sulfur in fuel oil, by weight

The maximum expected annual emissions from the Facility (assuming average annual ambient conditions, CTGs fired with natural gas and low sulfur No. 2 distillate fuel oil) and the corresponding Prevention of Significant Deterioration (PSD) significant emission rates are as follows:

Pollutant	Maximum Expected Annual Emissions (tons/yr)[a,b]	PSD Threshold for Major Sources (tons/yr)
NO_X	1,010	40
CO	580	100
VOC	32	40
PM-10[c]	170	15
SO_2	274	40

[a] Emissions are based on maximum hourly emission rates.
[b] Based on 2,500 hours operation per turbine, up to 1000 hours (per turbine) of which could be on fuel oil
[c] All PM assumed to be PM-10.

Since the projected emissions of NO_X, CO, PM-10, and SO_2 are all greater than their respective PSD thresholds, the project is a major source as defined by the regulations governing PSD for each of these pollutants. As such, a PSD permit is required, including a demonstration of BACT, and a dispersion modeling analysis to demonstrate that there will not be a violation of any National Ambient Air Quality Standards (NAAQS) and that no PSD increments will be exceeded.

3.1.2 Non-regulated Pollutants

EPA's guidance on the assessment of non-regulated "toxic pollutants" requires that permit applicants evaluate emissions of toxic substances for those pollutants that the proposed Facility could emit in amounts potentially of concern to the public. In the case of combustion turbines, potential toxic air pollutants could include acetaldehyde, benzene, formaldehyde, and heavy metals. A more complete analysis of these non-regulated pollutants is provided in Section 6.5.2.

3.2 Other Emission Sources

In order to facilitate the determination of PSD increment consumption and compliance with the National Ambient Air Quality Standards (NAAQS) resulting from the operation of the Facility, an inventory of existing and permitted emission sources would normally be requested from the Florida Department of Environmental Protection (FDEP) for all emission sources with the potential to interact with emissions from the proposed Facility. However, the dispersion modeling analysis of the proposed new emission sources (see Section 6) indicates that the Facility will result in an "insignificant" impact (as defined by FDEP and EPA) on ambient air quality at all locations and for all applicable averaging periods. Therefore, it will not be necessary to consider other sources of emission in the analysis.

4.0 Applicable Regulations

4.1 Applicable Pollutants

Expected emissions rates for the proposed Facility's combustion turbines were summarized in Section 3. The maximum expected annual emissions from the Facility for NO_X, CO, PM-10, and SO_2 will each exceed the applicable PSD threshold making the Facility a major source of emissions under the regulations governing PSD (40 Code of Federal Regulations [CFR] 52.21). As a result, an ambient air quality impact analysis and demonstration of BACT are required for each of these pollutants.

4.2 Ambient Air Quality Impact Analysis Requirements

The ambient limits with which the proposed project must comply are the NAAQS for SO_2, NO_2, CO, and particulate matter (PM-10) (40 CFR 50 and Rule 62-204.240, Florida Administrative Code [FAC]), and the PSD Class II and Class I increments for SO_2, PM-10, and NO_2 (40 CFR 52 and Rule 62-204.260, FAC). These limits are summarized in Table 4-1. Analyses of the proposed Facility emissions (see Section 6) demonstrate that the Facility will be in compliance with all state and federal ambient air quality regulations.

Also listed in Table 4-1 are the "significant" impact levels for each pollutant. The impact area for the proposed Facility is defined as the area from the source of emissions to the distance at which the emissions from the Facility no longer produce a significant impact for each pollutant. When the ambient concentrations at a particular location attributable to a given source are below the significant impact levels, the impact of the source at that location is considered to be insignificant. There are no significant impact levels defined for VOC emissions since VOCs are not a modeled pollutant.

TABLE 4-1
Applicable Ambient Air Quality Limits and Significant Impact Levels
Duke Energy Fort Pierce, LLC
Fort Pierce, Florida

	National Ambient Air Quality Standards		Florida	PSD Increments		
Pollutant and Averaging Period	Primary	Secondary	AAQS	Class II	Class I	Significant Impact Level (Class II Areas)
SO_2						
3-hour	-	1300[a]	1300[a]	512[a]	25[a]	25
24-hour	365[a]	-	260[a]	91[a]	5[a]	5
Annual	80	-	60	20	2	1
NO_2						
Annual	100	100	100	25	2.5	1
CO						
1-hour	40,000[a]	-	40,000[a]	[b]	[b]	2,000
8-hour	10,000[a]	-	10,000[a]	[b]	[b]	500
PM-10[c]						
24-hour	150[a]	150[a]	150[a]	30	8	5
Annual	50	50	50	17	4	1

(Concentrations in $\mu g/m^3$)

Notes:
[a] Concentrations not to be exceeded more than once per year, on an average basis.
[b] No increments applicable.
[c] Particulate matter with aerodynamic diameters less than or equal to 10 μm.

4.3 Emission Limits and Performance Standards

4.3.1 Combustion Turbines

New Source Performance Standards (NSPS) have been developed by the United States Environmental Protection Agency (US EPA) for stationary gas turbines (40 CFR 60, Subpart GG). These NSPS impose maximum allowable emission limitations on NO_X and SO_2 emissions from turbines with peak load heat inputs of greater than 10 MMBtu/hr. For the proposed turbines, Subpart GG specifies that the maximum NO_X emissions will be less than:

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

where:

STD = Maximum allowable NO_X emissions in percent by volume (15% O_2, dry)

Y = Manufacturers rated heat input (Kj/watt-hour)
= 12.644 Kj/watt-hr (Natural Gas)
= 13.217 Kj/watt-hour (Fuel Oil)

F = NO_X emission allowance based on FBN content
= .00060 (Fuel Oil)
= 0 (Natural Gas)

Therefore STD = 0.0081% or 81 ppm (Natural Gas)
0.0088 or 88 ppm (Fuel Oil)

Subpart GG also specifies that SO_2 emissions be less than 0.015 percent by volume (15 percent oxygen) and that fuels contain less than 0.8 percent sulfur by weight. The NO_X and SO_2 emissions from the proposed Facility will be substantially less than those specified by Subpart GG of the NSPS and the sulfur content of natural gas and low sulfur No. 2 distillate fuel oil will be substantially less than that specified by Subpart GG of the NSPS.

US EPA has also recently issued an "interpretative rule" on the applicability of sections 112(g) and (h) of the Clean Air Act to new combustion turbines. According to the rule, published in the April 21, 2000 Federal Register, all stationary combustion turbines constructed after June 29, 1998 are subject to case-by-case maximum available control technology (MACT) for hazardous air pollutants (HAPs). The EPA rule clarifies that the MACT review requirement applies to combustion turbines that are part of a combined cycle power plant, as well as those used in a simple cycle configuration. This interpretive ruling is essentially a clarification of an existing rule and its implications are that the project will have to demonstrate that the level and control of HAPs from the combustion turbines will reflect MACT. For combustion turbines firing natural gas and fuel oil, this assessment would essentially be limited to the emissions of formaldehyde, although there may be lesser amounts of acetaldehyde, benzene, polycyclic organic matter (POM), polycyclic aromatic hydrocarbons (PAH), and trace amounts of heavy metals. As discussed in Section 6.5.2, the emissions of Formaldehyde are estimated to be less than 1 lb/hr. No individual HAP will exceed 10 tons/yr, and all HAPs combined will not exceed 25 tons/yr. Therefore, there is no requirement for case-by-case MACT for this facility.

4.3.2 Fuel Oil Storage Tanks

There are four No. 2 distillate fuel oil storage tanks on-site which may emit a regulated pollutant (VOCs). All four fuel oil storage tanks are subject to 40 CFR 60, Kb. Annual emissions are estimated to be less than 1.0 ton per year.

4.4 Monitoring Requirements

4.4.1 Pre-construction Monitoring

PSD regulations and Rule 62-212.400, FAC, have a potential requirement for the development and operation of an ambient air quality and/or meteorological monitoring station for the purpose of determining ambient air quality and meteorological conditions in the immediate vicinity of the site. Air quality monitoring could be required for any criteria pollutant emitted in significant amounts if representative data are not available. Exemptions from the pre-construction monitoring requirements can be obtained if:

- Representative meteorological data is available for use in the air quality modeling;
- The predicted ambient impact(s) attributable to the operation of the proposed turbine or the existing ambient pollutant concentrations are less than the US EPA prescribed *de minimis* level of concentrations; and
- The proposed source is located in an area not affected by other major stationary sources so that existing ambient monitoring data from representative regional sites are appropriate for ambient background concentrations.

Section 6.2 describes the meteorological data available for use in the transport and dispersion modeling analysis. Personnel from the FDEP have indicated that they consider these data representative of the area of the proposed Facility site. Therefore, pre-application meteorological monitoring will not be required for this project.

Transport and dispersion modeling performed for the proposed turbine configuration has indicated that the predicted air quality impacts (Section 6.0) attributable to the proposed

Facility for all pollutants emitted in excess of the significant emission rates are less than the US EPA defined *de minimis* ambient impact levels for NO_X, PM-10, SO_2, and CO. Therefore, pre-construction monitoring for these pollutants will not be required. Ozone is not an emitted pollutant, rather it forms as a result of complex chemical reactions between precursor emissions of VOCs and NO_X in the presence of sunlight and higher temperatures, resulting in peak ozone levels occurring at mid-day during the warmest months of the year. The proposed Facility will be a source of both NO_X and VOC emissions, with proposed maximum allowable emissions of 822 and 29 tons/year, respectively. Maximum NO_X emissions of 822 tons/year will occur only under the scenario of maximum oil firing (i.e., 1,000 hours/year in all eight units). Under the preferred operating scenario of 100 percent natural gas-fired operation, NO_X emissions will be only 310 tons/year. The Facility will be located in St. Lucie County, which is designated as being in attainment of all ambient air quality standards, including ozone. Background ozone monitoring data was requested from FDEP for use in lieu of pre-construction monitoring. FDEP staff provided three years (1996 to 1998) of ozone monitoring results from Fort Pierce, approximately 8 kilometers northeast of the project site. The results of this monitoring are summarized below:

Monitored Ozone Concentrations in St. Lucie County (ppm)			
Year	Site Identification Number	1st High	2nd High
1996	3960 002 F01	0.082	0.072
1997	3960 002 F01	0.085	0.082
1998	12 111 1002	0.095	0.095

These monitoring results are well below the 1-hour ozone standard of 0.12 ppm, indicating that the area is in attainment for ozone.

4.4.2 Operational Monitoring

The Facility, and in particular the proposed new turbines, will comply with all applicable operational monitoring requirements imposed by Federal and State regulations. Sections 4.4.2.1 and 4.4.2.3 summarize the monitoring requirements that are applicable to this project.

4.4.2.1 Combustion Turbines

In addition to any one-time or periodic performance testing requirements, the Facility will install, calibrate, maintain, and operate the necessary monitoring equipment to monitor and record the fuel consumption in the combustion turbines as specified by 40 CFR 60, Subpart GG, and 40 CFR 75.

4.4.2.3 Fuel

Due to the expected requirement to continuously monitor NO_X emissions and due to the inherently low sulfur content in natural gas and low sulfur No. 2 distillate fuel oil, Duke may seek a waiver of the fuel monitoring requirements of 40 CFR 60 (Subparts Dc and GG). Otherwise, annual testing would be anticipated.

4.4.2.4 Other

The Facility will comply with all other operational monitoring and reporting requirements as may be determined necessary by FDEP in order to ensure compliance with any Federal or State rules or regulations. This will include any applicable future monitoring, reporting, and record keeping required as a result of the implementation of Title V (Operating Permits) and Title IV (Acid Deposition Control) of the Clean Air Act Amendments of 1990. Additionally, this will include Rules 62-213 (Operating Permits for Major Sources of Air Pollution) and 62-214 (Acid Rain Program Requirements), FAC.

5.0 Demonstration of Best Achievable Control Technology

5.1 Introduction

Under PSD regulations, a new or modified "major source" is required to apply BACT for any pollutant emitted in "major" or "significant" amounts. As discussed in section 3.0, the proposed Facility will have the potential to emit NO_X, PM-10, CO, and SO_2 in "significant" quantities. A BACT analysis is therefore required for these pollutants. The purpose of this review is to demonstrate that the air pollution control measures to be utilized at the proposed Facility represent BACT as defined by Section 169 of the Clean Air Act:

> "An emission limitation (including a visible emissions standard) based on the maximum degree of reduction of each pollutant subject to regulations under the Act which would be emitted from any proposed major stationary source or major modification, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, economic impacts and other costs, determines is achievable for such source or modifications through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment of innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61."

Both the US EPA and FDEP require that the demonstration of BACT described above must follow the "top-down" approach. This approach will ensure that a BACT demonstration considers the most stringent level of control technology available. If it can be shown that this level of control is technically, economically, or environmentally infeasible, then the next most stringent level of control is determined and similarly evaluated. The process continues until the BACT level under consideration cannot be eliminated by any substantial or unique economic or environmental objectives. For this project, the only emission sources for which BACT will apply will be the eight GE 7EA combustion turbines.

Currently, the only pollutants from combustion turbines for which a new source performance standard exists are nitrogen oxides and sulfur oxides. Firewater pump engines that will be installed on-site will not be operated concurrently with the combustion turbines (except during periodic performance and reliability testing) and are therefore exempt from BACT review and will not be considered further.

The purpose of this section is to demonstrate that the proposed emission control systems and methods will be representative of BACT. The following sections present the available control technology alternatives and a demonstration of BACT for each pollutant that will be emitted in significant amounts from the Facility, as discussed previously in Section 3.

A BACT analysis is presented for each emissions unit that contributes to the total emissions of a pollutant.

5.2 Methodology

The top-down BACT analysis presented here consists of the following steps:

1) Identify and rank feasible control technologies
2) Determine the economic, energy, and environmental impacts of the control technology
3) Propose the highest remaining technology as BACT

The first step is to compile a list of all feasible control options for each pollutant subject to PSD review. These control options are then ranked and listed in order of overall control effectiveness in descending order, with the most effective control option at the top of the list. The second step is to determine the potential economic, energy, and environmental impacts the control option would have on the project, starting at the top of the list. The last step is to propose the most effective control (which was not eliminated in the second step) as BACT. The three-step process described above simply compresses into a single step, for purposes of description, the first three steps described in US EPA's Draft New Source

Review Workshop Manual (October 1990) but is otherwise essentially the same as the BACT process outlined in the Draft Manual.

Identification of Feasible Control Options

The first step in the BACT analysis is the identification of feasible control options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits, applicable air quality standards, or other minimum state or local requirements that would prevail in the absence of BACT decision making. In a top-down BACT analysis, the option that represents lowest achievable emission rate (LAER), the most stringent permitted emission limitation achieved in practice by another unit in the same class or category of source, must be examined as the starting point for the analysis. Options that are technically infeasible for the intended application are eliminated from further review. If there is only a single feasible option, or if the applicant is proposing the "top," or LAER alternative, then no further analysis is required.

If several feasible options are identified, the next step is applied to identify and compare the economic, energy, and environmental impacts of the options. Technical considerations and site-specific issues will often play a role in BACT determinations.

Economic Impact Analysis

The cost estimation methodology used in this BACT analysis is consistent with the latest US EPA guidance (Office of Air Quality Planning and Standards [OAQPS] Cost Control Manual [EPA 453/b-96-001]). Vendor quotes and engineering estimates are the basis for calculating the total capital and operating costs, or cost differentials, for control options, and are documented accordingly. Standard engineering economic analyses are used to convert all costs to equivalent annual costs, so that the pollution control cost-effectiveness, in dollars per ton of pollutant controlled, may be calculated for comparison with other control options. The cost estimates include capital costs and annual operation and maintenance costs. Capital costs include both direct costs (equipment purchase costs, sales taxes, freight), installation costs (foundations, supports, field erection, electrical, piping, insulation, painting), and indirect capital costs (engineering, construction, contractor fees, start-up, performance tests, contingencies, and interest during construction). Annual costs also include direct and indirect costs. Direct costs include instrumentation, losses in generating revenue, operating and supervision labor, routine replacement parts, maintenance labor, maintenance replacement parts, and contingencies. Annual indirect costs include overhead, administration, property taxes, and insurance.

The following variables, equations, and assumptions were used to evaluate the cost effectiveness of alternative control strategies for the pollutants in question:

$$CRF = i(1+i)^n/((1+i)^n-1)$$

where,

CRF = capital recovery factor
i = interest rate (assumed at 7 percent)
n = equipment life (assumed 10 years for the equipment and 3 years for the catalyst)

Table 5-1 presents the site-specific economic assumptions used in the BACT analysis. These assumptions include labor rates, estimates of operational and maintenance labor requirements, cost and usage rates of consumables, and indirect costs. The cost effectiveness of a control technology is calculated by dividing the total annualized costs of the control technology by the potential reduction in emissions from the application of the control technology.

TABLE 5-1
Summary of BACT Costing Assumptions
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Assumption	Cost
Operator Labor Rate	0.5 Hours/Shift	$35.00/Hour
Supervisor Labor Rate	15 percent of Operating Labor	-
Instrumentation Labor	40 Hours/Year	$35.00/Hour
Catalyst Replacement Labor	320 man-hours every 3 years[1]	$35.00/Hour
Material	100 percent of Labor	-
Electricity	NA	$0.065/kWh
Overhead	60 percent of labor and materials	-
Administrative	2 percent of Total Installed Cost	-
Property Taxes	1 percent of Total Installed Cost	-
Insurance	1 percent of Total Installed Cost	-

[1] 8 workers for 40 hours every 3 years.

Energy Impact Analysis

Two forms of energy impacts that may be associated with a control option can normally be quantified. The first impact is an increase in energy consumption resulting from increased heat rate (which can be shown as a reduction of electrical generation resulting from the application of the control technology due to increased parasitic load or back pressure). The second impact is the reduced unit availability due to additional maintenance requirements for the applied control technology.

Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutants being controlled. Increases and decreases in other criteria or non-criteria pollutants may occur with some technologies, and should also be identified. Non-air impacts, such as solid waste disposal and increased water consumption, may be an issue as well.

5.3 Simple Cycle Generating Units

The proposed Facility will include eight simple cycle generating units. Each unit will consist of a GE Model 7EA combustion turbine generator set, and a dedicated exhaust stack. The combustion turbines will operate up to 2,500 hours per year using natural gas as a primary fuel, although they will be capable of operating up to 1,000 hours/yr on backup distillate fuel oil during periods of natural gas curtailment. For operational flexibility, Duke is requesting that the Facility be permitted to operate up to 20,000 hours per year for all eight units combined, or 2,500 hours per unit, whichever is less restrictive. An analysis of BACT for the emissions from the simple cycle generating units is provided below.

5.3.1 Nitrogen Oxides (NO_X)

There are several technologies to consider for controlling NO_X emissions from combustion turbines in a simple cycle configuration. These are categorized into pre-combustion controls and post-combustion controls. The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Pre-Combustion NO_X Control Technologies

Water or Steam Injection - The injection of water or steam into the combustor of a combustion turbine quenches the flame and absorbs heat, reducing the combustion temperature. This temperature reduction minimizes the formation of thermal NO_X. Water or steam injection also allows more fuel to be burned without overheating critical turbine parts, increasing the combustion turbine's maximum power output. For gas-fired operation, this technology has effectively been superceded in the industry by Dry Low NO_X (DLN) combustor technology which produces lower NO_X emissions and improves combustion turbine unit energy efficiency. Therefore, water/steam injection technology will not be considered in this analysis for gas-fired operation. During oil-fired operation, water injection is still considered to be a viable means of emission control, with the capability of achieving 60 to 80 percent control efficiency, with NOx emissions as low as 42 ppmvd.

Dry Low NO_X Combustors. There are two potential types of DLN combustors that may be appropriate for this application. These are lean pre-mix and catalytic technologies. The lean pre-mix type is the most popular DLN combustor available. Conventional combustors are diffusion controlled. Fuel and air are injected separately with combustion occurring at stoichiometric interfaces. This method of combustion can result in combustion "hot spots" which produce higher levels of NO_X. In the lean pre-mix combustor, air and fuel are mixed before they enter the combustor. Lean pre-mix combustors have only been developed for gas-fired turbines and the more advanced designs are capable of achieving a 70 to 90 percent NO_X reduction with a range of NO_X concentration from 9 to 25 ppmvd. DLN technology has been successfully installed and operated at several combustion turbine facilities. Therefore, the lean pre-mix DLN technology is considered to be feasible for use at the Facility.

The other type of DLN combustor is a catalytic combustor, such as Catalytica's XONON™ system, that uses a catalyst inside the combustor where the air/fuel mixture passes through the catalyst. Combustion typically occurs at much lower temperatures when compared to a standard combustor. This reduction in combustion temperature can significantly reduce the formation of thermal NO_X. Emissions of NO_X from catalytic combustors are typically below 5 ppmvd. Catalytica Combustion Systems has successfully demonstrated the XONON™ system on a pilot scale 1.5 MW combustion turbine located in Santa Clara, CA (in October

1998). This system was operated with NO_X concentrations observed to be below 3 ppm. Catalytic combustors have not been applied commercially to large gas turbines such as the GE 7EA, and discussions with Catalytica indicate that the first possible commercial availability of the XONON system for large combustion turbines is still several years away. A company, in cooperation with Catalytica and General Electric, is in the process of commercially demonstrating the XONON system at a power plant being developed in Central California (Pastoria District Energy Center). The Pastoria project has recently started the siting process in California and is not expected to be operational until the third quarter of 2003 and initial operating results are not expected until early 2004. The Pastoria facility will utilize two one-on-one GE 7FA combined cycle powers blocks and is being designed to utilize SCR control technology if XONON technology is not commercially available before the facility commences operation, or if it does not perform as expected in practice. Because the Facility is scheduled to begin construction in May of 2001 and commence operation in June 2002, and since this technology has not been demonstrated on GE 7EA gas turbines in practice for a facility of the size being proposed, this technology is not considered feasible for use on this project.

Post Combustion NOx Control Technologies

Three post-combustion controls exist for combustion turbines. These are the $SCONO_X$™, selective catalytic reduction (SCR), and Cannon Technology's Low Temperature Oxidation (LTO).

$SCONO_X$™ System. The $SCONO_X$™ system is produced by Goal Line Environmental Technologies and is currently being licensed by Asea Brown Boveri (ABB). The $SCONO_X$™ system uses a coated catalyst to oxidize and adsorb NO_X onto the catalyst. The system consists of a catalyst bed installed in a location where the temperature is between 280 °F and 700 °F. NO_X emissions are oxidized to NO_2, and then adsorbed onto the catalyst. The catalyst requires periodic regeneration, up to several times per hour, using a regeneration gas containing 4 percent hydrogen, 3 percent nitrogen, and 1.5 percent carbon dioxide. The regeneration gas is created by reacting natural gas with air in the presence of a nickel oxidation catalyst which is electrically heated to 1,900 °F. This gas is then mixed with steam and passed over a second catalyst to form the regeneration gas. The regeneration gas is introduced into the catalyst rack through a system of piping, valves, and louvers.

The catalyst rack being regenerated must be isolated from the exhaust gases. This is accomplished using two sets of louvers located both upstream and downstream of the catalyst module. The regeneration gas exits the catalyst rack and is ducted back into the exhaust stream, upstream of the SCONOx™ system. The SCONOx™ louver dampers isolate the catalyst system from the exhaust gases during regeneration. These louver dampers and associated supports are all exposed to the exhaust gas stream which could present long-term maintenance and reliability problems. The SCONOx™ demonstration project in Southern California has experienced numerous outages as a result of failures of the louver system. ABB, as part of its scale-up process, has reportedly redesigned the louver system and is testing the redesigned system to determine the function and reliability. The SCONOx™ system has achieved NOx emissions of less than 3.5 ppmvd on the Southern California demonstration project that is a much smaller turbine than the size of what is being proposed herein. Goal Line Environmental has made claims that the SCONOx™ system is capable of achieving emission rates as low as 2.0 ppmvd. However, these claims represent data derived from the pilot facility in Southern California which is a GE LM-2500 based combustion turbine combined cycle cogeneration facility (rated at approximately 23 MW) and does not represent emissions from a Frame 7 sized simple cycle combustion turbine project (nominally rated at 80 MW). SCONOx™ technology has not been demonstrated on a combustion turbine the size of that being proposed herein.

Several US EPA Regions (including Region IV) have notified the state agencies that SCONOx technology should be considered technically feasible for large combustion turbine projects. Additionally, a San Diego Union Tribune newspaper article (January 28, 2000) reported that Pacific Gas and Electric (PG&E) Generating Company has announced that it would install the SCONOx™ system on one of the four combustion turbines at its Otay Mesa Power Project. However, the hearing transcripts for the Otay Mesa Power Plant licensing process (through the California Energy Commission), indicate that PG&E Generating Company qualifies the January 28th announcement with the statement that the SCONOx system will be installed "if it is able to be commercialized" (California Energy Commission, November 15, 1999 Hearing Transcript). Additionally, PG&E Generating Company, in concert with ABB, is requesting a 3-year demonstration period for the SCONOx system in the Otay Mesa Power Plant air quality permits, and is incorporating provisions to install an SCR system if the SCONOx™ system fails to meet contractual guarantees (California Energy Commission, March 2, 2000 Status Conference Transcript).

As discussed above, SCONOx™ is an emerging technology that shows promise for future combined cycle applications (i.e., it has not been proven for large turbines) where gas temperatures can be lowered in the heat recovery process to a narrow temperature range in the Heat Recovery Steam Generator (HRSG) of between 280 °F and 700 °F. Since the simple cycle unit exhaust gas streams will be in the range of 1,100 °F, SCONOx™ substantial cooling of the exhaust stream would be required for the system to function properly. Therefore, SCONOx™ is not considered to be a technically feasible NOx emission control option for use on the proposed simple cycle units and will not be considered further.

Selective Catalytic Reduction. Selective catalytic reduction (SCR) involves the injection of ammonia into the flue gas stream where it selectively reacts with NOx in the presence of oxygen and a catalyst to form molecular nitrogen and steam. Because the reactions normally proceed at temperatures between 1,600 and 1,800°F, a catalyst is used to promote the reactions at lower temperatures. Reduction catalysts are divided into two groups: base metal (lower temperature - primarily vanadium, platinum, or titanium) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NOx ratio, and optimum oxygen concentration. A disadvantage common to platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NOx emissions) or ammonium nitrate. Vanadium-titanium catalyst systems have been shown to operate efficiently at temperatures from 550 to 800°F, which is significantly higher than earlier platinum catalyst systems. However, the vanadium-titanium catalyst systems begin to break down when continuously operated at temperatures above this range or under the wide temperature swings that are normal for simple-cycle peaking turbines. Consequently, operating above the maximum temperature for the catalyst system would result in the oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NOx emissions) or ammonium nitrate and would permanently damage the catalyst.

Zeolite is the only currently available SCR catalyst material that may be used at the elevated temperatures and load swings associated with peaking turbine installations. However, zeolite has a maximum temperature limitation of approximately 1,025°F, which corresponds to the normal operating exhaust temperatures of the GE 7EA combustion turbines. There are only four known installations of this technology on gas-fired simple cycle peaking units, and none of these has a long-term history of success. All are substantially smaller than the 80 MW GE 7EA turbines being proposed for this project, and three of the turbines have operating histories of less than only a few thousand hours. Operating experience with the existing installations has indicated that there is a pattern of degradation of SCR performance after only a few hundred hours of operation, and/or catastrophic catalyst failure. Ammonia slip has also been observed to increase over time.

A second concern associated with SCR technology is the effect of sulfur-bearing fuels on the catalyst. The problems associated with the use of sulfur-bearing fuels are due to the formation of ammonium bisulfate, NH_4HSO_4, and ammonium sulfate, $(NH_4)_2SO_4$. These are ammonia salts formed by the chemical reaction between the sulfur in the fuel and ammonia injected for NO_x control and they are emitted to the atmosphere as particulate matter. Ammonium bisulfate is a sticky substance which forms in the lower temperature section of the system where it deposits on the combustion turbine downstream surfaces. These surface deposits result in increased pressure drop, reduced power output, and lower cycle efficiency. To prevent corrosion damage, the system must be shut down periodically and water-washed, thereby reducing availability. While ammonium sulfate is not corrosive, its formation also contributes to increased pressure drop, reduced power output, lower cycle efficiency, and higher particulate emissions. Because of these problems, the use of SCR is not considered to be technically feasible.

Also of significant concern is the handling and use of ammonia. Ammonia is regulated under the EPA Risk Management Program and Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Releases of ammonia to the atmosphere may occur in several ways, including ammonia slip, or it can be accidentally released during transport, transfer, or storage. In addition, ammonia is potentially a PM-10 precursor and concerns about the potential health impacts of secondary emissions, such as nitrous oxide and nitroamines, have been raised.

Cannon Technology's Low Temperature Oxidation (LTO). The Cannon LTO technology was primarily developed to control emissions from large steam boilers. The basic operation of the LTO system injects ozone into a cooled exhaust gas (approximately 300 °F) to oxidize NO_X, CO, and SO_2 to nitrates, carbonates, and sulfates. These higher oxides are absorbed by a dilute nitric acid solution in a scrubber. Testing on natural gas fired boilers has shown NO_X concentrations below 3.5 ppmvd at 3 percent oxygen and vendor literature indicates NO_X guarantees of less than 4 ppmvd.

The LTO system has been demonstrated on relatively small natural gas-fired boilers ranging in size from 4.1 to 16.7 MMBtu/hr. The volume of exhaust gas from a 16.7 MMBtu/hr boiler will be approximately 145,457 standard dry cubic feet per hour (SDCFH). The exhaust gas volume from one of the combustion turbines proposed for use on this project will be 28,857,148 SDCFH. This would require a drastic scale-up of the LTO technology. Additionally, the scrubber solution would result in the generation of additional pollution (scrubber waste), and would require disposal. Cannon Technology literature indicates the scrubber waste can be discharged to sanitary sewer systems, but this option has not been verified and would directly impact costs. Therefore, the LTO technology was rejected as a technically infeasible NO_X control measure for this project.

Control Technology Ranking

Based on the above discussion, there are only three technically feasible NO_X control technologies identified for this Project – high temperature SCR, DLN, and/or water/steam injection. There are numerous examples of projects where DLN has been permitted as BACT with emission rates between 9 and 15 ppm natural gas fired units. There are no examples of high temperature SCR technology being permitted (and successfully demonstrated) as BACT for a large scale turbine installation. The proposed BACT for this project is DLN combustors which are capable of achieving a NO_X emission rate of 12.0 ppmvd at 15 percent oxygen.

Because SCR has the potential for greater removal efficiency than DLN combustors, the cost-effectiveness of the system to reduce NO_X emissions was also evaluated. The cost analysis is presented below.

Selective Catalytic Reduction Cost Effectiveness

High temperature SCR is not considered by Duke Energy to be a technically feasible option for a dual fuel (oil/gas) turbine. However its hypothetical cost effectiveness was calculated for comparison with other technologies. Capital costs associated with supplying a base SCR system (natural gas operation only) to each turbine are shown in Table 5-2. SCR capital equipment includes the catalyst housing, auxiliary equipment, instrumentation, catalyst, and structural support. The basic equipment cost is estimated at $2,485,450 based on a quote from Englehard. With other direct and indirect installation and start-up costs, the total capital investment for installing a SCR system is estimated at $4,511,200.

Table 5-2
Combustion Turbine NO_x BACT Analysis
71 Percent NO_x Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliaries	As Estimated, A	Vendor Quote	$2,037,250
Instrumentation	0.1 X A	(EPA, 1995a)	$203,700
State Sales Taxes	0.07 X A	State Sales Tax	$142,600
Freight	0.05 X A	(EPA, 1995a)	$101,900
PEC Subtotal (B)			**$2,485,450**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$198,800
Labor	0.14 X B	(EPA, 1990a)	$348,000
Electrical	0.04 X B	(EPA, 1990a)	$99,400
Piping	0.02 X B	(EPA, 1995a)	$49,700
Insulation	0.01 X B	(EPA, 1995a)	$24,900
Painting	0.01 X B	(EPA, 1990a)	$24,900
DIC Subtotal	0.3 X B	(EPA, 1990a)	**$745,700**
Total Dc	PEC+DIC	-	**$3,231,200**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$248,500
Construction Overhead	0.05 X B	(EPA,1990a)	$124,300
Contractor Fees	0.10 X B	(EPA,1990a)	$248,500
Contingencies	0.20 X B	(EPA,1990a)	$497,100
Start-Up	0.02 X B	(EPA,1990a)	$49,700
Performance Testing	0.01 X B	(EPA,1990a)	$24,900
Simple Interest During Construction	PEC X 7% X 0.5 YEARS	Estimate	$86,990
Total IDC		-	**$1,280,000**
Total Capital Investment (TCI)	**Dc + IDC**		**$4,511,200**

Table 5-2
Combustion Turbine NOx BACT Analysis
71 Percent NOx Control Efficiency for a SCR system (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Operating Cost Factors For The SCR			
Cost Data			
Interest Rate	7%	*CAPITAL RECOVERY FACTOR (CRF)*	
Catalyst Life	3	0.380	
Equipment Life	10	0.1440	
Direct Annual Costs, $/Yr			
	FACTOR	**REFERENCE**	**COSTS, $/Yr**
Power Loss Due To Pressure Drop Across Catalyst	0.3% per inch of pressure drop @ $0.065/kWh and 245 KW loss	Vendor	$39,780
Operating Labor	$30/hr @ 3 hr/12-hr shift	Industry Average/Estimate	$65,700
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$9,855
Maintenance Labor	$30/hr @ 4 hr/12-hr shift	Estimate	$87,600
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$87,600
Revenue Loss During Cat, Replacement (A)	72 Hours at $0.065/kWh	Estimate	$381,888
Catalyst Cleaning	80 Man-hours per year	Estimate	$2,800
Catalyst Replacement Labor (B)	8 Workers for 40 hours	Estimate	$11,200
Catalyst Replacement (Cr) (C)	$1,077,000 every 3 years including disposal	Vendor Quote	$1,077,000
Sales Tax (D)	7%	State Tax Rate	$75,390
Capital Recovery	[A+B+C+D] * CRF	(EPA, 1995a)	$587,281
TOTAL DIRECT ANNUAL COSTS, $/YR			**$880,600**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$111,033
Insurance & Administration	3% of TCI	(EPA,1990a)	$135,336
Capital Recovery	CRF X TCI	N/A	$ +649,612
Property Tax	1% of TCI	Estimate	$45,112
			$941,093
Total Annual Costs, $/Yr	**$1,821,693**		
Total Net NOx Reductions (TPY)	36	Natural gas operation, 71% removal, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$50,602**		

Annualized costs for operation of SCR on each turbine are also summarized in Table 5-2. The total annualized cost of SCR operation is estimated at $1,821,693. The amount of NO_X that would be removed annually by the SCR would be approximately 36 tons, based on 2,500 hours of natural gas operation and an estimated removal efficiency of 71 percent. This would result in a cost of removal of $50,602/ton of NO_X. Clearly, this is not a cost effective technology for controlling of NO_X emissions from the simple cycle turbines at the proposed Facility.

Proposed BACT for NO_X

Duke proposes to utilize DLN combustors in the turbines to limit NO_X emissions during gas fired operation to an average NO_X emission rate of 12.0 ppmvd corrected to 15 percent oxygen. During oil fired operation, Duke proposes to utilize good combustor design and water injection to limit NOx emissions to 42 ppmvd corrected to 15 percent oxygen.

5.3.2 Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs)

Only two feasible technologies exist to control CO and VOC emissions from a combustion turbine: good combustor design and high temperature oxidation catalyst.

Good Combustor Design. CO and VOCs are formed during the combustion process due to incomplete combustion of the carbon present in the fuel. The formation of CO and VOCs is limited by designing the combustion system to completely oxidize the fuel carbon to CO_2. This is achieved by ensuring that the combustor is designed to allow for complete mixing of the combustion air and fuel at combustion temperatures (in excess of 1,800°F) with an excess of combustion air. Higher combustion temperatures tend to reduce the formation of CO and VOCs, but increase the formation of NO_X. The application of steam/water injection or staged combustion tends to lower combustion temperatures (in order to reduce NO_X formation), increasing CO and VOC formation. A good combustor design will minimize the formation of CO and VOCs while reducing the combustion temperature and NO_X emissions. The proposed combustion turbines already incorporate this control technology into the design, controlling CO and VOC emissions to 25 ppmvd and 1.4 part per million based on wet volume (ppmvw), at 100 percent load, respectively.

Oxidation Catalyst. The oxidation catalyst is typically a precious metal catalyst bed located in the exhaust system. The catalyst enhances oxidation of CO and VOCs to CO_2, without the addition of any reactant. Oxidation catalysts have been successfully installed on combined cycle combustion turbines for a number of years, achieving high levels of control in areas designated as non-attainment for CO. Traditionally, combustion turbine vendor estimates for CO and VOC emissions tend to be very conservative. As a result, early CO BACT analyses have shown that the installation of an oxidation catalyst was cost effective. However, as actual source testing data was generated for combustion turbines without oxidation catalysts, the results showed that the CO emission estimates were significantly greater than the actual CO emissions measured. Regardless of this fact, oxidation catalysts are considered to be technically feasible for use on combustion turbines.

Control Technology Ranking

Aside from the use of good combustion design and operating practices, the only feasible method of controlling CO emissions from a GE 7EA combustion turbine is the use of an oxidation catalyst. Several 7EA units have recently been permitted in Florida and a summary of the determinations for CO is contained in Table 5-3. Table 5-4 summarizes recent BACT determinations for VOC emissions from combustion turbines. The CO and VOC emissions being proposed for this project are consistent with these recent determinations.

Economic Analysis of CO and VOC Controls

An initial capital equipment cost of $1,515,075 for a basic oxidation catalyst system was provided by Engelhard and included the catalyst modules, internal frame, and internal seals. The remainder of the cost analyses were based on accepted engineering economic principles. Annual capital and operating costs for the installation and operation of the oxidation catalyst system for one combustion turbine were estimated using US EPA Control Cost Manual methodology. These costs include the operating and maintenance labor, supervision labor, material costs, catalyst cleaning and replacement costs (both labor and expenses), and capital recovery for both the initial equipment purchase and periodic catalyst replacement costs.

TABLE 5-3
Summary of Florida CO BACT Determinations for GE 7EA Turbines
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Technology	Permitted CO Emission Rate ppmvd at 15% O_2	Project	Turbine Type
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	FPC Int. City, FL	General Electric 7EA
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	TECO Hardee, FL	General Electric 7EA
Clean Fuels, Good Combustion Design	25 (gas) 20 (oil)	GPU Gainesville, FL	General Electric 7EA

TABLE 5-4
Summary of VOC BACT Determinations for Combustion Turbines
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Permitted VOC Emission Rate ppmvd at 15% O_2	Project
0.6	BACT, Bear Mountain Ltd., CA RBLCID Number CA-0858 08/19/1994
1.0	BACT, Florida Power and Light, FL RBLCID Number FL-0053 03/14/1991
1.5	BACT, Lakewood Cogeneration, L.P., NJ RBLCID Number NJ-0013 04/01/99
1.6	BACT, Florida Power and Light, FL RBLCID Number FL-0052 06/05/1991
1.7	BACT, Public Service of Colorado, CO RBLCID Number CO-0024 05/01/1996
1.9	BACT, Southern California Gas RBLCID Number CA-0418 10/29/1991
2.0	BACT, Tiverton Power Associates, RI RBLCID Number RI-0018 02/13/99
4.0	BACT, Blue Mountain Power, LP., PA RBLCID Number PA-0148 07/31/1996

The most cost-effective installation of the oxidation catalyst equipment (including the catalyst module, auxiliary equipment, instrumentation, catalyst, and structural supports) results in an estimated total annual cost of $1,157,071, and will reduce the combustion turbine CO emissions by 52 tons per year (80 percent CO control efficiency) and VOC emissions by 1 ton per year (45 percent VOC control efficiency). The cost-effectiveness of this system is $21,832/ton of CO and VOC removed. Table 5-5 presents the economic analyses (for a single turbine) for the installation of an oxidation catalyst to control CO and VOC emissions.

Table 5-5
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Direct Costs (Dc)			
Purchased Equipment Costs (PEC)			
Basic Equipment & Auxiliary Equipment (A)	As Estimated	Vendor Quote	$1,241,875
Instrumentation	0.1 X A	(EPA, 1995a)	$124,200
State Sales Taxes	0.07 X A	State Sales Tax	$86,900
Freight	0.05 X A	(EPA, 1995a)	$62,100
PEC Subtotal (B)			**$1,515,075**
Direct Installation Costs (DIC)			
Foundations & Supports	0.08 X B	(Ulrich, 1984)	$121,200
Labor	0.14 X B	(EPA, 1990a)	$212,100
Electrical	0.04 X B	(EPA, 1990a)	$60,600
Piping	0.02 X B	(EPA, 1995a)	$30,300
Insulation	0.01 X B	(EPA, 1995a)	$15,200
Painting	0.01 X B	(EPA, 1990a)	$15,200
DIC Subtotal		(EPA, 1990a)	**$454,600**
Total Dc	PEC+DIC	-	**$1,969,700**
Indirect Costs (IDC)			
Engineering	0.10 X B	(EPA,1990a)	$151,500
Construction Overhead	0.05 X B	(EPA,1990a)	$75,800
Contractor Fees	0.10 X B	(EPA,1990a)	$151,500
Contingencies	0.03 X B	(EPA,1990a)	$45,500
Start-Up	0.02 X B	(EPA,1990a)	$30,300
Performance Testing	0.01 X B	(EPA,1990a)	$15,200
Simple Interest During Construction	PEC X 7% X 0.5 YEARS	Estimate	$53,027
Total IDC		-	**$522,827**
Total Capital Investment (TCI)	**Dc + IDC**		**$2,492,500**

Table 5-5
Combustion Turbine CO and VOC BACT Analysis (Per Turbine)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Cost Item	Cost Factor	Reference	Cost ($1999)
Operating Cost Factors For The Oxidation Catalyst			
Cost Data			
Interest Rate	7%	***CAPITAL RECOVERY FACTOR (CRF)***	
Catalyst Life	3	0.38	
Equipment Life	10	0.1440	
Direct Annual Costs, $/Yr			
Power Loss Due To Pressure Drop Across Catalyst	0.1% per inch of pressure drop @ $0.065/kWh and 245 KW loss	Vendor	$39,780
Operating Labor	$30/hr @ 1 hr/12-hr shift	Industry Average/Estimate	$21,900
Supervisory Labor	15 % of operating labor	(EPA,1993a)	$3,285
Maintenance Labor	$30/hr @ 1 hr/12-hr shift	Estimate	$21,900
Maintenance Materials	100 % of maintenance labor	(EPA,1993a)	$21,900
Revenue Loss During Cat, Replacement (A)	72 hours at $0.065/kWh	Estimate	$381,888
Catalyst Cleaning	80 man-hours per year	Estimate	$2,800
Catalyst Replacement Labor (B)	8 workers for 40 hours every 3 years	Estimate	$11,200
Catalyst Replacement (Cr) (C)	$1,006,540 every 3 years including disposal	Vendor Quote	$1,006,540
Sales Tax (D)	7%	State Tax Rate	$70,458
Capital Recovery	[A+B+C+D] * CRF	(EPA, 1995a)	$558,632
TOTAL DIRECT ANNUAL COSTS, $/YR			**$670,200**
Indirect Annual Costs, $/Yr			
Overhead	60% of All Labor Main. Costs	(EPA,1990a)	$28,251
Insurance & Administration	3% of TCI	(EPA,1990a)	$74,775
Capital Recovery	CRF X TCI	N/A	$358,920
Property Tax	1% of TCI	Estimate	$24,925
TOTAL INDIRECT ANNUAL COSTS, $/YR			**$486,871**
Total Annual Costs, $/Yr	**$1,157,071**		
Total Net CO Reductions (TPY)	52	80% Removal Efficiency, 2,500 hours/yr operation	
Total Net VOC Reductions (TPY)	1	45% Removal Efficiency, 2,500 hours/yr operation	
Incremental Cost Effectiveness, $/Ton	**$21,832**		

Environmental Impacts

Although the use of an oxidation catalyst has the technical potential to further reduce CO and VOC emissions (when compared to good combustion design and operating practices), its application would also result in some negative environmental impacts that must be considered. The primary environmental concerns regarding catalytic oxidation include:

- Disposal of spent catalyst
- Increase in PM-10 emissions
- Increase of SO_3 emissions

Spent catalyst from catalytic oxidation systems will have to be disposed of either by the user or through some type of agreement with the vendor. There is some concern about the future possibilities that catalyst might have to be treated as a hazardous waste. The quantity of catalyst to be disposed would be significant and on the order of approximately 2 tons/year per unit.

PM-10 emissions can increase due to the additional oxidation of sulfur and ammonia present in the combustion turbine exhaust gas. The combustion turbine oxidizes any sulfur compounds in natural gas (either naturally occurring or added as an odorant) to SO_2. The SO_2 would be further oxidized to SO_3 across the oxidation catalyst and could be emitted either as a sulfate or as H_2SO_4. Additionally, the oxidation catalyst may oxidize unreacted ammonia (from the SCR) to form PM-10.

Given the fact that the emissions of CO from the proposed Facility have been shown (see Section 6) to result in an insignificant impact on ambient air quality, further reductions in CO emissions from the Facility do not appear to be environmentally justified. This is supported by the fact that there are no nonattainment areas for CO in Florida, and there is no threat to the ambient air quality standards for CO as a result of the operation of the Facility.

Proposed BACT for CO and VOC

Catalytic oxidation has primarily been used to meet specialized requirements such as LAER, typically in areas that are designated as nonattainment for CO ambient air quality standards. Most of the recent permits listed in the RBLC indicate that combustion control practices are the preferred method of CO control on combustion turbines. To date there has been no BACT determination for VOC controls applied to combustion turbines other than combustion controls and good combustion practices.

Considering all the relevant impacts, it is proposed that BACT for CO and VOC be the most efficient combustion possible while achieving the proposed BACT for NOx. The maximum emissions for CO and VOC (and proposed BACT) will be 25 ppmvd and 1.4 ppmvw, respectively, at 100 percent load during natural gas firing. During limited periods of fuel oil firing, the maximum emissions of CO and VOC (and proposed BACT) will be 20 ppmvd and 3.5 ppmvd, respectively, at 100 percent load.

5.3.3 Particulate Matter (PM-10)

Emissions of particulate matter less than 10 micrometers in diameter (PM-10) from the combustion turbine result primarily from inert solids contained in the fuel and unburned fuel hydrocarbons which agglomerate to form particles. The only feasible PM-10 emissions control technology for the combustion turbines is the use of low sulfur, low ash fuel. Post combustion particulate matter controls have never been applied to combustion turbines, the primary reasons being the very large volumes of low concentration exhaust air and excessive back pressure. The use of Electrostatic Precipitators (ESPs) and baghouse are considered technically infeasible and environmentally unjustified.

PM-10 emission rates are inherently extremely low because of very high combustion efficiencies and the clean burning nature of natural gas and low sulfur No. 2 distillate fuel oil. Clean fuels such as these are required to prevent damage to the turbine blades and other high-precision turbine components. Therefore, their use is in and of itself, a highly efficient method of controlling emissions. Based on the lack of technically feasible controls and the fact that add-on controls have not been used or proposed to reduce PM-10 emissions from combustion turbines, the use of clean burning natural gas and low ash transportation grade No. 2 fuel oil is therefore proposed as BACT for PM-10 emissions from the combustion turbines.

5.3.4 Sulfur Dioxide (SO_2)

The proposed Facility will utilize natural gas and low sulfur No. 2 distillate fuel oil (0.05 percent sulfur, by weight). The use of natural gas will result in negligible SO_2 emissions while the use of low sulfur No. 2 distillate fuel oil produces SO_2 emissions in proportion to the sulfur content of the fuel.

Add-on SO_2 controls have not been required on gas or low sulfur No. 2 distillate fuel oil-fired combustion turbines because of the extremely low sulfur content that is typical of these fuels. A review of US EPA's RACT/LAER/BACT clearinghouse for recent SO_2 BACT determinations for combustion turbines and boilers identified low sulfur natural gas and low sulfur No. 2 distillate fuel oil as BACT for all recent BACT determinations. The proposed Facility will emit a maximum of only 236 tons of SO_2 per year from the simple cycle generating units (based on 1500 hours per year operation on gas and 1000 hours per year on fuel oil). The SO_2 emissions are directly proportional to the sulfur content of the fuel the project will be burning. The above emissions estimates are based on a fuel sulfur content less than 2 grains per 100 standard cubic feet of natural gas. Therefore, the use of clean burning natural gas and low sulfur No. 2 distillate fuel oil is consistent with recent BACT determinations and is therefore being proposed as BACT for this Facility.

5.3.5 Sulfuric Acid Mist (H_2SO_4)

During the combustion process approximately 10 percent of the sulfur dioxide (SO_2) is oxidized to sulfur trioxide (SO_3). SO_3 is hydrophilic and combines with available moisture to form sulfuric acid mist (H_2SO_4) when the temperature drops below the acid dew point. For a combustion turbine, this condition is normally only reached after several minutes and some distance from the plant when the exhaust stream has dispersed and cooled.

Emission reduction alternatives for H_2SO_4 mist are the same as those reviewed for emissions of SO_2. Limiting the fuel sulfur content reduces the sulfur entering the combustion process and reduces the resultant SO_3, thus minimizing H_2SO_4 emission formation. The use of natural gas and low sulfur No. 2 distillate fuel oil is proposed as BACT for H_2SO_4 mist. Due to the low emissions of SO_2 expected from the turbine, the formation of sulfuric acid mist is expected to be insignificant.

5.3.6 Other Pollutants

The combustion of natural gas and low sulfur No. 2 distillate fuel oil may release trace amounts of a number of materials such as formaldehyde, acetaldehyde, lead, beryllium, mercury, fluorides, arsenic, benzene, manganese, chromium, nickel, copper, cadmium, and radionuclides. As discussed in Section 3.0, the emissions of these pollutants from this Facility are not expected to be significant.

5.4 BACT Summary

Table 5-6 presents the control technologies proposed as BACT for the proposed Duke Energy Fort Pierce, LLC.

TABLE 5-6
Summary of Proposed BACT
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Control Technology	Proposed BACT
Nitrogen Oxides (NOx)	Dry Low-NO_X for Natural Gas Wet Injection and Limited Fuel Oil usage	12.0 ppmvd at 15% O_2 (Natural Gas) 42 ppmvd, at 15% O_2 (Fuel Oil)
Carbon Monoxide (CO)	Good Combustor Design and Operating Practice	25 ppmvd (Natural Gas, 100% Load) 20 ppmvd (Fuel Oil, 100% Load)
Volatile Organic Compounds (VOCs)	Good Combustor Design and Operating Practice	1.4 ppmvw (Natural Gas, 100% Load) 3.5 ppmvw (Fuel Oil, 100% Load)
Sulfur Dioxide (SO_2)	Pipeline Natural gas or Low Sulfur Fuel Oil	Sulfur content $\leq$ 2 grains/100 scf) (Natural Gas) 0.05% S by weight (Fuel Oil)
Particulate Matter (PM-10)	Pipeline Natural gas or low ash fuel oil, Good Combustor Design and Operating Practice	11 lb/hr (Natural Gas, 100% Load) 26 lb/hr (Fuel Oil, 100% Load)

6.0 Ambient Air Quality Impact Analysis

The dispersion modeling analyses documented herein were designed to assess the potential impact on ambient air quality of the proposed Facility located near Fort Pierce, Florida. Prior to initiation of the air quality impact analysis performed for the Facility, a meeting was held on July 26, 2000 with FDEP modeling staff to review and approve the modeling protocol. The dispersion models, meteorological data, modeling methodology, and results of the analyses described in this application are consistent with the previously approved protocol.

6.1 Dispersion Model

Dispersion modeling results were obtained using EPA's short-term Industrial Source Complex Model (ISCST3), version 00101 (EPA, 1999). The short-term model was used exclusively to determine short-term concentrations (i.e., 1-hour to 24-hour averaging periods) as well as annual average concentrations.

6.2 Meteorological Input Data

The meteorological database used in the air quality modeling analyses consisted of 5 years (1987 to 1991) of surface observations and upper air data from West Palm Beach, Florida. FDEP staff provided the meteorological data. The West Palm Beach Airport is located approximately 75 km to the south of the proposed project site in an area of similar topographic features. The anemometer height used by the observing station is reported to be 10 meters. These data were reportedly processed using EPA's meteorological data preprocessor program PCRAMMET, and the results made ready for input into the ISCST3 model.

6.3 Receptor Grids

A Cartesian grid was utilized for all analyses. Initial modeling was performed on a receptor grid beginning at a location 100 meters from the turbine exhaust stacks (approximate nearest fenceline). Receptor spacing was set at 100 m spacing from 100 m out to 3.0 km, 250 m from 3.0 km out to 6 km, 500 m spacing from 6.0 km out to 12 kilometers, and 1.0 km beyond 12 km. The modeling approach was based on the assumption that a refined receptor grid (minimum 100 meter spacing) would be used as necessary in order to determine maximum predicted concentrations in various areas of the initial grid.

6.4 Other Modeling Considerations

The ISC model contains options that determine the way in which calculations are made. The choice of options was made consistent with EPA's current recommended approach, including the regulatory default option. The options utilized in the analysis included stack tip downwash, final plume rise, buoyancy-induced dispersion, building wake effects, and rural dispersion coefficients. Data obtained from the 1990 United States census indicates that the population density of St. Lucie County is 101.3 people per square kilometer. This is well below the 750 people per square kilometer that an Auer Land Use analysis would trigger a requirement to use urban dispersion coefficients. Additionally, a review of topographic maps within 3 kilometers of the project site indicates that the area is predominantly rural in nature and there are no areas of high density housing or industry to suggest that an urban classification would be warranted. The ISC calms processor was used to account for calm winds in the calculations. The area around the proposed Facility is generally flat, therefore terrain elevations were not used in the modeling.

The emissions from the proposed Facility will be released from eight 93-foot exhaust stacks (simple cycle units). The dispersion modeling was designed to incorporate building wake and downwash effects attributable to the largest onsite structure, namely the air intake housings on each unit. No consideration was given to the effects of adjacent turbine stack(s) in the building wake effects analysis since the centerline spacing between the stack(s) will be sufficiently large to avoid those effects.

6.5 Dispersion Modeling Methodology and Results

6.5.1 Facility Emission Sources

The dispersion modeling results reported in this section are based on the emission source information discussed previously in Section 3.0. Tables 3-1 through 3-6 summarized the emissions and emission source characteristics for the simple cycle combustion turbine trains. The emissions summarized in these tables are maximum expected emission rates computed at ambient conditions representative of the range of ambient conditions expected for operation. It is noted that these emissions also are representative of BACT as demonstrated in Section 5.0. With the exception of NO_x emissions, all emissions were modeled at the maximum hourly rate. NO_x emissions for the simple cycle units were modeled at the effective hourly emission rate corresponding to natural gas usage of 2500 annual operating hours (i.e., maximum hourly emission rate x 2500/8760) and fuel oil usage of 1000 annual operating hours (i.e., maximum hourly emission rate x 1000/8760).

The modeling analyses described in this report were based on four different objectives, namely to determine or demonstrate: (1) the maximum impact and radius of significant impact of the proposed Facility during maximum/full load operation; (2) the maximum impact and radius of significant impact of the proposed Facility based on part load operation (i.e., as low as 60 percent load); (3) PSD increment consumption in the area surrounding the Facility; and (4) compliance with the NAAQS. In accordance with US EPA and FDEP guidance, if maximum predicted impacts due to the operation of the proposed Facility are determined to be less than the EPA-defined level of significant impacts presented below (43 FR 26398), further modeling analysis to demonstrate compliance with the applicable PSD increments and NAAQS will not be required.

Significant Impact Concentration ($\mu g/m^3$)

Pollutant	Annual	1-Hour	3-Hour	8-Hour	24-Hour
SO_2	1	-	25	-	5
PM-10	1	-	-	-	5
NO_X	1	-	-	-	-
CO	-	2000	-	500	-

Modeling analyses were performed for winter and summer ambient temperatures as well as for the average annual ambient temperature for three operational load levels in order to ensure that maximum concentrations would be identified under all operating scenarios. Electronic copies of all relevant input and output files used in the modeling analyses presented herein are submitted on a CD-ROM as part of this application (see Appendix B for index).

6.5.1.1 Maximum Impact and Radius of Significant Impact

The maximum impact and radii of significant impact for each pollutant emitted from the proposed Facility was determined by modeling the maximum expected emissions as previously presented in Tables 3-1 through Table 3-6. NO_x emissions for the simple cycle units were modeled at the hourly rate corresponding to their annual hours of operation for natural gas and fuel oil. This analysis was performed for SO_2, PM-10, NO_x, and CO emissions since the emissions for these pollutants will be greater than the US EPA-defined significant emission rates.

The results of this analysis are summarized (for the winter operating conditions) in Tables 6-1 through 6-6. The results of the modeling analyses indicated that maximum predicted concentrations generally occurred for winter conditions (27 °F ambient conditions). Modeling was performed for all ambient and operating conditions, however only the winter ambient conditions are presented here since those conditions generally result in the highest concentrations. The model input and output files are included electronically on the CD-ROM that is being submitted with this application. As shown in Tables 6-1 through 6-6, the maximum predicted offsite concentrations attributable to the operation of the proposed Facility are less than the significant impact levels for all pollutants. It is noted that this is true for all operating scenarios and for all seasons. As a result, the impact of the proposed Facility is considered to be "insignificant" for all criteria pollutants and no further dispersion modeling or ambient air quality impact analysis is necessary.

Since the emissions from all eight turbines will be released from eight identical stacks that will be located in close proximity to one another, all emissions were modeled as a single source with the emission release characteristics of a single stack. Because the emissions were treated as a single source, pollutant emissions from the simple cycle turbines were modeled using a nominal emission rate of 10 grams/second (79.3 lb/hr). The results were then scaled up or down according to the ratio of the proposed emission rates (Tables 3-1 through 3-3) to the nominal emission rate. Detailed calculations can be found in spreadsheets contained in Appendix B.

Table 6-1
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (Maximum Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.028 Location (554500, 3033000) ROI = 0 km	0.029 Location (554500, 3033000) ROI = 0 km	0.030 Location (553500, 3033500) ROI = 0 km	**0.032** Location (553500, 3033500) ROI = 0 km	**0.032** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.33 Location (552000, 3037000) ROI = 0 km	0.32 Location (543000, 3032000) ROI = 0 km	0.33 Location (549500, 3025500) ROI = 0 km	**0.34** Location (550000, 3036000) ROI = 0 km	**0.34** Location (552000, 3033000) ROI = 0 km	0
NO_X	Annual	1	0.032 Location (554500, 3033000) ROI = 0 km	0.033 Location (554500, 3033000) ROI = 0 km	0.035 Location (553500, 3033500) ROI = 0 km	0.036 Location (553500, 3033500) ROI = 0 km	**0.037** Location (554000, 3033000) ROI = 0 km	0
SO_2	Annual	1	0.017 Location (554500, 3033000) ROI = 0 km	0.017 Location (554500, 3033000) ROI = 0 km	0.018 Location (553500, 3033500) ROI = 0 km	**0.019** Location (553500, 3033500) ROI = 0 km	**0.019** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.21 Location (552000, 3037000) ROI = 0 km	0.21 Location (543000, 3032000) ROI = 0 km	0.21 Location (549500, 3025500) ROI = 0 km	0.21 Location (550000, 3036000) ROI = 0 km	**0.22** Location (552000, 3033000) ROI = 0 km	0
	3-hour	25	0.85 Location (545000, 3039000) ROI = 0 km	0.86 Location (549000, 3039000) ROI = 0 km	0.86 Location (563000, 3022750) ROI = 0 km	0.79 Location (569500, 3017000) ROI = 0 km	**0.87** Location (568000, 3012000) ROI = 0 km	0
CO	1-Hour	2000	15.0 Location (561700, 3030500) ROI = 0 km	14.6 Location (561500, 3030600) ROI = 0 km	17.7 Location (562300, 3030300) ROI = 0 km	16.9 Location (562900, 3029600) ROI = 0 km	**18.1** Location (561500, 3030400) ROI = 0 km	0
	8-Hour	500	**4.43** Location (559500, 3026100) ROI = 0 km	4.18 Location (544000, 3025000) ROI = 0 km	4.06 Location (572000, 3014000) ROI = 0 km	3.88 Location (549000, 3039000) ROI = 0 km	3.90 Location (557000, 3032500) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-2
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (75 Percent Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.033 Location (555500, 3032500) ROI = 0 km	0.034 Location (555500, 3032500) ROI = 0 km	0.036 Location (555500, 3032500) ROI = 0 km	0.038 Location (553500, 3033500) ROI = 0 km	**0.039** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.41 Location (550500, 3028500) ROI = 0 km	0.41 Location (553000, 3036000) ROI = 0 km	0.40 Location (550500, 3041000) ROI = 0 km	0.41 Location (556000, 3036500) ROI = 0 km	**0.51** Location (561800, 3029200) ROI = 0 km	0
NO_X	Annual	1	0.032 Location (555500, 3032500) ROI = 0 km	0.032 Location (555500, 3032500) ROI = 0 km	0.034 Location (555500, 3032500) ROI = 0 km	0.036 Location (553500, 3033500) ROI = 0 km	**0.037** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.018 Location (555500, 3032500) ROI = 0 km	0.018 Location (555500, 3032500) ROI = 0 km	0.020 Location (555500, 3032500) ROI = 0 km	**0.021** Location (553500, 3033500) ROI = 0 km	**0.021** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.22 Location (550500, 3028500) ROI = 0 km	0.22 Location (553000, 3036000) ROI = 0 km	0.22 Location (550500, 3041000) ROI = 0 km	0.22 Location (556000, 3036500) ROI = 0 km	**0.28** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	0.87 Location (549000, 3039000) ROI = 0 km	0.88 Location (549000, 3039000) ROI = 0 km	0.83 Location (548000, 3031000) ROI = 0 km	0.81 Location (569500, 3017000) ROI = 0 km	**1.99** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	14.0 Location (561700, 3030400) ROI = 0 km	13.71 Location (558500, 3029500) ROI = 0 km	16.35 Location (562300, 3030200) ROI = 0 km	18.6 Location (562000, 3030300) ROI = 0 km	**51.6** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	4.98 Location (559700, 3026400) ROI = 0 km	4.39 Location (544000, 3025000) ROI = 0 km	4.53 Location (558800, 3031800) ROI = 0 km	4.18 Location (549000, 3039000) ROI = 0 km	**7.40** Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-3
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (60 Percent Load, Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.037 Location (555500, 3032500) ROI = 0 km	0.037 Location (555500, 3032500) ROI = 0 km	0.039 Location (555500, 3032500) ROI = 0 km	0.042 Location (554500, 3033000) ROI = 0 km	**0.043** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.45 Location (551000, 3028500) ROI = 0 km	0.44 Location (553000, 3036000) ROI = 0 km	0.43 Location (551000, 3040500) ROI = 0 km	0.46 Location (556000, 3036500) ROI = 0 km	**0.54** Location (561800, 3029200) ROI = 0 km	0
NO_X	Annual	1	0.031 Location (555500, 3032500) ROI = 0 km	0.031 Location (555500, 3032500) ROI = 0 km	0.033 Location (555500, 3032500) ROI = 0 km	0.035 Location (554500, 3033000) ROI = 0 km	**0.036** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.017 Location (555500, 3032500) ROI = 0 km	0.017 Location (555500, 3032500) ROI = 0 km	0.018 Location (555500, 3032500) ROI = 0 km	0.019 Location (554500, 3033000) ROI = 0 km	**0.020** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.21 Location (551000, 3028500) ROI = 0 km	0.20 Location (553000, 3036000) ROI = 0 km	0.20 Location (551000, 3040500) ROI = 0 km	0.21 Location (556000, 3036500) ROI = 0 km	**0.25** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	0.80 Location (561800, 3029100) ROI = 0 km	0.79 Location (549000, 3039000) ROI = 0 km	0.74 Location (548000, 3031000) ROI = 0 km	0.73 Location (569500, 3017000) ROI = 0 km	**1.78** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	18.6 Location (561800, 3029100) ROI = 0 km	10.4 Location (561500, 3030600) ROI = 0 km	12.5 Location (562300, 3030200) ROI = 0 km	14.1 Location (562000, 3030300) ROI = 0 km	**41.7** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	4.09 Location (559800, 3026500) ROI = 0 km	**3.75** Location (557000, 3028250) ROI = 0 km	3.64 Location (558900, 3031700) ROI = 0 km	3.38 Location (551000, 3037500) ROI = 0 km	5.98 Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-4
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (Maximum Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.061 Location (554500, 3033000) ROI = 0 km	0.063 Location (554500, 3033000) ROI = 0 km	0.066 Location (553500, 3033500) ROI = 0 km	0.069 Location (553500, 3033500) ROI = 0 km	**0.071** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	0.78 Location (552000, 3037000) ROI = 0 km	0.76 Location (543000, 3032000) ROI = 0 km	0.76 Location (549500, 3025500) ROI = 0 km	0.78 Location (550000, 3036000) ROI = 0 km	**0.79** Location (552000, 3033000) ROI = 0 km	0
NO_X	Annual	1	0.048 Location (554500, 3033000) ROI = 0 km	0.050 Location (554500, 3033000) ROI = 0 km	0.053 Location (553500, 3033500) ROI = 0 km	0.055 Location (553500, 3033500) ROI = 0 km	**0.057** Location (554000, 3033000) ROI = 0 km	0
SO_2	Annual	1	0.14 Location (554500, 3033000) ROI = 0 km	0.14 Location (554500, 3033000) ROI = 0 km	0.15 Location (553500, 3033500) ROI = 0 km	**0.15** Location (553500, 3033500) ROI = 0 km	**0.16** Location (554000, 3033000) ROI = 0 km	0
	24-hour	5	1.73 Location (552000, 3037000) ROI = 0 km	1.69 Location (543000, 3032000) ROI = 0 km	1.70 Location (549500, 3025500) ROI = 0 km	1.75 Location (550000, 3036000) ROI = 0 km	**1.77** Location (552000, 3033000) ROI = 0 km	0
	3-hour	25	6.99 Location (545000, 3039000) ROI = 0 km	7.01 Location (549000, 3039000) ROI = 0 km	7.14 Location (563000, 3022750) ROI = 0 km	6.47 Location (572000, 3013000) ROI = 0 km	**7.16** Location (568000, 3012000) ROI = 0 km	0
CO	1-Hour	2000	12.1 Location (561700, 3030500) ROI = 0 km	11.8 Location (561500, 3030600) ROI = 0 km	14.3 Location (562300, 3030300) ROI = 0 km	13.7 Location (562900, 3029600) ROI = 0 km	**14.6** Location (561500, 3030400) ROI = 0 km	0
	8-Hour	500	**3.54** Location (559500, 3026100) ROI = 0 km	3.36 Location (544000, 3025000) ROI = 0 km	3.26 Location (572000, 3014000) ROI = 0 km	3.11 Location (548000, 3040000) ROI = 0 km	3.13 Location (557000, 3032500) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-5
Summary of Dispersion Modeling Results
Maximim Predicted Offsite Concentrations and Radii of Significant Impact (75 Percent Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Averaging Period	Significant Impact Level (ug/m3)	Maximum Predicted Offsite Concentration (ug/m3) 1987	1988	1989	1990	1991	Maximum Radius of Significant Impact (km)
PM-10	Annual	1	0.075 Location (555500, 3032500) ROI = 0 km	0.076 Location (554000, 3033000) ROI = 0 km	0.080 Location (555500, 3032500) ROI = 0 km	0.085 Location (553500, 3033500) ROI = 0 km	**0.087** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	0.91 Location (550500, 3028500) ROI = 0 km	0.92 Location (553000, 3036000) ROI = 0 km	0.89 Location (550500, 3041000) ROI = 0 km	0.91 Location (556000, 3036500) ROI = 0 km	**1.01** Location (553000, 3032500) ROI = 0 km	0
NO_X	Annual	1	0.049 Location (555500, 3032500) ROI = 0 km	0.049 Location (555500, 3032500) ROI = 0 km	0.052 Location (555500, 3032500) ROI = 0 km	0.056 Location (553500, 3033500) ROI = 0 km	**0.057** Location (555500, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.14 Location (555500, 3032500) ROI = 0 km	0.14 Location (555500, 3032500) ROI = 0 km	0.15 Location (555500, 3032500) ROI = 0 km	**0.16** Location (553500, 3033500) ROI = 0 km	**0.16** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	1.67 Location (550500, 3028500) ROI = 0 km	1.69 Location (553000, 3036000) ROI = 0 km	1.64 Location (550500, 3041000) ROI = 0 km	1.67 Location (556000, 3036500) ROI = 0 km	**1.86** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	6.58 Location (549000, 3039000) ROI = 0 km	6.66 Location (549000, 3039000) ROI = 0 km	6.27 Location (548000, 3031000) ROI = 0 km	6.15 Location (569500, 3017000) ROI = 0 km	**8.89** Location (563000, 3029400) ROI = 0 km	0
CO	1-Hour	2000	9.64 Location (561700, 3030500) ROI = 0 km	9.49 Location (558500, 3029500) ROI = 0 km	11.3 Location (562300, 3030200) ROI = 0 km	12.9 Location (562000, 3030300) ROI = 0 km	**13.5** Location (561400, 3030300) ROI = 0 km	0
	8-Hour	500	**3.40** Location (559700, 3026400) ROI = 0 km	3.02 Location (544000, 3025000) ROI = 0 km	3.11 Location (558800, 3031800) ROI = 0 km	2.86 Location (549000, 3039000) ROI = 0 km	2.88 Location (557750, 3032000) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

Table 6-6
Summary of Dispersion Modeling Results
Maximim Predicted Concentrations and Radii of Significant Impact (60 Percent Load, Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

			Maximum Predicted Offsite Concentration (ug/m3)					
Pollutant	**Averaging Period**	**Significant Impact Level (ug/m3)**	**1987**	**1988**	**1989**	**1990**	**1991**	**Maximum Radius of Significant Impact (km)**
PM-10	Annual	1	0.080 Location (555500, 3032500) ROI = 0 km	0.081 Location (555500, 3032500) ROI = 0 km	0.085 Location (555000, 3032500) ROI = 0 km	0.091 Location (554500, 3033000) ROI = 0 km	**0.093** Location (555000, 3032500) ROI = 0 km	0
	24-hour	5	0.98 Location (551000, 3028500) ROI = 0 km	0.96 Location (553000, 3036000) ROI = 0 km	0.94 Location (551000, 3040500) ROI = 0 km	0.98 Location (556000, 3036500) ROI = 0 km	**1.18** Location (561800, 3029200) ROI = 0 km	0
NO_X	Annual	1	0.048 Location (555500, 3032500) ROI = 0 km	0.048 Location (555500, 3032500) ROI = 0 km	0.051 Location (555000, 3032500) ROI = 0 km	0.055 Location (554500, 3033000) ROI = 0 km	**0.056** Location (555000, 3032500) ROI = 0 km	0
SO_2	Annual	1	0.13 Location (555500, 3032500) ROI = 0 km	0.13 Location (555500, 3032500) ROI = 0 km	0.14 Location (555000, 3032500) ROI = 0 km	0.15 Location (554500, 3033000) ROI = 0 km	**0.16** Location (555500, 3032500) ROI = 0 km	0
	24-hour	5	1.63 Location (551000, 3028500) ROI = 0 km	1.59 Location (553000, 3036000) ROI = 0 km	1.56 Location (551000, 3040500) ROI = 0 km	1.64 Location (556000, 3036500) ROI = 0 km	**1.96** Location (561800, 3029200) ROI = 0 km	0
	3-hour	25	6.30 Location (561800, 3029100) ROI = 0 km	6.25 Location (549000, 3039000) ROI = 0 km	5.87 Location (548000, 3031000) ROI = 0 km	5.77 Location (569500, 3017000) ROI = 0 km	**14.1** Location (561800, 3029200) ROI = 0 km	0
CO	1-Hour	2000	15.1 Location (561800, 3029100) ROI = 0 km	8.49 Location (561500, 3030600) ROI = 0 km	10.2 Location (562300, 3030200) ROI = 0 km	11.6 Location (562000, 3030300) ROI = 0 km	**33.9** Location (561800, 3029200) ROI = 0 km	0
	8-Hour	500	3.33 Location (559800, 3026500) ROI = 0 km	3.06 Location (557000, 3028250) ROI = 0 km	2.96 Location (558900, 3031700) ROI = 0 km	2.75 Location (551000, 3037500) ROI = 0 km	**4.86** Location (561800, 3029200) ROI = 0 km	0

Notes:
Location = (UTM Coordinates)
Bold indicates maximum value

The proposed Facility is located approximately 360 km south of the Georgia border. Based on the modeling analyses conducted and summarized herein, no significant air quality impacts are expected in Georgia.

6.5.1.2 PSD Class II Increment Consumption

Since the proposed Facility has been shown to have an insignificant impact on ambient air quality at all locations, PSD Class II increment will not be consumed by this project and no additional analysis of PSD Class II increment is required.

6.5.1.3 Compliance with National Ambient Air Quality Standards

Since the emissions of NO_X, SO_2, PM-10, and CO, from the proposed Facility do not result in a significant impact (Section 6.5.1.1), it is not necessary to demonstrate compliance with the NAAQS for these pollutants; however, it is noted that St. Lucie County is considered by FDEP to be in attainment of all ambient air quality standards. Ozone is not an emitted pollutant; rather, it forms as a result of complex chemical reactions between precursor emissions of VOCs and NO_X in the presence of sunlight and higher temperatures, resulting in peak ozone levels occurring at mid-day during the warmest months of the year. The proposed Facility will be a source of both NO_X and VOC emissions; however, the increase in regional emissions is not expected to be significant enough to result in a measurable increase in ozone levels at any downwind location. Furthermore, emissions of NO_X and VOC will be minimized through the use of BACT as described in Section 5.0. St. Lucie County is currently considered to be an attainment for ozone, as previously discussed in Section 4.4.1, based on the most recent three year-period of ambient ozone monitoring data.

6.5.1.5 Impact on PSD Class I Areas

The closest PSD Class I area to the proposed Facility is the Everglades National Park, which is located approximately 190 km southeast of the project site. Since the distance to the Sipsey National Wilderness Area is greater than 100 km, and the predicted impacts on ambient air quality resulting from the operation of the Facility have been shown to be insignificant, no significant impacts (for any pollutant) are expected in this Class I area.

6.5.1.6 Ambient Air Quality Monitoring

The maximum predicted ambient air quality impacts are below *de minimis* impact levels for NO_X, PM-10, SO_2, and CO for all averaging periods. Therefore the proposed Facility is exempt from any preconstruction monitoring requirements for these pollutants. A comparison of maximum predicted impacts and the *de minimis* impact levels is as follows:

Pollutant	Duke Energy Fort Pierce, LLC Maximum Predicted Concentration ($\mu g/m^3$)	EPA De Minimis Impact Level ($\mu g/m^3$)
NO_X (annual)	0.096	14
PM-10 (24-hour)	1.18	10
SO_2 (24-hour)	1.96	13
CO (8-hour)	7.40	575

6.5.2 Air Toxics Impact Assessment

The US EPA's guidance on the assessment of non-regulated "toxic pollutants" requires that permit applicants evaluate emissions of toxic air pollutants, which the proposed Facility could emit in amounts potentially of concern to the public. Additional information is therefore provided on the potential impacts of formaldehyde emissions, as well as an estimate of other emissions (including heavy metals) from the proposed Facility.

6.5.2.1 Formaldehyde Emissions

The estimate of formaldehyde emissions for the proposed Facility was based on the results of formaldehyde stack tests for a similar facility at a recently constructed combustion turbine facility located in the South Coast Air Quality Management District (SCAQMD) of Southern California. The Facility underwent stack testing in 1995 in accordance with California Air Resources Board (CARB) Method 430 testing guidelines for formaldehyde, which consist of three tests, each with a duration of 2 hours. The units tested included two 80 - 100 MW class gas-fired, steam injected, industrial combustion turbines. The Facility in question is equipped with SCR, however, the SCRs were not in operation at the time of the test. Formaldehyde emissions rates obtained during this testing were 0.0000116 lb/MMBtu, based on lower heating value (LHV) fuel input (Unit 1) and 0.0000095 lb/MMBtu (LHV) for Unit 2, which represents an average emissions rate of 0.00001055 lb/MMBtu (LHV). For the proposed Facility, formaldehyde emissions rates based on these test data would be 0.0823 lb/hr (0.0104 g/s), using a facility heat input of 7,800 MMBtu/hr (HHV).

This value is significant because it is non-zero and the USEPA has determined that any emissions of formaldehyde are "significant". Formaldehyde is readily oxidized at combustion turbine temperatures and combustion is an acceptable method for controlling formaldehyde emissions. The proposed Facility will utilize complete combustion as demonstrated in the BACT section of the permit application. Therefore, the BACT for formaldehyde is proposed to be efficient combustion, which is consistent with previous BACT determinations for similar gas turbine installations. No significant ambient air quality impact is expected to occur as a result of this very low emission rate.

6.5.2.2 Other Emissions

The combustion of natural gas and No. 2 low sulfur fuel oil is not expected to result in any significant emissions of lead, beryllium, mercury, fluorides, arsenic, hydrogen sulfide, total reduced sulfur, manganese, nickel, cadmium, chromium, copper, or radionuclides. Of these, six have "significant" emission limits as defined by EPA. These are lead, beryllium, mercury, fluorides, hydrogen sulfide, and total reduced sulfur. Although trace amounts may result from the combustion of natural gas and No. 2 low sulfur fuel oil, EPA has not defined a significance level for benzene, manganese, nickel, chromium, copper, cadmium, or radionuclides. Estimated emissions for HAPs are shown in Tables 6-7 and 6-8 for natural gas firing and fuel oil firing, respectively.

TABLE 6-7
Summary of Air Toxic Emission Factors and Emission Rates (Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Formaldehyde	1.055 E-05	Test Results[a]	0.103
Benzene	1.2 E-05	AP-42	0.117
Acetaldehyde	4.5 E-05	Memorandum[b]	0.439
POM	3.69 E-06	Memorandum[b]	0.036
Acrolein	6.4 E-06	AP-42	0.062
Ethylbenzene	3.2 E-05	AP-42	0.312
Naphthalene	1.3 E-06	AP-42	0.013
PAH	2.2 E-06	AP-42	0.021

TABLE 6-7
Summary of Air Toxic Emission Factors and Emission Rates (Natural Gas Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Toluene	1.3 E-04	AP-42	1.27
Xylene	6.4 E-05	AP-42	0.624

[a]California test results as described in Section 6.5.2.3.
[b]EPA/Sims Memorandum dated 12/30/99.

TABLE 6-8
Summary of Air Toxic Emission Factors and Emission Rates (Fuel Oil Firing)
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Facility
Fort Pierce, Florida

Pollutant	Emission Factor (lb/mmBtu)	Emission Factor Source	Total Plant Emissions (tons/yr)
Acetaldehyde	3.03 E-05	Memorandum[a]	0.124
Benzene	8.30 E-05	Memorandum[a]	0.341
Cadmium	4.80 E-06	Memorandum[a]	0.020
Chromium	1.08 E-05	Memorandum[a]	0.044
Formaldehyde	3.42 E-04	Memorandum[a]	1.40
Lead	1.42 E-05	Memorandum[a]	0.058
Manganese	7.89 E-04	Memorandum[a]	3.24
Mercury	1.20 E-06	Memorandum[a]	0.005
Naphthalene	3.5 E-05	AP-42	0.144
Nickel	5.20 E-05	Memorandum[a]	0.213
PAH	4.0 E-05	AP-42	0.164
POM	8.74 E-05	Memorandum[a]	0.359

[a] EPA/Sims Memorandum dated 12/30/99.

Emissions are estimated using emission factors for natural gas and distillate oil-fired stationary gas turbines found in Supplement F to the Fifth Edition of AP-42 "Compilation of Emission Factors Volume I: Stationary and Area Sources" and an EPA Memorandum authored by Roy Sims (Dated 12/30/99). A copy of the 12/30/99 memo is available on EPA's web site at www.epa.gov./ttn/uatw/combust/turbine/turbpg.html. Emissions are calculated based on a plant heat input of 7,800 MMBtu/hr and 8,208 MMBtu/hr for natural gas and fuel oil, respectively. Total emissions of air toxic pollutants from the Facility indicate that HAP emissions will not trigger a requirement for case-by-case MACT, since no single HAP emission will exceed 10 tons/yr, and total HAPs will be less than 25 tons/yr.

Organic compounds are readily oxidized at combustion turbine temperatures and combustion is an acceptable method for controlling these emissions. The proposed Facility will utilize complete combustion as demonstrated in the BACT section of the permit application. Therefore, BACT is proposed to be efficient combustion, which is consistent with previous BACT determinations for similar gas turbine installations.

7.0 Additional Impact Analyses

As required by PSD regulations, this section addresses possible impacts on visibility, vegetation and soils, growth, PSD Class I areas, and nonattainment areas.

7.1 Effects on Visibility and PSD Class I Areas

The impact on visibility in the nearest PSD Class I area (i.e., the Everglades National Park, 190 km to the Southwest) attributable to the operation of the proposed Facility is not expected to be either significant or measurable. Inasmuch as the increase in emissions associated with the operation of the proposed Facility will result in only an insignificant impact on ambient air quality in the vicinity of the Facility, it is unlikely that the operation of the proposed Facility will cause any impairment to visibility at any location.

7.2 Effects on Vegetation and Soils

One indicator of potential effects to vegetation and soils is a comparison of predicted ambient concentrations with ambient air quality standards. Of most significance here is the fact that the secondary NAAQS were established to prevent adverse "welfare" effects such as direct damage to vegetation and harmful contamination of soils. In light of the fact that it has been shown that the operation of the Facility will not result in a significant impact on air quality at any location, there should not be any discernible effects on vegetation and soils.

7.3 Effects on Associated Growth

Employment at the Facility is expected to total approximately 30 personnel once the Facility becomes operational. No significant impact on local air quality conditions is expected that might otherwise accompany significant population growth. Personnel hired for this project will most likely be drawn from the existing regional population, with no appreciable changes in traffic or other growth associated parameters.

7.4 Impacts on Nonattainment Areas

There are no nonattainment areas for any pollutant in Florida. The Facility is not expected to have a significant impact on any nonattainment area, based on the air quality impact assessment performed.

8 References

U.S. Environmental Protection Agency, 2000. Industrial Source Complex Model, Version 00101. Office of Air Quality Planning and Standards. Available from EPA TTN Electronic Bulletin Board System (919) 541-5742.

U.S. Environmental Protection Agency, 1999. Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, Docket A-95-51, December 30, 1999.

Appendix A
Permit Application Forms

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Duke Energy Fort Pierce, LLC	
2. Site Name: Duke Energy Fort Pierce Generating Station	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: ½ mile east of Florida Turnpike, 1 mile north of Midway Road Street Address or Other Locator: City: Fort Pierce County: St. Lucie Zip Code: 34981	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: Nathan K. Plagens; Manager, Environmental Services; Duke Energy North America
2. Application Contact Mailing Address: Nathan K. Plagens Organization/Firm: Duke Energy North America Street Address: 5400 Westheimer Court City: Houston State: Texas Zip Code: 77056-5310
3. Application Contact Telephone Numbers: Telephone: (713) 627-5985 Fax: (713)- 627-5644

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	10-5-00
2. Permit Number:	1110100-001-AC
3. PSD Number (if applicable):	PSD-FL-302
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:____________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:____________________

Operation permit number to be revised:____________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:____________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:____________________

Reason for revision:____________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Steven F. Gilliland, Senior Vice President
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Duke Energy North America Street Address: 5400 Westheimer Court City: Houston State: Texas Zip Code: 77056-5310
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (713) 627-6500 Fax: (713) 627-5644
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [X], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.* [signature] 9/18/00 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: Pamela A. Lehr, P.E. Registration Number: 042634
2.	Professional Engineer Mailing Address: Organization/Firm: CH2M HILL Street Address: 800 Fairway Dr., Suite 350 City: Deerfield Beach State: FL Zip Code: 33441
3.	Professional Engineer Telephone Numbers: Telephone: (954) 426-4008 Fax: (954) 698-6010

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X], 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.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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.

Pamela A Peters — Signature

August 25, 2000 — Date

(seal)

*Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	**Description of Emissions Unit**	**Permit Type**	**Processing Fee**
CTG-1 – CTG-8	Combustion Turbines (8 identical units)	AC1A	$7,500

Application Processing Fee

Check one: [X] Attached - Amount: $7,500 [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: Duke Energy Fort Pierce, LLC (Duke) proposes to construct and operate a power generating facility near the City of Fort Pierce, Florida (the Facility) in St. Lucie County. The Facility will be known as the Fort Pierce Generating Station and will utilize eight simple cycle generating units to produce up to 640 MW of peak power at its design operating conditions. The Facility will be permitted to operate each of the turbines up to 2,500 hours per year, or 20,000 hours per year for all units combined, whichever is less restrictive. The primary fuel used by the turbines will be natural gas, with the capability of using ultra low sulfur (0.05 percent) No. 2 distillate fuel oil as a backup fuel in the unlikely event of a natural gas curtailment. Fuel oil use will be limited to 1,000 hours per turbine per year.
2. Projected or Actual Date of Commencement of Construction: May 2001
3. Projected Date of Completion of Construction: June 2002

Application Comment

Additional information relative to the proposed project is provided by the in a document entitled "Application for Permit to Construct Air Emissions Equipment", in which this application is included as an Appendix.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="4">1. Facility UTM Coordinates:
Zone: 17 East (km): 561.591 North (km): 3028.963</td></tr>
<tr><td colspan="4">2. Facility Latitude/Longitude:
Latitude (DD/MM/SS): Longitude (DD/MM/SS):</td></tr>
<tr><td>3. Governmental Facility Code: 0</td><td>4. Facility Status Code: C</td><td>5. Facility Major Group SIC Code: 49</td><td>6. Facility SIC(s): 4911</td></tr>
<tr><td colspan="4">7. Facility Comment (limit to 500 characters):</td></tr>
</table>

Facility Contact

<table>
<tr><td colspan="3">1. Name and Title of Facility Contact: Nathan K. Plagens, Manager, Environmental Services, Duke Energy North America.</td></tr>
<tr><td colspan="3">2. Facility Contact Mailing Address:
Organization/Firm: Duke Energy North America
Street Address: 5400 Westheimer Court
City: Houston State: Texas Zip Code: 77056-5310</td></tr>
<tr><td colspan="3">3. Facility Contact Telephone Numbers:
Telephone: (713)-627-5985 Fax: (713)-627-5644</td></tr>
</table>

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

See Section 4.0 of attached PSD Permit Application Report	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NO_X	A				
PM10	A				
SO_2	A				
CO	A				
VOC	SM				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: Figure 2-1 [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Document ID: Figure 2-2 [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [X] Attached, Document ID: Figure 2-4 [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: PSD Application Report [ ] Not Applicable	
7. Supplemental Requirements Comment: Supplemental information is provided in the attached "Application for Permit to Construct Air Emissions Equipment" submitted in September of 2000, and in which this application is included as an appendix.	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [X] Not Applicable	
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable	
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable	
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable	
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [X] Not Applicable	
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [X] Not Applicable	
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [X] Not Applicable	
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [X] Not Applicable	

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): 80 MW simple cycle combustion turbine generating units 1 through 8 (8 identical units)

4. Emissions Unit Identification Number: [X] No ID
ID: [ ] ID Unknown

5. Emissions Unit Status Code: C	6. Initial Startup Date: 6/2002	7. Emissions Unit Major Group SIC Code: 4911	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters) Eight identical simple cycle generating units that will be fired on natural gas as a primary fuel for up to 2,500 hours/year (maximum average annual hours per unit), with distillate fuel oil as a backup fuel for up to 1,000 hours/year (maximum average annual hours per unit).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Proposed controls are described in the attached PSD Permit Application Report. NO_X Emissions will be controlled by utilizing dry low NO_X combustors (gas and oil firing), as well as water injection during periods of oil firing; clean burning pipeline natural gas and low sulfur, low ash fuel oil for the control of SO_2 and PM10 emissions; good operating practices for CO and VOC emission control.
2. Control Device or Method Code(s): 024, 028, 030

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric		Model Number: 7EA
2. Generator Nameplate Rating:	80 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	975 mmBtu/hr (gas), 1026 mmBtu/hr (oil) (HHV) 878 mmBtu/hr (gas), 925 mmBtu/hr (oil) (LHV)	
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate: 80 MW per turbine (8 identical)		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 2,500 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): To be operated as a fully dispatchable peak power generating facility, up to 20,000 hours per year for all eight units combined (i.e., an average of 2,500 hours per year per unit). If natural gas is not available, each turbine could operate (on average) up to 1,000 hours/yr on backup fuel oil (i.e., 8,000 hours per year for all eight units combined). Production rate and heat inputs are based on average ambient temperature conditions.		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Section 4.0 of attached PSD Permit Application Report	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? CTG-1 – CTG-8	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Not Applicable
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: V	6. Stack Height: 93 feet	7. Exit Diameter: 15 feet
8. Exit Temperature: 1005 °F	9. Actual Volumetric Flow Rate: 1,456,800 acfm	10. Water Vapor: 9 %

11. Maximum Dry Standard Flow Rate: 477,790 dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:		
Zone: 17	East (km): 561.591	North (km): 3028.963

14. Emission Point Comment: Exit temperature and volumetric flow rate based on average ambient temperature conditions.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural gas** fired in combustion turbines		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.975	5. Maximum Annual Rate: 2437.5	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: Negligible	8. Maximum % Ash: Negligible	9. Million Btu per SCC Unit: 1,000
10. Segment Comment (limit to 200 characters): Calculations based on 1,000 Btu per cubic foot of natural gas and HHV heat input of 975 mmBtu/hr. Maximum annual heat input is based on 2,500 hours/year operation. Information provided is per turbine.		

Segment Description and Rate: Segment __2___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Fuel oil** firing in combustion turbines		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 8.085	5. Maximum Annual Rate: 8,085	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.05	8. Maximum % Ash: Negligible	9. Million Btu per SCC Unit: 126.9
10. Segment Comment (limit to 200 characters): Calculations based on 1026 mmBtu/hr heat input (HHV), 18,000 Btu/lb of fuel oil, 7.05 lb/gallon of fuel oil. Maximum annual heat input is based on 1,000 hours/year operation. Information provided is per turbine.		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_X	**024 (Gas + Oil)**	**028 (Oil)**	**EL**
PM10	**0**	**0**	**EL**
SO_2	**0**	**0**	**EL**
CO	**0**	**0**	**EL**
VOC	**0**	**0**	**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units: CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions **Note: Emissions are per Turbine (8 Identical)**

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 182 lb/hour 126.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: 42 ppm Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly NO_X emissions are based on maximum load, 27 °F, and a manufacturer's guarantee of 42 ppmvd (at 15 percent O_2) as shown in Table 3-4 of PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (at 12.0 ppmvd, 27 °F) and 1,000 hours/year oil firing (at 42 ppmvd, 27 °F). Total potential annual NO_X emissions <u>for all 8 units combined</u> are 1,010 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 12.0 ppmvd (at 15 percent O_2)	4. Equivalent Allowable Emissions: 47 lb/hour 58.75 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or continuous monitoring as required by 40 CFR 60, Subpart GG and 40 CFR 75.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly NO_X emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual NO_X emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 470 tons/yr.	

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 42 ppmvd (at 15 percent O_2)	4. Equivalent Allowable Emissions: 182 lb/hour 91.0 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or continuous monitoring as required by 40 CFR 60, Subpart GG and 40 CFR 75	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly NO_X emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual NO_X emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 728 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION

**(Regulated Emissions Units - : CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 58 lb/hour 34.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Sulfur content of fuel Reference: Fuel specification	7. Emissions Method Code: 2

8. Calculation of Emissions (limit to 600 characters): Potential hourly SO_2 emissions are based on maximum load, 27 °F, and the sulfur content of the fuel oil burned as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (at 2 grains sulfur per 100 SCF gas burned, 27 °F) and 1,000 hours/year oil firing (at 0.05% Sulfur, 27 °F), as shown in Tables 3-1 and 3-4 of the PSD Permit Application. Total potential annual SO_2 emissions for all 8 units combined are 274 tons/year.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions __1____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.01 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 7 lb/hour 8.75 tons/year

5. Method of Compliance (limit to 60 characters): Fuel monitoring in accordance with 40 CFR 60 Subparts Dc and GG

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly SO_2 emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual SO_2 emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions for all 8 units combined is 70 tons/yr.

Emissions Unit Information Section ______ of ______

Allowable Emissions Allowable Emissions __2____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.06 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 58 lb/hour 29 tons/year
5. Method of Compliance (limit to 60 characters): Fuel monitoring in accordance with 40 CFR 60 Subparts Dc and GG	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly SO_2 emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions for all 8 units combined is 232 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 26.0 lb/hour 21.25 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: 0.028 lb/mmBtu Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly PM10 emissions are based on maximum load, 27 °F, and the manufacturer's recommendations, as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (11.0 lb/hr at 27 °F) and 1,000 hours/year oil firing (26.0 lb/hr at 27 °F), as shown in Tables 3-1 and 3-4. Total potential annual PM10 emissions <u>for all 8 units combined</u> are 170 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.013 lb/mmBtu (LHV)	4. Equivalent Allowable Emissions: 11.0 lb/hour 13.75 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or visible emissions monitoring as required by 40 CFR Part 60	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly PM10 emissions based on maximum load, **GAS-FIRED OPERATION**, 27 °F. Annual PM10 emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 110 tons/yr.	

Emissions Unit Information Section ______ of ______

Allowable Emissions Allowable Emissions __2____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 0.028 lb/mmBtu	4. Equivalent Allowable Emissions: 26.0 lb/hour 13.0 tons/year
5. Method of Compliance (limit to 60 characters): Stack testing and/or visible emissions monitoring as required by 40 CFR Part 60	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly PM10 emissions based on maximum load, **OIL FIRED OPERATION**, 27 °F. Annual PM10 emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 104 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 58 lb/hour 72.5 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: 25 ppm Reference: Manufacturer guarantee	7. Emissions Method Code: 1
8. Calculation of Emissions (limit to 600 characters): Potential hourly CO emissions are based on maximum gas-fired operation, 27 °F, and the manufacturer's recommendations, as shown in Table 3-1 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year gas-fired operation (58.0 lb/hr at 27 °F), as shown in Table 3-1. Total potential annual CO emissions <u>for all 8 units combined</u> are 580 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 25 ppm	4. Equivalent Allowable Emissions: 58.0 lb/hour 72.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and periodic testing as required by DEP	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly CO emissions based on maximum load, **GAS FIRED OPERATION**, 27 °F. Annual CO emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 580 tons/yr.	

Emissions Unit Information Section ______ of ______

<u>Allowable Emissions</u> Allowable Emissions __2____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 20 ppm	4. Equivalent Allowable Emissions: 47.0 lb/hour 23.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and periodic testing as required by DEP	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly CO emissions based on maximum load, **OIL-FIRED OPERATION**, 27 °F. Annual CO emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions <u>for all 8 units combined</u> is 188 tons/yr.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - CTG-1 – CTG-8 [8 identical]
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions **Note: Emissions are Per Turbine (8 Identical)**

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control: N/A
3. Potential Emissions: 5.0 lb/hour 4.0 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 3.5 ppm Reference: Manufacturer guarantee	7. Emissions Method Code:1
8. Calculation of Emissions (limit to 600 characters): Potential hourly VOC emissions are based on maximum load, 27 °F, oil-fired operation, and the manufacturer's recommendations, as shown in Table 3-4 of the PSD Permit Application Report. Potential annual emissions are based on 2,500 hours/year operation, with 1,500 hours/year gas firing (2.0 lb/hr at 27 °F) and 1,000 hours/year oil firing (5.0 lb/hr at 27 °F), as shown in Tables 3-1 and 3-4. Total potential annual VOC emissions for all 8 units combined are 32.0 tons/year.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 1.4 ppm	4. Equivalent Allowable Emissions: 2.0 lb/hour 2.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and the use of CO emissions as a surrogate for VOC	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly VOC emissions based on maximum load, **GAS-FIRED OPERATION**, 27 °F. Annual VOC emissions are based on 2,500 hours/yr operation, 27 °F, as shown in Table 3-1 of PSD Application. Total allowable annual emissions for all 8 units combined is 20 tons/yr.	

Allowable Emissions Allowable Emissions __2____ of __2____

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: June 2002
3. Requested Allowable Emissions and Units: 3.5 ppm	4. Equivalent Allowable Emissions: 5.0 lb/hour 2.5 tons/year
5. Method of Compliance (limit to 60 characters): Initial compliance test and use of CO emissions limit as a surrogate for VOC	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Hourly VOC emissions based on maximum load, **OIL-FIRED OPERATION**, 27 °F. Annual VOC emissions are based on 1,000 hours/yr operation, 27 °F, as shown in Table 3-4 of PSD Application. Total allowable annual emissions for all 8 units combined is 20 tons/yr.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: 10 % Maximum Period of Excess Opacity Allowed: 0 min/hour	
4. Method of Compliance: Periodic visual observation using EPA Reference Method 9 as required by DEP	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code: EM	2. Pollutant(s): NO_X
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: To be determined Manufacturer: To be determined Model Number: To be determined	Serial Number:
5. Installation Date: To be determined	6. Performance Specification Test Date: To be determined
7. Continuous Monitor Comment (limit to 200 characters): CEM system for NO_X monitoring to be installed and operated in conformance with 40 CFR Subpart 75.	

Emissions Unit Information Section ______ of ______

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Figure 2-4 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID:PSD Report [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: PSD Report [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID:PSD Report [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID:PSD Report [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: To be provided [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NO_X Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NO_X Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

Appendix B
Dispersion Modeling Information

INDEX of FILES on CD ROM

The CD-ROM included with this application contains all of the input and output files used or generated in the analysis described herein. The files are organized in the following Directories.
Duke Energy Fort Pierce, LLC Modeling 8/2000

Max-ROI
Fuel (Natural Gas, Oil)
Load% (100%, 75%, 60%)
Season (Average Annual, Summer, Winter)

A description of the files contained in the above Subdirectories is provided below:

Max-ROI

Analysis of maximum impact and Radius of Impact (ROI) for proposed Facility's General Electric (Model GE 7EA) simple cycle combustion turbines.

Natural Gas, Maximum Load
Gas100mm.DTA Input Data File
Gas100mm.LST Output Data File
Gas100mm.GRF Plot File
Gas100mm.SO, Gas100mm.SUM, Gas100mm.TAB BPIP processing files and results

Natural Gas, 75% Load
Gas75mm.DTA Input Data File
Gas75mm.LST Output Data File
Gas75mm.GRF Plot File
Gas75mm.SO, Gas75mm.SUM, Gas75mm.TAB BPIP processing files and results

Natural Gas, 60% Load
Gas60mm.DTA Input Data File
Gas60mm.LST Output Data File
Gas60mm.GRF Plot File
Gas60mm.SO, Gas60mm.SUM, Gas60mm.TAB BPIP processing files and results

Oil, Maximum Load
Oil100mm.DTA Input Data File
Oil100mm.LST Output Data File
Oil100mm.GRF Plot File
Oil100mm.SO, Oil100.SUM, Oil100.TAB BPIP processing files and results

Oil, 75% Load
Oil100mm.DTA Input Data File
Oil10mm 0.LST Output Data File
Oil100mm.GRF Plot File

Oil100mm.SO, Oil100mm.SUM, Oil100mm.TAB BPIP processing files and results

Oil, 60% Load
Oil100 mm.DTA Input Data File
Oil100 mm.LST Output Data File
Oil100 mm.GRF Plot File
Oil100 mm.SO, Oil100mm.SUM, Oil100mm.TAB BPIP processing files and results

Where:
"mm" is year of met data modeled

Duke Energy - St. Lucie

100% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0296	0.0306	0.0320	0.0338	0.0348
CO - 1-hr. Avg.	13.114	12.771	15.412	**17.595**	17.171
- 8-hr. Avg.	**4.158**	3.835	3.755	3.588	3.583
PM-10 - Annual Avg.	0.028	0.029	0.031	**0.033**	**0.033**
- 24-hr.	0.349	0.344	0.346	0.359	**0.379**
SO_2 - Annual Avg.	0.016	0.016	0.017	**0.018**	**0.018**
- 24-hr. Avg.	0.191	0.187	0.189	0.196	**0.207**
- 3-hr. Avg.	0.778	0.786	0.755	0.725	**1.139**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0297	0.0304	0.0322	0.0340	0.0347
CO - 1-hr. Avg.	13.591	13.235	15.987	**18.256**	17.816
- 8-hr. Avg.	**4.235**	3.926	3.837	3.669	3.695
PM-10 - Annual Avg.	0.028	0.029	0.030	0.032	**0.033**
- 24-hr.	0.344	0.339	0.342	0.354	**0.369**
SO_2 - Annual Avg.	0.015	0.016	0.017	0.017	**0.018**
- 24-hr. Avg.	0.187	0.185	0.186	0.193	**0.201**
- 3-hr. Avg.	0.766	0.773	0.751	0.713	**1.136**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0316	0.0330	0.0345	0.0362	0.0369
CO - 1-hr. Avg.	15.008	14.610	17.685	16.890	**18.060**
- 8-hr. Avg.	4.426	4.180	4.063	3.876	**3.900**
PM-10 - Annual Avg.	0.026	0.027	0.028	0.030	**0.030**
- 24-hr.	0.330	0.324	0.326	0.336	**0.340**
SO_2 - Annual Avg.	0.017	0.017	0.018	**0.019**	**0.019**
- 24-hr. Avg.	0.210	0.206	0.207	0.214	**0.217**
- 3-hr. Avg.	0.852	0.855	0.864	0.789	**0.873**

Example Calculations

NO_x Annual Average, 1988 Winter Scenario

NO_x (ug/m^3) = (0.0244 ug/m^3)*(376 lb/hr/79.36508 lb/hr)*(2500 hrs/8760 hrs)

= 0.033 ug/m^3

PM-10 24-hr, 1988 Winter Scenario

PM-10 (ug/m^3) = (0.292 ug/m^3)*(88 lb/hr/79.36508 lb/hr)

= 0.324 ug/m^3

Duke Energy - St. Lucie **100% Gas Load**

Summer Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0257	0.0266	0.0278	0.0294	0.0302
24-hr	0.315	0.310	0.312	0.324	0.342
8-hr	0.825	0.761	0.745	0.712	0.711
3-hr	1.287	1.299	1.248	1.199	1.884
1-hr	2.602	2.534	3.058	3.491	3.407

Average Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0252	0.0258	0.0273	0.0288	0.0294
24-hr	0.310	0.306	0.308	0.319	0.333
8-hr	0.808	0.749	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.525	3.050	3.483	3.399

Winter Scenario **Conversion Factors**

Averages	1987	1988	1989	1990	1991
Annual	0.0234	0.0244	0.0255	0.0268	0.0273
24-hr	0.298	0.292	0.294	0.303	0.307
8-hr	0.757	0.715	0.695	0.663	0.667
3-hr	1.207	1.212	1.225	1.118	1.237
1-hr	2.567	2.499	3.025	2.889	3.089

Duke Energy - St. Lucie

75% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0293	0.0295	0.0311	0.0334	0.0341
CO - 1-hr. Avg.	17.853	10.074	12.104	13.751	**40.150**
- 8-hr. Avg.	3.930	3.624	3.505	3.252	**5.753**
PM-10 - Annual Avg.	0.036	0.037	0.039	**0.042**	**0.042**
- 24-hr.	0.445	0.437	0.427	0.448	**0.538**
SO_2 - Annual Avg.	0.017	0.017	0.018	**0.019**	**0.019**
- 24-hr. Avg.	0.202	0.199	0.194	0.204	**0.244**
- 3-hr. Avg.	0.783	0.778	0.731	0.719	**1.761**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0302	0.0305	0.0321	0.0321	0.0349
CO - 1-hr. Avg.	10.862	10.556	10.556	12.677	**41.219**
- 8-hr. Avg.	4.012	3.492	3.605	3.605	**5.907**
PM-10 - Annual Avg.	0.035	0.036	0.037	0.037	**0.041**
- 24-hr.	0.429	0.425	0.415	0.415	**0.526**
SO_2 - Annual Avg.	0.016	0.016	0.017	0.017	**0.019**
- 24-hr. Avg.	0.195	0.193	0.188	0.188	**0.239**
- 3-hr. Avg.	0.749	0.759	0.714	0.714	**1.718**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0319	0.0323	0.0343	0.0364	0.0374
CO - 1-hr. Avg.	13.958	13.712	16.349	18.623	**51.604**
- 8-hr. Avg.	4.980	4.392	4.529	4.178	**7.401**
PM-10 - Annual Avg.	0.033	0.034	0.036	0.038	**0.039**
- 24-hr.	0.406	0.409	0.397	0.407	**0.507**
SO_2 - Annual Avg.	0.018	0.018	0.019	0.021	**0.021**
- 24-hr. Avg.	0.221	0.223	0.217	0.222	**0.276**
- 3-hr. Avg.	0.867	0.878	0.826	0.810	**1.985**

Duke Energy - St. Lucie **75% Gas Load**

Summer Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0328	0.0331	0.0349	0.0375	0.0382
24-hr	0.401	0.394	0.385	0.404	0.485
8-hr	1.026	0.946	0.915	0.849	1.502
3-hr	1.554	1.544	1.451	1.426	3.494
1-hr	4.661	2.630	3.160	3.590	10.482

Average Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0318	0.0321	0.0338	0.0338	0.0368
24-hr	0.387	0.383	0.374	0.374	0.474
8-hr	0.995	0.866	0.894	0.894	1.465
3-hr	1.487	1.506	1.416	1.416	3.408
1-hr	2.694	2.618	2.618	3.144	10.223

Winter Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0300	0.0303	0.0322	0.0342	0.0351
24-hr	0.366	0.369	0.358	0.367	0.457
8-hr	0.950	0.838	0.864	0.797	1.412
3-hr	1.434	1.451	1.366	1.339	3.282
1-hr	2.663	2.616	3.119	3.553	9.845

Duke Energy - St. Lucie

60% Gas Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0294	0.0292	0.0313	0.0337	0.0343
CO - 1-hr. Avg.	30.015	26.478	18.784	26.893	**66.070**
- 8-hr. Avg.	6.642	5.805	6.150	5.396	**9.465**
PM-10 - Annual Avg.	0.040	0.040	0.043	0.046	**0.047**
- 24-hr.	0.498	0.473	0.467	0.503	**0.579**
SO_2 - Annual Avg.	0.015	0.015	0.016	**0.017**	**0.017**
- 24-hr. Avg.	0.181	0.172	0.170	0.183	**0.210**
- 3-hr. Avg.	0.690	0.671	0.629	0.619	**1.519**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0293	0.0292	0.0312	0.0335	0.0341
CO - 1-hr. Avg.	17.973	9.660	11.587	15.956	**39.884**
- 8-hr. Avg.	3.970	3.538	3.734	3.248	**5.715**
PM-10 - Annual Avg.	0.039	0.039	0.041	**0.045**	**0.045**
- 24-hr.	0.478	0.459	0.452	0.481	**0.563**
SO_2 - Annual Avg.	0.018	0.018	0.019	0.020	**0.021**
- 24-hr. Avg.	0.217	0.209	0.206	0.219	**0.256**
- 3-hr. Avg.	0.832	0.815	0.766	0.753	**1.847**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0307	0.0309	0.0327	0.0352	0.0357
CO - 1-hr. Avg.	18.602	10.371	12.454	14.144	**41.683**
- 8-hr. Avg.	4.092	3.746	3.636	3.381	**5.975**
PM-10 - Annual Avg.	0.037	0.037	0.039	0.042	**0.043**
- 24-hr.	0.452	0.442	0.434	0.456	**0.544**
SO_2 - Annual Avg.	0.017	0.017	0.018	0.019	**0.020**
- 24-hr. Avg.	0.206	0.201	0.197	0.207	**0.247**
- 3-hr. Avg.	0.795	0.787	0.739	0.727	**1.781**

Duke Energy - St. Lucie **60% Gas Load**

Summer Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0365	0.0363	0.0389	0.0419	0.0426
24-hr	0.449	0.427	0.421	0.454	0.522
8-hr	1.136	0.993	1.052	0.923	1.619
3-hr	1.711	1.664	1.560	1.536	3.767
1-hr	5.134	4.529	3.213	4.600	11.301

Average Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0351	0.0350	0.0374	0.0402	0.0409
24-hr	0.431	0.414	0.408	0.434	0.508
8-hr	1.094	0.975	1.029	0.895	1.575
3-hr	1.651	1.618	1.519	1.495	3.664
1-hr	4.953	2.662	3.193	4.397	10.991

Winter Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0334	0.0336	0.0355	0.0382	0.0388
24-hr	0.408	0.399	0.391	0.411	0.491
8-hr	1.041	0.953	0.925	0.860	1.520
3-hr	1.577	1.562	1.467	1.442	3.534
1-hr	4.732	2.638	3.168	3.598	10.603

Duke Energy - St. Lucie

100% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0449	0.0459	0.0486	0.0512	**0.0526**
CO - 1-hr. Avg.	10.276	10.013	12.069	13.775	**14.266**
- 8-hr. Avg.	**3.342**	3.055	3.000	2.870	2.870
PM-10 - Annual Avg.	0.067	0.069	0.073	0.077	**0.079**
- 24-hr.	0.811	0.799	0.804	0.837	**0.897**
SO_2 - Annual Avg.	0.124	0.127	0.134	0.141	**0.145**
- 24-hr. Avg.	1.493	1.470	1.479	1.539	**1.651**
- 3-hr. Avg.	6.111	6.172	5.828	5.694	**8.773**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0461	0.0472	0.0499	0.0527	**0.0540**
CO - 1-hr. Avg.	10.978	10.694	12.912	**14.746**	14.390
- 8-hr. Avg.	**3.421**	3.175	3.099	2.964	2.985
PM-10 - Annual Avg.	0.064	0.065	0.069	0.073	**0.074**
- 24-hr.	0.784	0.771	0.776	0.804	**0.842**
SO_2 - Annual Avg.	0.127	0.130	0.138	0.145	**0.149**
- 24-hr. Avg.	1.567	1.542	1.552	1.608	**1.683**
- 3-hr. Avg.	6.386	6.441	6.260	5.942	**9.470**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0484	0.0501	0.0528	0.0549	**0.0565**
CO - 1-hr. Avg.	12.133	11.816	14.308	13.659	**14.606**
- 8-hr. Avg.	**3.539**	3.359	3.259	3.108	3.127
PM-10 - Annual Avg.	0.061	0.063	0.066	0.069	**0.071**
- 24-hr.	0.776	0.757	0.763	0.784	**0.791**
SO_2 - Annual Avg.	0.135	0.140	0.147	0.153	**0.158**
- 24-hr. Avg.	1.731	1.690	1.701	1.748	**1.766**
- 3-hr. Avg.	6.986	7.010	7.144	6.466	**7.156**

Duke Energy - St. Lucie **100% Oil Load**

Summer Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0267	0.0273	0.0289	0.0305	0.0313
24-hr	0.322	0.317	0.319	0.332	0.356
8-hr	0.850	0.777	0.763	0.730	0.730
3-hr	1.318	1.331	1.257	1.228	1.892
1-hr	2.614	2.547	3.070	3.504	3.629

Average Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0252	0.0258	0.0273	0.0288	0.0295
24-hr	0.311	0.306	0.308	0.319	0.334
8-hr	0.808	0.750	0.732	0.700	0.705
3-hr	1.267	1.278	1.242	1.179	1.879
1-hr	2.593	2.526	3.050	3.483	3.399

Winter Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0231	0.0239	0.0252	0.0262	0.0270
24-hr	0.296	0.289	0.291	0.299	0.302
8-hr	0.747	0.709	0.688	0.656	0.660
3-hr	1.195	1.199	1.222	1.106	1.224
1-hr	2.561	2.494	3.020	2.883	3.083

Duke Energy - St. Lucie

75% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0446	0.0449	0.0475	0.0509	**0.0519**
CO - 1-hr. Avg.	14.468	8.212	9.865	11.209	**32.579**
- 8-hr. Avg.	3.184	2.753	2.844	2.640	**4.668**
PM-10 - Annual Avg.	0.079	0.079	0.084	0.090	**0.092**
- 24-hr.	0.963	0.946	0.927	0.970	**1.168**
SO_2 - Annual Avg.	0.125	0.126	0.133	0.142	**0.145**
- 24-hr. Avg.	1.524	1.498	1.467	1.536	**1.850**
- 3-hr. Avg.	5.910	5.883	5.527	5.432	**13.311**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0464	0.0468	0.0493	0.0527	**0.0538**
CO - 1-hr. Avg.	8.945	8.705	10.442	11.879	**33.780**
- 8-hr. Avg.	3.280	2.864	2.954	2.734	**4.843**
PM-10 - Annual Avg.	0.076	0.077	0.081	0.087	**0.088**
- 24-hr.	0.927	0.922	0.898	0.931	**1.139**
SO_2 - Annual Avg.	0.130	0.131	0.138	0.148	**0.151**
- 24-hr. Avg.	1.583	1.575	1.533	1.591	**1.947**
- 3-hr. Avg.	6.104	6.183	5.815	5.707	**13.990**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0489	0.0494	0.0523	0.0556	**0.0571**
CO - 1-hr. Avg.	9.638	9.493	11.296	12.871	**13.459**
- 8-hr. Avg.	**3.404**	3.016	3.110	2.863	2.881
PM-10 - Annual Avg.	0.075	0.076	0.080	0.085	**0.087**
- 24-hr.	0.907	0.920	0.892	0.910	**1.013**
SO_2 - Annual Avg.	0.138	0.139	0.147	0.157	**0.161**
- 24-hr. Avg.	1.669	1.692	1.641	1.674	**1.864**
- 3-hr. Avg.	6.584	6.663	6.274	6.148	**8.889**

Duke Energy - St. Lucie 75% Oil Load

Summer Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0326	0.0328	0.0347	0.0372	0.0379
24-hr	0.398	0.391	0.383	0.401	0.483
8-hr	1.019	0.881	0.910	0.845	1.494
3-hr	1.543	1.536	1.443	1.418	3.475
1-hr	4.630	2.628	3.157	3.587	10.426

Average Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0315	0.0318	0.0335	0.0358	0.0365
24-hr	0.383	0.381	0.371	0.385	0.471
8-hr	0.986	0.861	0.888	0.822	1.456
3-hr	1.477	1.496	1.407	1.381	3.385
1-hr	2.689	2.617	3.139	3.571	10.155

Winter Scenario **Conversion Factors**

Averages	**1987**	**1988**	**1989**	**1990**	**1991**
Annual	0.0297	0.0300	0.0318	0.0338	0.0347
24-hr	0.360	0.365	0.354	0.361	0.402
8-hr	0.938	0.831	0.857	0.789	0.794
3-hr	1.420	1.437	1.353	1.326	1.917
1-hr	2.656	2.616	3.113	3.547	3.709

Duke Energy - St. Lucie

60% Oil Load

Summer Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0433	0.0432	0.0462	0.0498	**0.0504**
CO - 1-hr. Avg.	14.397	7.567	9.060	12.975	**31.738**
- 8-hr. Avg.	3.184	2.794	2.958	2.591	**4.547**
PM-10 - Annual Avg.	0.084	0.084	0.089	0.096	**0.098**
- 24-hr.	1.034	0.983	0.971	1.043	**1.206**
SO_2 - Annual Avg.	0.124	0.124	0.132	0.143	**0.144**
- 24-hr. Avg.	1.529	1.453	1.436	1.542	**1.782**
- 3-hr. Avg.	5.826	5.675	5.322	5.250	**12.845**

Average Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0448	0.0448	0.0478	0.0513	**0.0522**
CO - 1-hr. Avg.	14.359	7.767	9.322	10.573	**31.738**
- 8-hr. Avg.	3.169	2.838	2.993	2.599	**4.575**
PM-10 - Annual Avg.	0.084	0.084	0.090	0.096	**0.098**
- 24-hr.	1.033	0.994	0.980	1.040	**1.222**
SO_2 - Annual Avg.	0.126	0.126	0.135	0.144	**0.147**
- 24-hr. Avg.	1.549	1.491	1.470	1.560	**1.833**
- 3-hr. Avg.	5.940	5.835	5.476	5.389	**13.209**

Winter Scenario	1987	1988	1989	1990	1991
NO_X - Annual Avg.	0.0478	0.0483	0.0509	0.0548	**0.0557**
CO - 1-hr. Avg.	15.112	8.493	10.203	11.590	**33.933**
- 8-hr. Avg.	3.326	3.058	2.961	2.751	**4.864**
PM-10 - Annual Avg.	0.080	0.081	0.085	0.091	**0.093**
- 24-hr.	0.977	0.956	0.936	0.982	**1.178**
SO_2 - Annual Avg.	0.133	0.134	0.142	0.152	**0.155**
- 24-hr. Avg.	1.629	1.593	1.560	1.637	**1.964**
- 3-hr. Avg.	6.298	6.250	5.871	5.770	**14.140**

Duke Energy - St. Lucie 60% Oil Load

Summer Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0362	0.0361	0.0386	0.0416	0.0421
24-hr	0.446	0.424	0.419	0.450	0.520
8-hr	1.128	0.990	1.048	0.918	1.611
3-hr	1.700	1.656	1.553	1.532	3.748
1-hr	5.101	2.681	3.210	4.597	11.245

Average Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.0348	0.0348	0.0371	0.0398	0.0405
24-hr	0.427	0.411	0.405	0.430	0.505
8-hr	1.084	0.971	1.024	0.889	1.565
3-hr	1.637	1.608	1.509	1.485	3.640
1-hr	4.912	2.657	3.189	3.617	10.921

Winter Scenario Conversion Factors

Averages	1987	1988	1989	1990	1991
Annual	0.033	0.0333	0.0351	0.0378	0.0384
24-hr	0.404	0.395	0.387	0.406	0.487
8-hr	1.031	0.948	0.918	0.853	1.508
3-hr	1.562	1.550	1.456	1.431	3.507
1-hr	4.685	2.633	3.163	3.593	10.52

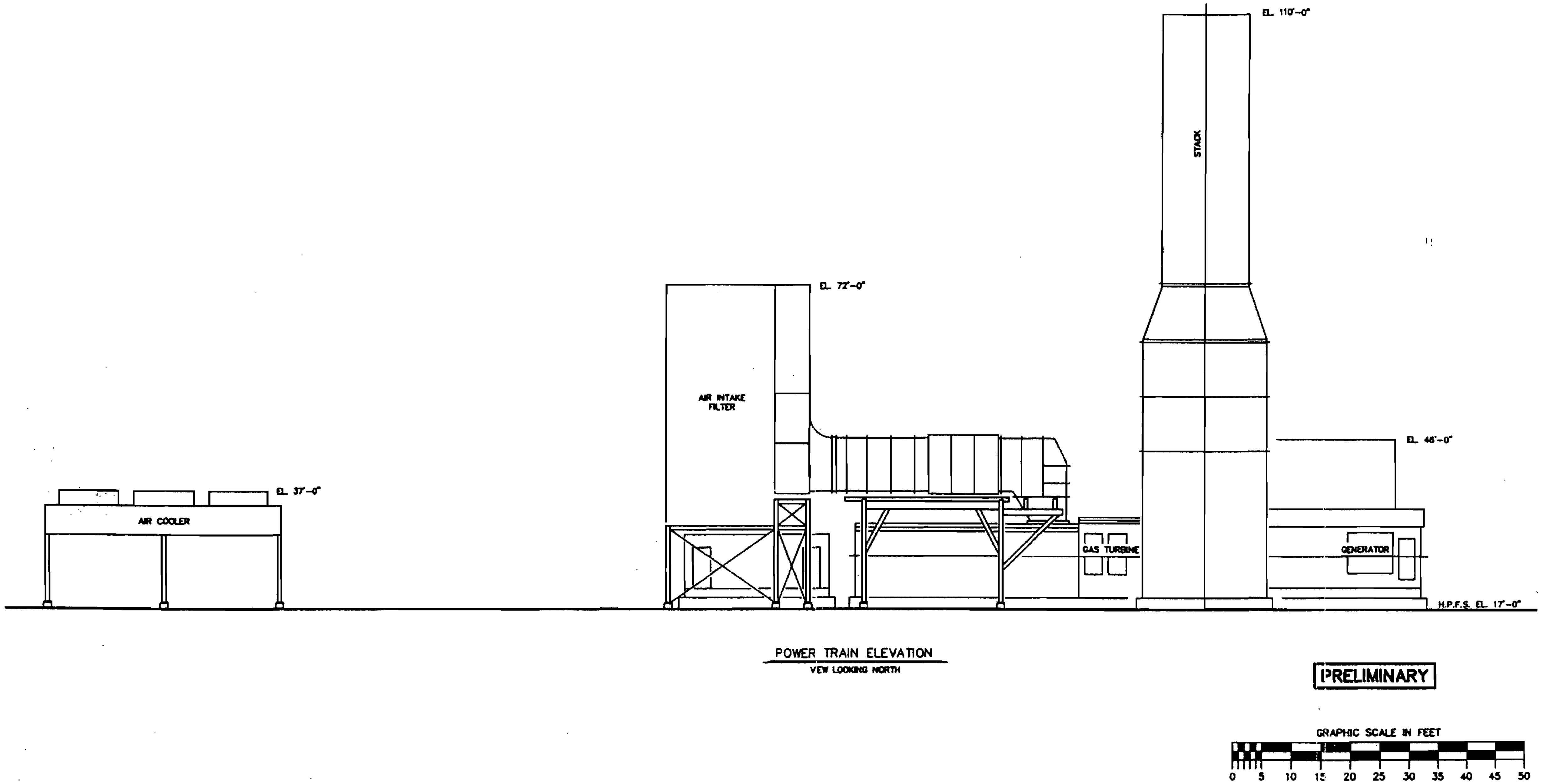
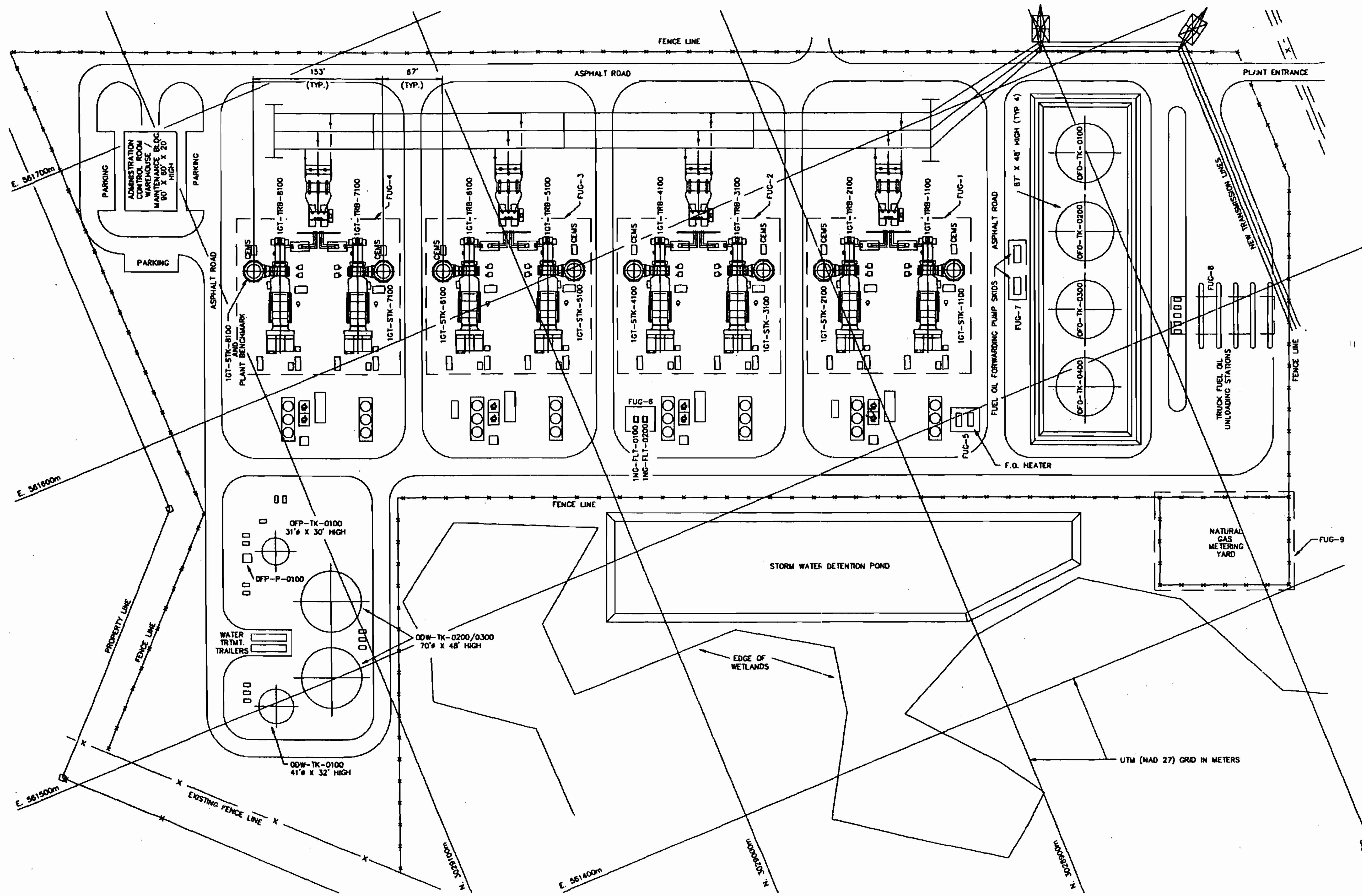
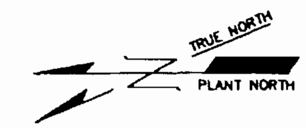


Figure 2-3
Power Train Elevation
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida





EMISSION POINT COORDINATES

DESCRIPTION	NORTHING	EASTING
OGT-STK-1100	N. 3028859m	E. 561548m
OGT-STK-2100	N. 3028901m	E. 561565m
OGT-STK-3100	N. 3028921m	E. 561573m
OGT-STK-4100	N. 3028963m	E. 561591m
OGT-STK-5100	N. 3028983m	E. 561599m
OGT-STK-6100	N. 3029025m	E. 561616m
OGT-STK-7100	N. 3029045m	E. 561625m
OGT-STK-8100	N. 3029087m	E. 561642m

EQUIPMENT LIST

1GT-TRB-1100 - 8100	COMBUSTION TURBINE GENERATOR
1GT-STK-1100 - 8100	TURBINE EXHAUST STACK
1NG-FLT-0100/0200	FUEL GAS COALESCING FILTERS
0DW-TK-0100	FOGGING WATER STORAGE TANK
0DW-TK-0200/0300	NOx WATER STORAGE TANK
0FP-TK-0100	FIRE WATER/SERVICE WATER TANK
0FP-P-0100	DIESEL FIRE WATER PUMP
0FO-TK-0100 - 0400	FUEL OIL STORAGE TANKS

NOTES:

1. POST-CONSTRUCTION ELEVATION OF SITE = 17' ABOVE MSL.
2. FUG-X DENOTES FUGITIVE EMISSIONS AREAS.
3. ALL COORDINATES SHOWN ARE UTM ZONE 17 GRID, NAD27, AND ARE GIVEN IN METERS.

PRELIMINARY

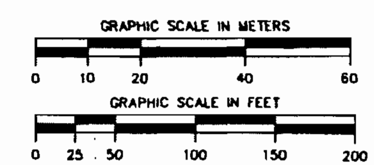


Figure 2-2
Proposed Plot Plan
Duke Energy Fort Pierce, LLC
Fort Pierce Generating Station
Fort Pierce, Florida

CH2MHILL

E082000002ATL\Duke102.FH8

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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* Trevor Woodruff
B. Date of Delivery 5/4/01
C. Signature X Trevor Woodruff ☐ Agent ☐ Addressee
D. Is delivery address different from item 1? ☐ Yes ☐ No
If YES, enter delivery address below:

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 1996

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 1996

Article Sent To:

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

Name *(Please Print Clearly) (to be completed by mailer)* Mr. Steven F. Gilliland
Street, Apt. No.; or PO Box No. 5400 Westheimer Ct.
City, State, ZIP+4 Houston, TX 77056-5310

PS Form 3800, July 1999 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. Gregory M. Nelson, P.E.
Director
Environmental Affairs
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* MAY 17 2001 B. Date of Delivery

C. Signature
X ☐ Agent ☐ Addressee

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

MAY 17 2001

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

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

2 Article Number *(Copy from service label)*
7099 3400 0000 1449 5267

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

UNITED STATES POSTAL SERVICE

First-Class Mail
Postage & Fees Paid
USPS
Permit No. G-10

• Sender: Please print your name, address, and ZIP+4 in this box •

DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF AIR RESOURCES MANAGEMENT
BUREAU OF AIR REGULATION - TITLE V
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400
MS 5505

RECEIVED
MAY 21 2001
BUREAU OF AIR REGULATION

01

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. Steven F. Gilliland
Sr. Vice President
Duke Energy North America
5400 Westheimer Ct
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 10-30-00

C. Signature
X H Herrick ☐ Agent ☐ Addressee

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 *(Copy from service label)*
7099 3400 0000 1453 1552

PS Form **3811**, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 1552

Article Sent To:
Mr. Steven F. Gilliland, Sr. VP
Duke Energy North America

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

Postmark
Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland, SR. VP
Street, Apt. No.; or PO Box No.
5400 Westheimer Ct
City, State, ZIP+4
Houston, TX 77056-5310

PS Form 3800, July 1999 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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X Edwin [signature]

☒ ~~Agent~~
☐ Addressee

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 *(Copy from service label)*
7000 0600 0026 4129 9426

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7000 0600 0026 4129 9426

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

Recipient's Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Steven F. Gilliland
Street, Apt. No.; or PO Box No.
5400 Westheimer Court
City, State, ZIP+4
Houston, Tx 77056-5310

PS Form 3800, February 2000 See Reverse for Instructions

THE TRIBUNE

ST. LUCIE COUNTY, FLORIDA

P.O. Box 69, Fort Pierce, FL 34954-0069

SCRIPPS HOWARD

AFFIDAVIT OF PUBLICATION

RECEIVED
JUN 12 2001
BUREAU OF AIR REGULATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Lynn Ferraro, General Manager; Kathy LeClair, Business Manager or Dorothy Dicks, Advertising Manager of The Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida; that the attached copy of advertisement was published in The Tribune in the following issues below. Affiant further says that the said Tribune is a newspaper published at Fort Pierce in said St. Lucie County, Florida and that the said newspaper has heretofore been continuously published in said St. Lucie County, Florida daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of attached copy of advertisement; and affiant further says that he/she 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. The Tribune has been entered as second class matter at the Post Office in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Name	Date	Price Per Day	PO #
2146609	CH2M HILL	05/10/2001	$390.04	
		Total	$390.04	

Subscribed and sworn to me before this date:

06/05/2001

Cathy LeClair

Kathy Lee

Notary Public

KATHY LEE
My Comm Exp. 7/30/2002
No. CC 763706
[✓] Personally Known [ ] Other I.D.

cc: J. Kahn
C. Holladay
J. Goldman, SED
B. Worley, EPA
J. Bunyak, NPS

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Project No. 1110100-001-AC
Draft Permit PSD-FL-302
Duke Energy Fort Pierce, LLC
Proposed 640 MW Simple Cycle Gas Turbine Plant
Emissions Units 001 - 009

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Duke Energy Fort Pierce, LLC to construct a nominal 640 MW simple cycle gas turbine plant. The proposed plant will be located approximately one mile east of the Florida Turnpike and one-half mile north of Midway Road in St. Lucie County, Florida. The applicant plans to install eight new simple cycle gas turbine-electrical generator sets with inlet air fogging systems and necessary support equipment. Each unit is a General Electric Model PG7121(EA) gas turbine with a nominal generating capacity of 80 MW. The applicant's authorized representative is Mr. Steven F. Gilliland, Senior Vice President of Duke Energy North America. The applicant's mailing address is 5400 Westheimer Court, Houston, TX 77056-5310.

Each simple cycle gas turbine will be fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. Operation is restricted to an average of 2500 hours per gas turbine per year with an average of no more than 500 hours of oil firing per gas turbine per year. When firing natural gas, nitrogen oxide emissions will be minimized with dry low-NOx combustion technology. When firing very low sulfur distillate oil, nitrogen oxide emissions will be minimized with wet injection and restricted operation. Emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxides, and volatile organic compounds will be minimized by the efficient combustion of these clean fuels.

The potential emissions from this project are shown in the following table.

Pollutant	Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	BACT Required?
CO	540	100	Yes	Yes
NOx	632	40	Yes	Yes
PM/PM10	60	25/15	Yes	Yes
SAM	17	7	Yes	Yes
SO2	147	40	Yes	Yes
VOC	29	40	No	No

As indicated, a determination of Best Available Control Technology (BACT) was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM) and sulfur dioxide (SO2) pursuant to Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. An air quality impact analysis was conducted by the applicant and reviewed by the Department. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of tha Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department 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 Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

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

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project for additional information at the address and phone numbers listed above.

Florida Department of Environmental Protection
Bureau of Air Regulation
(111 S. Magnolia Drive, Suite 4)
2800 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Florida Department of Environmental Protection
Southeast District Office - Air Resources
(400 NORTH CONGRESS AVENUE)
P.O. BOX 15425
West Palm Beach, Florida 33401
Telephone: 561/681-6600
Fax: 561/681-6790

Publish: May 10, 2001

2146601

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. Steven F. Gilliland
Duke Energy North America
5400 Westheimer Court
Houston, FL 77056-5310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 6/25/01

C. Signature
X Helen Butler
☐ Agent
☐ Addressee

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 *(Copy from service label)*
7000 0600 0026 4129 8504

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7000 0600 0026 4129 8504

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

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland

Street, Apt. No.; or PO Box No.
5400 Westheimer Court

City, State, ZIP+4
Houston, FL 77056-5310

PS Form 3800, February 2000 See Reverse for Instructions

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 26, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Steven F. Gilliland, Sr. Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-5310

Re: Request for Additional Information
Project No. 1110100-001-AC (PSD-FL-302)
Duke Energy Fort Pierce, LLC

Dear Mr. Gilliland:

On October 5, 2000, the Department received an application with sufficient processing fee from Duke Energy for a PSD air permit to construct eight new 80 MW simple cycle combustion turbine/electrical generator sets. Completion of the project will create a new 640 MW electrical generating station located approximately ½ mile east of the Florida Turnpike and 1 mile north of Midway Road in St. Lucie County, Florida. The application is incomplete. To continue processing your application, the Department will need the additional information requested below. Should your response to any of these items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Simple Cycle Operation: The application requests simple cycle operation only. Does Duke Energy plan to convert these units in the future to combined cycle operation? Do the engineering plans include any provisions for accommodating the future installation of heat recovery steam generators (HRSGs)? The Department intends to limit operation to simple cycle only. Any future request to add combined cycle operation will require a permit modification and PSD review for CO and NOx. Please plan accordingly.

2. Combustors and Control System: Please identify the model of dry low-NOx combustors that will be included with each unit. Please identify the model and describe the automated gas turbine control system that will be installed with each unit.

3. Inlet Air-Cooling System: Please describe and detail the "air-cooled" auxiliary inlet air cooling system (page 2-5). The application also mentions an inlet fogging system to enhance power output during the summer months. Is this a high-pressure, direct water spray system? Please describe the system and identify the manufacturer, model, designed cooling reduction (°F), operating pressure, and water consumption rate.

4. Fuel Tanks: What is the size (gallons) of each of the four fuel oil tanks to be installed?

5. CO Emissions Standards: Although the application requests a CO standard for gas firing of 25.0 ppmvd, the Department is aware of actual field data showing CO emissions to be less than 10 ppmvd, particularly at typical stack test conditions near 100% base load. The Department has recently permitted GE 7EA units with the following CO emissions standards for gas firing:

   - 25.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, first year of operation
   - 20.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, after first year of operation

Table 3-3 indicates CO emissions of 42.0 ppmvd (58.0 lb/hour) at 60% of base load and an inlet temperature of 101° F. Is this correct? Please comment on these items.

6. NOx Emissions Standards: The application requests a NOx emission standard for gas firing of 12.0 ppmvd corrected to 15% oxygen for the General Electric 7EA gas turbine. The Department has emissions performance data from General Electric that indicates NOx emissions for this unit will be 9.0 ppmvd corrected to 15% oxygen. The Department has recently permitted GE 7EA units with the following NOx emissions standards:

   - 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and
     9.0 ppmvd @ 15% oxygen based on a 24-hour block CEMS average of available operating hours
   - 9.0 ppmvd @ 15% oxygen based on a 3-hour test at 100% base load, and
     10.0 ppmvd @ 15% oxygen based on a 3-hour rolling CEMS average

   Please comment.

7. SAM Emissions: Page 5-21 states that approximately 10% of the SO_2 emissions are oxidized to SO_3, eventually forming sulfuric acid mist (H_2SO_4, SAM). Based on the application, the project would result in 27.4 tons of SAM per year. Table 62-212.400-2, F.A.C. identifies "7.0 tons per year" as the PSD Significant Emission Rate for SAM. Please provide a BACT analysis for SAM emissions.

8. VOC Standard: Please correct the VOC emissions rate from "ppmvw" to "ppmvd corrected to 15% oxygen".

9. SCR and CO Oxidation Catalyst Cost Analyses:

   The application indicates an incremental cost effectiveness of $50,602 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $21,832 per ton of CO removed for the installation of an oxidation catalyst. After reviewing information for similar projects, the Department believes these estimates are inaccurate. In fact, a similar Duke Energy project in Madison, Ohio involved the General Electric Model 7EA with annual operation of 2500 hour of gas firing and 500 hours of oil firing. The agency's permit documentation (July 1999) indicates an incremental cost effectiveness of $19,000 per ton of NOx removed for the installation of SCR and an incremental cost effectiveness of $9000 per ton of CO removed for the installation of an oxidation catalyst. Other projects in the United States have estimated the cost effectiveness of each of these technologies to be much lower than presented in this application.

   For projects requesting operating limits on "groups" of gas turbines instead of individual units, EPA requires calculating the "cost effectiveness" based on the maximum operation for a given unit. For example, based on the application provided, this would be 7760 hours per year of gas firing and 1000 hours per year of oil firing. This would result in annual NOx emissions of 239 tons per year and a potential NOx reduction from SCR of 167 tons per year based on 71% control efficiency. Please base the NOx and CO cost effectiveness calculations ($/ton pollutant removed) on the worst case requested. If the worst case is for oil firing, then include emissions from oil firing based on the same control efficiency. The worst case may be different for the SCR analysis and oxidation catalyst analysis. Note: In addition to the caps requested on total operation of the 8 gas turbines, the Department is considering an operating limit of 5000 hours per year for each turbine.

   a. Please provide the actual vendor's quotes (with equipment listed) for the SCR system and for the oxidation catalyst system.

   b. Please describe the "instrumentation" that would be provided for the SCR system ($203,700) and for the oxidation catalyst system ($124,200). Is this instrumentation already included in the vendor quotes? If no instrumentation is proposed, please remove these costs.

c. Please revise the SCR cost analysis and the oxidation catalyst cost analysis for the following items:

Capital Cost Items

- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased equipment;
- Revise the "contingency" factor under indirect capital costs for hot SCR from 0.20 to 0.10; and
- Remove the cost for "simple interest during construction";

Annual Cost Items

- Revise the cost for "power loss due to pressure drop across the catalyst" based on $0.04 / kWh or provide supporting documentation for $0.065 / kWh;
- Revise the cost for "operating labor" based on 625 hours of labor per year (2500 hr/yr* / 12 hr/shift x 3 hr labor/shift);
- Revise cost for "supervisory labor" accordingly;
- Revise the cost for "maintenance labor" based on 833 hours of labor per year (2500 hr/yr* / 12 hr/shift x 4 hr labor/shift);
- Revise the cost for "maintenance materials" accordingly;
- Remove the cost for "revenue loss during catalyst replacement" (can be scheduled during normal down time);
- Remove the costs for " catalyst cleaning" and "catalyst replacement labor";
- Revise the state sales tax from 7% to 6% (Florida); verify that there will actually be a sales tax for the purchased catalyst;
- Revise the "overhead" costs based on previous changes; and
- Remove the cost for "property tax" for the control equipment.

Emissions Reduction

- If the costs are estimated at 8760 hours per year, then the emissions reductions should be based on the same. * If a limit is requested for each simple cycle gas turbine of 5000 hours per year, substitute 5000 for 2500.
- Revise the oxidation catalyst control efficiency from 80% to 90% or provide a reference for the assumed 80% control efficiency.

10. PSD Class I Impact Analysis: In July of 2000, representatives for Duke Energy met with representatives of the Department in a pre-application meeting to discuss various issues. During this meeting, Duke Energy questioned whether or not a PSD Class I Ambient Air Quality Impact Analysis for the Everglades National Park was necessary for a combustion turbine project fired completely with natural gas. The Department relayed a response to Duke Energy from the National Park Service that a PSD Class I Ambient Air Quality Impact Analysis was not necessary for the project, as described, fired solely with natural gas. The following table lists the annual emissions given to the Department at that time of the meeting as well as the annual potential emissions as submitted in the application:

Pollutant	Pre-Application TPY	Application TPY
CO	400	580
NOx	225	1010
PM10	120	170
SO_2	100	274

Obviously, Duke Energy now intends to fire low sulfur distillate oil as a backup fuel based on an interruptible gas supply contract (page 2-7) and has requested up to 1000 hours of oil firing per gas turbine. Please submit the required PSD Class I Ambient Air Quality Impact Analysis for this project.

11. Class II Building Downwash Analysis: The modeling files that were submitted with the application modeled all six combustion turbines as a single stack and building. The results were then multiplied by six to obtain the modeled concentration. This configuration does not adequately address all building downwash concerns. Please resubmit a modeling analysis that models each of the six combustion turbines and their associated buildings explicitly. Also, please submit the input file for the BPIP program.

12. Modeled Annual NOx Concentrations: Please submit some example calculations that show how the modeled annual NOx concentrations for the oil scenario were derived from the conversion factors presented in Appendix B.

13. NSPS Monitoring: Is Duke Energy proposing an Alternate Monitoring Plan to demonstrate compliance with the NSPS Subpart GG monitoring requirements for NOx and SO_2? Which proposed emission units would be subject to 40 CFR 60 Subpart Dc requirements as indicated on page 4-6?

14. Acid Rain: The application does not indicate whether or not the application for an Acid Rain permit has been submitted. The new gas turbines will be subject to the Acid Rain (Title IV) provisions. You are notified that an application for a Title IV Acid Rain Permit must be submitted at least 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. The application must be submitted to the Region 4 office of the U.S. Environmental Protection Agency in Atlanta, Georgia with a copy to the Department's Bureau of Air Regulation in Tallahassee.

The Department will resume processing your application after receipt of the requested information. 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. For material changes to the application, please submit a new certification statement by the authorized representative or responsible official. Rule 62-4.055(1), F.A.C. now requires permit applicants to response to requests for information within 90 days. If there are any questions, please contact me at 850/414-7268. Questions regarding the air quality analysis should be directed to the project meteorologist, Chris Carlson, at 850/921-9537.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

cc:

Mr. Nathan L. Plagens, Duke Energy North America
Ms. Pamela A. Lehr, CH2M HILL
Mr. Isidore Goldman, SED
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA Region 4

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. Steven F. Gilliland
Senior Vice President
Duke Energy North America
5400 Westheimer Court
Houston, TX 77056-6310

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1-12-01

C. Signature
X H Herrick
☐ Agent
☐ Addressee

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 *(Copy from service label)*

~~7099 3400 0000 1453 2801~~

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 2801

Article Sent To:

Mr. Steven F. Gilliland

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

Duke Energy
North America

Postmark
Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Steven F. Gilliland
Street, Apt. No.; or PO Box No.
5400 Westheimer Ct.
City, State, ZIP+4
Houston, TX 77056-5310

PS Form 3800, July 1999 See Reverse for Instructions