STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Gary Lambert, Executive Vice President
CPV Cana, Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, MA 02184
______________________________/

DEP File No. 1110103-001-AC and PSD-FL-323
Combined Cycle Facility
St Lucie County

Enclosed is the Final Permit Number 1110103-001-AC (PSD-FL-323) to construct a Combined Cycle Plant called the CPV Cana Power Generating Facility in St Lucie County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

for 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 1/17/02 to the person(s) listed:

Gary Lambert, CPV Atlantic, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Tom Tittle, DEP SED
Danna Civetti, DEP St. Lucie Branch
Chair, St. Lucie County BCC*
Mayor, Port St. Lucie*
Scott Sumner, P.E., TRC
Cathy Sellers, Esq., Moyle Flanagan

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.

Barbara J. Friday 1/17/02
(Clerk) (Date)

FINAL DETERMINATION
File No. 1110103-001-AC (PSD-FL-323)
CPV – CANA POWER GENERATING FACILITY
COMBINED CYCLE POWER PROJECT

The Department distributed a Public Notice package on November 21, 2001 for the project to construct a natural gas and fuel oil-fired combined cycle unit to be known as the CPV – Cana Power Generating Facility located approximately 3 miles west of the City of Port St. Lucie in St.Lucie County. The project consists of a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a separate steam-electrical generator; a 175-foot stack; a mechanical draft cooling tower; a 975,000 gallon fuel oil storage tank, and other ancillary equipment. The Public Notice of Intent to Issue was published on December 3, in The Tribune, St. Lucie County, Florida.

Written comments were received during the 30-day public comment period from CPV Cana. Within the comments, CPV requested minor clarifications, corrections, and modifications of conditions of the draft permit and BACT determination. These minor changes are addressed and corrected in the final permit and the final BACT determination documents.

The most significant comments and requested changes are listed below. Each is followed by the Department's response.

Draft Air Permit PSD-FL-323

<u>Comment No 1 and 6. Specific Condition 9 - Section III</u>
On page 4 of the draft permit, paragraph 9, CPV Cana requests that the permit expiration date and construction deadline each be increased by one year, to June 30, 2005 and December 31, 2005, respectively. This will enable CPV Cana to complete its construction within the projected construction timeframe, with a time margin built in to accommodate potential short-term construction delays.

The Department agrees with the permittee and modified this condition as requested.

<u>Comment Nos. 16 y 17. Specific Condition 3.d, and Specific Condition 29- Section III</u>. *The last bullet point concerning "One exhaust stack……" should be deleted since the bypass stack option is not an appropiate mode for the CPV Cana facility, and the facility will not be operated in this mode.*

In a separate letter dated January 10, 2002, CPV recommended instead to fix startup times for reaching the "DLN" modes when design details are better known. This would occur after selection of a supplier for the heat recovery steam generator.

In response to the same permit requirement on a different but similar project, El Paso submitted a letter prepared by General Electric dated September 21, 2001. The Department had suggested startup time could be minimized by installation of a separate bypass stack and damper to facilitate startup of the steam cycle while operating the combustion turbine in low emission modes 5, 5Q, and 6Q. GE commented as follows:

"Operating the damper door as a modulating valve is not recommended. We are aware of a similar application at a project at KEPCO (Hungary?). Because of the turbulent flows, damage to the damper door and its seals allowed leakage to the atmosphere after the damper was closed resulting in a significant loss in performance".

The Department reviewed GE's letter and wrote an e-mail to their representative re-framing the issue and asking <u>how</u> startup emissions can be minimized for a combined cycle configuration and whether modulating valves (instead of dampers) can be designed for this purpose. General Electric's further input will be useful when reviewing future projects, but will not come in time to implement it into the present project.

The Department agrees with the permittee and modified these conditions as requested:

Specific Condition 3. d. Emission Unit 004: One Exhaust Stack: The stack shall be approximately 170 feet tall and 18.5 feet in diameter. ~~A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emissions Modes 5, 5Q, and 6Q.~~

Specific Condition 29 - Excess Emissions Defined:

~~b. Best Operational Standard (Bypass Stack Option): The unit will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire. Ammonia injection will be initiated within x, y, and z minutes for cold, warm, and hot startups respectively to minimize NO_x emissions. (Note: Times to be determined during public comment period).~~

b ~~c~~ . Best Operational Standard ~~(No Bypass)~~: The unit will reach Mode 5Q within x, y, and z minutes for cold, warm, and hot startups respectively (to minimize CO and NO_X emissions). Ammonia injection will be initiated within x, y, and z minutes for cold, warm, and hot startups respectively to minimize NO_X emissions. The following measures shall be employed following shutdowns to reduce subsequent excess startup emissions: (Note: Times and measures to be determined for modification of this permit and incorporation of the final conditions into the required Title V Operation permit ~~during public comment period~~)

Appendix BACT- BACT Determination (comments 33 through 37)

Comments 33, 34 and 35 were revised in the final BACT document.

Comments 36 and 37 are basically the same as the Draft Permit comments 16 and 17 above. Therefore, the paragraphs in the Appendix BACT (fourth and fifth bullet of page BD19) have been revised reflecting the same changes as in the final permit. This is, to submit the information after testing to be included in the Title V permit

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

CPV Cana, Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, Massachusetts 02184

File No.	1110103-001-AC
Permit No.	PSD-FL-323
SIC No.	4911
Expires:	December 31, 2005

Authorized Representative:

Gary Lambert, Executive Vice President

PROJECT AND LOCATION:

Air construction permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD) for the construction of a nominal 245 MW gas-fired combined cycle electrical power plant. The steam-electrical generator is limited to less than 75 MW. Diesel fuel with a maximum sulfur content of 0.05 percent will be used as back-up fuel. The plant will be known as the CPV Cana Power Generating Facility.

The project will be located in Port St. Lucie in St. Lucie County. UTM coordinates are Zone 17; 550.9 km E; 3018.1 km N.

STATEMENT OF BASIS:

This permit is issued under the provisions of Chapter 403 of the Florida Statutes, Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendices are made a part of this permit:

Appendix GC Construction Permit General Conditions
Appendix BD BACT Determination
Appendix GG NSPS Subpart GG Requirements

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

The proposed CPV facility is a combined cycle power plant. Key components include:

- One nominal 170 megawatt (MW) gas-fired combustion turbine-electrical generator with an un-fired heat recovery steam generator (HRSG) and 170-foot stack;
- A selective catalytic reduction unit located within the HRSG;
- A 975,000 gallon storage tank for backup No. 2 distillate fuel oil;
- A separate steam-electrical generator;
- A five-cell mechanical draft cooling tower;
- Ancillary facilities including miscellaneous equipment buildings, ammonia storage, demineralized water storage, fire water storage, one diesel-fired 250 hp fire water pump, and a 500 kW emergency generator.

EMISSION UNITS

This permit addresses the following emission units:

EMISSIONS UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One 170-megawatt combustion turbine-electrical generator with unfired heat recovery steam generator
002	Fuel Storage	One 975,000 gallon fuel oil storage tank
003	Water Cooling	One five-cell mechanical cooling tower
004	Ancillary Equipment	One diesel-fired 250 hp fire water pump, one 500 kW emergency generator, and an aqueous ammonia storage tank.

REGULATORY CLASSIFICATION

Title V: This facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

PSD: This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). With respect to Table 62-212.400-2, this facility results in emissions increases greater than 40 TPY of NO_X and SO_2, 25/15 TPY of PM/PM_{10}, 100 TPY of CO, and 7 TPY of sulfuric acid mist. These pollutants require PSD review and determinations of Best Available Control Technology pursuant to Rule 62-212.400, F.A.C.

SECTION I - FACILITY INFORMATION

Title III: This facility is not a major source of hazardous air pollutants (HAPs). This facility is not subject to MACT applicability.

Title IV: The new combined cycle unit is subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

NSPS: The new combined cycle gas turbine is subject to New Source Performance Standards 40 CFR 60, Subpart GG for Gas Turbines and the Storage Tank is subject to 40 CFR 60, Subpart Kb.

NESHAP: The permittee did not identify any emission unit as being subject to a National Emissions Standards for Hazardous Air Pollutants (NESHAP).

SITING: The project is not subject to Section 403.501-518, F.S., Florida Electrical Power Plant Siting Act, based on information regarding gross electrical power generated from the steam (Rankine) cycle submitted by the applicant and reviewed by the Department.

PERMIT SCHEDULE

- 12/03/01 Notice of Intent to Issue published in The Tribune, St. Lucie County
- 11/19/01 Distributed Intent to Issue Permit
- 10/25/01 Application deemed complete
- 09/05/01 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on September 5, 2001
- Comments from the Fish and Wildlife Service dated 06/12/01
- Department letter to CPV dated October 2, 2001
- CPV responses dated October 25, 2001
- Department's Intent to Issue and Public Notice Package dated November 21, 2001.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II. COMMON SPECIFIC CONDITIONS

GENERAL AND 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 (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114.

2. Compliance Authority: All documents related to reports, tests, and notifications should be submitted to the DEP Southeast District Office, 400 North Congress Avenue W, West Palm Beach, Florida, 33401 and phone number 561/681-6755, fax 561-681-6755. Copies shall be sent to the DEP Port St. Lucie Branch Office, 1801 S.E. Hillmoor Dr, C 204, Port St. Lucie, Florida 34952 and phone number 561/398-2806, fax 561/398-2815.

3. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

4. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

5. Forms and Application Procedures: 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. [Rule 62-210.900, F.A.C.]

6. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

7. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]

8. PSD Approval to Construct 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)]

9. Completion of Construction: The permit expiration date is December 31, 2005. Physical construction shall be complete by February 28, 2005. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

10. Permit Expiration Date Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

11. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, the extension of the December 31, 2004 permit expiration date, or any increases in MW generated by steam, heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes; the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.
[40 CFR 52.21(j)(4); 40CFR 51.166(j) and Rule 62-4.070 F.A.C.]

12. Application for Title IV Permit: An application for a Title IV Acid Rain Permit must be submitted to the DEP's Bureau of Air Regulation in Tallahassee at least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW and a copy to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia [40 CFR 72]

13. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southeast District Office. [Chapter 62-213, F.A.C.]

OPERATIONAL REQUIREMENTS

14. 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.]

15. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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

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

TESTING REQUIREMENTS

18. Test Notification: The permittee shall notify each 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. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and conducting the test.
[Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

19. 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.]

20. Applicable Test Procedures

- *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 sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)1. and 2., F.A.C.]
- *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.
[Rule 62-297.310(4)(b), F.A.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)(d), F.A.C.]

21. Determination of Process Variables

- *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.]
- *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.]

22. 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.]

23. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

24. 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)(b), F.A.C.]

RECORDS

25. 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.]

REPORTS

26. Emissions Performance Test Results 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.].

27. Annual Operating Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southeast District Office by March 1st of each year.

APPLICABLE STANDARDS AND REGULATIONS

1. Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. Applicable Requirements: Issuance of a permit does not relieve the owner or operator of an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law, notwithstanding that these applicable requirements are not explicitly stated in this permit. In cases where there is an ambiguity or conflict in the specific conditions of this permit with any of the above-mentioned regulations, the more stringent local, state, or federal requirement applies.
[Rules 62-204.800 and Rules 62-210.300 and 62-4.070 (3) F.A.C.]

3. Construction Authorization: The permittee is authorized to construct/install:

   a. EU 001: A combined cycle unit consisting of a General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 170 MW of shaft-driven electrical power and less than 75 MW of steam-generated electrical power. The unit is also subject to Subpart GG of 40 CFR 60, an NSPS for gas turbines as specified in Appendix GG of this permit.

   b. EU 002: One nominal 975,000-gallon distillate fuel oil storage tank. This unit is subject to NSPS requirements as stated in Section III, Specific Condition No.3. {Permitting Note: Tanks store fuel with relatively low Reid Vapor Pressure. Potential VOC emissions are expected to be less than 0.5 tons per year.}

   c. EU 003: One five-cell mechanical draft cooling tower with drift eliminators: This unit shall be designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. {Permitting Note: Potential PM/PM_{10} emissions are expected to be less than 0.8 lb/hr and 3.5 ton/year}.

   d. EU 004: Ancillary equipment as follows:

      - One 500 kW Emergency Generator: This generator shall be operated with diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.1 for PM/PM_{10}, SO_2, or VOC, less than 4.0 for NO_X, and less than 1.1 for CO.}

- One 250 HP Diesel Fire Water Pump: This engine shall be operated with diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.2 for PM/PM_{10}, 2.2 for NO_X, 0.5 for CO, 0.02 for SO_2 and 0.2 for VOC}
- One Aqueous Ammonia Storage Tank: This tank shall contain aqueous ammonia (less than 20 percent concentration by volume) and is not subject to applicable provisions of 40 CFR 68, Chemical Accident Provisions.
- One Exhaust Stack: The stack shall be approximately 170 feet tall and 18.5 feet in diameter.

[Application, Rule 62-204.800(7)(b), F.A.C., and 40 CFR 60 Subparts GG and Kb]

4. NSPS Requirements: The combined cycle gas turbine (Emissions Unit 001) shall comply with the applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The diesel fuel storage tank (Emissions Unit 002) shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. Emissions units subject to a specific NSPS subpart shall also comply with the applicable requirements of 40 CFR 60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

GENERAL OPERATION REQUIREMENTS

5. Authorized Fuels: The combined cycle gas turbine and ancillary units shall fire only pipeline-quality natural gas or diesel fuel containing no more than 0.05 percent sulfur by weight. [Rules 62-210.200 (Definitions - Potential Emissions) and 62-212.400, F.A.C.]

6. Combined Cycle Gas Combustion Turbine: The maximum heat input to the combined cycle gas turbine shall not exceed 1,680 million Btu per hour (mmBtu/hr) when firing natural gas nor 1,898 mmBtu/hr when firing distillate fuel oil. The heat input limits are based on the lower heating value (LHV) of each fuel, 100% load, and ambient conditions of 25°F temperature, 60% relative humidity, and 14.7 psi pressure. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. Hours of Operation: The combined cycle gas turbine may operate 8760 hours per year while firing natural gas. Diesel fuel firing shall not exceed 720 hours during any consecutive 12 months. Power augmentation while firing gas is permitted 2000 hours per year and is not limited if oxidation catalyst is installed. The 2000-hour limit may be revised at the request of the applicant based upon review of actual performance and control equipment cost-effectiveness following proper public notice.
[Applicant Request, Rule 62-210.200 (Definitions - Potential Emissions), F.A.C.]

CONTROL TECHNOLOGY

8. Automated Control System: The permittee shall install an automated gas turbine control system (Speedtronic™ Mark VI). The system shall monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, temperatures, heat input, and fully automated startup/shutdown. [Design; 62-212.400(BACT), F.A.C.]

9. DLN Combustion Technology: The permittee shall install, tune, operate and maintain the General Electric Dry Low-NO_X combustion system (DLN 2.6 or better) to control NO_X emissions from the combined cycle gas turbine. Prior to the initial emissions performance tests for the gas turbine, the dry low-NO_X combustors and automated gas turbine control system shall be tuned to optimize the reduction of CO, NO_X, and VOC emissions.

   Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. The permittee shall provide at least 5 days advance notice prior to any tuning session. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems upon installation and completion of testing. [Design; Rule 62-212.400(BACT), F.A.C.]

10. Wet Injection: A wet injection system shall be installed for use during diesel fuel firing to reduce NO_X emissions from the combustion turbine exhaust entering the HRSG.
[Design, Rule 62-212.400, F.A.C.]

11. Selective Catalytic Reduction (SCR) System: The permittee shall install, optimize, operate and maintain an SCR system to control NO_X emissions from the combined cycle gas turbine. The SCR system consists of an ammonia injection grid, catalyst, aqueous ammonia storage, monitoring and control system, electrical, piping and other support equipment. The SCR system shall be designed to control NO_X emissions to the permitted levels with an ammonia slip no greater than 5 ppmvd corrected to 15% oxygen. [Design, Rule 62-212.400, F.A.C.]

12. Drift Eliminators: Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

13. Nitrogen Oxides (NO_X) Emissions:

NO_X emissions are defined as oxides of nitrogen measured as NO_2.

a. **Performance Tests**:

When firing natural gas, NO_X emissions from the combined cycle gas turbine shall not exceed 2.5 ppmvd @ 15% oxygen nor 17.2 pounds per hour, based on a 24-hour average.

When firing distillate oil, NO_X emissions from the combined cycle gas turbine shall not exceed 10 ppmvd @ 15% oxygen nor 80 pounds per hour. based on a 24-hour average.

Compliance shall be determined in accordance with EPA Method 7E or Method 20 (40CFR60, Subpart GG).

b. **CEM System**:

When firing natural gas, NO_X emissions from the combined cycle gas turbine shall not exceed 2.5 ppmvd @ 15% oxygen, based on a 24-hour block average.

When firing distillate oil, NO_X emissions from the combined cycle gas turbine shall not exceed 10 ppmvd @ 15% oxygen, based on a 24-hour block average.

Compliance shall be determined by valid data from the required NO_X CEM system.

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

14. Carbon Monoxide (CO) Emissions:

a. **Performance Tests**:

When firing natural gas (excluding operation in the Power Augmentation Mode), CO emissions from the combined cycle gas turbine shall not exceed 8 ppmvd @15% O_2 nor 31 pounds per hour, based on a 24-hour average.

When firing natural gas and operating in the Power Augmentation Mode, CO emissions from the combined cycle gas turbine shall not exceed 13 ppmvd @15% O_2 nor 50 pounds per hour, based on a 24-hour average.

When firing diesel fuel, CO emissions from the combined cycle gas turbine shall not exceed 17 ppmvd @15% O_2 nor 70 pounds per hour, based on a 24-hour average.

Compliance shall be determined in accordance with EPA Method 10.

b. **CEM System**:

When firing natural gas, (excluding operation in the Power Augmentation Mode), CO emissions from the combined cycle gas turbine shall not exceed 8 ppmvd @15% O_2 based on a 24-hour block average.

When firing natural gas and operating in the Power Augmentation Mode, CO emissions from the combined cycle gas turbine shall not exceed 13 ppmvd @15% O_2 based on a 24-hour block average.

When firing diesel fuel, CO emissions from the combined cycle gas turbine shall not exceed 17 ppmvd @15% O_2 at 90-100 percent of full load, 19 ppmvd @15% O_2 at 76-89 percent of full load nor 26 ppmvd @ 15% O_2 at 50-75 percent of full load based on a 24-hour block average.

Compliance shall be determined by valid data from the required CO CEM system.

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

15. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist Emissions (SAM): The fuel specifications listed Condition No. 5 of this section effectively limit the potential emissions of SO_2 and SAM. Compliance with the fuel sulfur limits shall be demonstrated by the fuel sampling, analysis, record keeping and reporting requirements of Condition No. 27 of this section. [Rule 62-212.400, F.A.C.; 40 CFR 60.333]

16. PM/PM_{10} and Visible Emissions (VE): When firing either natural gas or diesel fuel, visible emissions shall not exceed 10% opacity, based on a 6-minute average as determined by EPA Method 9. The fuel specifications in conditions No. 5 and 27 of this section combined with the efficient combustion design and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for particulate matter.

{Permitting Note: Particulate matter emissions are expected to be less than 11 pounds per hour when firing natural gas and less than 36 pounds per hour when firing diesel fuel, as determined by EPA Method 5, front-half catch only.} [Rule 62-212.400(BACT), F.A.C.]

17. Ammonia Emissions: The concentration of ammonia in the stack exhaust gas shall not exceed 5 ppmvd @15% O_2 as determined by EPA Method CTM-027. [Rules 62-4.070 and 62-212.400(BACT), F.A.C.]

COMPLIANCE DETERMINATION

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

EPA Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
5	Determination of Particulate Matter Emissions from Stationary Sources • For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run. • For oil firing, the minimum sampling time shall be one hour per run and the minimum sampling volume shall be 30 dscf per run.
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.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Except for Method CTM-027, the methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CT-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

19. Testing Modes of Operation: The permittee shall conduct all required tests for each mode of operation defined below:
    a. **Standard Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas as well as low sulfur diesel fuel.
    b. **Alternate Mode of Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas and implementing the power augmentation mode with steam injection. Hourly rates of steam injection for power augmentation (pounds of steam) shall be restricted to the rates that demonstrated compliance during the test for this alternate mode of operation.

       The maximum steam injection rate (lb steam/hour) for power augmentation shall be established in the operation permit. Note: Alternate mode of operation is not allowed when firing low sulfur fuel oil. [Rule 62-4.070(3), F.A.C.]
20. Initial Compliance Tests: The combined cycle gas turbine shall be tested when firing each authorized fuel to demonstrate compliance with the emission standards for CO, NO_X, visible emissions and ammonia slip. The tests must 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 the combined cycle gas turbine.

    Tests for CO and NO_X shall be conducted concurrently. Certified CEM system data may be used to demonstrate compliance with all CO and NO_X standards.
    [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]
21. Initial and Quarterly Ammonia Stack Compliance Tests: An initial and quarterly stack emissions test shall be conducted when firing natural gas and fuel oil to demonstrate compliance with the limit on ammonia slip. The initial and annual (one of the quarters) NO_X and ammonia tests shall be conducted at four points within the operating range of the gas turbine. The test results for ammonia slip shall also report the ammonia injection rates and average NO_X emissions during each test run. [Rules 62-4.070 (3) and 62-212.400(BACT), F.A.C.]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combined cycle gas turbine shall be tested when firing natural gas to demonstrate compliance with the emission standards for CO, NO_X, ammonia slip and visible emissions. If the combined cycle gas turbine fires more than 200 hours of diesel fuel during the federal fiscal year, it shall also be tested for visible emissions and ammonia slip when firing oil. RATA data can substitute for annual compliance testing for CO and NO_X.

23. Tests After Substantial Modifications: All performance tests required for initial start up shall also be required by the Department after any substantial modifications (and shake down period not to exceed 100 days after re-starting the gas turbine) of air pollution control equipment such as installation of an oxidation catalyst or change of combustors. [Rule 62-4.070 (3) F.A.C]

24. Compliance with the CO/NO_X Emissions Limits: Annual compliance with the applicable CO and NOx emissions standards shall also be demonstrated with valid data collected by the required CEM systems during the required annual RATA at permitted capacity. Refer to Specific Conditions 18 and 22. Continuous compliance shall be demonstrated as specified in Specific Conditon 30. [Rule 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

25. Compliance with the Ammonia Emissions Limits: The permittee shall calculate and report the ppmvd ammonia slip @15% O_2 at the measured lb/hr emission rate as a means of compliance with the BACT standard. The compliance procedures are described in Specific Conditions 18 and 21. [Rule 62-212.400 F.A.C. (BACT)]

26. Compliance with the VE and PM/PM_{10} Emissions Limits: Compliance with the VE limits shall be demonstrated by stack tests. Compliance with the fuel specifications, CO standards, and visible emissions standards of this section shall serve as surrogate standards for particulate matter. [Rule 62-212.400 F.A.C. (BACT)]

27. Compliance with the SO_2/H_2SO_4- Fuel Sulfur Limits: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for *natural gas* shall be demonstrated by keeping reports obtained from the vendor indicating the 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 D4084-82, D3246-81 or more recent versions.

    b. 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 the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel 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.]

EXCESS EMISSIONS

28. 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 are prohibited. These emissions shall be included in the 24-hour compliance averages for NO_X and for CO emissions. [Rule 62-210.700(4), F.A.C.]

29. Excess Emissions Defined: During startup, shutdown, and documented unavoidable malfunction of the combined cycle 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. *Best Operational Standard*: The unit will reach Mode 5Q with x, y, and z minutes for cold, warm, and hot startups respectively (to minimize CO and NOX emissions). Ammonia injection will be initiated within x, y, and z minutes for cold, warm, and hot startups respectively to minimize NOX emissions. The following measures shall be employed following shutdowns to reduce subsequent excess startup emissions: (Note: Times and measures to be determined for modification of this permit and incorporation of the final conditions into the required Title V Operation permit.

    c. *Low-Load Restriction*: Except for startup and shutdown, operation under DLN Modes 1, 2, 3, and 4 is prohibited.

    d. In accordance with Condition No. 30 of this section, specific data collected by the CEM systems during startup, shutdown, malfunction, and tuning may be excluded from the CO and NO_X compliance averaging periods.

If a CEM system reports emissions in excess of a 24-hour block emissions standard, the permittee shall notify the Compliance Authority within (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.

[G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]

MONITORING REQUIREMENTS

30. Continuous Emission Monitoring System: The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the combustion turbine exhaust stack (EU 001) to measure and record the emissions of NO_X and CO 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 NO_X and CO are monitored to correct the measured CO and NO_X emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEM system using F-factors that are appropriate for the fuel fired. The CEM system shall be used to demonstrate compliance with the CEM emission standards for NO_X and CO specified in this permit.

    a. *Data Collection.* Compliance with the CEM emission standards for NO_X and CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. 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 owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system 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 owner or operator 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 CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

    b. *NO_X Certification.* The NO_X monitor shall be certified and operated in accordance with the following requirements. The NO_X 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 block average shall be determined using the remaining hourly data in the 24-hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

c. *CO, CO_2, and Oxygen Certification.* The CO monitor and CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. The oxygen monitor shall be certified pursuant to 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 semi-annually to each Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 60 ppm, as corrected to 15% oxygen. The RATA tests required for the CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60. The RATA tests required for the oxygen monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

d. *Data Exclusion.* Emissions data for NO_X, CO and CO_2 (or oxygen content) shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_X and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards as provided in this paragraph.

(1) Periods of data excluded for a cold startup shall not exceed four hours in any block 24-hour period. A "*cold star*tup" is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.

(2) Periods of data excluded for a warm startup shall not exceed two hours in any block 24-hour period. A "*warm startup*" is defined as a startup to combined cycle operation following a complete shutdown lasting 8 hours or more, but less than 48 hours.

(3) Periods of data excluded for a hot startup shall not exceed one hour in any block 24-hour period. A "*hot startup*" is defined as a startup to combined cycle operation following a complete shutdown lasting less than 8 hours.

(4) Periods of data excluded for a shutdown shall not exceed three hours in any block 24-hour period. A "*shutdown*" is the process of bringing a gas turbine off line and ending fuel combustion.

(5) Periods of data excluded for a documented unavoidable malfunction shall not exceed two hours in any 24-hour block period. 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.

(6) If the permittee provides at least five days advance notice prior to a *tuning session*, data may be excluded from the block average calculated to demonstrate compliance with the CEM emission standards. Periods of data excluded for such episodes shall not exceed a total of three hours in any 24-hour block period. Tuning sessions must be performed in accordance with the manufacturer's recommendations. No more than two tuning sessions are expected during any year.

All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. 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.

e. *Data Exclusion Reports.* A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported semi-annually 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 CEM system 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 semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

f. *Data Conversion.* Upon request from the Department, the CEM systems emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

g. *Availability.* The NO_X and CO monitor availability threshold shall not be less than 95% in any calendar quarter. The report required by this section 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 owner or operator shall implement the reported corrective actions within the next calendar quarter.

{Permitting Note 1: As required by EPA's March 12, 1993 determination, the NO_X 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 NO_X 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.}

{Permitting Note 2: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 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.]

31. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate, an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet emissions limitations over the range of combustion turbine load conditions allowed by this permit by comparing NO_X emissions recorded by the NO_X monitor with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

32. SCR Operational Requirements: The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by the manufacturer's guidelines and in accordance with this permit. During turbine start-up, permittee shall begin use of SCR (i.e., commence ammonia injection) as soon as possible and within two (2) hours of the initial turbine firing or when the temperature of the catalyst bed reaches a suitable predetermined temperature level, whichever occurs first. During turbine shutdown, permittee shall discontinue use of the SCR (i.e., discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature levels, but no more than one hour prior to the time at which the fuel feed to the turbine is discontinued.

    Suitable temperature for activation and deactivation of the SCR shall be established during performance testing. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit while minimizing ammonia slip to below the emission limit. Design, Rule 62-212.400, F.A.C.]

33. Fuel Consumption Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of consumption of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of the combined 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 CEM system 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.]

34. Fuel Consumption Rates Monthly Monitoring: By the fifth calendar day of each month, the permittee shall record the monthly fuel consumption and hours of operation for the gas turbine. The information shall be recorded in a written (or electronic log) and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. [Rule 62-4.070(3), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

35. Records: All measurements, records, and other data required to be maintained by CPV shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request. [Rules 62-4.160 and 62-213.440, F.A.C]

36. NSPS Notifications: All notifications and reports required by the 40CFR 60, Subpart A applicable requirements shall be submitted to each Compliance Authority.

37. Semi-Annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (2000 version), shall be submitted to each Compliance Authority.

38. Continuous Compliance with the 74.9 MW Steam Power Generated Limitation: Electrical power from the steam-electrical generator shall be limited to 74.9 MW (as measured at the generator) on an hourly basis. CPV Cana shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW rolling one-hour average limit by the stored information in the power plant's electronic data system.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

CPV Cana Power Generating Facility
PSD-FL-323 and 1110103-001-AC
St. Lucie County, Florida

BACKGROUND

The applicant, CPV Cana, Ltd, proposes to install a construct a combined cycle power plant at a new facility located in unincorporated St Lucie County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 170 MW, General Electric 7FA combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) connected to a separate steam turbine-electrical generator. The project also includes a 975,000-gallon storage tank for backup No. 2 fuel oil, a mechanical draft cooling tower, a 170-foot stack, and other ancillary equipment. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 21, 2001 accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on September 5, 2001 (complete October 25) and included a proposed BACT proposal prepared by the applicant's consultant, TRC Environmental Corporation in Windsor, Connecticut.

BACT REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	2.5 ppmvd @15% O_2 (gas) 10 ppmvd@15% O_2 (oil)
Carbon Monoxide	Combustion Controls	9 ppmvd (gas) 20 ppmvd (oil)
Particulate Matter (front + back-half)	Inherently Clean Fuels Combustion Controls	20 lb/hr (gas) 53 lb/hr (oil)
Sulfur Dioxide Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)
All Pollutants from Auxiliary Units	Low Sulfur Fuels Drift Eliminators on cooling tower	0.0065% sulfur (gas) 0.05% sulfur (oil) 0.0005 percent drift

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the CPV is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by CPV. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

There is a National Emission Standard for Hazardous Air Pollutants (NESHAP) under development by EPA, but it is not applicable to this project. Because emissions of HAP are less than 10 tons per year, there is no requirement to conduct a case-by-case maximum achievable control technology determinaion.

DETERMINATIONS BY STATES:

The following table is a sample of information on some recent applications, proposals, and determinations in Florida (primarily) for combined cycle projects. The CPV Cana Project is included for reference.

TABLE 1

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
CPV Cana	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT. Under Review
CPV Pierce	245	2.5 – NG 10 – FO	SCR	170 MW GE 7FA CT. Issued 7/2001
El Paso Manatee	250	2.5 – NG	SCR	175 MW GE 7FA CT. Draft 9/2001
El Paso Belle Glade	250	2.5 – NG	SCR	175 MW GE 7FA CT. Draft 9/2001
El Paso Broward	250	2.5 – NG	SCR	175 MW GE 7FA. Draft 8/2001
Metcalf Energy, CA	600	2.5 – NG	SCR	2x170 MW WH501F & Duct Burners
Enron/Ft. Pierce	~250	3.5 – NG 10 - FO	SCR	170 MW MHI501F CT. Repowering
CPV Atlantic	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT. Issued 5/2001
CPV Gulfcoast	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT. Issued 2/2001
TECO Bayside	1750	3.5 – NG 12 - FO	SCR	7x170 MW GE 7FA CTs. Repowering
FPC Hines II	530	3.5 - NG 12 - FO	SCR	2x170 MW WH501F
Calpine Osprey	527	3.5 – NG	SCR	2x170 MW WH501F. Issued 7/2001
Calpine Blue Heron	1080	3.5 – NG	SCR	4x170 MW WH501F. Draft 2/00
KUA Cane Island 3	250	3.5 – NG (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs. 11/98

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

TABLE 2

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
CPV Cana	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Pierce	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Belle Glade	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Manatee	9 (7.4 @15% O_2) 15 (12 @15% O_2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
El Paso Broward	9 (7.4 @15% O2) 15 (12 @15% O2) (PA)	1.4 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Metcalf Energy, CA	6 - NG (100% load)	.00126 lb/mmBtu-NG	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Enron Ft. Pierce	3.5 - NG 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity	Oxidation Catalyst Clean Fuels Good Combustion
CPV Atlantic	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
CPV Gulfcoast	9 - NG (50 - 100% load) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside	9 – NG (24-hr CEMS) 20 – FO (24-hr CEMS)	1.3 – NG 3 - FO	12 lb/hr – NG 30 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II	16 - NG (24-hr CEMS) 30 – FO (24-hr CEMS)	2 – NG 10 – FO	10% Opacity – NG 5/9 ammonia – NG/FO	Clean Fuels Good Combustion
Calpine Osprey	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Calpine Blue Heron	10 – NG (24-hr CEMS) 17 – NG (DB&PA)	1.2 – NG 6.6 – NG (DB&PA)	32 lb/hr – NG (DB&PA) 10 percent Opacity 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
KUA Cane Island 3	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

All of the projects listed above control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, pipeline quality natural gas is used and has a sulfur content less than 2 grains per 100 cubic feet. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil.

Some of the projects listed above include front and back half catch for PM limits. Therefore comparison is not simple.

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. *Thermal* NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. *Prompt* NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air-cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 1 which is from a General Electric discussion on these principles.

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

Uncontrolled NO_X concentrations from combustion turbines would be from 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled NO_X concentrations at approximately 200 ppmvd @15% O_2 for the turbine of the CPV Cana Project.

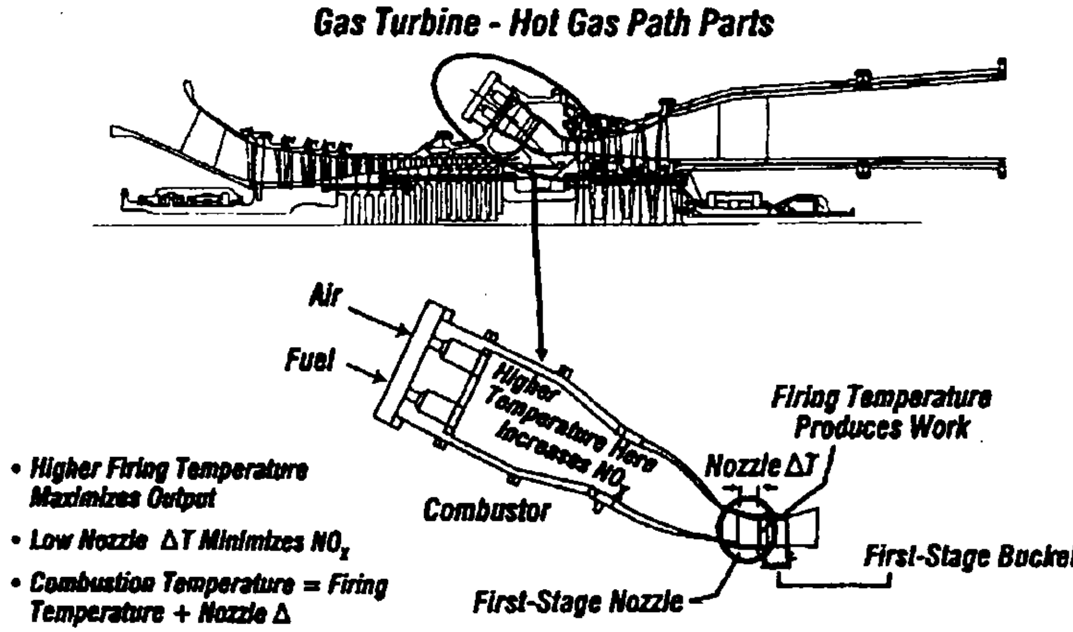

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

<u>Wet Injection</u>

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

<u>Combustion Controls: Dry Low NO_X (DLN)</u>

The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

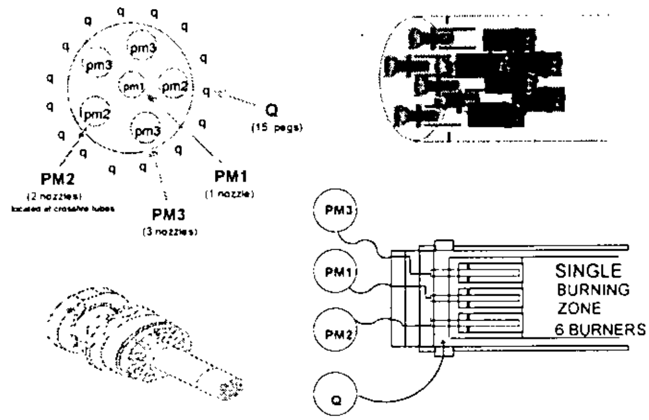

Figure 2 – DLN-2.6 Fuel Nozzle Arrangement

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X.

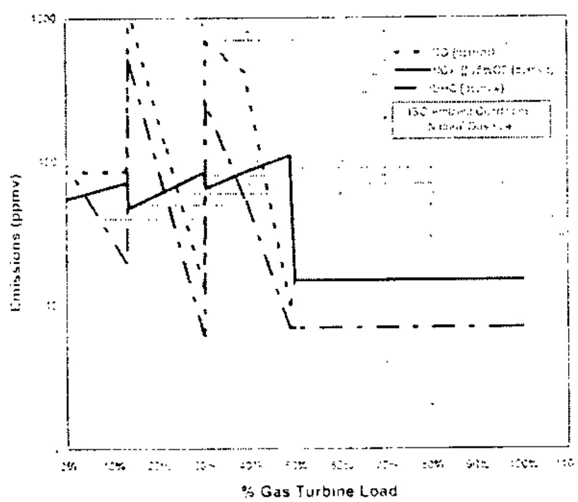

Figure 3 – Emissions Characteristics for DLN-2.6 **(if tuned to 15 ppmvd NO_X)**

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd. The results are all superior to the emission characteristics given in Figure 3 above.

Table 1 - City of Tallahassee Purdon Power Plant (Station Unit 8) Test Results

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	
80	6.1	
90	6.6	
100	8.7	0.85
Limit	12	25

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[2] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd. Again, the results are all superior to the emission characteristics given in Figure 3 above.

Table 2 - Tampa Electric Polk Power Station Test Results

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Recent conversations with other operators indicate that the Low NO_X characteristics extend to operations somewhat less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.[3]

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[4] where water is scarce, but the Department has no information on the results.

Mitsubishi (who also make a 501F) is also developing a dual-fuel premixed DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[5] The details are not available in English.

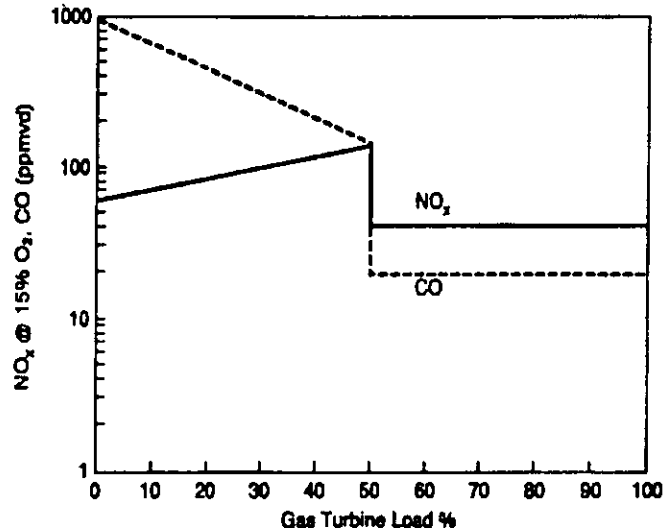

Figure 4 - Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 5 from an EPRI report.[6] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 5.

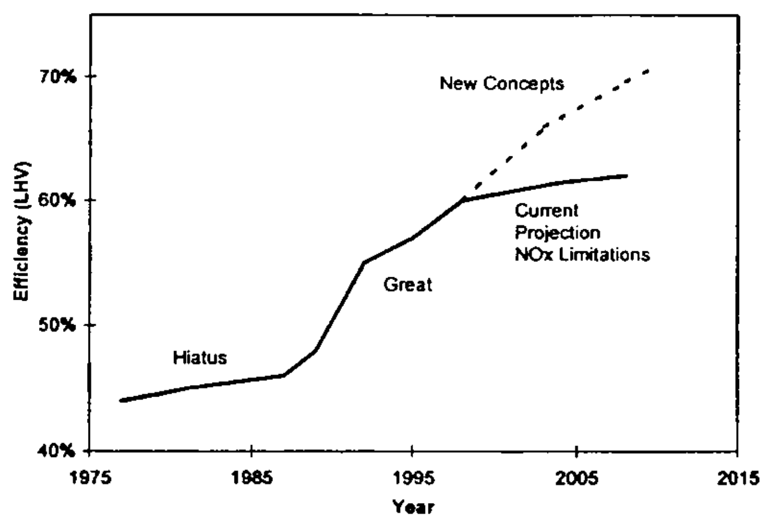

Figure 5 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (Westinghouse G or General Electric H Class technology) than the units planned by CPV. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

Catalytic Combustion: XONON ™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described in the DLN technology above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[7] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents. Westinghouse is working to replace the central pilot in its DLN technology with a catalytic pilot in a project with Precision Combustion Inc.

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[8] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma, which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[9] The project was expected to enter commercial operation by the summer of 2001. However actual installation of XONON on the Pastoria project is doubtful.

In principle, XONON™ will work on a combined cycle project. However, the Department does not have information regarding the status of the technology for fuel oil firing, cycling operations, or reasonable assurance that the technology is technically and economically feasible for a GE 7FA unit in an attainment area.

Selective Catalytic Combustion: SCR

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Kissimmee Utilities Authority (KUA) will install SCR at the Cane Island Unit 3 project. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued recently to Competitive Power Ventures (CPV), Calpine, Florida Power Corporation, and Tampa Electric to achieve 3.5 ppmvd. More recently a permit was issued to CPV for its Pierce, Polk County project with a limit of 2.5 ppmvd @15% O_2 by SCR. Draft permits were issued to El Paso for planned projects in Palm Beach, Manatee, and Broward Counties with a limit of 2.5 ppmvd @15% O_2 by SCR.

Figure 6 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 7 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

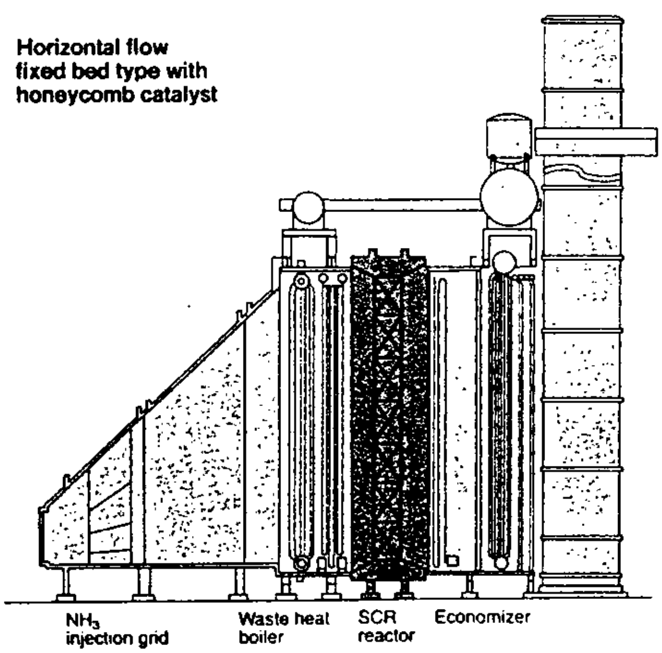

Figure 6 – SCR System within HRSG

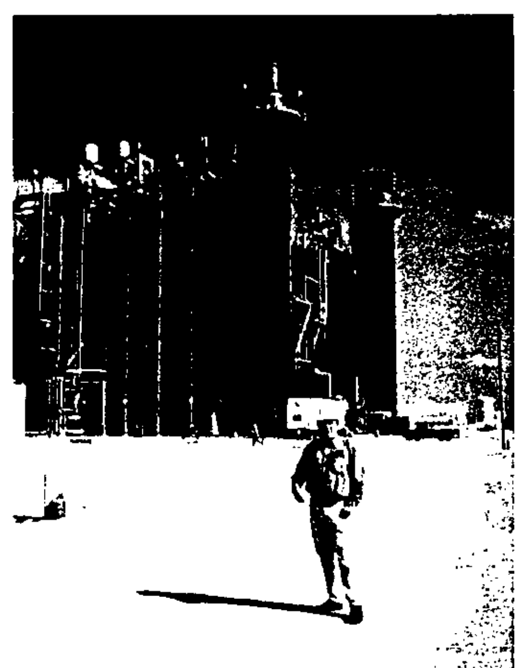

Figure 7 – FPC Hines Power Block I

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. Temperatures on the order of 1800 °F can be achieved in supplementally-fired HRSGs with very large duct burners. An example is the Santa Rosa Energy Center, which incorporates a 585-mmBtu/hr duct burner. SNCR is not feasible for un-fired HRSG planned for the CPV project.

$SCONO_X$™

$SCONO_X$ is a catalytic add-on technology (and registered trademark) that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[10]

California regulators and industry sources have stated that the first 250 MW block to install $SCONO_X$ will be at PG&E's La Paloma Plant near Bakersfield.[11] The overall project includes several more 250 MW blocks with SCR for control.[12] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

$SCONO_X$ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the $SCONO_X$ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. $SCONO_X$™ has not been applied on any major sources in ozone attainment areas.

Recently EPA Region IX acknowledged that $SCONO_X$ was demonstrated in practice to achieve 2.0 ppmv NO_X.[13] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv. Recently, Goaline submitted information to EPA and states in support of its contention that the technology has achieved 1 ppmvd in practice.[14]

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 76 TPY of SO_2 and 8 TPY of SAM. The Department expects that emissions will be lower because of the limited oil consumption and because typical natural gas distributed in Florida contains less than the 0.0065% sulfur specification proposed as BACT.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. As previously mentioned, the NO_X control technology of SCR increases PM/PM_{10} emissions due to formation of ammonium nitrates and ammonium sulfates. The problem is more significant when firing fuel oil (despite the low sulfur specification). This effect will be minimized by limiting fuel oil firing to less than 720 hours per year and limiting ammonia emissions (slip) to 5 ppmvd.

Total annual emissions for this project are expected not to exceed 96 tons per year (including filterable and condensable particulate fractions as well as emissions from ancillary equipment emission units)

For the cooling tower, drift eliminators will be incorporated into the design specifications, which will limit drift from the cooling tower to less than 0.0005 percent of the circulating water flow rate. The dissolved and suspended solids in water are reported in the application as 4200 mg/l.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil.[15] As previously discussed, GE 7FA units achieved similar results when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2.

CO emissions *should* be low (at least at full load) because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO emissions for F-Class units, at least at high loads.

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review, which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[16]

A recent draft permit was issued by the Department that limits CO to 3.5 ppmvd on a Mitsubishi 501F combustion turbine. Enron will install an oxidation catalyst at Ft. Pierce in order to avoid very high emissions at low load (<70 percent of full load). This results in the ability to meet the low level at full load. This would not have been a concern if the units were GE7FAs for the reasons discussed above.

A recent permit was issued by the Bay Area AQMD in California for the Metcalf Energy Center. The limit for CO is 6 ppmvd (at full load). No Catalyst is required. However it is doubtful that performance can be maintained at low load.

The limit proposed by CPV when firing natural gas is 9 ppmvd (equals 8 ppmvd @15% O_2) at the entire operating range between 50 and 100 percent of full load. This is consistent with the description of the DLN-2.6 technology. The expected results are 1-2 ppmvd and actually better than what the Enron and Metcalf projects will achieve across the 50-100 percent operating range.

A higher limit of 15 ppmvd (equals 13 ppmvd @15% O_2) is proposed during power augmentation. Under this mode, steam from the HRSG is re-injected into the combustors to boost power production. One consequence is that CO emissions can increase. The emission limit of 20 ppmvd (equals 17 ppmvd @15% O_2) during limited fuel oil firing appears reasonable, although much lower values are likely to be achieved.

Total annual emissions of CO for this project (including ancillary equipment emission units) are expected not to exceed 170 tons per year.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by CPV for this project are 1.4 ppmvw for gas and 3.6 ppmvw for oil firing. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[17]

Based on the chosen equipment, the Department believes that annual VOC emissions will be less than 40 TPY. The applicant has estimated an annual emission level of 16 tons per year (including ancillary equipment emission units). Therefore, a BACT determination is not required.

BACKGROUND ON SELECTED GAS TURBINE

CPV plans to the purchase a 170 MW (nominal) General Electric 7FA combined cycle gas turbine with an unfired heat recovery steam generator (HRSG). Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by CPV as BACT.

The GE Speedtronic™ Mark VI Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark VI also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values prior to the SCR unit.[18]

STARTUP AND SHUTDOWN EMISSIONS

The Department defines "Startup" as follows[19]:

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

The Department permits excess emissions during startup and shut down as follows:[20]

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

The Department defines "Excess Emissions" as follows:[21]

"Excess Emissions" - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, sootblowing, load changing or malfunction.

The U.S. EPA Region IV office recently recommended that the Department consider "establishment of startup and shutdown BACT for CO and NO_X such as mass emission limits (e.g., pounds of emissions in any 24-hour period) that include startup and shutdown emissions, or future emission limits derived from monitoring results during the first few months of commercial operation."[22]

The Department reviewed a number of emission estimates and permit conditions addressing startup and shutdowns for projects in California, Georgia, Washington, and Mississippi and has determined that much of the information is based on estimates that are very difficult to verify.

A review of published General Electric information indicates that features are incorporated into the design of the DLN-2.6 technology specifically aimed at minimizing emissions. One of the key elements was to incorporate lean pre-mixed burning while operating the unit in low load and startup.[23] This is in contrast with the previous DLN-2.0 technology that relied on diffusion mode combustion at four of the burners in each combustor during startup and low load operation.

During startup of GE 7FA <u>simple cycle</u> unit, NO_X concentrations in the exhaust are greater than during full-load operation. The concentrations are estimated at 20 to 80 ppmvd @15% O_2 during the first 10 minutes or so after the unit is actually firing fuel. This occurs while only one to four of the six nozzles shown in Figure 2 are in operation on each combustor.

Within the following 5 minutes, the unit switches to Mode 5 (or 5 Q), during which NO_X concentrations are typically less than 10 ppmvd even though the unit is not yet at full load.[24] The Low-NO_X modes occur when at least the five outer nozzles are in operation.

The startup scenarios for a GE 7FA combined cycle unit are as follows:

Hot Start:	One hour following a shutdown less than or equal to 8 hours.
Warm Start:	Two hours following a shutdown between 8 and 48 hours.
Cold Start:	Four hours following a shutdown greater than or equal to 48 hours.

During a combined cycle cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated up. During a portion of the 4 hour startup, emissions will be roughly 60 to 80 ppmvd NO_X @15% O_2. Once the HRSG is heated sufficiently, the ammonia system is turned on to abate emissions.

While NO_X emissions during the initial phase of startup (low load and no ammonia injection) are greater than during full load steady state operation, such startups are infrequent. Also, it is noted that such a cold startup would be preceded by a shutdown of at least 48 hours. Therefore the startup emissions would not cause annual emissions greater than the potential-to-emit under continuous operation. Similar analyses can be performed for warm startups and hot startups.

The combined cycle startup scenario described above can (at least in theory) be modified by use of a bypass stack and damper.[25] Under this scenario, the steam cycle can be slowly brought up to load while the gas turbine reaches full load as fast as it would under simple cycle mode. The exhaust gas can be modulated in such a fashion that the HRSG and steam turbine are ramped up slowly in accordance with their respective specifications. At the same time, the gas turbine will quickly accelerate to the DLN modes (5Q or 6Q) thus minimizing emissions. In this manner the startup NO_X and CO concentrations are reduced to the values observed during simple cycle startup. Thereafter the unit will exhibit the same characteristics (for about three hours) as a simple cycle unit in steady-state operation until the ammonia system is actuated.

Implementation of bypass modulation requires an additional stack and design features to minimize stratification and uneven heating of boiler tube bundles in the HRSG. The initial response from GE is that such a configuration at a project in Hungary resulted in equipment damage and leakage of exhaust gas to the atmosphere resulting in a significant loss in performance.[26]

The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions for NO_X and address carbon monoxide too.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the CPV project assuming full load. Values for NO_X and CO are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 13 through 17.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	2.5 ppmvd @15% O_2 (gas) 10 ppmvd@15% O_2 (oil)
Carbon Monoxide	Combustion Controls	8 ppmvd @15% O_2 (gas) 13 ppmvd @15% O_2 (power augmentation) 17 ppmvd @15% O_2 (oil)
Particulate Matter	Inherently Clean Fuels Combustion Controls Ammonia Slip < 5 ppmvd	11 lb/hr (gas) (front-half) 36 lb/hr (oil) (front-half) 10 percent Opacity
Sulfur Dioxide and Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)
All Pollutants from Auxiliary Units	Low Sulfur Fuels Drift Eliminators on cooling tower	0.0065% sulfur (gas) 0.05% sulfur (oil) 0.0005 percent drift

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd at 15 percent oxygen (@15% O_2) while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line, has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice.*
- There are several projects for large turbines requiring SCR with a NO_X emission limit of 2 ppmvd @15% O_2.
- The "Top" technology in a top/down analysis will achieve 2 ppmvd @15% O_2 by either $SCONO_X$ or SCR.
- CPV proposes a NO_X limit of 2.5 ppmvd (natural gas) and 10 ppmvd (fuel oil) @15% O_2. This is equal to the lowest emission rate in Florida and nearby states to-date
- CPV chose SCR over $SCONO_X$ for technical and economic reasons. CPV estimated the cost of NO_X control at \$3,396 and \$20,604 per ton of NO_X removed by SCR and $SCONO_X$ respectively.
- If the costs submitted by CPV were *doubled* to \$ 6,792 per ton by SCR and halved to \$ 10,302 per ton by $SCONO_X$, the former control technology would still be more cost-effective than the latter. The difference of approximately \$4,000 per ton of NO_X removed is sufficient reason to select SCR over $SCONO_X$ for this project.

- The Department concludes that 2.5 ppmvd (natural gas) and 10 ppmvd (fuel oil) @15% O_2 (with 5 ppmvd ammonia slip) constitutes BACT for NO_X. This value for the SCR option takes into consideration the measurement uncertainties at low emission rates and minimizes the negative effects of ammonia emissions.
- The CO limits of 8 ppmvd @15% O_2 while firing natural gas and 13 ppmvd @15% O_2 under power augmentation are low and within the range of recent BACT determinations for combustion turbines in the Southeast. The CO limit during the limited hours of fuel oil firing will be set at 17 ppmvd @15% O2 (full load).
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- CPV estimated levelized costs for CO catalyst control at \$2,852 to reduce emissions from the range of 8-17 ppmvd @15% O_2 to a 2-4 ppm range. In view of the performance of GE 7FA units cited in the discussion above (Tallahassee and TECO Polk Power data) without add-on control (~ 1 ppmvd), it appears to the Department that oxidation catalyst costs are substantially biased to the low side based on actual emissions.
- The Department will set CO limits reflecting the "new and clean test" guarantees rather than actual performance because GE will not (yet) guarantee the lower values. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state. The Department will also limit the extent to which CPV can operate in power augmentation mode to 2000 hours unless CPV installs oxidation catalyst or proves that actual performance is much better than guaranteed (thus rendering control not cost effective).
- There is no benefit in penalizing the applicant with a lower limit at this time just because the performance at another site was far better than guaranteed or expected. There also appears to be no benefit in installing a catalytic oxidation system. The applicant will install a continuous CO monitor. It is expected that data from continuous measurement will conclusively show that oxidation catalyst is not needed and is not cost effective for this project.
- BACT for sulfur oxides for this project (including the ancillary equipment) is the exclusive use of pipeline natural gas with a specification of 0.0065% sulfur (by weight) content (gas) and 0.05 % sulfur (by weight) content (oil).
- The Department agrees that inlet air filtration, good combustion, and use of inherently clean fuels constitute BACT for PM/PM_{10} for this project (including ancillary equipment emission units). Drift eliminators will be incorporated into the cooling tower design specifications to limit drift from the cooling tower to less than 0.0005 percent of the circulating water flow rate. Furthermore, the Department will set the ammonia limit at 5 ppmvd to minimize additional PM/PM_{10} formation.
- PM_{10} emissions will be very low and difficult to measure. The values of 11 and 36 lb/hr for natural gas and oil respectively will be included in the permit. These values include front-half catch only.
- The Department will set a visible emissions BACT limit at 10 percent. The Department will rely on VE observation as a surrogate for PM/PM_{10} BACT compliance (after the initial PM/PM_{10} test).

BACT EXCESS EMISSIONS APPROVAL

- Excess emissions may occur under the following startup scenarios:

  Hot Start: One hour following a shutdown less than or equal to 8 hours.
  Warm Start: Two hours following a shutdown between 8 and 48 hours.
  Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

- The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[27]

- Although startup and shutdown emissions are generally exempt, emissions during startup and shutdown are less than the NSPS limit of 110 ppmvd @15% O_2 (that applies during steady-state operation).

- The Department does not yet have sufficient information from field experience to set start-up and shutdown emissions limits. However, the modes that give rise to high NO_X concentration have been identified.

- Because CPV and GE believe a startup BACT requiring a bypass stack is not feasible, the applicant will submit an alternative Best Operational Practice during the construction or initial testing phase of the facility. The procedure shall include features that minimize the time required to complete a startup following a shutdown. This could include installing dampers where necessary to reduce the rate of cooling when the unit is down. It shall include a more precise description regarding commencement of ammonia injection. The procedure (based on the following paragraph) shall be submitted to the Department for modification of the construction permit at the time of submittal of a Title V Operation Permit application.

- Best Operational Standard – Startup BACT:

  The unit will reach Mode 5Q with x, y, and z minutes for cold, warm, and hot startups respectively (to minimize CO and NO_X emissions). Ammonia injection will be initiated within x, y, and z minutes for cold, warm, and hot startups respectively to minimize NO_X emissions. The following measures shall be employed following shutdowns to reduce subsequent excess startup emissions: (Note: Times and measures to be determined for modification of this permit and incorporation of the final conditions into the required Title V Operation permit for incorporation into the required Title V operation permit during public comment period)

- The NO_X and CO monitors will provide information that will allow the Department to set startup emission limits at future projects.

- Oxidation catalyst can reduce CO emissions from startup. However, based on the few startups expected and the startup procedures to be implemented, oxidation catalyst will not be cost-effective in reducing CO emissions.

- Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows:

  Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as described in the permit. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C.]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

COMPLIANCE PROCEDURES

The following compliance procedures apply to this BACT determination. The details are contained in the permit.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions (initial, annual)	Method 9
PM/PM_{10}	Method 5 (Front-half catch)
VOC	Method 25A corrected by methane from Method 18
CTM-027 (initial, quarterly, annual)	Procedure for Collection and Analysis of Ammonia in Stationary Sources
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (initial, annual, CEMS)	Method 10; CO-CEMS (continuous 24-hr)
NO_X (continuous 24-hr)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

1/15/02

Date:

Approved By:

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

1/16/02

Date:

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NSPS SUBPART GG REQUIREMENTS

[Note: 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 defined 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: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is 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: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

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

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

Department requirement: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator 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 EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 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: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[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 provided 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 O_2 and ISO standard ambient conditions, volume percent.
NOxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H_2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

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

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

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

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

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

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

<u>Department requirement</u>: The owner or operator 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.]

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

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

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

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. Doug Coward, Chair
St. Lucie County Board of
County Commissioners
2300 Virginia ve.
Ft. Pierce, FL 34982

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1-22-02

C. Signature
X Lora H. McComas ☐ 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) 7001 0320 0001 3692 8567

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 8567

Mr. Doug Coward, Chair

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

Postmark Here

Sent To
St. Lucie B oard of County Comm.
Street, Apt. No.; or PO Box No.
2300 Virginia Ave.
City, State, ZIP+4
Ft. Pierce, FL 34982

PS Form 3800, January 2001 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:

The Honorable Robert E. Minsky
Mayor of Port St. Lucie
121 SW Port St. Lucie Blvd.
Port St. Lucie, FL 34984-5099

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1/22/02

C. Signature

X Karen Phillips

☐ 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) 7001 0320 0001 3692 8574

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)

The Honorable Robert E. Minsky

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

Postmark Here

7001 0320 0001 3692 8574

Sent To
Mayor Of Port St. Lucie
Street, Apt. No.; or PO Box No. 121 SW Port St. Lucie Blvd.
City, State, ZIP+4 Port St. Lucie, FL 34984-5099

PS Form 3800, January 2001 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. Gary Lambert
Executive Vice President
CPV Cana, Ltd.
35 Braintree Hill Office Park
Suite 107
Braintree, MA 02184

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1/22/02

C. Signature

X A LeBlanc

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☐ No

BRAINTREE, MA
JAN 22 2002
02184

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)*
7001 0320 0001 3692 8550

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)

7001 0320 0001 3692 8550

Mr. Gary Lambert

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

Postmark Here

Sent To CPV Cana LTd.

Street, Apt. No.; or PO Box No. 35 Braintree Hill Office Park

City, State, ZIP+4 Braintree, MA 02184

PS Form 3800, January 2001 See Reverse for Instructions

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: Clair H. Fancy
A.A. Linero aaj for CHF

FROM: Teresa Heron TH

DATE: January 15, 2002

SUBJECT: CPV Cana Power Generating Facility
245 MW Combined Cycle Plant
DEP File No. 1110103-001-AC (PSD-FL-323)

Attached is the final permit package for construction of a 245 MW Combined Cycle Plant at the CPV Cana Power Generating facility in St. Lucie County.

The basic unit is a nominal 170-megawatt General Electric 7FA gas and oil-fired combustion turbine-generator. The project includes an un-fired HRSG that will raise sufficient steam to produce another 74.9 MW via a steam-driven electrical generator. A selective catalytic reduction system including ammonia storage is included.

A 975,000 gallon storage tank will be constructed for the back-up distillate fuel that will be used for no more than 720 hours per year.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by SCR to 2.5 ppmvd (gas) and 10 ppmvd (oil). The ammonia limit is proposed at 5 ppmvd by agreement with the applicant. This will reduce formation of ammoniated particulate species.

Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and the design of the GE unit.

It is our opinion that the project will actually emit less than the thresholds for PSD applicability. However the CO emissions estimates reflect the GE guarantees and not the very low values achieved in the field.

The applicant submitted information describing the measures that insure the steam generator will produce less than 75 MW.

Day 90 is February 5, 2002. We recommend your signature and approval.

AAL/th

Attachments