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.

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.

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.

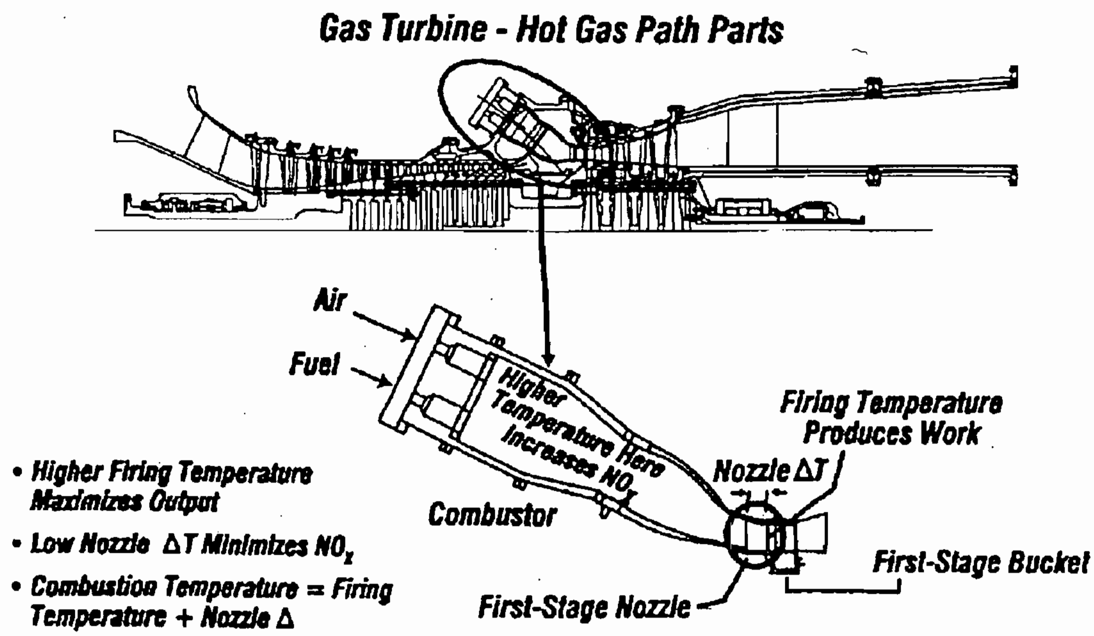

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

Wet Injection

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.

Combustion Controls: Dry Low NO_X (DLN)

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

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

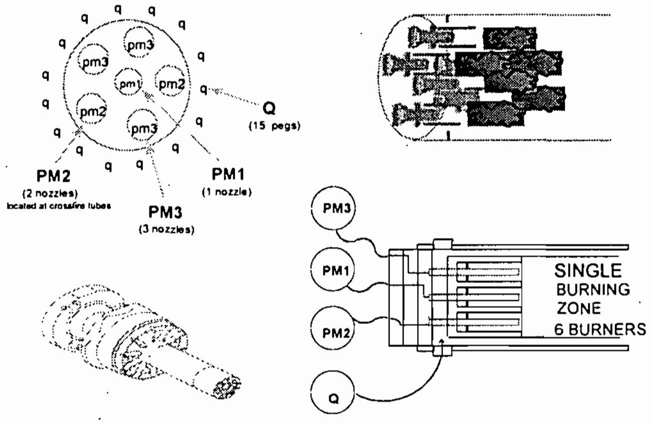

Figure 2 – DLN-2.6 Fuel Nozzle Arrangement

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.

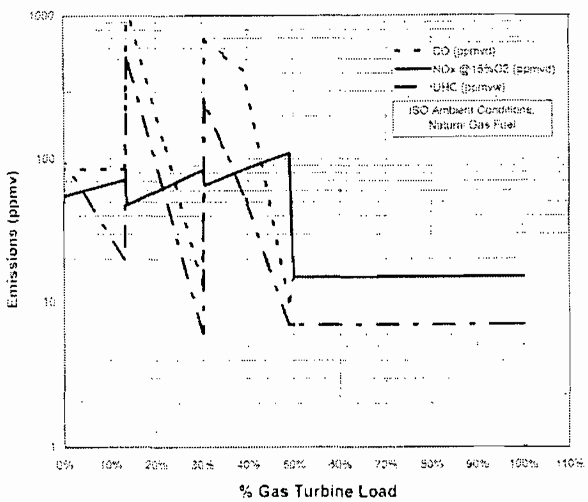

Figure 3 – Emissions Characteristics for DLN-2.6 **(if tuned to 15 ppmvd NO_X)**

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.

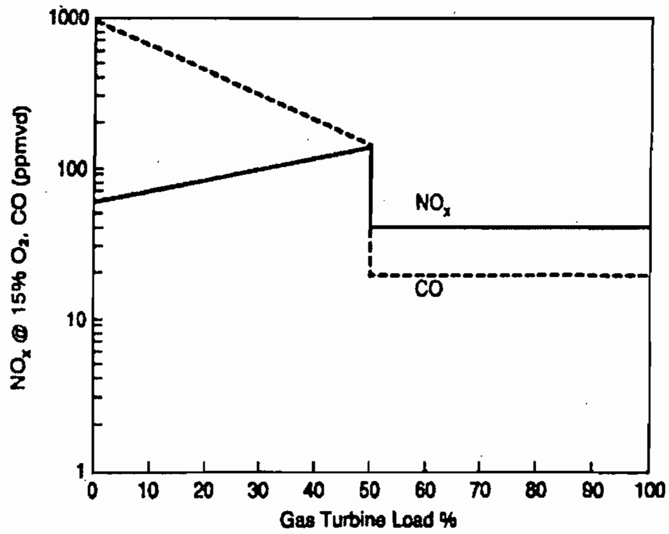

Figure 4 - Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

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.

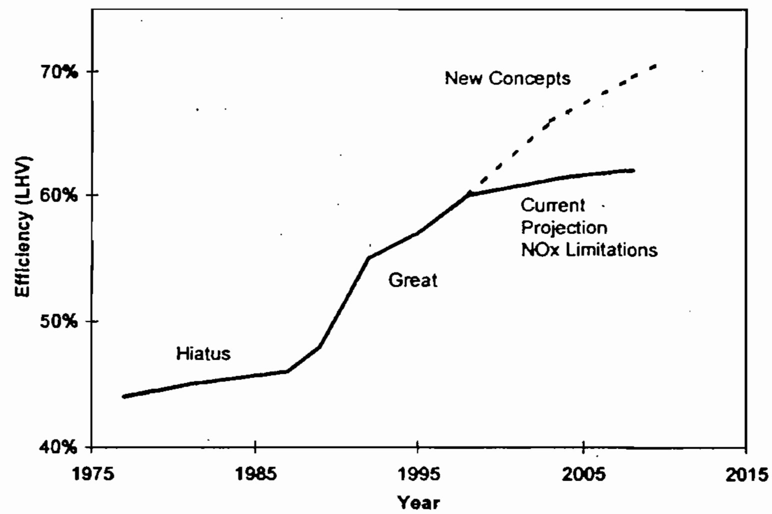

Figure 5 – Efficiency Increases in Combustion Turbines

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.

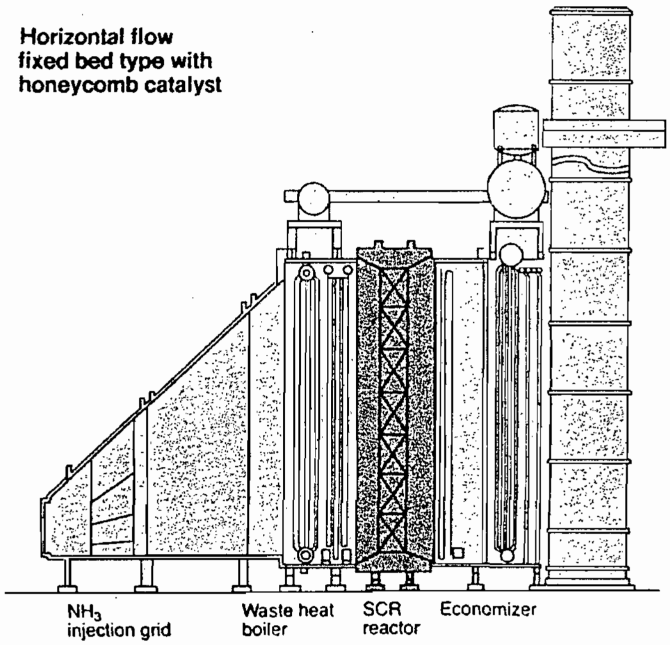

Figure 6 – SCR System within HRSG

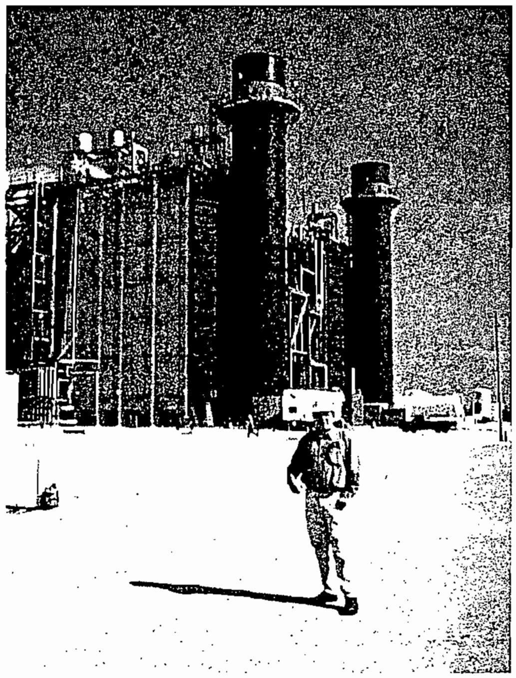

Figure 7 – FPC Hines Power Block I

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 simple cycle 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.]

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:

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

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

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

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 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.

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

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

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

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

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

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

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

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

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

APPENDIX GC

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

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

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

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

7001 0320 0001 3692 8574

The Honorable Robert E. Minsky

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

Postmark
Here

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 LeBlam ☐ Agent ☐ Addressee

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

BRAINTREE, MA
JAN 22 2002
02184-9998

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)

OFFICIAL USE

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

7001 0320 0001 3692 8550

PS Form 3800, January 2001 See Reverse for Instructions

Florida Department of
Environmental Protection

Memorandum

TO: Howard L. Rhodes

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

FROM: Teresa Heron T.H

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

VIA ELECTRONIC MAIL AND TELEFAX

Competitive
Power Ventures, Inc.

January 10, 2002

Post-it® Fax Note 7671	Date 1-10-02 # of pages ▶ 3
To AL LINERO	From PETER PODURGIEL
Co./Dept.	Co. CPV Cana, Ltd.
Phone #	Phone # 781-405-3492
Fax # 850-922-6979	Fax #

Alvaro Linero, P.E.
Administrator,
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Additional Comments on CPV Cana Electric Generating Facility Draft PSD Permit, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

On January 2, 2002, CPV Cana submitted comments on the draft PSD Air Construction proposed to be issued for the CPV Cana Electric Generating Facility, and in that comment letter stated that it would submit additional comments specifically to address Condition No. 29.c. (or, in renumbered Condition No. 29 b., if the paragraph concerning the bypass stack option has been deleted pursuant to the January 2, 2002 comments) best operational standard (no bypass) for minimization of startup NOx and CO emissions. Pursuant to our telephone discussion today, following are our comments, and we have provided language for inclusion in No. 29.c. of the PSD permit and in the BACT Determination to address this issue.

Comment:

As we discussed, we believe it is premature to define the "Best Operational Standard" information for the CPV Cana Project as part of the construction permit for the Project. Based on input from the turbine manufacturer, it is our belief that it is appropriate that the "Best Operational Standard" should be determined on a schedule appropriate for its incorporation into the required Title V operation permit for the Project. This is because at this time, sufficient vendor information and guarantees do not exist to warrant inclusion of such information in the construction permit.

Specifically, we are concerned about specifying the numbers of minutes within which the unit will reach "Mode 5Q" during cold, warm and hot startups, respectively, as well as specifying the numbers of minutes within which ammonia injection will be initiated for cold, warm and hot startups, respectively. We can envision circumstances under which such specific requirements would not constitute a "Best Operational Standard". For example, we do not believe that the amount of time required to reach "Mode 5Q" can be fixed under all circumstances, and we would anticipate that ammonia injection prior to having the equipment reach the appropriate temperature, will likely vary depending upon the operational circumstances.

Therefore, in lieu of specifying the numbers of minutes for these operational conditions at this time, we request that the "x, y and z minutes" phrase is left unchanged wherever it appears in both the construction permit (i.e., twice in Item 29.c. (or 29.b., if the "Best Operational Standard (Bypass Stack Option)" entry has been deleted as requested)) and BACT Determination (i.e., twice in the 5th from the last bullet on page BD-19, followed immediately by insertion of the following parenthetical phrase: "(to be determined for incorporation into the required Title V operation permit)". In addition, the parenthetical sentences at the end of Item 29.c. in the construction permit and in the 5th from the last bullet on page BD-19 of the BACT Determination need to be revised to read: "(Note: Times and measures to be determined for incorporation into the required Title V operation permit)". In addition, the word "operation" needs to be added prior to the word "permit" at the end of the last sentence of the preceding bullet on page BD-19 of the BACT Determination.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253
FAX (781) 848-5804

Language for inclusion in the permit and in the BACT Determination

Following is language to be inserted directly into the permit for Condition No. 29c (or renumbered Condition No. 29 b., if the provision concerning the bypass stack option in the draft permit was deleted pursuant to the comments previously submitted on January 2, 2002):

c. Best Operational Standard (No Bypass): 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 emissions: (Note: Times and measures to be determined for incorporation into the required Title Voperation permit ~~during public comment period~~)

Following is language to be inserted into the last paragraph of the fourth bullet point on page BD-19 of the BACT Determination:

- If the startup BACT described above is not feasible, then the applicant will submit an alternative Best Operational Practice. 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 prior to issuance of the final air operation permit.

Following is language to be inserted into the fifth bullet point on page BD-19 of the BACT Determination:

- Best Operational Standard – Startup BACT (No Bypass Stack):

  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 emissions: (Note: Times and measures to be determined for incorporation into the required Title V operation permit ~~during public comment period~~)

We believe this is the most responsible approach to achieve the Florida Department of Environmental Protection's (DEP) objective of minimizing NOx (and CO) emissions during startup (and shutdown) periods. CPV Cana is willing to operate the facility as needed to minimize those emissions, but the specific steps needed to do so will be determined during the testing phase and therefore can be addressed in the air operation permit. This fact is acknowledged by DEP in the 2nd to the last paragraph on page BD-16 of the BACT Determination, which reads as follows: "The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions of NOx and address carbon monoxide too."

We appreciate the opportunity to provide these comments and look forward to issuance of the permit.

Sincerely,

Peter J Podurgiel

Peter J. Podurgiel
CPV Cana, Ltd.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Teresa Heron, FDEP

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184

VIA ELECTRONIC MAIL AND TELEFAX

Competitive
Power Ventures, Inc.

January 10, 2002

Post-it® Fax Note 7671	Date 1-10-02 # of pages ▶ 3
To Teresa Heron	From Peter Podurgiel
Co./Dept.	Co. CPV Cana, Ltd.
Phone #	Phone # 781-405-3442
Fax # 850-922-6979	Fax #

Alvaro Linero, P.E.
Administrator,
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Additional Comments on CPV Cana Electric Generating Facility Draft PSD Permit, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

On January 2, 2002, CPV Cana submitted comments on the draft PSD Air Construction proposed to be issued for the CPV Cana Electric Generating Facility, and in that comment letter stated that it would submit additional comments specifically to address Condition No. 29.c. (or, in renumbered Condition No. 29 b., if the paragraph concerning the bypass stack option has been deleted pursuant to the January 2, 2002 comments) best operational standard (no bypass) for minimization of startup NOx and CO emissions. Pursuant to our telephone discussion today, following are our comments, and we have provided language for inclusion in No. 29.c. of the PSD permit and in the BACT Determination to address this issue.

Comment:

As we discussed, we believe it is premature to define the "Best Operational Standard" information for the CPV Cana Project as part of the construction permit for the Project. Based on input from the turbine manufacturer, it is our belief that it is appropriate that the "Best Operational Standard" should be determined on a schedule appropriate for its incorporation into the required Title V operation permit for the Project. This is because at this time, sufficient vendor information and guarantees do not exist to warrant inclusion of such information in the construction permit.

Specifically, we are concerned about specifying the numbers of minutes within which the unit will reach "Mode 5Q" during cold, warm and hot startups, respectively, as well as specifying the numbers of minutes within which ammonia injection will be initiated for cold, warm and hot startups, respectively. We can envision circumstances under which such specific requirements would not constitute a "Best Operational Standard". For example, we do not believe that the amount of time required to reach "Mode 5Q" can be fixed under all circumstances, and we would anticipate that ammonia injection prior to having the equipment reach the appropriate temperature, will likely vary depending upon the operational circumstances.

Therefore, in lieu of specifying the numbers of minutes for these operational conditions at this time, we request that the "x, y and z minutes" phrase is left unchanged wherever it appears in both the construction permit (i.e., twice in Item 29.c. (or 29.b., if the "Best Operational Standard (Bypass Stack Option)" entry has been deleted as requested)) and BACT Determination (i.e., twice in the 5th from the last bullet on page BD-19, followed immediately by insertion of the following parenthetical phrase: "(to be determined for incorporation into the required Title V operation permit)". In addition, the parenthetical sentences at the end of Item 29.c. in the construction permit and in the 5th from the last bullet on page BD-19 of the BACT Determination need to be revised to read: "(Note: Times and measures to be determined for incorporation into the required Title V operation permit)". In addition, the word "operation" needs to be added prior to the word "permit" at the end of the last sentence of the preceding bullet on page BD-19 of the BACT Determination.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253
FAX: (781) 848-5804

Language for inclusion in the permit and in the BACT Determination

Following is language to be inserted directly into the permit for Condition No. 29c (or renumbered Condition No. 29 b., if the provision concerning the bypass stack option in the draft permit was deleted pursuant to the comments previously submitted on January 2, 2002):

c. Best Operational Standard (No Bypass): 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 emissions: (Note: Times and measures to be determined for incorporation into the required Title Voperation permit ~~during public comment period~~)

Following is language to be inserted into the last paragraph of the fourth bullet point on page BD-19 of the BACT Determination:

* If the startup BACT described above is not feasible, then the applicant will submit an alternative Best Operational Practice. 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 prior to issuance of the final air operation permit.

Following is language to be inserted into the fifth bullet point on page BD-19 of the BACT Determination:

* Best Operational Standard -- Startup BACT (No Bypass Stack):

  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 emissions: (Note: Times and measures to be determined for incorporation into the required Title V operation permit ~~during public comment period~~)

We believe this is the most responsible approach to achieve the Florida Department of Environmental Protection's (DEP) objective of minimizing NOx (and CO) emissions during startup (and shutdown) periods. CPV Cana is willing to operate the facility as needed to minimize those emissions, but the specific steps needed to do so will be determined during the testing phase and therefore can be addressed in the air operation permit. This fact is acknowledged by DEP in the 2nd to the last paragraph on page BD-16 of the BACT Determination, which reads as follows: "The Department is gathering information from recently commissioned 7FA units to more accurately estimate startup emissions of NOx and address carbon monoxide too."

We appreciate the opportunity to provide these comments and look forward to issuance of the permit.

Sincerely,

Peter J. Podurgiel

Peter J. Podurgiel
CPV Cana, Ltd.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Teresa Heron, FDEP

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184

Department of Environmental Protection

FLORIDA

Jeb Bush
Governor

Southeast District
P.O. Box 15425
West Palm Beach, Florida 33416

David B. Struhs
Secretary

January 4, 2002

Certified - Return Receipt Requested
7000 0600 0024 1599 6285

RECEIVED
JAN 07 2002
BUREAU OF AIR REGULATION

Gary A. Lambert
Vice President
CPV Cana, L.L.C.
35 Braintree Hill Office, Suite 107
Braintree, MA 02184

Dear Mr. Lambert:

Enclosed is Environmental Resource Permit No. ES 56-0186076-001 issued pursuant to Part IV of Chapter 373, Florida Statutes (F.S.), and Title 62, Florida Administrative Code (F.A.C.).

Appeal rights for you as the permittee and for any affected third party are described in the text of the permit along with conditions which must be met when permitted activities are undertaken. Please review this document carefully to ensure compliance with both the general and specific conditions contained herein. As the permittee, you are responsible for compliance with these conditions. **Please ensure all construction personnel associated with your activity review and understand the approved drawings and conditions.** Failure to comply with this permit may result in liability for damages and restoration, and the imposition of civil penalties up to $10,000.00 per violation per day pursuant to Sections 403.141 and 403.161, F.S.

In addition please ensure the construction commencement notice and all other reporting conditions are forwarded to the appropriate office as indicated in the specific conditions.

If you have any questions about this document, please contact me at 561/681-6640.

Sincerely,

Timothy Rach

for Indar Jagnarine, P.E.
Submerged Lands & Environmental
Resources Program

Department of
Environmental Protection

Jeb Bush
Governor

Southeast District
P.O. Box 15425
West Palm Beach, Florida 33416

David B. Struhs
Secretary

ENVIRONMENTAL RESOURCE PERMIT

PERMITTEE:
Gary A. Lambert
Vice President
CPV Cana, Ltd.
35 Braintree Hill Office, Suite 107
Braintree, MA 02184

Permit Number: ES 56-0186076-001
Date of Issue: JAN 04 2002
Expiration Date of Construction JAN 03 2007
Phase:
Project: Power Plant-Stormwater-ERP
County: St. Lucie

This permit is issued under the authority of Part IV of Chapter 373, F.S., and Title 62, Florida Administrative Code (F.A.C.). The activity is not exempt from the requirement to obtain an Environmental Resource Permit. Pursuant to operating agreements executed between the Department and the water management districts, as referenced in Chapter 62-113, F.A.C., the Department is responsible for reviewing and taking final agency action on this activity.

ACTIVITY DESCRIPTION:

CPV Cana, Ltd.. proposes to construct and operate an electric generating facility and associated infrastructure called CPV Cana, Ltd. The facility will be sited on a 61.54-acre parcel in St. Lucie County. To serve the proposed development, stormwater runoff from the power generating facility is designed to meet State and South Florida Water Management District (SFWMD) water quality and quantity requirements. No wetlands are proposed to be impacted for this project.

ACTIVITY LOCATION:

CPV Cana, Ltd. project is located at off Range Line Road, approximately 0.75 miles south of the intersection of Glades Cut-off Road and Range Line Road, St. Lucie County, in Section 01, Township 37 South, Range 38 East.

This permit also constitutes a finding of consistency with Florida's Coastal Zone Management Program, as required by Section 307 of the Coastal Management Act.

This permit also constitutes certification of compliance with water quality standards under Section 401 of the Clean Water Act, 33 U.S.C. 1341.

A copy of this authorization also has been sent to the U.S. Army Corps of Engineers (USACOE) for review. The USACOE may require a separate permit. Failure to obtain this authorization prior to construction could subject you to enforcement action by that agency. You are hereby advised that authorizations also may be required by other federal, state, and local entities. This authorization does not relieve you from the requirements to obtain all other required permits and authorizations.

The above named permittee is hereby authorized to construct the work shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof. **This permit is subject to the limits, conditions, and locations of work shown in the attached exhibits, and is also subject to the attached General Conditions (1-19) and Specific Conditions (1-10) which are a binding part of this permit.** You are advised to read and understand these drawings and conditions prior to commencing the authorized activities, and to ensure the work is conducted in conformance with all the terms, conditions, and drawings. If you are utilizing a contractor, the contractor also should read and understand these drawings and conditions prior to commencing the authorized activities. Failure to comply with all drawings and conditions shall constitute grounds for revocation of the permit and appropriate enforcement action.

Operation of the facility is not authorized except when determined to be in conformance with all applicable rules and with the general and specific conditions of this permit, and as specifically described below.

SURFACE WATER SYSTEM DESIGN:

Project Area: 61.54 acres **Drainage Area**: 31.1 acres

Drainage Basin: SFWMD C-24

Receiving Body: Range Line Road, roadside ditch

Background: On July 3, 2001, the applicant, Mr. Gary A. Lambert, Vice President, CPV Cana Ltd. applied for an Environmental Resource Permit (ERP) to construct/operate a surface water management system to serve the proposed electric generating facility located in St. Lucie County. The proposed plant's steam generator will generate less than 75 megawatts and is, therefore, not required to be reviewed under the Florida Electrical Power Plant Siting Act.

Existing Facility: The site is an abandoned vegetable field/current pasture with one jurisdictional wetland associated with a cattle pond and two off-site jurisdictional wetlands with a small portion of each of the two wetlands encroaching into the site. The site's topography averages 26.5 to 27 feet NGVD. The site is currently zoned utility and industrial.

Proposed Facility:

Proposed Landuse Summary:

Landuse	Basin 1, acres	Basin 2, acres
Powerplant	23.3	-
Lakes (stormwater)	2.9	1.1
Swales	3.4	1
Un-developed	20.44	-
Landscape Buffer	1.3	1.9
Access Paving/Staging	-	6
Total	51.54	10.0

The facility's stormwater management system is designed to meet SFWMD C-24 allowable discharge criteria and water quality volumetric treatment requirements. The site is hydraulically separated into two drainage basins, Basin 1 and Basin 2. Stormwater from Basin 1 (power generating facility site) will be routed to the connected dry retention areas discharging to the on-site stormwater lakes and outfalls into Range Line Road swale via a single weir structure. Basin 2 consists of dry retention, wet detention, landscape areas, construction staging and construction employee parking. Stormwater from Basin 2 will be directed to grass retention areas to the wet detention system and outfalls into Range Line Road swale. The entrance road outside the property boundary is permitted by St. Lucie County.

There will be no chemical discharge to stormwater. All on-site chemicals or additives are stored under roof, on concrete flooring with containment and/or on skids in containment. All containment provides 110% volume.

Stormwater Management System Water Control Structure:

Identification	Structure Type	Elevation (feet NGVD)	Benchmark	Location
Basin 1	6.5 " orifice	26.0	Invert of flood Control Orifice	To Range Line Road, ditch
Basin 2	3" orifice	26.0	Invert of Flood Control Orifice	To Range Line Road, ditch

Basin Information:

Basin	Area (AC)	WSWT Elev. (ft NGVD)	Normal/Dry Ctrl Elev. (ft NGVD)	Method of Determination
Basin 1 & 2	61.54	25.5	26.0	Soil Survey

Discharge Rate: Flow control orifices will limit the discharge rate of stormwater to based on the SFWMD C-24 criteria as follows:

Design Storm Freq.: 10-yr, 3-day **Design Rainfall:** 7.34 inches

Basin	Allow Disch (cfs)	Method of Determination	Design Disch (cfs)	Design Stage (ft. NGVD)
1	1.47	Allowable Discharge – 30.25cfs/mi^2	1.41	27.91
2	.47	"	0.31	27.94

Water Quality: Treatment is provided in dry retention /detention areas computed as the first inch over the site.

Basin	Pervious Area Ac.	Impervious Area for water quality Ac.	Treatment Method	Volume Req'd (ac.ft)	Volume Prov'd (ac.-ft)
1	10.68	20.42	Dry retention	1.39	1.39
2	11.62	4.90	Dry detention	0.82	0.82

Minimum Building Floor Elevation:

The minimum elevation of paved drives/parking areas within Basin 1 is set at 30.5 feet NGVD, which is above the 10-year, 3 day stage of 27.91 feet NGVD. The minimum elevation of paved drives/parking areas within Basin 2 is set at 29.0 feet NGVD, which is above the 10-year, 3-day stage of 27.94 feet NGVD. The minimum elevation of building floors is set at 32.0 feet NGVD which is above the 100-year, 3-day, zero discharge stage of 29.69 feet NGVD.

Environmental Review: The project is located on 61.54 acres of agricultural pasture land. A cattle pond exists in the northern portion of the project site. The cattle pond is vegetated with various pasture grass species. Herbaceous wetlands exist at the border and cross over onto the project site. The on-site wetlands are dominated by Maidencane and sodgrasses. No wetland impacts are proposed. BMP'S such as slit fences and hay bails will be used to protect an average 25 feet wetland buffer areas during construction.

The upland vegetative community consists primarily of a shrub layer of Brazilian Pepper (Schinus terebinthifolius) and Wax Myrtle (Myrica cerifera). The ground cover consists primarily of Bahia (Paspalum notata) and Broomsedge (Andropogon virginicus) along with other forage grasses and sedges.

System Operation: CPV Cana, Ltd.

Water Use Permit Status: A water use permit has not been applied for. A water use permit will be submitted prior to 2002.

Water and Wastewater Supplier: Initially, Water from Floridan Aquifer will be treated for use and deep well for disposal and ultimately by the City of Port St. Lucie.

Save Our Rivers: This project is not within or adjacent to lands under consideration by the Save Our Rivers program.

Swim Basin: This project is not located within a Swim Basin

Right-of-way Permit Status: A right-of-way permit is not required from the South Florida Water Management District.

Well Field Zone of Influence: This project is not located within the zone of influence of a well-field.

GENERAL CONDITIONS:

(1) All activities authorized by this permit shall be implemented as set forth in the plans, specifications and performance criteria as approved by this permit. Any deviation from the permitted activity and the conditions for undertaking that activity shall constitute a violation of this permit and Part IV, Chapter 373, F.S.

(2) This permit or a copy thereof, complete with all conditions, attachments, exhibits, and modifications shall be kept at the work site of the permitted activity. The complete permit shall be available for review at the work site upon request by the Department staff. The permittee shall require the contractor to review the complete permit prior to commencement of the activity authorized by this permit.

(3) Activities approved by this permit shall be conducted in a manner which does not cause violations of state water quality standards. The permittee shall implement best management practices for erosion and pollution control to prevent violation of state water quality standards. Temporary erosion control shall be implemented prior to and during construction, and permanent control measures shall be completed within 7 days of any construction activity. Turbidity barriers shall be installed and maintained at all locations where the possibility of transferring suspended solids into the receiving water body exists due to the permitted work. Turbidity barriers shall remain in place at all locations until construction is completed and soils are stabilized and vegetation has been established. All practices shall be in accordance with the guidelines and specifications described in Chapter 6 of the Florida Land Development Manual; A Guide to Sound Land and Water Management (Department of Environmental Regulation, 1988), unless a project-specific erosion and sediment control plan is approved as part of the permit. Thereafter the permittee shall be responsible for the removal of the barriers. The permittee shall correct any erosion or shoaling that causes adverse impacts to the water resources.

(4) The permittee shall notify the Department of the anticipated construction start date within 30 days of the date that this permit is issued. **At least 48 hours prior to commencement** of activity authorized by this permit, the permittee shall submit to the Department an "Environmental Resource Permit Construction Commencement" notice (Form No. 62-343.900(3), F.A.C.) indicating the actual start date and the expected completion date.

(5) When the duration of construction will exceed one year, the permittee shall submit construction status reports to the Department on an annual basis utilizing an "Annual Status Report Form"

(Form No. 62-343.900(4), F.A.C.). Status Report Forms shall be submitted the following June of each year.

(6) **Within 30 days after completion of construction** of the permitted activity, the permittee shall submit a written statement of completion and certification by a registered professional engineer or other appropriate individual as authorized by law, utilizing the supplied "Environmental Resource Permit As-Built Certification by a Registered Professional" (Form No. 62-343.900(5), F.A.C.). The statement of completion and certification shall be based on on-site observation of construction or review of as-built drawings for the purpose of determining if the work was completed in compliance with permitted plans and specifications. This submittal shall serve to notify the Department that the system is ready for inspection. Additionally, if deviation from the approved drawings are discovered during the certification process, the certification must be accompanied by a copy of the approved permit drawings with deviations noted. Both the original and revised specifications must be clearly shown. The plans must be clearly labeled as "as-built" or "record" drawing. All surveyed dimensions and elevations shall be certified by a registered surveyor.

(7) The operation phase of this permit shall not become effective until the permittee has complied with the requirements of condition (6) above, has **submitted a "Request for Transfer of Environmental Resource Permit Construction Phase to Operation Phase" (Form No. 62-343.900(7), F.A.C.)**; the Department determines the system to be in compliance with the permitted plans and specifications; and the entity approved by the Department in accordance with Sections 9.0 and 10.0 of the Basis of Review for Environmental Resource Permit Applications Within the South Florida Water Management District - August 1995, accepts responsibility for operation and maintenance of the system. The permit shall not be transferred to such approved operation and maintenance entity until the operation phase of the permit becomes effective. Following inspection and approval of the permitted system by the Department, the permittee shall initiate transfer of the permit to the approved responsible operating entity if different from the permittee. Until the permit is transferred pursuant to Section 62-343.110(1)(d), F.A.C., the permittee shall be liable for compliance with the terms of the permit.

(8) Each phase or independent portion of the permitted system must be completed in accordance with the permitted plans and permit conditions prior to the initiation of the permitted use of site infrastructure located within the area served by that portion or phase of the system. Each phase or independent portion of the system must be completed in accordance with the permitted plans and permit conditions prior to transfer of responsibility for operation and maintenance of the phase or portion of the system to a local government or other responsible entity.

(9) For those systems that will be operated or maintained by an entity that will require an easement or deed restriction in order to enable that entity to operate or maintain the system in conformance with this permit, such easement or deed restriction must be recorded in the public records and submitted to the Department along with any other final operation and maintenance documents

required by sections 9.0 and 10.0 of the Basis of Review for Environmental Resource Permit Applications Within the South Florida Water Management District - August 1995, prior to lot or unit sales or prior to the completion of the system, whichever occurs first. Other documents concerning the establishment and authority of the operating entity must be filed with the Secretary of State where appropriate. For those systems which are proposed to be maintained by the county or municipal entities, final operation and maintenance documents must be received by the Department when maintenance and operation of the system is accepted by the local government entity. Failure to submit the appropriate final documents will result in the permittee remaining liable for carrying out maintenance and operation of the permitted system and any other permit conditions.

(10) Should any other regulatory agency require changes to the permitted system, the permittee shall notify the Department in writing of the changes prior to implementation so that a determination can be made whether a permit modification is required.

(11) This permit does not eliminate the necessity to obtain any required federal, state, local and special district authorizations prior to the start of any activity approved by this permit. This permit does not convey to the permittee or create in the permittee any property right, or any interest in real property, nor does it authorize any entrance upon or activities on property which is not owned or controlled by the permittee, or convey any rights or privileges other than those specified in the permit and Chapter 40E-4 or Chapter 40E-40, F.A.C.

(12) The permittee is hereby advised that Section 253.77, F.S. states that a person may not commence any excavation, construction, or other activity involving the use of sovereign or other lands of the state, the title to which is vested in the Board of Trustees of the Internal Improvement Trust Fund without obtaining the required lease, license, easement, or other form of consent authorizing the proposed use. Therefore, the permittee is responsible for obtaining any necessary authorizations from the Board of Trustees prior to commencing activity on sovereignty lands or other state-owned lands.

(13) The permittee is advised that the rules of the South Florida Water Management District require the permittee to obtain a water use permit from the South Florida Water Management District prior to construction dewatering, unless the work qualifies for a general permit pursuant to subsection 40E-20.302(4), F.A.C., also known as the "No Notice" rule.

(14) The permittee shall hold and save the Department harmless from any and all damages, claims, or liabilities which may arise by reason of the construction, alteration, operation, maintenance, removal, abandonment or use of any system authorized by the permit.

(15) Any delineation of the extent of a wetland or other surface water submitted as part of the permit application, including plans or other supporting documentation, shall not be considered binding unless a specific condition of this permit or a formal determination under section 373.421(2), F.S., provides otherwise.

(16) The permittee shall notify the Department in writing within 30 days of any sale, conveyance, or other transfer of ownership or control of a permitted system or the real property on which the permitted system is located. All transfers of ownership or transfers of a permit are subject to the requirements of section 62-343.130, F.A.C. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations prior to the sale, conveyance or other transfer of the system.

(17) Upon reasonable notice to the permittee, Department authorized staff with proper identification shall have permission to enter, inspect, sample and test the system to insure conformity with the plans and specifications approved by the permit.

(18) If historical or archaeological artifacts are discovered at any time on the project site, the permittee shall immediately notify the appropriate Department office.

(19) The permittee shall immediately notify the Department in writing of any previously submitted information that is later discovered to be inaccurate.

SPECIFIC CONDITIONS:

1. **Zoning.** The site is currently zoned utility and industrial. Prior to construction of the power plant, the applicant shall obtain the required zoning approval for the proposed electric power facility.

2. **Surface water management system.** The surface water system shall be constructed as shown in the attached exhibits. The dry detention basin bottom elevation shall be at 27.0 feet NGVD.

3. There shall be no chemical discharge to stormwater. Stormwater runoff collected in secondary containment storage shall not be disposed into the stormwater system.

4. **Sedimentation Controls.** Silt screens, hay bales or other such sediment control measures shall be utilized during construction. The selected sediment control measures shall be installed around the perimeter of the area to be developed. All areas shall be stabilized and vegetated immediately after construction to prevent erosion.

5. **Maintenance of Storm Drainage System.** Maintenance of the stormwater system is the responsibility of CPV Cana Ltd. A maintenance schedule shall be implemented to ensure that the stormwater management system is functioning as designed.

6. **Exotic Species.** The permittee shall maintain the project sites free from the invasion or establishment of the plants listed on the current year's Florida Exotic Pest Plant Council's Category I Invasive Exotic Species list (copy attached).

7. **Dewatering.** Dewatering activity may require an Industrial Wastewater permit (Tim Powell @ 561/681-6684, DEP/West Palm Beach) and SFWMD approval. Within 30 days of receipt of a dewatering permit, the permittee shall submit a copy of the permit to the Department (ATTN: Stormwater Section).
8. **Additional Water Quality Requirement.** The Department reserves the right to require that additional water quality treatment methods be incorporated into the drainage system if such measures are shown to be necessary.
9. **Drawings and Attachments.** Attached Drawing exhibits and DEP forms: 62-343.900(3), (4), (5), (7), and (8) F.A.C., are hereby attached to and become part of this permit.
10. **Compliance with General Conditions.** The permittee shall be aware of and operate under the attached general limiting conditions. General conditions are binding upon the permittee and enforceable pursuant to Chapters 403 and 373 of the Florida Statutes.

Executed in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

1/3/02

Melissa L. Meeker **Date**
Director of District Management
Southeast District

TR
MLM/TR/vn/ij

RECEIVED
JAN 07 2002
BUREAU OF AIR REGULATION

Copies furnished to:
USACOE
Al Linero, DEP/TLH
Department of Community Affairs
South Florida Water Management District - T. Waterhouse, P.E.
South Florida Water Management District – Jeff Rosenfeld
Dennis Murphy, St. Lucie County
Richard Stalker, ERP/Compliance & Enforcement
Scott Glaubitz, B.S.E. Consultants, 312 South Harbor City Blvd., Suite #4, Melbourne Fl 32901

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this permit and all copies were mailed to the above listed persons before the close of business on January 4, 2002.

FILING AND ACKNOWLEDGMENT

FILED, on this date, pursuant to 120.52(11),
Florida Statutes, with the designated Department Clerk,
receipt of which is hereby acknowledged.

Maria D. Serrano-Suarez 1-4-02

Clerk Date

Prepared by Indar Jagnarine, P.E. III and Victor Neugebauer, ES II

CPV CANA, LTD.

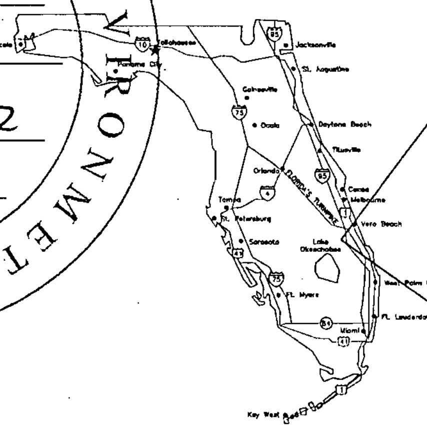
ST. LUCIE COUNTY, FLORIDA
SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST

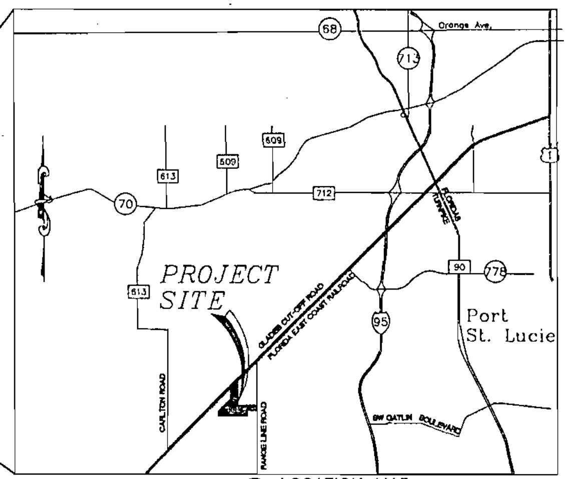
RECEIVED
NOV 06 2001
DEPT OF ENV PROTECTION
WEST PALM BEACH

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Exhibit: 1/22
Proj: CPV Cana Ltd.
ES-56-0186076-004
Date: 1-4-02
By: Indar Jagnarine

INDEX TO DRAWINGS

SHEET NO.	DWG. NO.	DWG. TITLE
1	10553401	COVER SHEET
2	10553402	OVERALL SITE PLAN
3	10553403	SITE PLAN
4	10553404	SITE PLAN
5	10553405	OVERALL UTILITY PLAN
6	10553406	UTILITY PLAN
7	10553407	UTILITY PLAN
8	10553408	OVERALL DRAINAGE PLAN
9	10553409	DRAINAGE PLAN
10	10553410	DRAINAGE PLAN
11	10553411	OVERALL LANDSCAPE PLAN
12	10553412	LANDSCAPE PLAN
13	10553413	LANDSCAPE PLAN
14	10553414	OVERALL IRRIGATION PLAN
15	10553415	IRRIGATION PLAN
16	10553416	IRRIGATION PLAN
17	10553417	SITE LIGHTING PLAN
18	10553418	CROSS SECTIONS
19	10553419	PAVING AND DRAINAGE DETAILS
20	10553420	POTABLE WATER DETAILS
21	10553421	SANITARY SEWER DETAILS
22	10553422	DEWATERING PLAN
23	10553100	BOUNDARY SURVEY – AREA 1
24	10553110	BOUNDARY SURVEY – AREA 2
25	10553425	EXISTING CONDITIONS
26	10553426	TREE SURVEY AREA 1 & AREA 2
27	10553427	SITE WITH AERIAL OVERLAY
28	10553428	SITE WITH TREE OVERLAY
29	10553429	GENERAL NOTES
30	10553430	GENERAL NOTES





LOCATION MAP
SCALE: 1"=10,000'

ENGINEERS

B.S.E. CONSULTANTS, INC.
312 S. HARBOR CITY BLVD., SUITE 4
MELBOURNE, FLORIDA 32901
PHONE (321) 725-3674
FAX (321) 723-1159

OWNER / DEVELOPER

CPV CANA, LTD.
C/O COMPETITIVE POWER VENTURES, INC.
35 BRAINTREE HILL OFFICE PARK, SUITE 107
BRAINTREE, MA 02184
(CONTACT) PETER J. PODURGIEL
PHONE (781) 848-0253

LEGAL

MOYLE FLANIGAN KATZ RAYMOND & SHEEHAN P.A.
625 NORTH FLAGLER DRIVE, 9TH FLOOR
WEST PALM BEACH, FLORIDA 33401
PETER BRETON
PHONE (561) 822-0385

ENVIRONMENTAL PERMITTING CONSULTANT

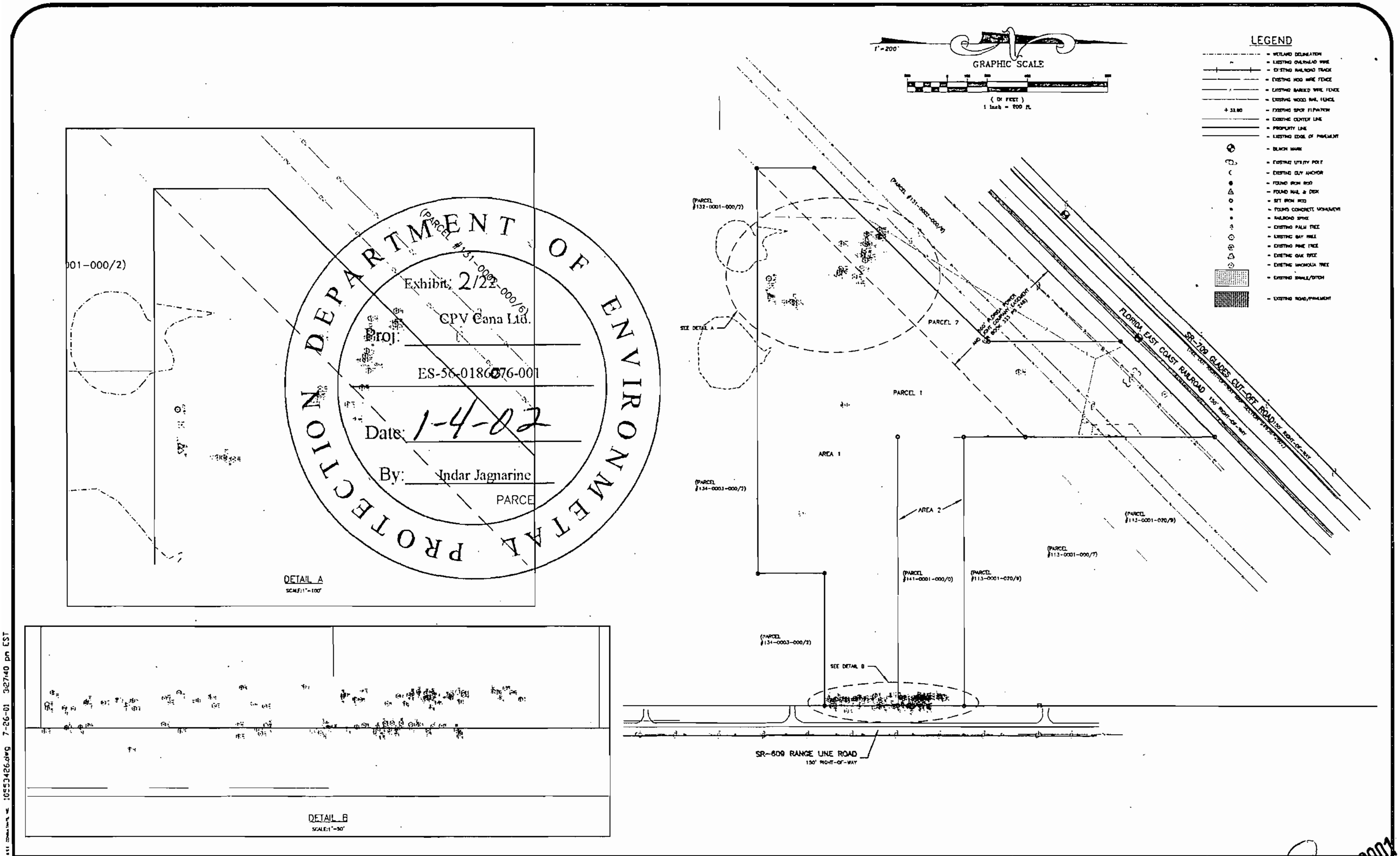
THE LOUIS BERGER GROUP, INC.
75 SECOND AVE., SUITE 700
NEEDHAM, MA 02494
NEIL COLLINS
PHONE (781) 444-3330

ARCHITECT

AEP PRO SERVE NORTHEAST
119 CANNETT DRIVE
SOUTH PORTLAND, ME 04106
KEITH PRICE
PHONE (207) 541-5800

REVISION: COUNTY COMMENTS – 7/2?/01
SHEET 1 OF 30
PROJECT NO. 10553 DRAWING NO. 10553401

NOV 8 2001



DEPARTMENT OF ENVIRONMENTAL PROTECTION

Exhibit: 2/22

Proj: CPV Cana Ltd.

ES-56-0186076-001

Date: 1-4-02

By: Indar Jagnarine

REVISIONS		
DESIGN SMG	DATE 7/25/01	
DRAWN BAW	DATE 7/25/01	
CHECKED	DATE	

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CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

TREE SURVEY
AREA 1 & AREA 2

DRAWING NO. 10553426
SHEET 15 OF 30
PROJECT NO. 10553

NOV 05 2001

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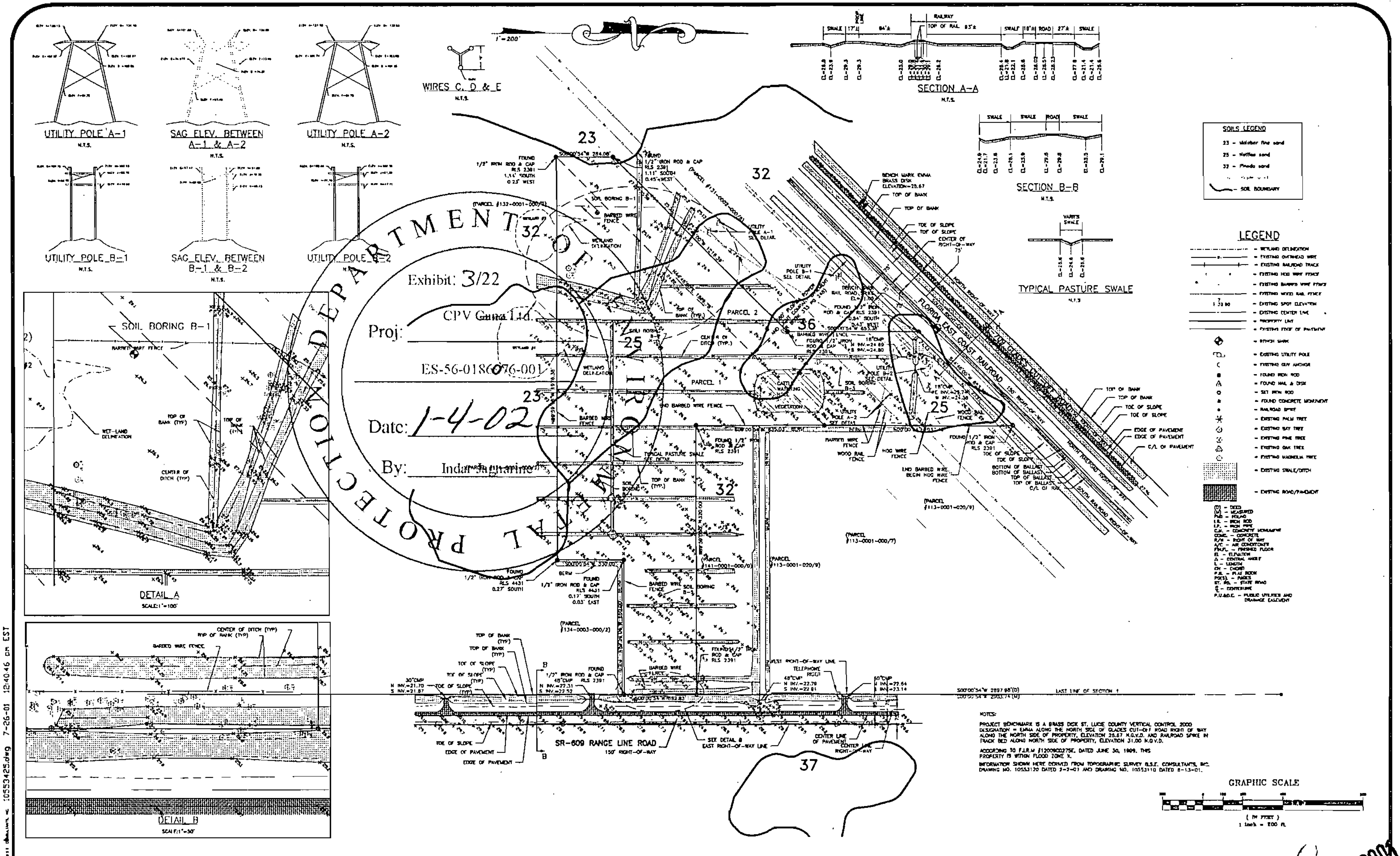

CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	EXISTING CONDITIONS

REVISIONS: COUNTY COMMENTS 7/20/01; 8/28/01
DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01
CHECKED DATE

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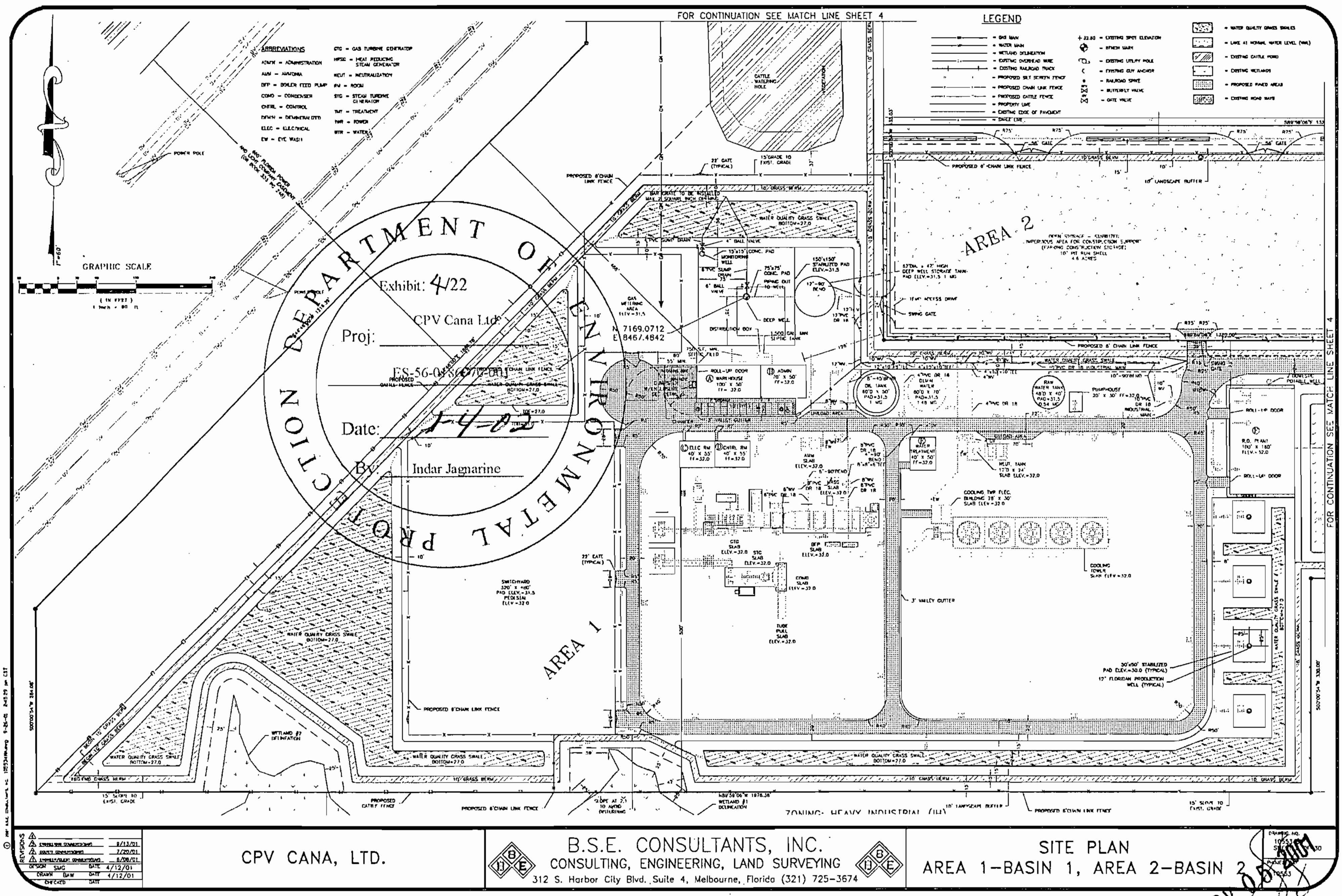
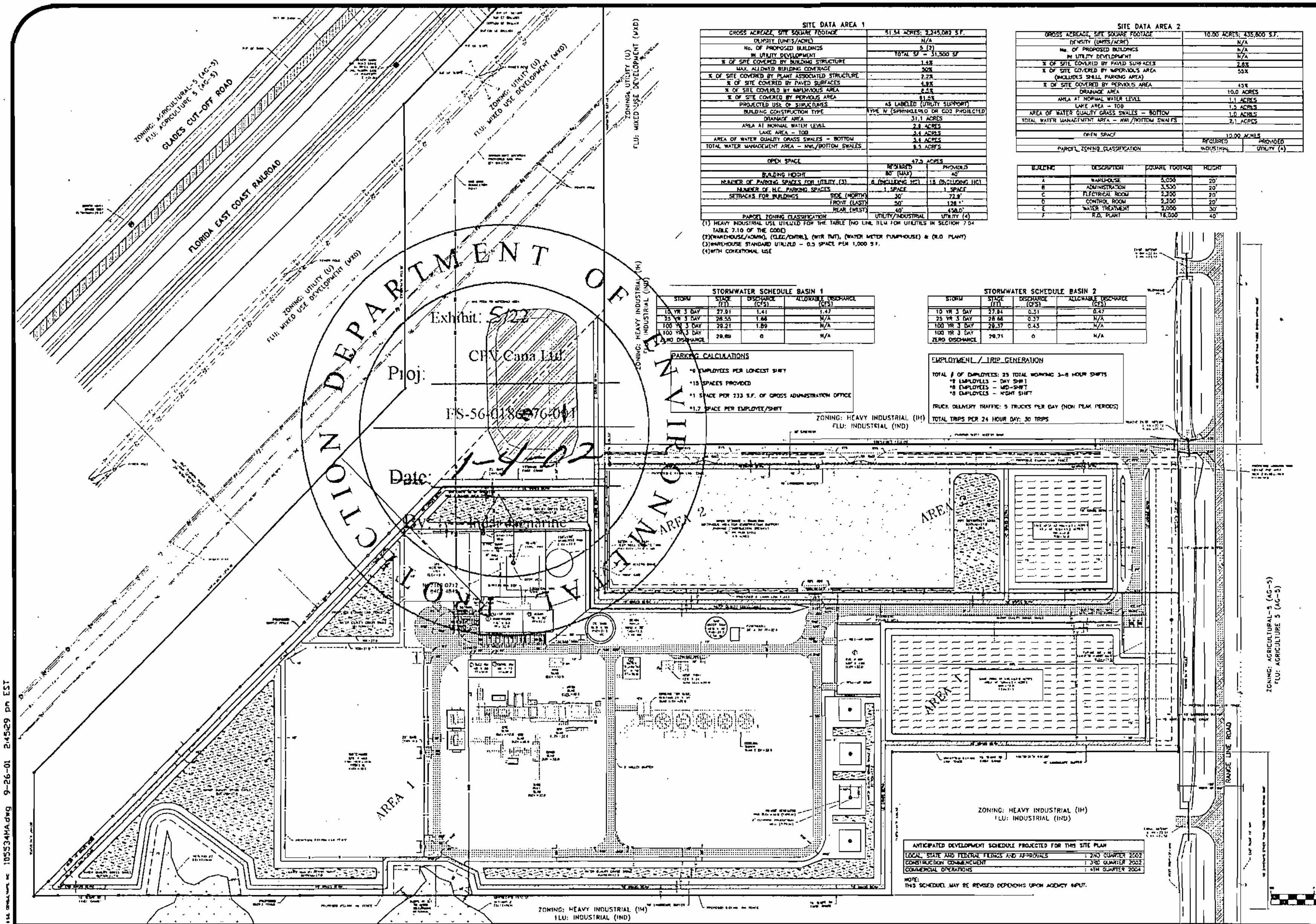
NOV 2001


FOR CONTINUATION SEE MATCH LINE SHEET 4
LEGEND
ABBREVIATIONS
ADMIN = ADMINISTRATION
AMM = AMMONIA
BFP = BOILER FEED PUMP
COND = CONDENSER
CNTRL = CONTROL
DEMIN = DEMINERALIZED
ELEC = ELECTRICAL
EW = EYE WASH
GTG = GAS TURBINE GENERATOR
HRSG = HEAT RECOVERY STEAM GENERATOR
NEUT = NEUTRALIZATION
RM = ROOM
STG = STEAM TURBINE GENERATOR
TMT = TREATMENT
PWR = POWER
WTR = WATER
GRAPHIC SCALE
(IN FEET)
1 inch = 60 ft.
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Exhibit: 4/22
Proj: CPV Cana Ltd.
Date: 1-4-02
By: Indar Jagnarine
AREA 1
AREA 2
SWITCHYARD
WATER QUALITY GRASS SWALE BOTTOM=27.0
PROPOSED 8' CHAIN LINK FENCE
COOLING TOWER
ZONING: HEAVY INDUSTRIAL (IH)
FOR CONTINUATION SEE MATCH LINE SHEET 4
CPV CANA, LTD.
B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674
SITE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2
REVISIONS
DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01
CHECKED DATE
NOV 05 2001



SITE DATA AREA 1

GROSS ACREAGE, SITE SQUARE FOOTAGE	51.54 ACRES; 2,245,082 S.F.	
DENSITY (UNITS/ACRE)	N/A	
No. OF PROPOSED BUILDINGS IN UTILITY DEVELOPMENT	5 (2) TOTAL SF = 31,500 SF	
% OF SITE COVERED BY BUILDING STRUCTURE	1.4%	
MAX. ALLOWED BUILDING COVERAGE	50%	
% OF SITE COVERED BY PLANT ASSOCIATED STRUCTURE	2.2%	
% OF SITE COVERED BY PAVED SURFACES	4.8%	
% OF SITE COVERED BY IMPERVIOUS AREA	8.5%	
% OF SITE COVERED BY PERVIOUS AREA	91.5%	
PROJECTED USE OF STRUCTURES	AS LABELED (UTILITY SUPPORT)	
BUILDING CONSTRUCTION TYPE	TYPE IV (SPRINKLERED OR CO2 PROTECTED	
DRAINAGE AREA	31.1 ACRES	
AREA AT NORMAL WATER LEVEL	2.9 ACRES	
LAKE AREA - TOB	3.4 ACRES	
AREA OF WATER QUALITY GRASS SWALES - BOTTOM	3.4 ACRES	
TOTAL WATER MANAGEMENT AREA - NWL/BOTTOM SWALES	6.5 ACRES	
OPEN SPACE	47.5 ACRES	
	REQUIRED	PROVIDED
BUILDING HEIGHT	80' (MAX)	40'
NUMBER OF PARKING SPACES FOR UTILITY (3)	6 (INCLUDING HC)	15 (INCLUDING HC)
NUMBER OF H.C. PARKING SPACES	1 SPACE	1 SPACE
SETBACKS FOR BUILDINGS SIDE (NORTH)	30'	72.9'
FRONT (EAST)	50'	128.1'
REAR (WEST)	40'	458.0'
PARCEL ZONING CLASSIFICATION	UTILITY/INDUSTRIAL	UTILITY (4)

(1) HEAVY INDUSTRIAL USE UTILIZED FOR THE TABLE (NO LINE ITEM FOR UTILITIES IN SECTION 7.04 TABLE 7.10 OF THE CODE)
(2)(WAREHOUSE/ADMIN), (ELEC/CNTRL), (WTR TMT), (WATER METER PUMPHOUSE) & (R.O. PLANT)
(3)WAREHOUSE STANDARD UTILIZED - 0.5 SPACE PER 1,000 S.F.
(4)WITH CONDITIONAL USE

SITE DATA AREA 2

GROSS ACREAGE, SITE SQUARE FOOTAGE	10.00 ACRES; 435,600 S.F.	
DENSITY (UNITS/ACRE)	N/A	
No. OF PROPOSED BUILDINGS	N/A	
IN UTILITY DEVELOPMENT	N/A	
% OF SITE COVERED BY PAVED SURFACES	2.8%	
% OF SITE COVERED BY IMPERVIOUS AREA (INCLUDES SHELL PARKING AREA)	55%	
% OF SITE COVERED BY PERVIOUS AREA	45%	
DRAINAGE AREA	10.0 ACRES	
AREA AT NORMAL WATER LEVEL	1.1 ACRES	
LAKE AREA - TOB	1.5 ACRES	
AREA OF WATER QUALITY GRASS SWALES - BOTTOM	1.0 ACRES	
TOTAL WATER MANAGEMENT AREA - NWL/BOTTOM SWALES	2.1 ACRES	
OPEN SPACE	10.00 ACRES	
	REQUIRED	PROVIDED
PARCEL ZONING CLASSIFICATION	INDUSTRIAL	UTILITY (4)

BUILDING	DESCRIPTION	SQUARE FOOTAGE	HEIGHT
A	WAREHOUSE	5,000	20'
B	ADMINISTRATION	3,500	20'
C	ELECTRICAL ROOM	2,200	20'
D	CONTROL ROOM	2,200	20'
E	WATER TREATMENT	2,000	30'
F	R.O. PLANT	18,000	40'

STORMWATER SCHEDULE BASIN 1

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.91	1.41	1.47
25 YR 3 DAY	28.55	1.66	N/A
100 YR 3 DAY	29.21	1.89	N/A
100 YR 3 DAY ZERO DISCHARGE	29.69	0	N/A

STORMWATER SCHEDULE BASIN 2

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.84	0.31	0.47
25 YR 3 DAY	28.66	0.37	N/A
100 YR 3 DAY	29.37	0.43	N/A
100 YR 3 DAY ZERO DISCHARGE	29.71	0	N/A

PARKING CALCULATIONS

*9 EMPLOYEES PER LONGEST SHIFT
*15 SPACES PROVIDED
*1 SPACE PER 233 S.F. OF GROSS ADMINISTRATION OFFICE
*1.7 SPACE PER EMPLOYEE/SHIFT

EMPLOYMENT / TRIP GENERATION

TOTAL # OF EMPLOYEES: 25 TOTAL WORKING 3-8 HOUR SHIFTS
*9 EMPLOYEES - DAY SHIFT
*8 EMPLOYEES - MID-SHIFT
*8 EMPLOYEES - NIGHT SHIFT

TRUCK DELIVERY TRAFFIC: 5 TRUCKS PER DAY (NON PEAK PERIODS)

TOTAL TRIPS PER 24 HOUR DAY: 30 TRIPS

ANTICIPATED DEVELOPMENT SCHEDULE PROJECTED FOR THIS SITE PLAN	
LOCAL, STATE AND FEDERAL FILINGS AND APPROVALS	: 2ND QUARTER 2002
CONSTRUCTION COMMENCEMENT	: 3RD QUARTER 2002
COMMERCIAL OPERATIONS	: 4TH QUARTER 2004

NOTE:
THIS SCHEDULE MAY BE REVISED DEPENDING UPON AGENCY INPUT.

ABBREVIATIONS

ADMIN = ADMINISTRATION
AMM = AMMONIA
BFP = BOILER FEED PUMP
COND = CONDENSER
CNTRL = CONTROL
DEMIN = DEMINERALIZED
ELEC = ELECTRICAL
EW = EYE WASH
GTG = GAS TURBINE GENERATOR
HRSG = HEAT REDUCING STEAM GENERATOR
NEUT = NEUTRALIZATION
RM = ROOM
STG = STEAM TURBINE GENERATOR
TMT = TREATMENT
TWR = TOWER
WTR = WATER

LEGEND

= GAS MAIN
= WATER MAIN
= WETLAND DELINEATION
= EXISTING OVERHEAD WIRE
= EXISTING RAILROAD TRACK
= PROPOSED SILT SCREEN FENCE
= PROPOSED CHAIN LINK FENCE
= PROPOSED CATTLE FENCE
+32.90 = EXISTING SPOT ELEVATION
= PROPERTY LINE
= EXISTING EDGE OF PAVEMENT
= SWALE LINE
= BENCH MARK
= EXISTING UTILITY POLE
= EXISTING GUY ANCHOR
= RAILROAD SPIKE
= BUTTERFLY VALVE
= GATE VALVE
= WATER QUALITY GRASS SWALES
= LAKE AT NORMAL WATER LEVEL (NWL)
= EXISTING CATTLE POND
= EXISTING WETLANDS
= PROPOSED PAVED AREAS
= EXISTING ROAD WAYS

GRAPHIC SCALE
(IN FEET)
1 inch = 150 ft.

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REVISIONS
ENGINEERING COMMENTS	9/13/01
COUNTY COMMENTS	7/20/01
ENGINEER/CLIENT COMMENTS	6/08/01
DESIGN SMG DATE	4/12/01
DRAWN BAW DATE	4/12/01
CHECKED DATE	

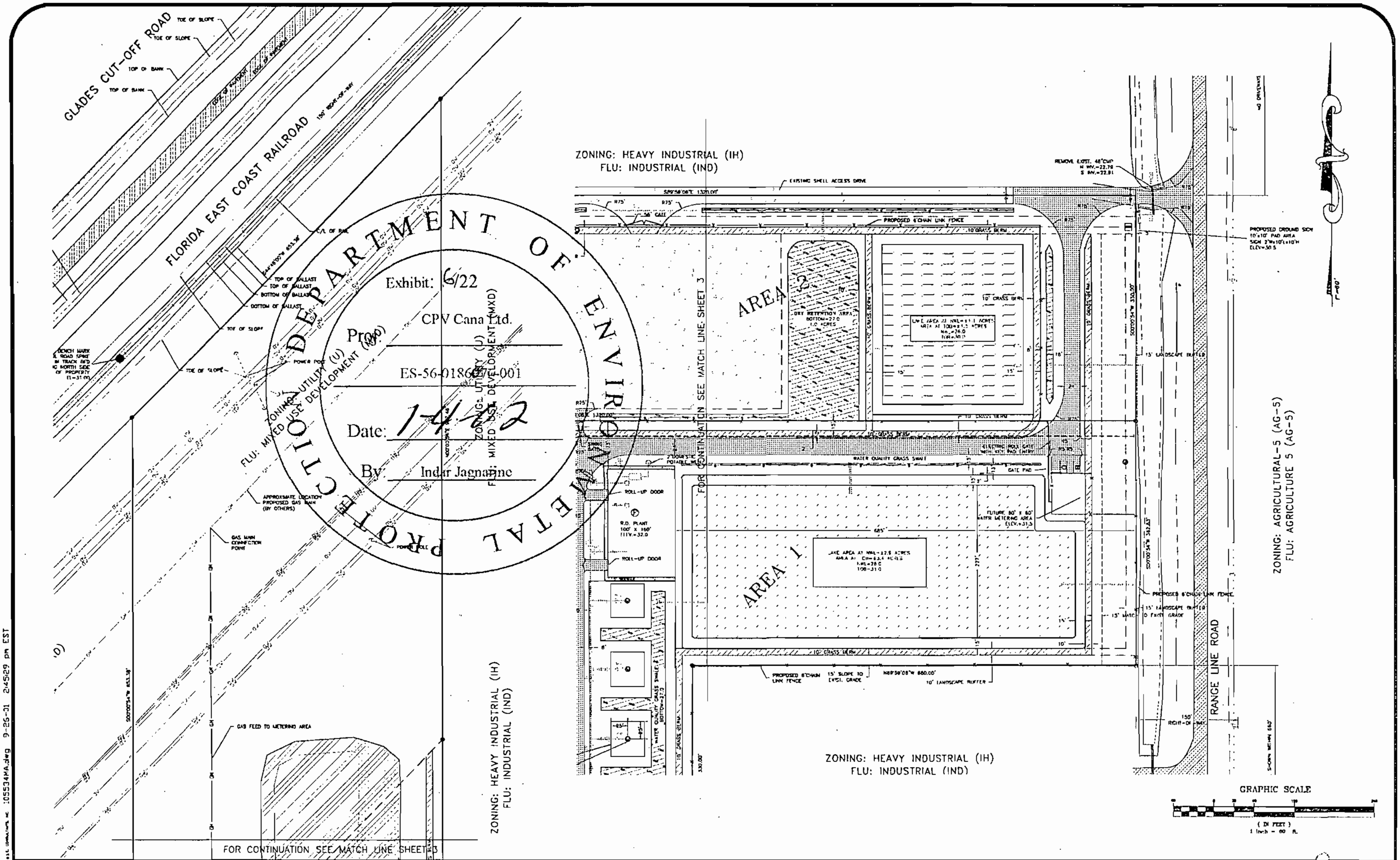
CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL SITE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DRAWING NO. 10553402
SHEET 2 OF 30
PROJECT NO. 10553

NOV 05 2001



CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	SITE PLAN AREA 1-BASIN 1, AREA 2-BASIN 2

REVISIONS: 9/13/01, 7/20/01, 6/08/01
DESIGN SMC DATE 4/12/01
DRAWN BAW DATE 4/12/01
CHECKED DATE

NOV 05 2001

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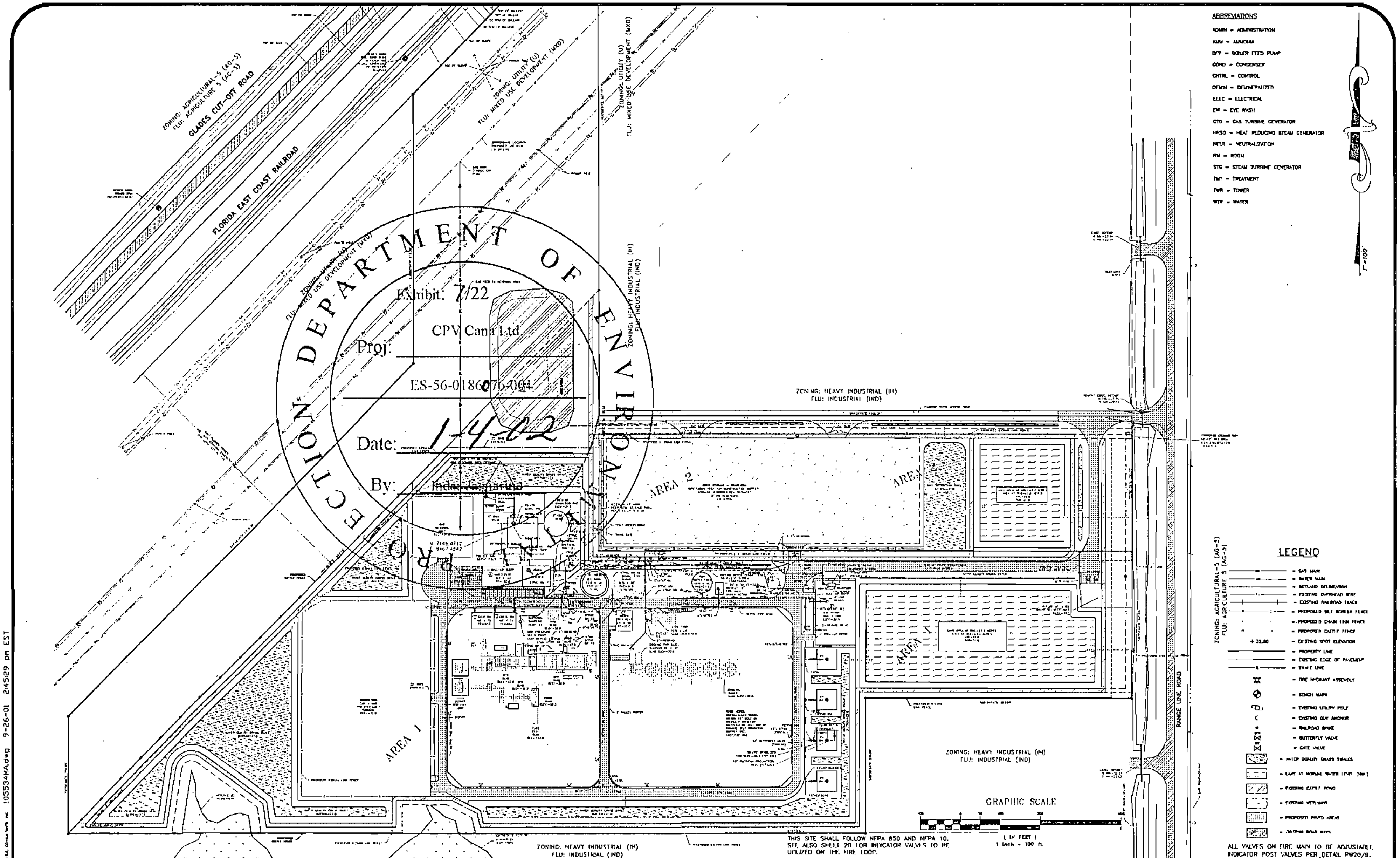

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REVISIONS		
DISTRICT COMMENTS	9/12/01	
COUNTY COMMENTS	7/20/01	
DESIGN/CLIENT COMMENTS	6/06/01	
DESIGN SMG	DATE 4/12/01	
DRAWN BAW	DATE 4/12/01	
CHECKED	DATE	

CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
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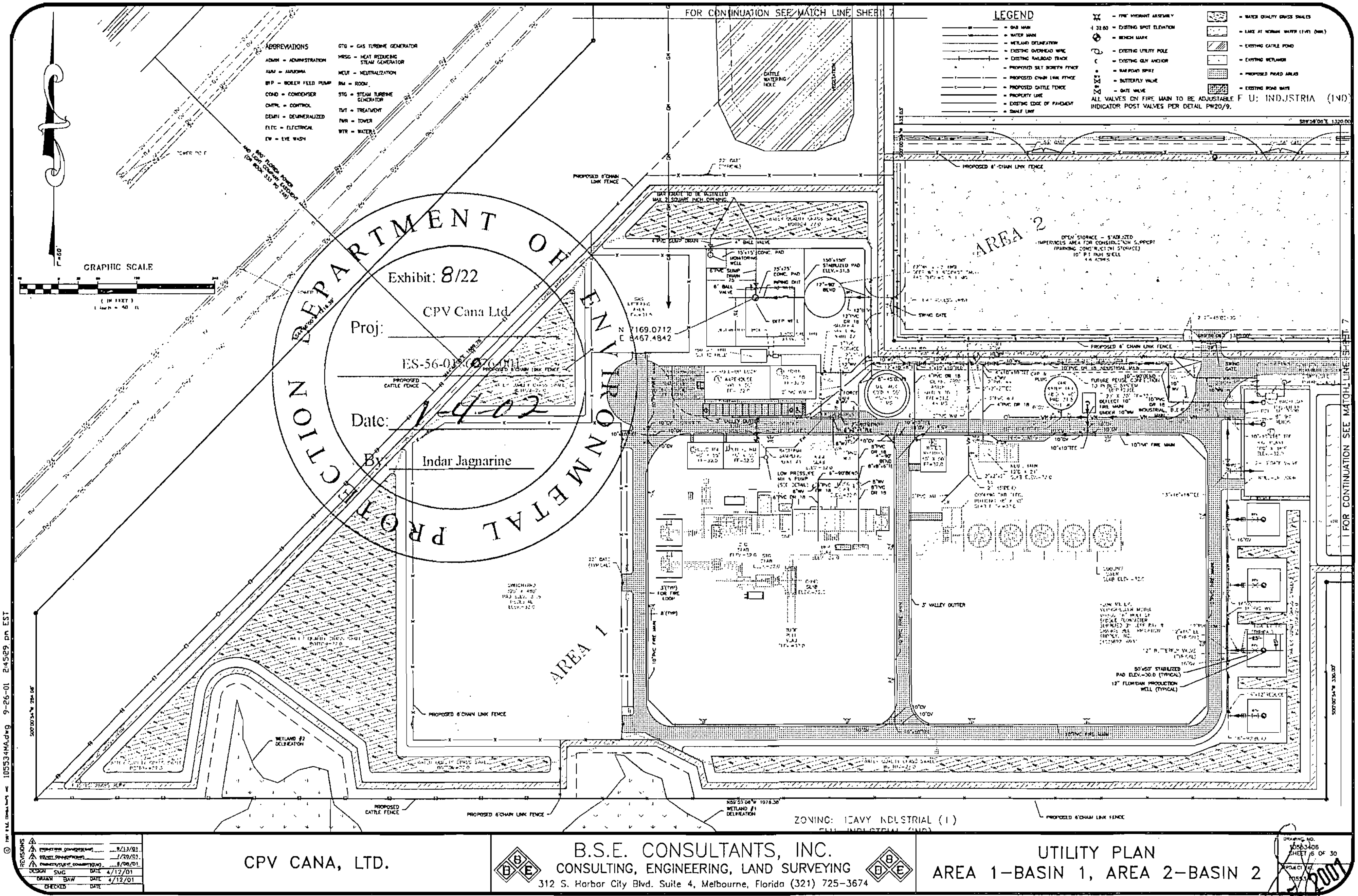
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL UTILITY PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001


FOR CONTINUATION SEE MATCH LINE SHEET 7
LEGEND
ABBREVIATIONS
GRAPHIC SCALE
(IN FEET)
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Exhibit: 8/22
Proj: CPV Cana Ltd.
ES-56-0
Date: 1-4-02
By: Indar Jagnarine
AREA 1
AREA 2
N 7169.0712
E 8467.4842
PROPOSED 6' CHAIN LINK FENCE
PROPOSED CATTLE FENCE
WETLAND #2 DELINEATION
WETLAND #1 DELINEATION
3' VALLEY GUTTER
10"PVC FIRE MAIN
ZONING: HEAVY INDUSTRIAL (I)
FOR CONTINUATION SEE MATCH LINE SHEET 7
ALL VALVES ON FIRE MAIN TO BE ADJUSTABLE INDICATOR POST VALVES PER DETAIL PW20/9.
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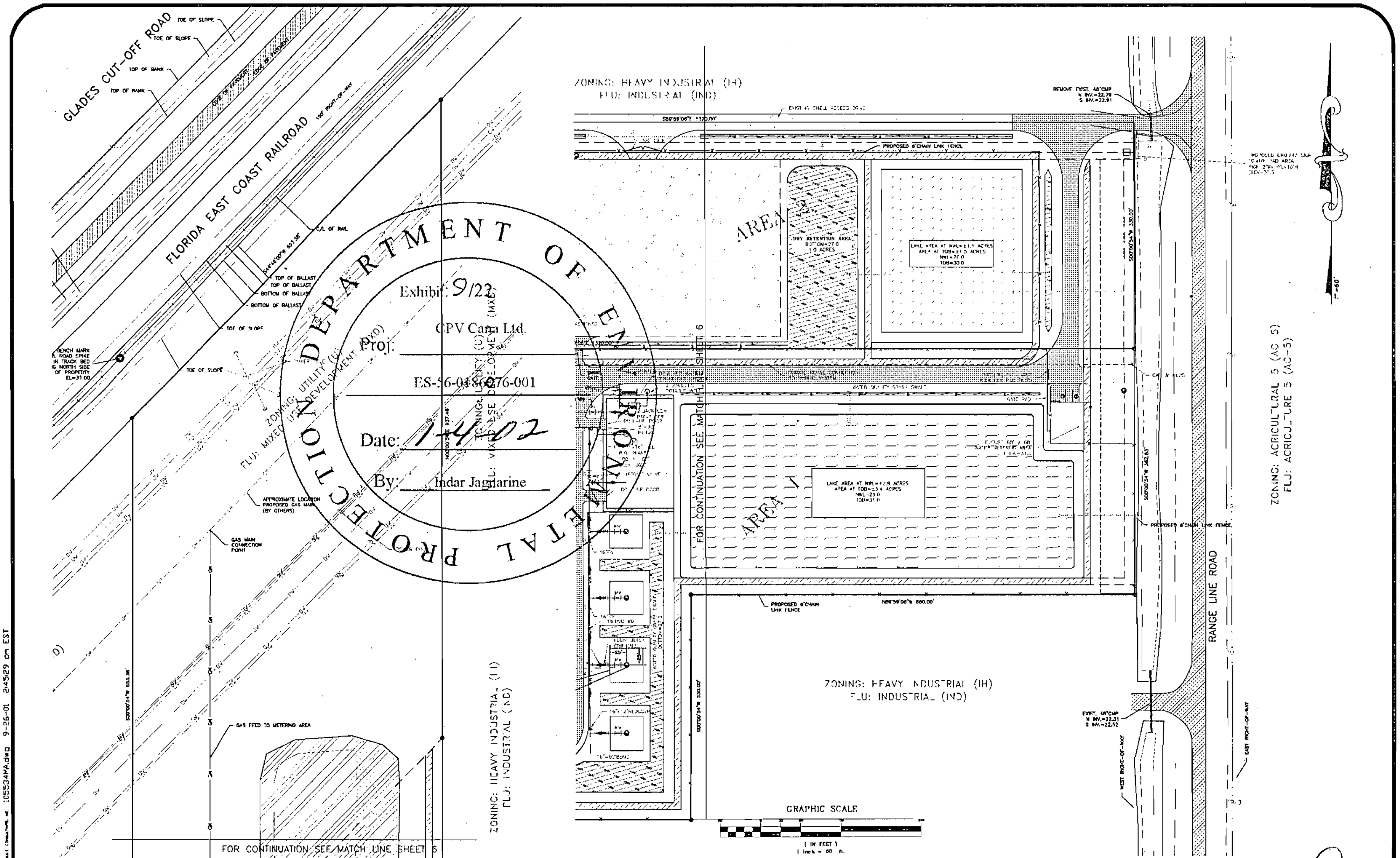
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674
UTILITY PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2
DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01
CHECKED
REVISIONS
SHEET 6 OF 30
NOV 05 2001
105534HA.dwg 9-26-01 2:45:29 pm EST



REVISIONS		
ENGINEERING COMMENTS		9/12/01
COUNTY COMMENTS		7/20/01
COMMENTS		6/08/01
DESIGN SMG	DATE	4/17/01
DRAWN BAW	DATE	4/17/01
CHECKED	DATE	

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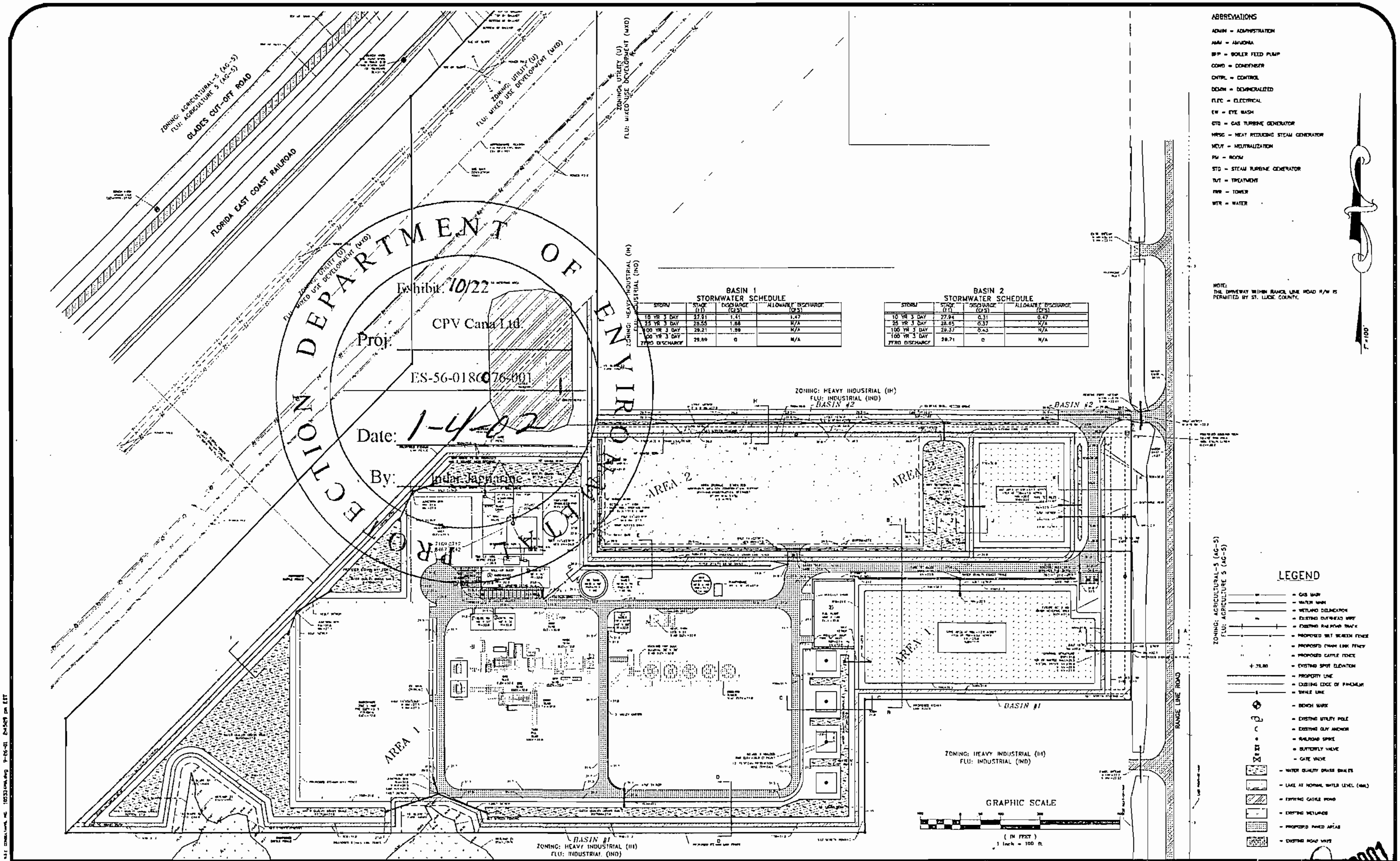
UTILITY PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DRAWING NO. 10553407

NOV 05 2001



BASIN 1
STORMWATER SCHEDULE

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.91	1.41	1.47
25 YR 3 DAY	28.55	1.66	N/A
100 YR 3 DAY	29.21	1.89	N/A
100 YR 3 DAY ZERO DISCHARGE	29.89	0	N/A

BASIN 2
STORMWATER SCHEDULE

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.94	0.31	0.47
25 YR 3 DAY	28.65	0.37	N/A
100 YR 3 DAY	29.37	0.43	N/A
100 YR 3 DAY ZERO DISCHARGE	29.71	0	N/A

ABBREVIATIONS

ADMIN = ADMINISTRATION
AMM = AMMONIA
BFP = BOILER FEED PUMP
COND = CONDENSER
CNTRL = CONTROL
DEMIN = DEMINERALIZED
ELEC = ELECTRICAL
EW = EYE WASH
GTG = GAS TURBINE GENERATOR
HRSG = HEAT RECOVERY STEAM GENERATOR
NEUT = NEUTRALIZATION
RM = ROOM
STG = STEAM TURBINE GENERATOR
TMT = TREATMENT
TWR = TOWER
WTR = WATER

NOTE:
THE DRIVEWAY WITHIN RANGE LINE ROAD R/W IS PERMITTED BY ST. LUCIE COUNTY.

REVISIONS		
4		
3	ENGINEERING COMMENTS(BAW)	8/13/01
2	COUNTY COMMENTS(BAW)	7/20/01
1	ENGINEER/CLIENT COMMENTS(BAW)	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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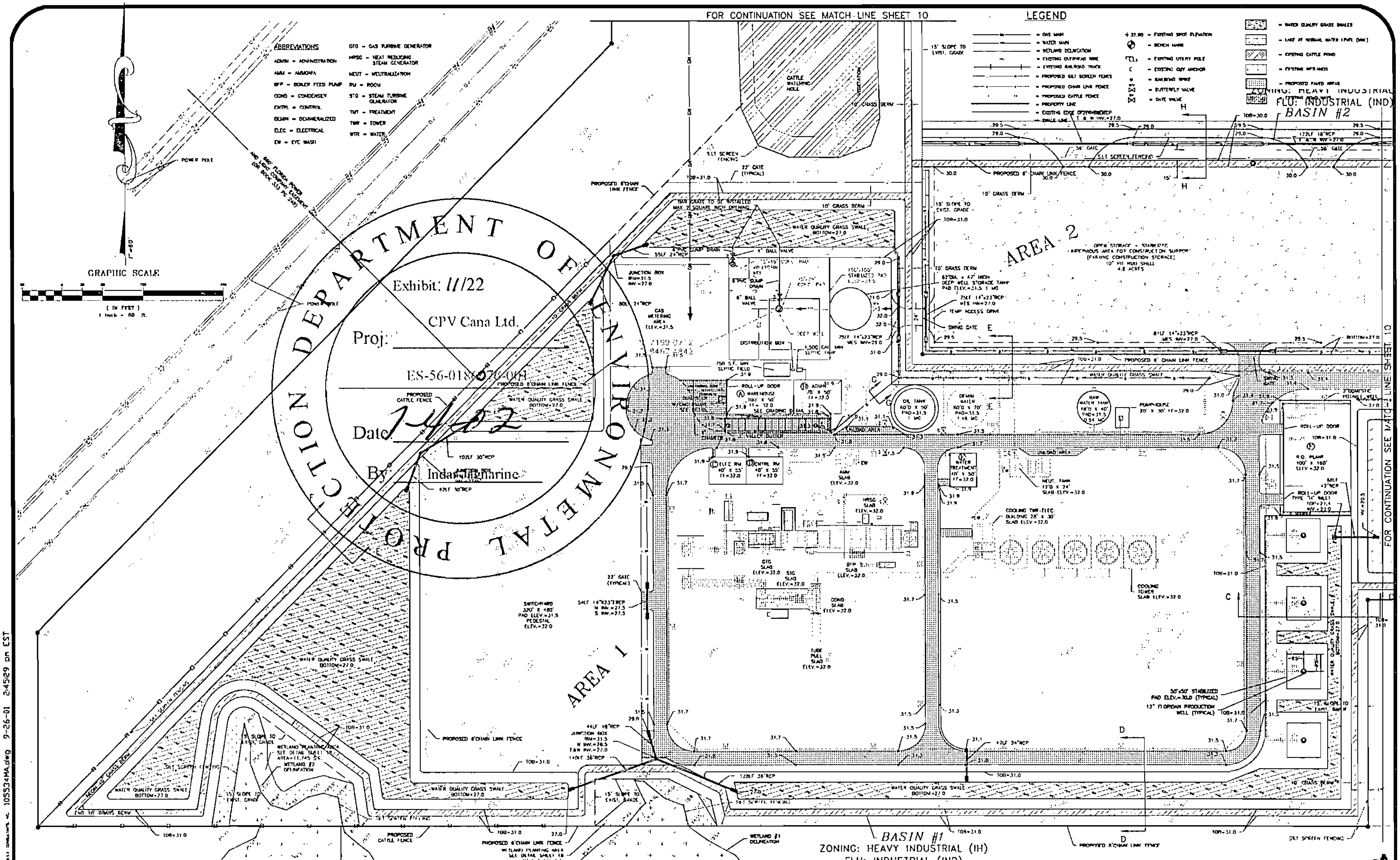
OVERALL DRAINAGE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

SHEET 8 OF 10

NOV 2001



105534MA.dwg 9-26-01 2:45:29 pm EST

REVISIONS	DATE
	9/13/01
	7/20/01
	6/08/01
DESIGN SMG	DATE 4/12/01
DRAWN BAW	DATE 4/12/01
CHECKED	DATE

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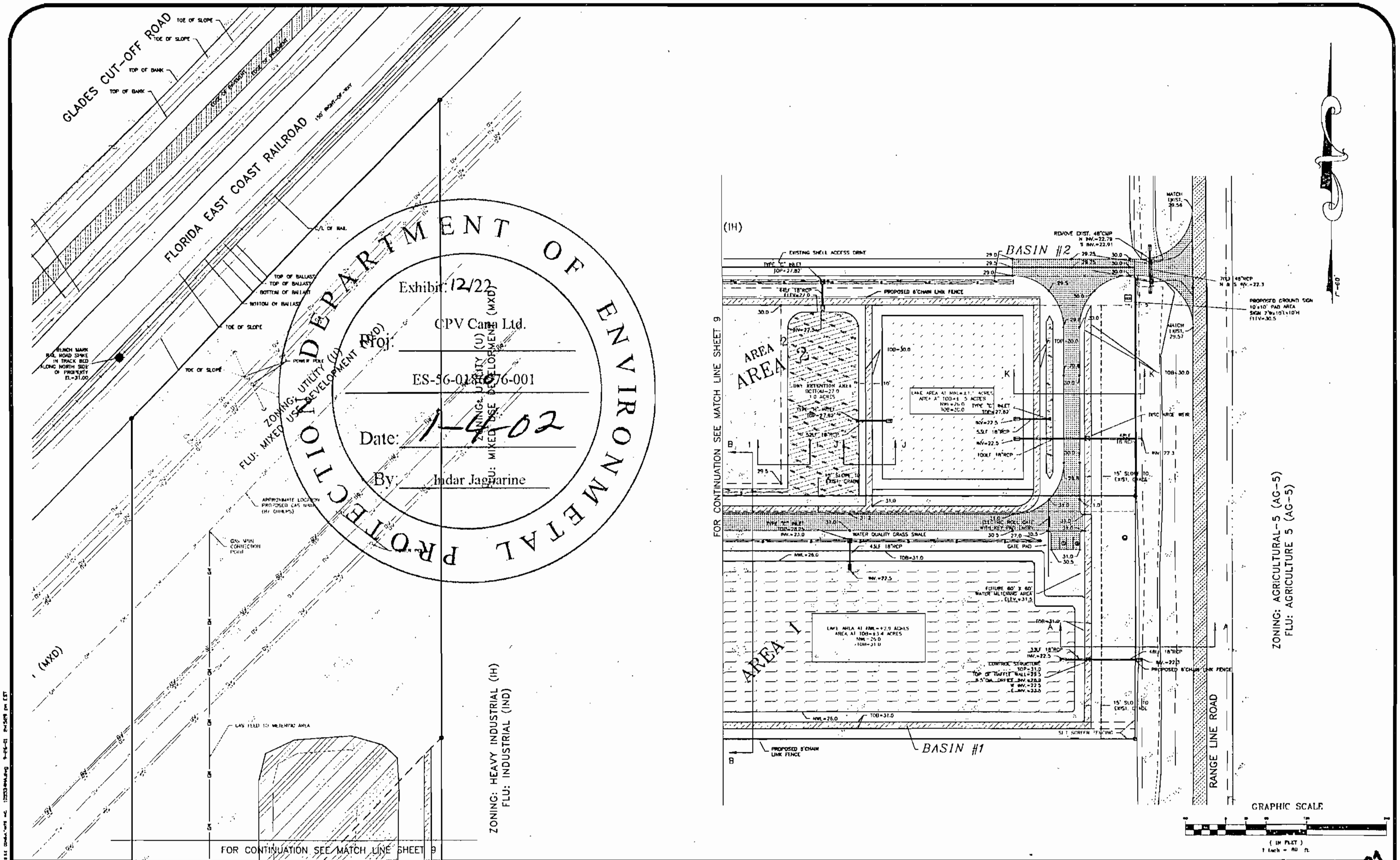
DRAINAGE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2



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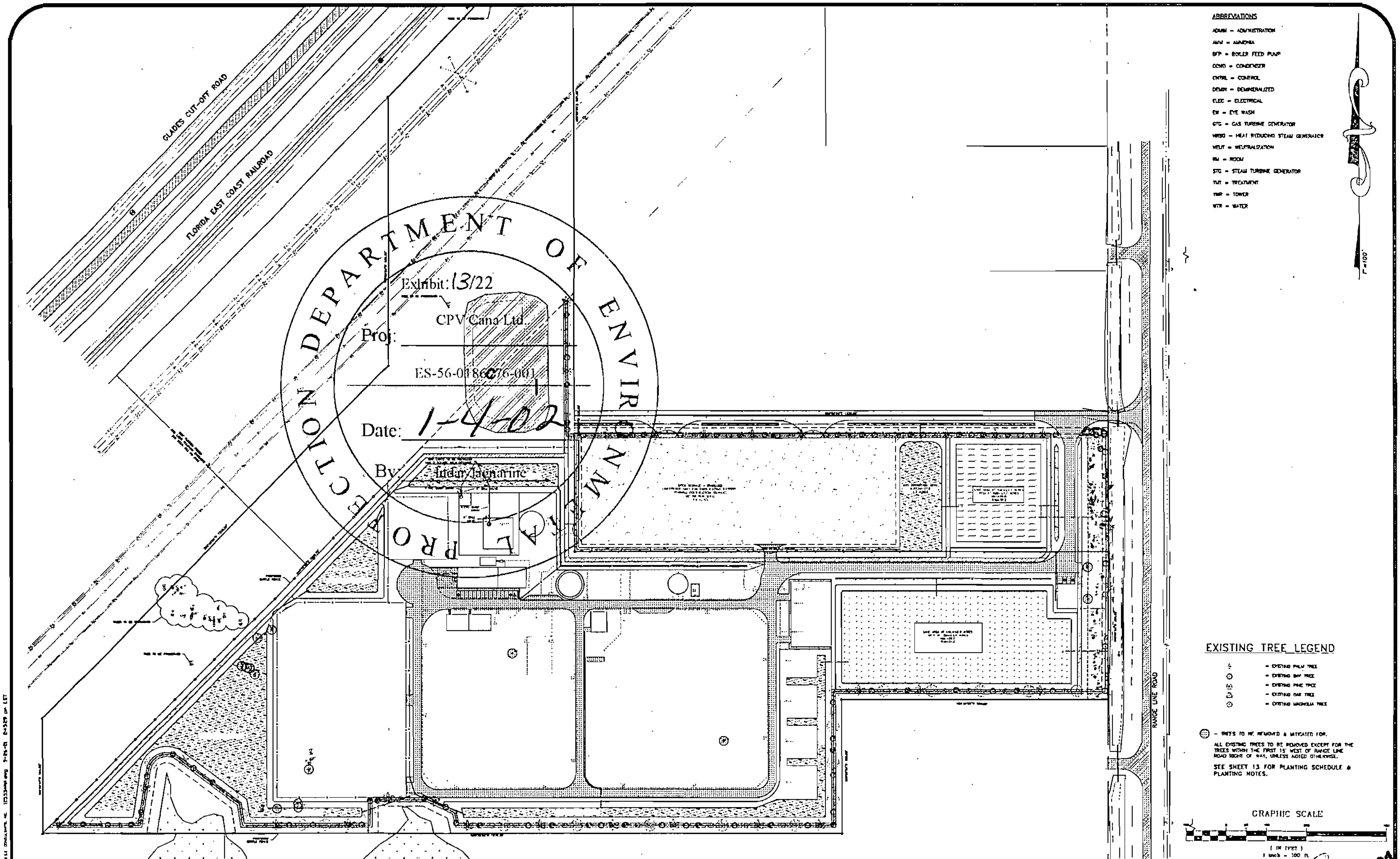
DRAINAGE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

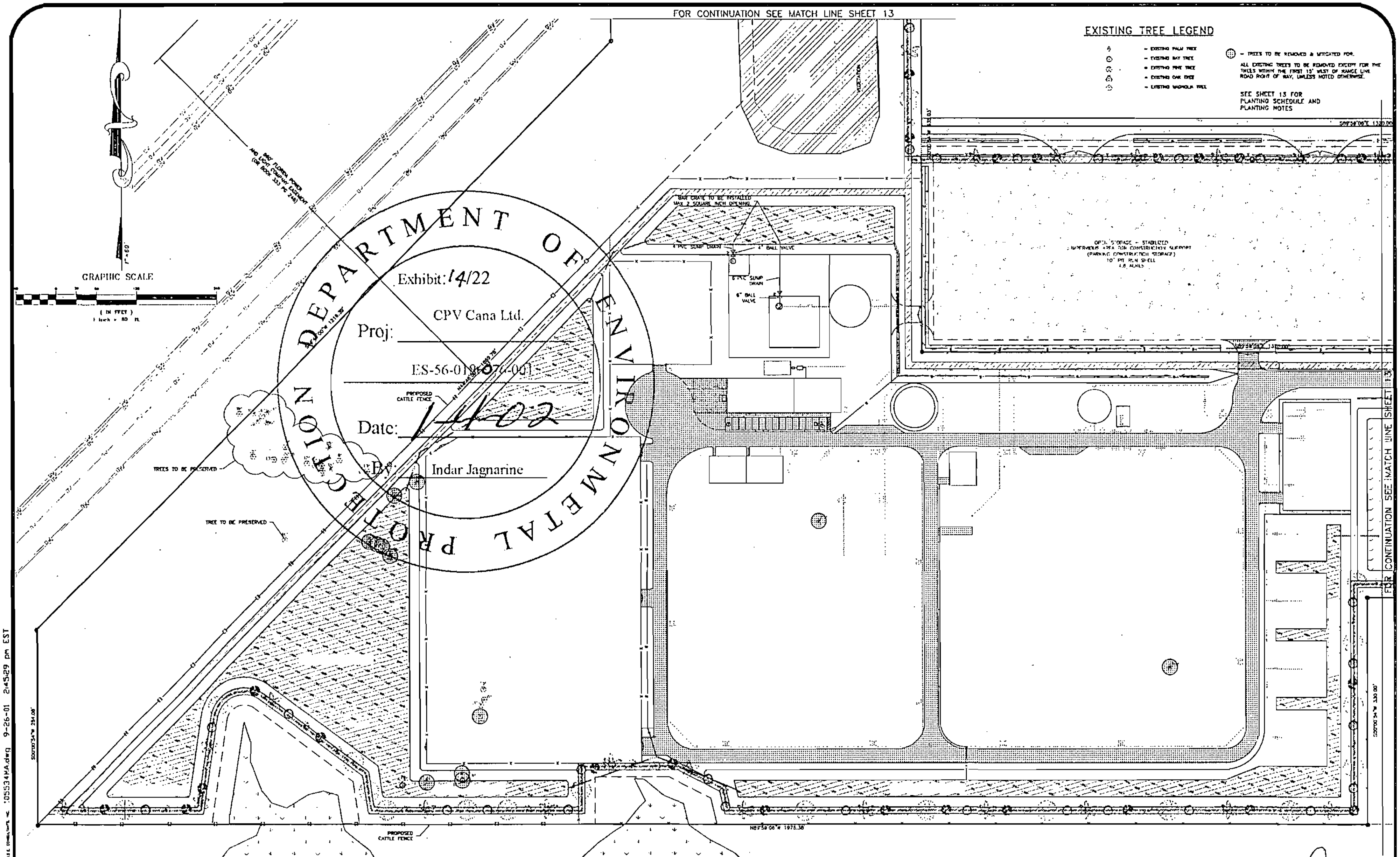
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

NOV 05 2001



REVISIONS: COUNTY COMMENTS 9/13/01; 7/20/01; 8/08/01. DESIGN SMG DATE 4/12/01; DRAWN BAW DATE 4/12/01; CHECKED DATE	CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	OVERALL LANDSCAPE PLAN AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001



DEPARTMENT OF ENVIRONMENTAL PROTECTION

Exhibit: 14/22

Proj: CPV Cana Ltd.

ES-56-010-070-001

Date: 1-4-02

By: Indar Jagnarine

REVISIONS		
4		
3	ENGINEERING COMMENTS(BAW)	8/13/01
2	CLIENT COMMENTS(BAW)	7/20/01
1	ENGINEER/CLIENT COMMENTS(BAW)	6/06/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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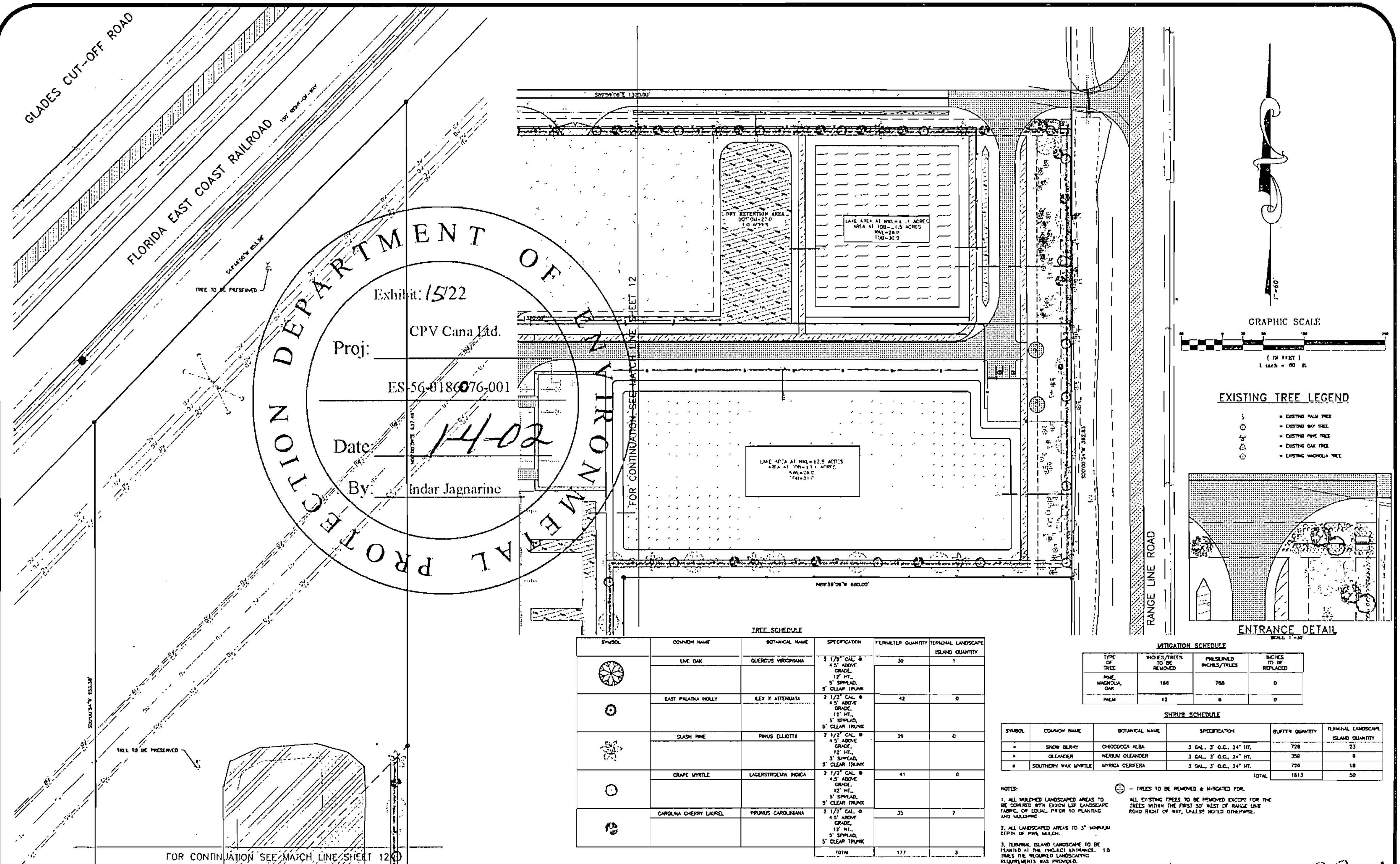
LANDSCAPE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10553412
SHEET 12

NOV 05 2001

10553414A.dwg 9-26-01 2:45:29 pm EST



TREE SCHEDULE

SYMBOL	COMMON NAME	BOTANICAL NAME	SPECIFICATION	PERIMETER QUANTITY	TERMINAL LANDSCAPE ISLAND QUANTITY
	LIVE OAK	QUERCUS VIRGINIANA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	30	1
	EAST PALATKA HOLLY	ILEX X ATTENUATA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	42	0
	SLASH PINE	PINUS ELLIOTTII	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	29	0
	CRAPE MYRTLE	LAGERSTROEMIA INDICA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	41	0
	CAROLINA CHERRY LAUREL	PRUNUS CAROLINIANA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	35	2
			TOTAL	177	3

MITIGATION SCHEDULE

TYPE OF TREE	INCHES/TREES TO BE REMOVED	PRESERVED INCHES/TREES	INCHES TO BE REPLACED
PINE, MAGNOLIA, OAK	188	768	0
PALM	12	6	0

SHRUB SCHEDULE

SYMBOL	COMMON NAME	BOTANICAL NAME	SPECIFICATION	BUFFER QUANTITY	TERMINAL LANDSCAPE ISLAND QUANTITY
•	SNOW BERRY	CHIOCOCCA ALBA	3 GAL., 3' O.C., 24" HT.	728	23
•	OLEANDER	NERIUM OLEANDER	3 GAL., 3' O.C., 24" HT.	359	9
•	SOUTHERN WAX MYRTLE	MYRICA CERIFERA	3 GAL., 3' O.C., 24" HT.	726	18
			TOTAL	1813	50

NOTES:

1. ALL MULCHED LANDSCAPED AREAS TO BE COVERED WITH EXXON LSF LANDSCAPE FABRIC, OR EQUAL, PRIOR TO PLANTING AND MULCHING

2. ALL LANDSCAPED AREAS TO 3" MINIMUM DEPTH OF PINE MULCH.

3. TERMINAL ISLAND LANDSCAPE TO BE PLANTED AT THE PROJECT ENTRANCE. 1.5 TIMES THE REQUIRED LANDSCAPING REQUIREMENTS WAS PROVIDED.

– TREES TO BE REMOVED & MITIGATED FOR.

ALL EXISTING TREES TO BE REMOVED EXCEPT FOR THE TREES WITHIN THE FIRST 50' WEST OF RANGE LINE ROAD RIGHT OF WAY, UNLESS NOTED OTHERWISE.

FOR CONTINUATION SEE MATCH LINE SHEET 12

105534HA.dwg 9-26-01 2:45:29 pm EST

REVISIONS
9/12/01
7/30/01
6/08/01
DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01
CHECKED DATE

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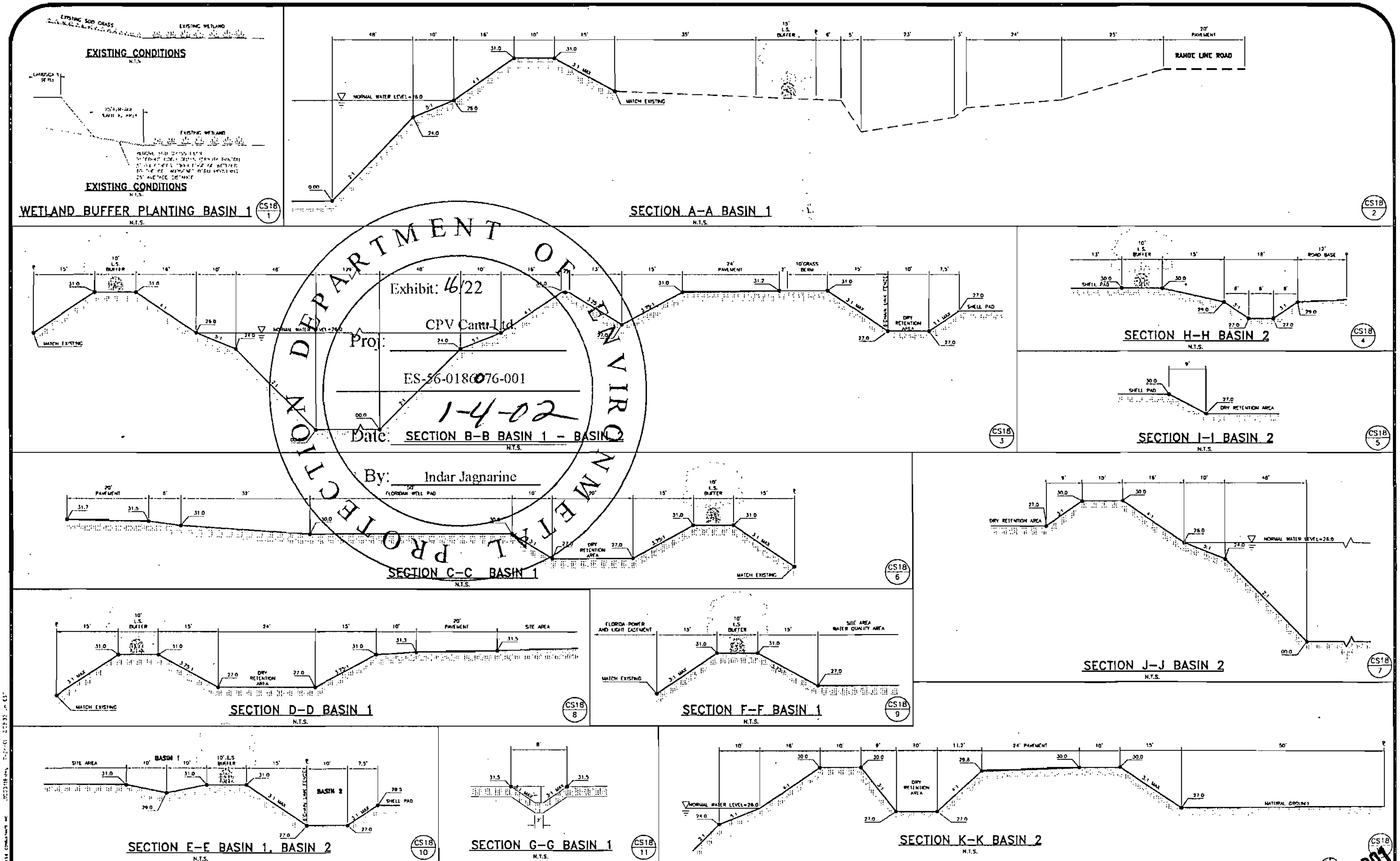
LANDSCAPE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 105534
SHEET 13 OF 30
PROJECT NO. 0553

NOV 2001



DEPARTMENT OF ENVIRONMENTAL PROTECTION

Exhibit: 6/22

Proj: CPV Cana Ltd.

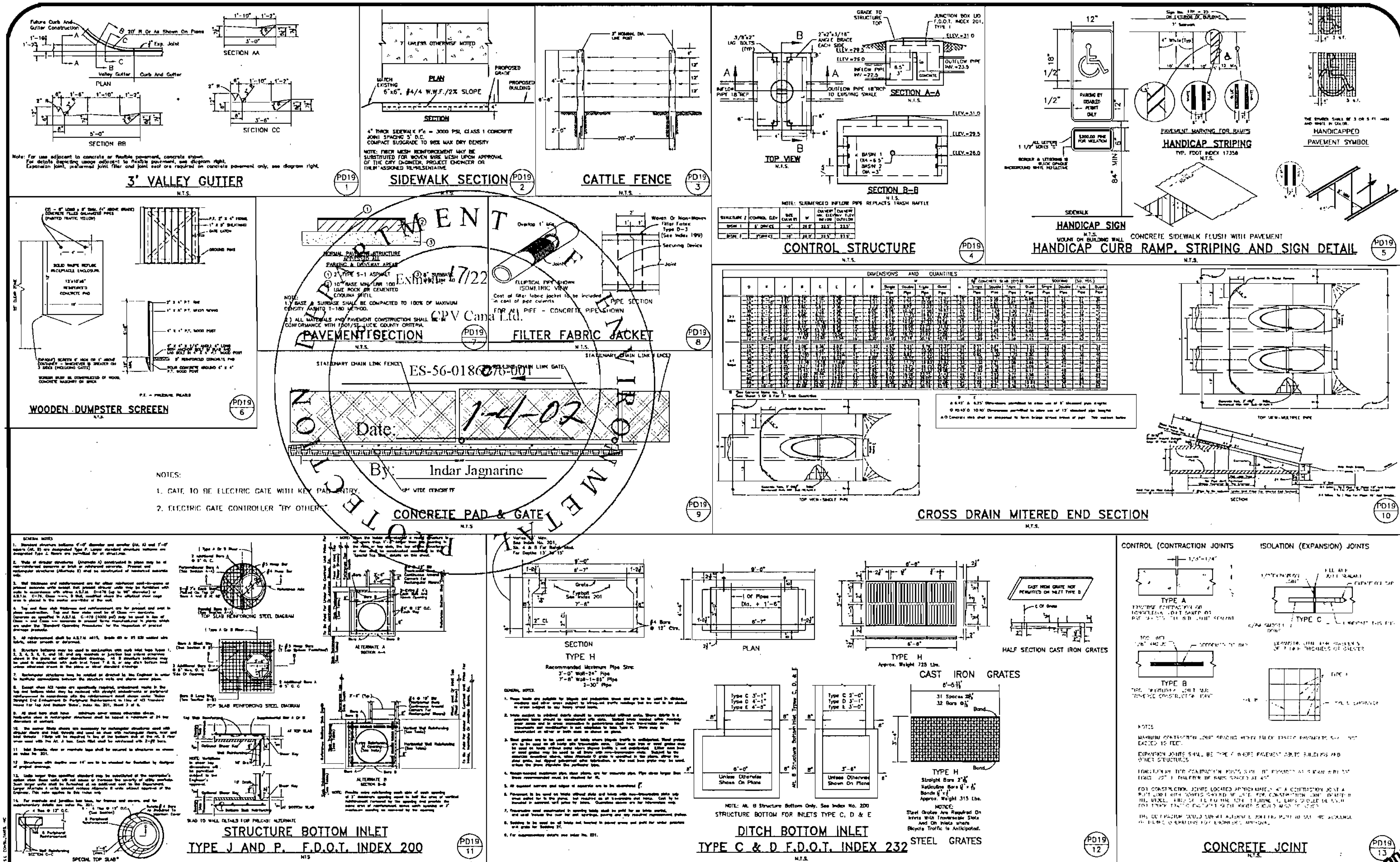
ES-56-0186076-001

Date: 1-4-02

By: Indar Jagnarine

DESIGN SMG DATE 4/12/01 DRAWN DAW DATE 4/12/01 CHECKED DATE	CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	CROSS - SECTIONS AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 0 5 2001



DEPARTMENT OF ENVIRONMENTAL PROTECTION

Exhibit 17/22

CPV Cana Ltd.

ES-56-0186876-001

Date: 1-4-02

By: Indar Jagnarine

REVISIONS	DATE
	9/17/01
	7/20/01
	8/09/01
DESIGN SMG	4/12/01
DRAWN BAW	4/12/01
CHECKED	

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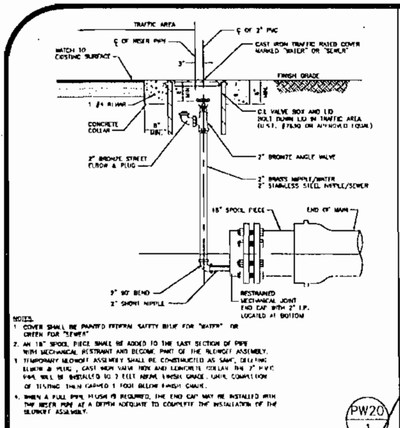
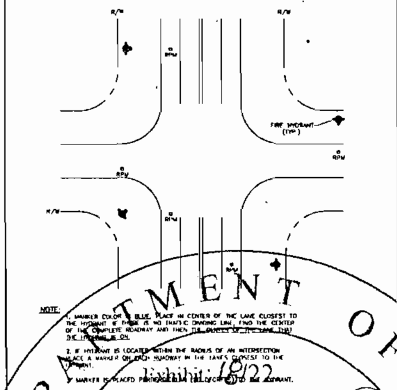
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

PAVING AND DRAINAGE DETAIL
AREA 1-BASIN 1, AREA 2-BASIN 2

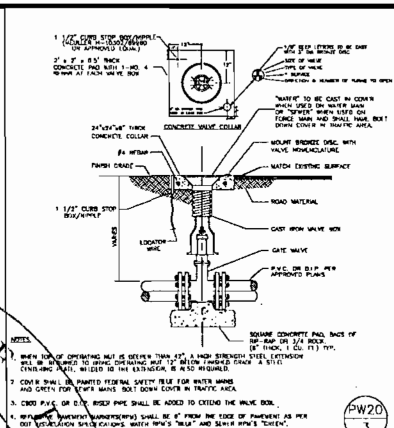
NOV 05 2001



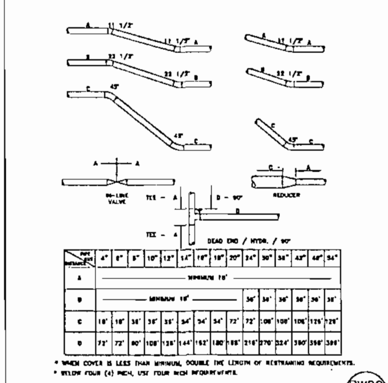
BLOWOFF ASSEMBLY
N.T.S.
PW20
1



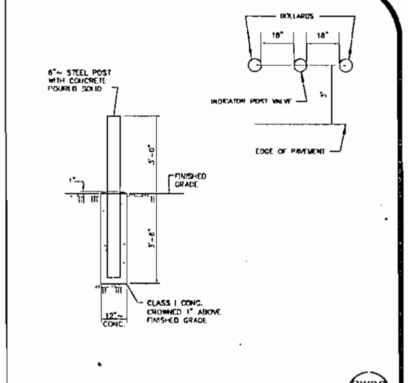
FIRE HYDRANT REFLECTIVE PAVEMENT MARKER PLACEMENT GUIDELINE
N.T.S.
PW20
2



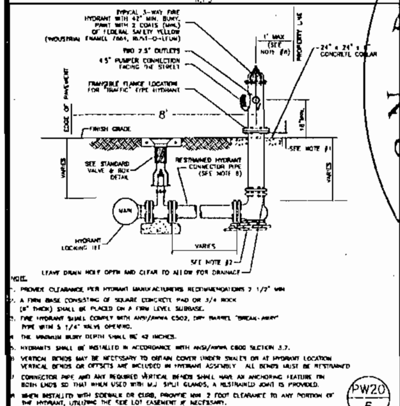
GATE VALVE BOX & COLLAR
N.T.S.
PW20
3



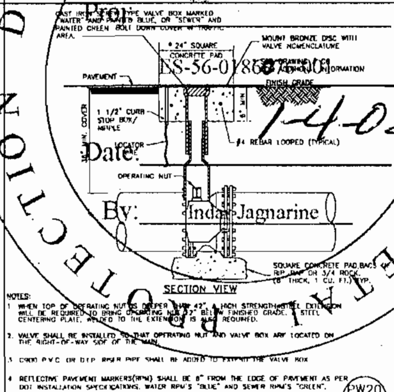
PIPELINE RESTRAINED REQUIREMENTS
N.T.S.
PW20
4



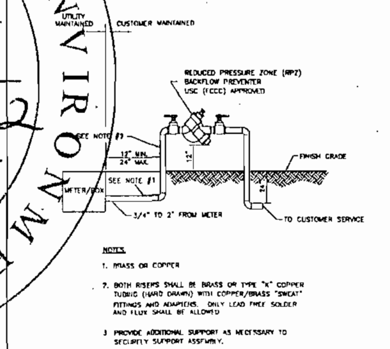
BOLLARD DETAIL
N.T.S.
PW20
5



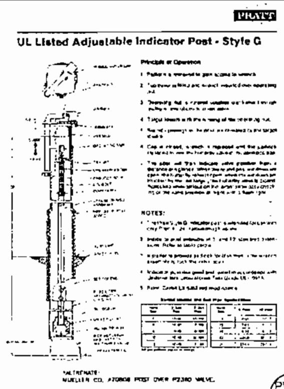
FIRE HYDRANT ASSEMBLY
N.T.S.
PW20
6



BUTTERFLY / PLUG VALVE AND VALVE BOX
N.T.S.
PW20
7



BACKFLOW PREVENTION ASSEMBLY FOR 3/4" THRU 2" SERVICES
N.T.S.
PW20
8



ADJUSTABLE INDICATOR POST VALVE ON FIRE LINE VALVE
N.T.S.
PW20
9

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Exhibit: 18/22
Proj: CPV Cana, Ltd.
LS-56-0186870-001
Date: 1-4-02
By: Linda Jagnarine

REVISIONS		
COUNTY COMMENTS		7/20/01
ENGINEER/CLIENT COMMENTS		8/28/01
DESIGN	SMG	DATE 4/12/01
DRAWN	BAW	DATE 4/12/01
CHECKED		DATE

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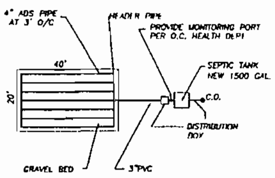
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

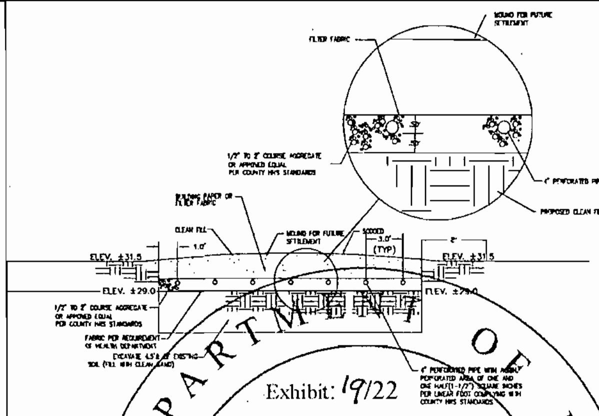
POTABLE WATER DETAILS

DRAWING NO. 10553420
SHEET 25 OF 30



DRAIN FIELD BED SYSTEM
N.T.S.

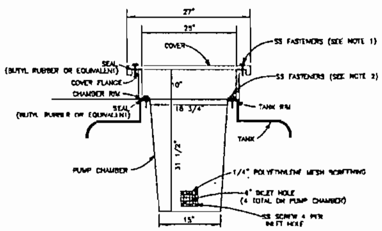
SS21 / 1



SEPTIC TANK DRAIN FIELD SECTION
N.T.S.

SS21 / 2

Exhibit: 19/22
Proj: CPV Cana Ltd.
ES 56-0186076-001
Date: 1-4-02
By: Indar Jagnarine
DEPARTMENT OF ENVIRONMENTAL PROTECTION



COVER DETAIL

NOTES:

1. LOAD BEARING COVER TO BE FASTENED TO TANK WITH FOUR 3/8"(18) x 1-1/2" STAINLESS STEEL BOLTS, LOCKING WASHERS AND NUT FASTENERS. ALL FASTENER HARDWARE TO BE 316 STAINLESS STEEL.
2. CHAMBER TO BE FASTENED TO TANK WITH FOUR #10 STAINLESS STEEL HEX HEAD SCREWS.
3. LID SHALL BE GREEN.

LOW PRESSURE SANITARY SEWER PUMP CHAMBER
N.T.S.

SS21 / 3

LOW PRESSURE SEWER SYSTEM

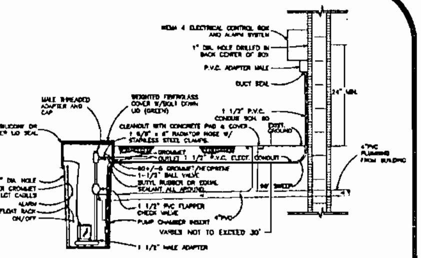
THE PUMP TO BE USED IS GOING TO BE A GP 2010 SERIES GRINDER PUMP WITH A COMPLETE UNIT INCLUDING, THE GRINDER PUMP, CHECK VALVE, TANK AND CONTROLS. THE PUMP AND IMPELLER WILL NOT BE SPECIFIED BECAUSE EACH UNIT WILL HAVE IT CUSTOMIZED DEPENDING ON THE BUILDING DESIGN CHARACTERISTICS, ELEVATIONS, ETC.

PUMP: CUSTOM DESIGNED, INTEGRAL, VECTOR ROTOR, MOTOR DRIVEN, SOLIDS HANDLING PUMP OF THE PROGRESSING CAVITY TYPE WITH A SINGLE MECHANICAL SEAL.

GRINDER: ROTATING TYPE, IMMEDIATELY BELOW THE PUMPING ELEMENTS, DIRECT DRIVEN BY A SINGLE, ONE PIECE STAINLESS STEEL MOTOR SHAFT.

ELECTRIC MOTOR: SHALL BE 1 HP, 1725 RPM, 240/120 VOLTS, 1 PHASE.

TANK: HIGH DENSITY POLYETHYLENE CONSTRUCTION, WITH ONE GROMMET (SDR 35) FITTING TO ACCEPT 4.5" OD DWV PIPE.



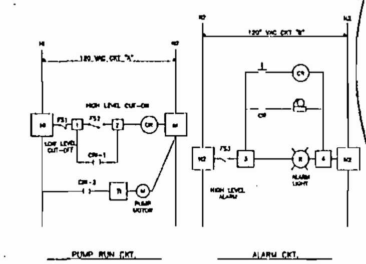
NOTES

1. LATERAL AND TANK TO BE LOCATED AS SHOWN ON PLAN.
2. ALL ELBOWS, NIPPLES AND COUPLINGS ARE TO BE SCH 40 PVC.
3. INTERCEPTOR TANK SHOULD BE SET 5' MIN. FROM NEAREST EXTERIOR WALL OF THE BUILDING.
4. FIBERGLASS COVER TO BE SEALED WITH BUTYL RUBBER OR EQUAL AND SECURED WITH 4 SS BOLTS.

PUMP DATA
NAME GRINDER
MODEL GP 1050-58
VOLT 240/120

LOW PRESSURE SANITARY SEWER PUMP CHAMBER INSERT
N.T.S.

SS21 / 4



PUMP RUN CKT.

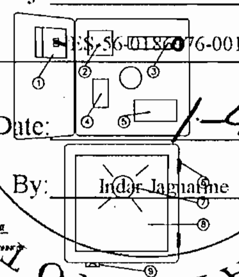
ALARM CKT.

ELECTRICAL NOTES:

1. HIGH WATER LEVEL ALARM BOX SHALL HAVE A SEPARATE 120 VAC SUPPLY SOURCE FROM THE PUMP MOTOR SUPPLY SOURCE.
2. ELECTRIC SERVICE SHALL BE FURNISHED BY ELECTRICAL CONTRACTOR.
3. ELECTRICAL INSTALLATION SHALL COMPLY WITH THE NEC., NESC, AND LOCAL CODES.
4. HIGH WATER BELL/BUZZER ALARM AND FLASHING LIGHT SHALL BE LOCATED IN COVER OF PUMP CONTROL BOX.

LOW PRESSURE SANITARY SEWER PUMP WIRING SCHEMATIC
N.T.S.

SS21 / 5



COMPONENT LAYOUT

1. SQUARE D-30A DISCONNECT
2. 30A 2P CONTACTOR
3. TERMINAL STRIP
4. ALARM SILENCE RELAY
5. TERMINAL STRIP DIAGRAM
6. STAINLESS STEEL PADLOCKABLE HASP
7. N4X ALARM LIGHT AND SILENCE BUTTON
8. N4X FIBERGLASS ENCLOSURE
9. ALARM HORN

LOW PRESSURE SANITARY SEWER CONTROL PANEL
N.T.S.

SS21 / 6

REVISIONS		
COUNTY COMMENTS		7/20/01
ENGINEER/CLIENT COMMENTS		6/28/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

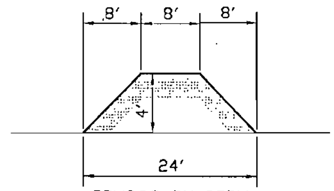
SANITARY SEWER DETAILS

DRAWING NO. SS21
SHEET 21 OF 30
PROJECT NO. 10563

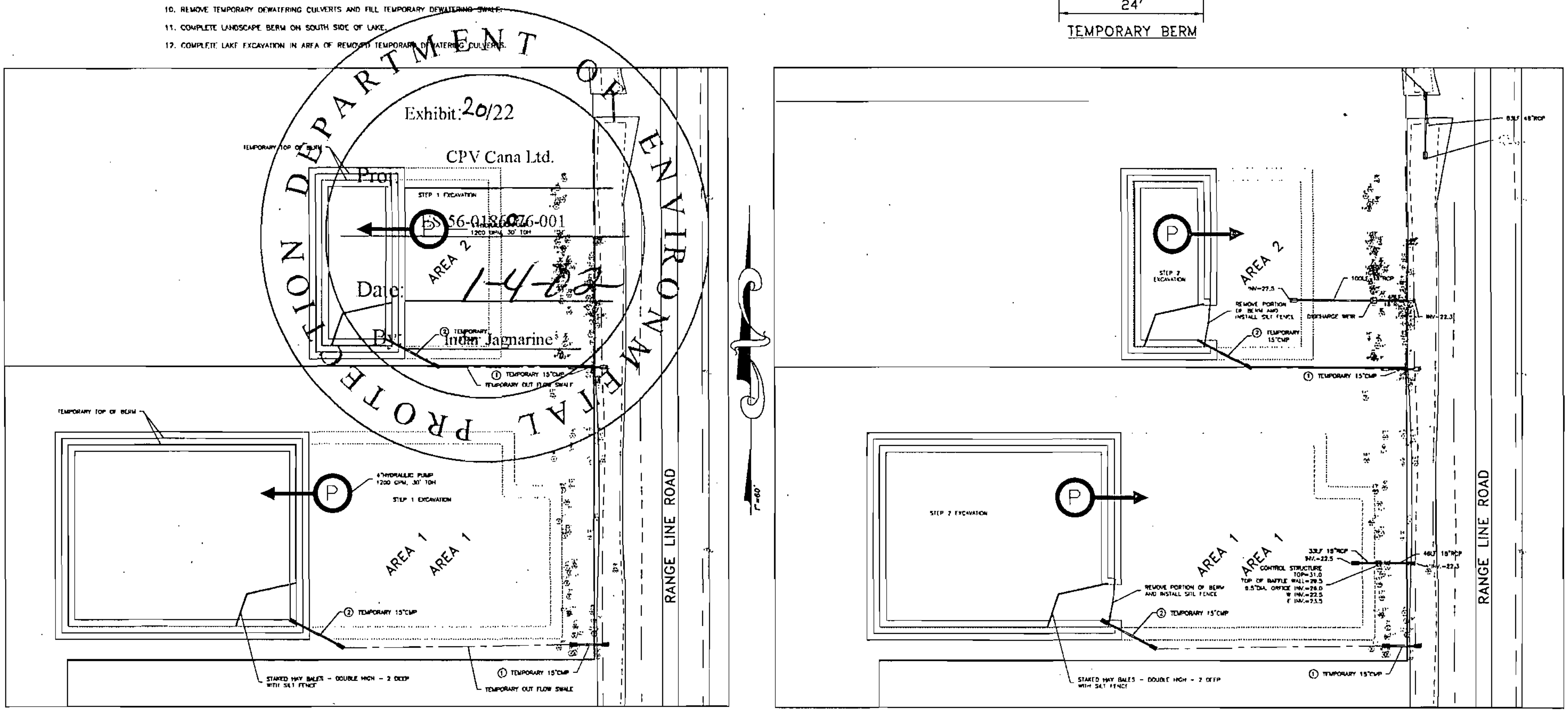
NOV 05 2001

DEWATERING PLAN:

1. INSTALL TEMPORARY 15" DRAINAGE CULVERT (1) TO RANGE LINE ROAD.
2. CONSTRUCT TEMPORARY BERM AS SHOWN.
3. INSTALL TEMPORARY 15" CULVERT (2) THROUGH TEMPORARY BERM. INSTALL HAY BALES & SILT FENCE.
4. EXCAVATE EAST END OF LAKE AS SHOWN (STEP 1).
5. EXCAVATE WEST END OF LAKE AS STEP 2. DEWATER INTO EAST END OF LAKE (EXCAVATED AS STEP 1).
6. REVERSE HYDRAULIC PUMP FOR EXCAVATION OF STEP 2.
7. CONTINUE TO UTILIZE TEMPORARY CULVERTS FOR DEWATERING.
8. CONSTRUCT PERIMETER LANDSCAPE BERMS AND PERIMETER BERMS.
9. INSTALL CONTROL STRUCTURE.
10. REMOVE TEMPORARY DEWATERING CULVERTS AND FILL TEMPORARY DEWATERING SWALE.
11. COMPLETE LANDSCAPE BERM ON SOUTH SIDE OF LAKE.
12. COMPLETE LAKE EXCAVATION IN AREA OF REMOVED TEMPORARY DEWATERING CULVERTS.



TEMPORARY BERM



PHASE 1 DEWATERING

PHASE 2 DEWATERING

GRAPHIC SCALE
(IN FEET)
1 inch = 100 ft.

REVISIONS		
DESIGN SMG	DATE 4/12/01	7/20/01
DRAWN BAW	DATE 4/12/01	8/28/01
CHECKED	DATE	

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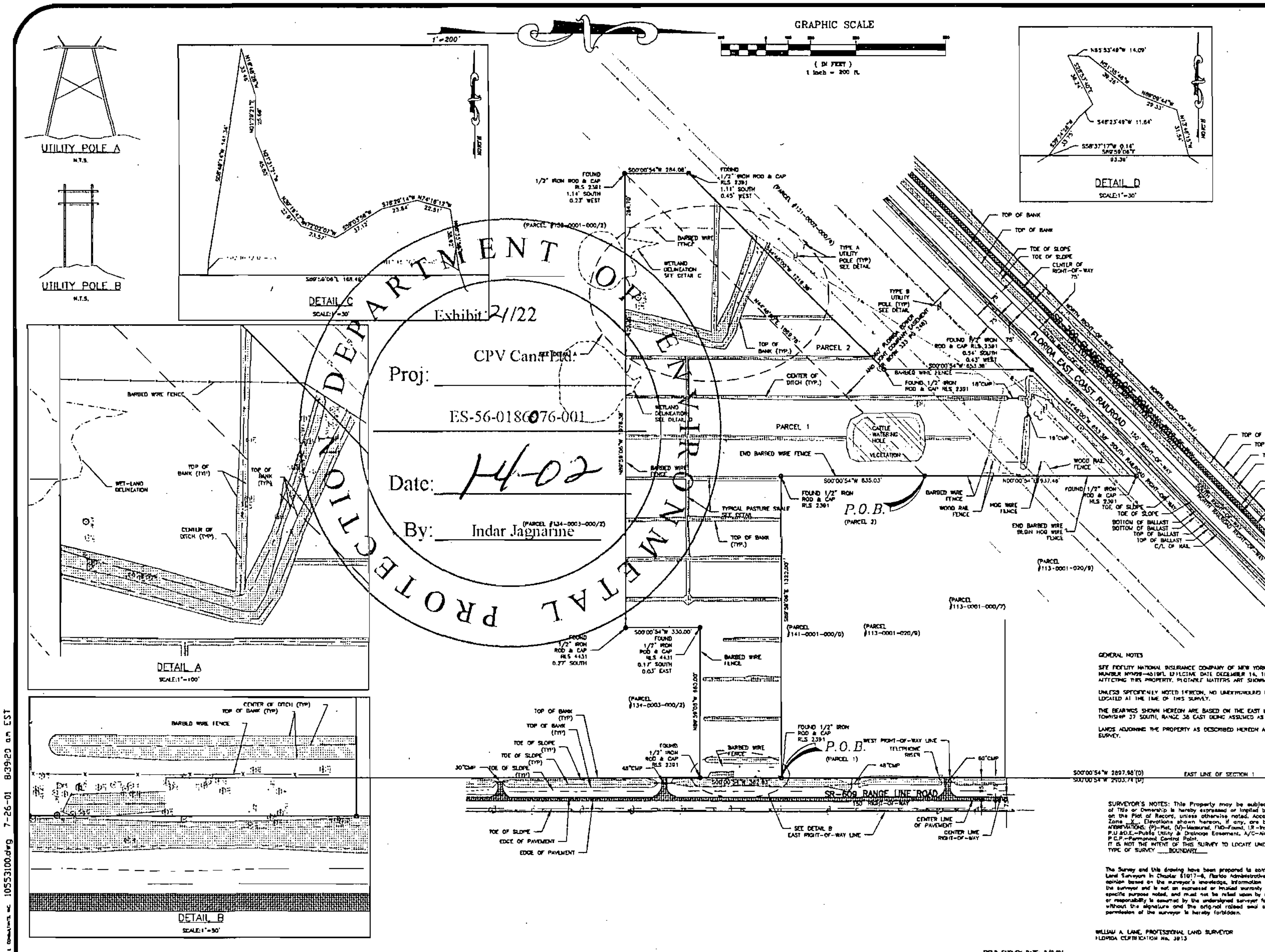
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

DEWATERING PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DRAWING NO. 10553422
SHEET 22 OF 30
PROJECT NO. 10553

NOV 05 2001



LEGAL DESCRIPTION (PARCEL 1) (O.R.B. 807, PG. 010)

COMMENCE AT THE NORTHEAST CORNER OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA; THENCE RUN S00°00'54"W ALONG THE EAST LINE OF SECTION 1, A DISTANCE OF 2697.98 FEET, TO THE POINT OF BEGINNING; THENCE RUN S00°00'54"W, ALONG THE EAST LINE OF SECTION 1, A DISTANCE OF 382.83 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 660 FEET; THENCE RUN S00°00'54"W, A DISTANCEOF 330.00 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 1976.38 FEET; THENCE RUN N44°46'00"E, ALONG THE EAST LINE OF A FLORIDA POWER AND LIGHT EASEMENT, A DISTANCE OF 1869.78 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 635.03 FEET; THENCE RUN S89°59'06"E, A DISTANCE OF 1,320.00 FEET TO THE POINT OF BEGINNING; ALL LYING AND BEING IN SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA, AND CONTAINING 38.06 ACRES MORE OR LESS.

LEGAL DESCRIPTION (PARCEL 2) (O.R.B. 807, PG. 010)

A PARCEL OF LAND IN SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA, SAID PARCEL IS DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 1, THENCE RUN S00°00'54"W, ALONG THE EAST LINE OF SECTION 1 A DISTANCE OF 2697.98 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 1320.00 FEET; THENCE RUN N00°00'54"E, A DISTANCE OF 635.03 FEET, TO THE SOUTHEASTERLY LINE OF THE 660 FOOT WIDE FLORIDA POWER AND LIGHT COMPANY EASEMENT, AS DESCRIBED IN OFFICIAL RECORDS BOOK 333, AT PAGE 246, OF THE PUBLIC RECORDS OF ST. LUCIE COUNTY, FLORIDA, AND THE POINT OF BEGINNING;

THENCE CONTINUE N00°00'54"E, A DISTANCE OF 837.46 FEET, TO THE NORTHWESTERLY LINE OF SAID EASEMENT, SAID LINE ALSO BEING THE SOUTHEASTERLY LINE OF THE 150 FOOT WIDE FLORIDA EAST COAST RAILROAD RIGHT-OF-WAY; THENCE RUN S44°46'00"W, ALONG SAID RIGHT-OF-WAY LINE, A DISTANCE OF 653.38 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 653.38 FEET; THENCE RUN S44°46'00"W, A DISTANCE OF 1316.39 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 284.08 FEET, TO THE SAID SOUTHEASTERLY LINE OF THE 660 FOOT WIDE FLORIDA POWER AND LIGHT COMPANY EASEMENT; THENCE RUN N44° 46'00"W, ALONG SAID SOUTHEASTERLY LINE, A DISTANCE OF 1889.78 FEET, TO THE POINT OF BEGINNING.

THE ABOVE DESCRIBED PARCEL CONTAINS 15.4846 ACRES, MORE OR LESS.

LEGEND

- = WETLAND DELINEATION
- = EXISTING OVERHEAD WIRE
- = EXISTING RAILROAD TRACK
- = EXISTING HOG WIRE FENCE
- = EXISTING BARBED WIRE FENCE
- = EXISTING WOOD RAIL FENCE
- = EXISTING SPOT ELEVATION
- = EXISTING CENTER LINE
- = PROPERTY LINE
- = EXISTING EDGE OF PAVEMENT
- = BENCH MARK
- = EXISTING UTILITY POLE
- = EXISTING GUY ANCHOR
- = FOUND IRON ROD
- = FOUND NAIL & DISK
- = SET IRON ROD
- = FOUND CONCRETE MONUMENT
- = RAILROAD SPIKE
- = EXISTING PALM TREE
- = EXISTING BAY TREE
- = EXISTING PINE TREE
- = EXISTING OAK TREE
- = EXISTING MAGNOLIA TREE
- = EXISTING SWALE/DITCH
- = EXISTING ROAD/PAVEMENT

GENERAL NOTES

SEE FIDELITY NATIONAL INSURANCE COMPANY OF NEW YORK TITLE COMMITMENT NUMBER NYN99-4519FL EFFECTIVE DATE DECEMBER 14, 1999 AT 11PM, FOR MATTERS AFFECTING THIS PROPERTY. PLOTABLE MATTERS ARE SHOWN HEREON.

UNLESS SPECIFICALLY NOTED HEREON, NO UNDERGROUND FACILITIES HAVE BEEN LOCATED AT THE TIME OF THIS SURVEY.

THE BEARINGS SHOWN HEREON ARE BASED ON THE EAST LINE OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST BEING ASSUMED AS S00°00'54"W

LANDS ADJOINING THE PROPERTY AS DESCRIBED HEREON ARE NOT A PART OF THIS SURVEY.

S00°00'54"W 2697.98'(D) EAST LINE OF SECTION 1
S00°00'54"W 2903.74'(M)

P.O.C.
NORTHEAST CORNER OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST
FOUND 4X4 C.M. NO IDENTIFICATION

SURVEYOR'S NOTES: This Property may be subject to easements, restrictions, or limitations, either recorded or implied. No opinion of Title or Ownership is hereby expressed or implied by the Surveyor. Bearings shown hereon are based on the Centerline of the Street as shown on the Plat of Record, unless otherwise noted. According to F.I.R.M. #12111C0275 F, Dated August 19, 1991, this property is within Flood Zone X. Elevations shown hereon, if any, are based on National Geodetic Vertical Control Datum of 1929, unless otherwise shown. ABBREVIATIONS: (P)-Plat, (M)-Measured, FND-Found, I.R.-Iron Rod, I.P.-Iron Pipe, C.M.-Concrete Monument, CONC.-Concrete, C/L-Centerline, R/W-Right of Way, P.U.&D.E.-Public Utility & Drainage Easement, A/C-Air Conditioner, Fin.Fl.-Finished Floor, Elev.-Elevation, Δ-Central Angle, L-Length, C.H.-Chord, P.C.P.-Permanent Control Point.
IT IS NOT THE INTENT OF THIS SURVEY TO LOCATE UNDERGROUND STRUCTURES.
TYPE OF SURVEY BOUNDARY

The Survey and this drawing have been prepared to conform with applicable Minimum Technical Standards as set forth by the Florida Board of Professional Land Surveyors in Chapter 61G17-6, Florida Administrative Code, pursuant to Section 472.027, Florida Statutes. This Certification is a statement of professional opinion based on the surveyor's knowledge, information and belief, which is based on the existing field evidence and documentary evidence as provided to the surveyor and is not an expressed or implied warranty or guaranty. This survey is for the sole and exclusive benefit of the parties named hereon and for the specific purpose noted, and must not be relied upon by any other individual or entity whatsoever, and is not transferable under any circumstances. No liability or responsibility is assumed by the undersigned surveyor for any other use of this survey or to any party not specifically named hereon. This drawing is not valid without the signature and the original raised seal of a Florida licensed surveyor and mapper, and reproduction of this drawing without written permission of the surveyor is hereby forbidden.

WILLIAM A. LANE, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 3913

SCOTT W. GLAUBITZ, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 5731
B.S.E. CONSULTANTS, INC. LB

FIELD SURVEY DATE: 2/2/01

REVISIONS		
COUNTY COMMENTS (BAW)		7/20/01
DESIGN SMG	DATE	2/2/01
DRAWN BAW	DATE	7/20/01
CHECKED	DATE	

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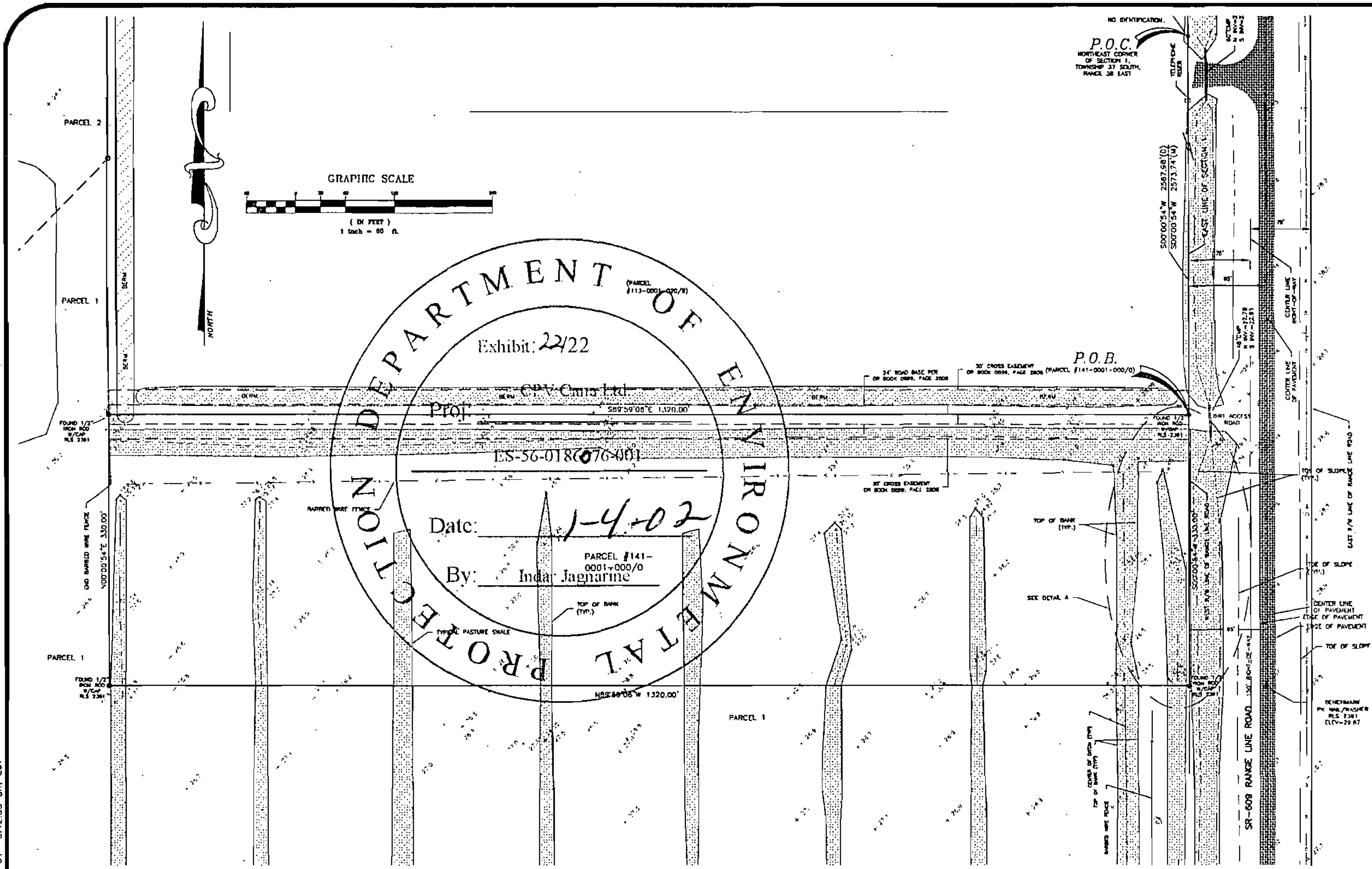
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

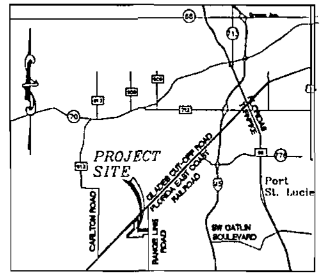
BOUNDARY SURVEY - AREA 1

DRAWING NO. 10553100
SHEET 23 OF 30
PROJECT NO. 10553

NOV 05 2001

10553100.dwg 7-26-01 8:39:20 am EST





LOCATION MAP
N.T.S.

LEGAL DESCRIPTION (PARCEL #141-0001-000/0)

A parcel of land in Section 1, Township 37 South, Range 38 East, St. Lucie County, Florida, said Parcel is described as follows:

Commence at the NE corner of Section 1, Township 37 South, Range 38 East, St. Lucie County, Florida, thence run S00°00'54" W along the East line of said Section 1, a distance of 2587.98 feet to the POINT OF BEGINNING, thence continue S00°00'54"W along the East line of said Section 1, a distance of 330.00 feet, thence run N89°59'06"W a distance of 1320 feet, thence run N00°00'54"E a distance of 330.00 feet, thence S89°59'06"E a distance of 1320 feet to the POINT OF BEGINNING, All LYING AND BEING IN Section 1, Township 37 South, Range 38 East East, St. Lucie County, Florida, and Containing 10.00 acres more or less.

LEGEND

- = WETLAND DELINEATION
- = EXISTING OVERHEAD WIRE
- = EXISTING RAILROAD TRACK
- = EXISTING HOG WIRE FENCE
- = EXISTING BARBED WIRE FENCE
- = EXISTING WOOD RAIL FENCE
- + 32.80 = EXISTING SPOT ELEVATION
- = EXISTING CENTER LINE
- = PROPERTY LINE
- = EXISTING EDGE OF PAVEMENT
- = BENCH MARK
- = EXISTING UTILITY POLE
- = EXISTING GUY ANCHOR
- = FOUND IRON ROD
- = FOUND NAIL & DISK
- = SET IRON ROD
- = FOUND CONCRETE MONUMENT
- = RAILROAD SPIKE
- = EXISTING PALM TREE
- = EXISTING BAY TREE
- = EXISTING PINE TREE
- = EXISTING OAK TREE
- = EXISTING MAGNOLIA TREE
- = EXISTING SWALE/DITCH
- = EXISTING ROAD/PAVEMENT

(D) – DEED
(M) – MEASURED
FND – FOUND
I.R. – IRON ROD
I.P. – IRON PIPE
C.M. – CONCRETE MONUMENT
CONC. – CONCRETE
R/W – RIGHT OF WAY
A/C – AIR CONDITIONER
FIN.FL. – FINISHED FLOOR
EL – ELEVATION
Δ – CENTRAL ANGLE
L – LENGTH
CH – CHORD
P.B. – PLAT BOOK
PG(S). – PAGES
ST. RD. – STATE ROAD
℄ – CENTERLINE
P.U.&D.E. – PUBLIC UTILITIES AND DRAINAGE EASEMENT

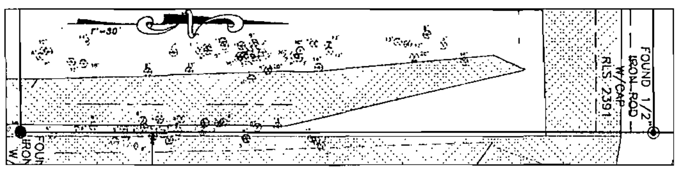
GENERAL NOTES

UNLESS SPECIFICALLY NOTED HEREON, NO UNDERGROUND FACILITIES HAVE BEEN LOCATED AT THE TIME OF THIS SURVEY.

THE BEARINGS SHOWN HEREON ARE BASED ON THE EAST LINE OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST BEING ASSUMED AS S00°00'54"W

LANDS ADJOINING THE PROPERTY AS DESCRIBED HEREON ARE NOT A PART OF THIS SURVEY.

PROJECT BENCHMARK IS A BRASS DISK ST. LUCIE COUNTY VERTICAL CONTROL 2000 DESIGNATION = EMMA ALONG THE NORTH SIDE OF GLADES CUT-OFF ROAD RIGHT OF WAY ALONG THE NORTH SIDE OF PROPERTY, ELEVATION 28.87 N.G.V.D. AND RAILROAD SPIKE IN TRACK SET ALONG NORTH SIDE OF PROPERTY, ELEVATION 31.00 N.G.V.D.



DETAIL A
SCALE: 1"=30'

SURVEYOR'S NOTES: This Property may be subject to easements, restrictions, or limitations, either recorded or implied. No opinion of Title or Ownership is hereby expressed or implied by the Surveyor. Bearings shown hereon are based on the Centerline of the Street as shown on the Plat of Record, unless otherwise noted. According to F.I.R.M. #12111C0275 F, Dated August 19, 1991, this property is within Flood Zone X. Elevations shown hereon, if any, are based on National Geodetic Vertical Control Datum of 1929, unless otherwise shown. ABBREVIATIONS: (P)-Plat, (M)-Measured, FND-Found, I.R.-Iron Rod, I.P.-Iron Pipe, C.M.-Concrete Monument, CONC.-Concrete, C/L-Centerline, R/W-Right of Way, P.U.&D.E.-Public Utility & Drainage Easement, A/C-Air Conditioner, Fin.Fl.-Finished Floor, Elev.-Elevation, Δ-Central Angle, L-Length, C.H.-Chord, P.C.P.-Permanent Control Point.
IT IS NOT THE INTENT OF THIS SURVEY TO LOCATE UNDERGROUND STRUCTURES.
TYPE OF SURVEY BOUNDARY

The Survey and this drawing have been prepared to conform with applicable Minimum Technical Standards as set forth by The Florida Board of Professional Land Surveyors in Chapter 61G17-6, Florida Administrative Code, pursuant to Section 472.027, Florida Statutes. This Certification is a statement of professional opinion based on the surveyor's knowledge, information and belief, which is based on the existing field evidence and documentary evidence as provided to the surveyor and is not an expressed or implied warranty or guaranty. This survey is for the sole and exclusive benefit of the parties named hereon and for the specific purpose noted, and must not be relied upon by any other individual or entity whatsoever, and is not transferable under any circumstances. No liability or responsibility is assumed by the undersigned surveyor for any other use of this survey or to any party not specifically named hereon. This drawing is not valid without the signature and the original raised seal of a Florida licensed surveyor and mapper, and reproduction of this drawing without written permission of the surveyor is hereby forbidden.

WILLIAM A. LANE, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 3913

SCOTT M. GLAUBITZ, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 4151
B.S.E. CONSULTANTS, INC. LB No. 4905

FIELD SURVEY DATE: 6/13/01

10553110.dwg 7-26-01 8:42:33 am EST

REVISIONS		
COUNTY COMMENTS(BAW)	7/20/01	
DESIGN SMG	DATE 2/2/01	
DRAWN RBS	DATE 6/27/01	
CHECKED	DATE	

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B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

BOUNDARY & TOPOGRAPHIC SURVEY – AREA 2

DRAWING NO. 10553110
SHEET 1 OF 1

NOV 05 2001

Form #62-343.900(3), F.A.C.
Form Title: Construction Commencement Notice
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
Construction Commencement Notice

PROJECT:______________________________ PHASE:__________

I hereby notify the Department of Environmental Protection that the construction of the surface water management system authorized by Environmental Resource Permit No.__________________ has commenced / is expected to commence on ______________ 199__, and will require a duration of approximately ______ months ______ weeks ______ days to complete. It is understood that should the construction term extend beyond one year, I am obligated to submit the Annual Status Report for Surface Water Management System Construction.

PLEASE NOTE: If the actual construction commencement date is not known, Department staff should be so notified in writing in order to satisfy permit conditions.

______________	______________	______________
Permittee or Authorized Agent	Title and Company	Date

______________	______________
Phone	Address

Form # 62-343.900(4), F.A.C.
Form Title: Annual Status Report
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
ANNUAL STATUS REPORT FORM

Florida Department of Environmental Protection
____
____
____

Permit No. __________________________ County: __________________________

Project Name: ________________________ Phase: ___________________________

The following activity has occurred at the above referenced project during the past year, between June 1, 19___ and May 30, 19___.

Permit Condition / Activity	% of Completion	Date of anticipated Completion	Date of Completion

(Use Additional Sheets As Necessary)

Benchmark Description (one per major control structure): _________________________________
____
____
____

_________________________ _________________________
Print Name Phone

_________________________ _________________________ _____________
Permittee's or Authorized Agent's Signature Title and Company Date

This form shall be submitted to the above referenced Department Office during June of each year for activities whose duration of construction exceeds one year.

Form #62-343.900(5), F.A.C.
Form Title: As-Built Certification by a Registered Professional
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
AS-BUILT CERTIFICATION BY A REGISTERED PROFESSIONAL

Permit Number:____

Project Name:____

I hereby certify that all components of this surface water management system have been built substantially in accordance with the approved plans and specifications and are ready for inspection. Any substantial deviations (noted below) from the approved plans and specifications will not prevent the system from functioning as designed when properly maintained and operated. These determinations are based upon on-site observation of the system conducted by me or by my designee under my direct supervision and/or my review of as-built plans certified by a registered professional or other appropriate individual as authorized by law.

____________________ Name (please print)	____________________ Signature of Professional
____________________ Company Name	____________________ Florida Registration Number
____________________ Company Address	____________________ Date
____________________ City, State, Zip Code	
____________________ Telephone Number	(Affix Seal)

Substantial deviations from the approved plans and specifications:

____

____

____

____

(Note: attach two copies of as-built plans when there are substantial deviations)

Within 30 days of completion of the system, submit two copies of the form to:

____

____

____

Form #62-343.900(7), F.A.C.
Form Title: Request for Transfer to Operation Phase
Date: October 3, 1995

REQUEST FOR TRANSFER OF ENVIRONMENTAL RESOURCE PERMIT CONSTRUCTION PHASE TO OPERATION PHASE

(To be completed and submitted by the operating entity)

Florida Department of Environmental Protection

____

____

____

It is requested that Department Permit No. ______________ authorizing the construction and operation of a surface water management system for the below mentioned project be transferred from the construction phase permittee to the operation phase operating entity.

PROJECT: ______________________________

FROM: Name: ______________________________
Address: ______________________________
City: ______________ State: ______________
Zipcode: ______________________________

TO: Name: ______________________________
Address: ______________________________
City: ______________ State: ______________
Zipcode: ______________________________

The surface water management facilities are hearby accepted for operation and maintenance in accordance with the engineers certification and as outlined in the restrictive covenants and articles of incorporation for the operating entity. Enclosed is a copy of the document transferring title of the operating entity for the common areas on which the surface water management system is located. Note that if the operating entity has not been previously approved, the applicant should contact the Department staff prior to filing for a permit transfer.

The undersigned hearby agrees that all terms and conditions of the permit and subsequent modifications, if any, have been reviewed, are understood and are hearby accepted. Any proposed modifications shall be applied for and obtained prior to such modification.

Operating Entity ______________________________

Name ______________________________ Title ______________________________

Telephone ______________________________

Enclosure:
( ) Copy of recorded transfer of title surface water management system
( ) Copy of plat(s)
( ) Copy of recorded restrictive covenants, articles of incorporation, and certificate of incorporation

Form # 62-343.900(8), F.A.C.
Form Title: Application for Transfer of ERP Permit
Date: October 3, 1995

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

APPLICATION FOR TRANSFER OF AN ERP PERMIT

Permit No. ____________________

Date Issued ____________________ Date Construction Phase Expires ____________________

NOTIFICATION OF SALE OR OF LEGAL TRANSFER (to be completed by the current permittee)

Project Name: ____________________ County: ____________________

Project Location: ____________________ City: ____________________

Permittee Name (existing): ____________________

Permittee's Title: ____________________

Mailing Address: ____________________

____

The undersigned hereby notifies the Department of the sale or legal transfer of the property [ ] or of the permit [ ] (please check one of the spaces). The permittee further agrees to assign the rights as permittee to the transferee in the event the Department agrees to the transfer of the permit.

REQUEST FOR TRANSFER OF PERMIT

Project Name: ____________________ County: ____________________

Project Location: ____________________ City: ____________________

Proposed Transferee's Name: ____________________

Transferee's Title (if applicable): ____________________

Mailing Address: ____________________

Telephone: (_______) ____________________

Proposed Project Engineer (name): ____________________

Engineer's Mailing Address: ____________________

Engineer's Telephone: (_______) ____________________

The undersigned hereby notifies the Department of [ ] having acquired title to the property subject to this permit, or, [ ] having entered into an agreement with the Permittee to accept transfer (please check one). The applicant further states that he or she has examined the application and documents submitted by the current permittee the basis of which the permit was issued by the Department, and states that they accurately and completely describe the permitted activity or project. The applicant further states he or she is familiar with the permit, agrees to comply with its terms and conditions, and agrees to assume the rights and liabilities contained therein. The applicant also agrees to promptly notify the Department of any future change in ownership of, or responsibility for, the permitted activity or project.

Signature of Applicant: ____________________
(please attach a letter of authorization if other than the owner or a corporate officer)

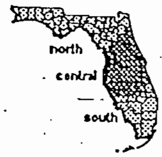
Title: ____________________

Date: ____________________

Florida Exotic Pest Plant Council's
2001 List of Invasive Species

DEFINITIONS: *Exotic*—a species introduced to Florida, purposefully or accidentally, from a natural range outside of Florida. *Native*—a species whose natural range included Florida at the time of European contact (1500 AD). *Naturalized exotic*—an exotic that sustains itself outside cultivation (it has not "become" native). *Invasive exotic*—an exotic that not only has naturalized but is expanding on its own in Florida plant communities.

Abbreviations used:
for "Gov. list": **P** = Prohibited by Fla. Dept. of Environmental Protection, **N** = Noxious weed listed by Fla. Dept. of Agriculture & Consumer Services, **U** = Noxious weed listed by U.S. Department of Agriculture. for "Reg. Dis.": **N** = north, **C** = central, **S** = south, referring to each species' current distribution in general regions of Florida (not its potential range in the state). See map.



Category I - Invasive exotics that are altering native plant communities by displacing native species, changing community structures or ecological functions, or hybridizing with natives. *This definition does not rely on the economic severity or geographic range of the problem, but on the documented ecological damage caused.*

Scientific Name	Common Name	Gov. list	Reg. Dist.
Abrus precatorius	rosary pea		C, S
Acacia auriculiformis	earleaf acacia		S
Albizia julibrissin	mimosa, silk tree		N, C
Albizia lebbeck	woman's tongue		C, S
Ardisia crenata (= A. crenulata)	coral ardisia		N, C
Ardisia elliptica (=A. humilis)	shoebutton ardisia		S
Asparagus densiflorus	asparagus-fern		C, S
Bauhinia variegata	orchid tree		C, S
Bischofia javanica	bischofia		C, S
Calophyllum antillanum (=C. calaba; C. inophyllum misapplied)	santa maria (names "mast wood," "Alexandrian laurel" used in cultivation)		S
Casuarina equisetifolia	Australian pine	P	N,C,S
Casuarina glauca	suckering Australian pine	P	C, S
Cestrum diurnum	day jessamine		C, S
Cinnamomum camphora	camphor-tree		N,C,S
Colocasia esculenta	wild taro		N,C,S
Colubrina asiatica	lather leaf		S
Cupaniopsis anacardioides	carrotwood	N	C, S
Dioscorea alata	winged yam	N	N,C,S
Dioscorea bulbifera	air-potato	N	N,C,S
Eichhornia crassipes	water-hyacinth	P	N,C,S
Eugenia uniflora	Surinam cherry		C, S
Ficus microcarpa (F. nitida & F. retusa var. *nitida* misapplied)	laurel fig		C, S
Hydrilla verticillata	hydrilla	P, U	N,C,S
Hygrophila polysperma	green hygro	P, U	N,C,S
Hymenachne amplexicaulis	West Indian marsh grass		C, S
Imperata cylindrica (I. brasiliensis misapplied)	cogon grass	N, U	N, C, S
Ipomoea aquatica	waterspinach	P, U	C
Jasminum dichotomum	Gold Coast jasmine		C, S
Jasminum fluminense	Brazilian jasmine		C, S
Lantana camara	lantana, shrub verbena		N,C,S
Ligustrum lucidum	glossy privet		N, C
Ligustrum sinense	Chinese privet, hedge privet		N,C,S
Lonicera japonica	Japanese honeysuckle		N,C,S
Lygodium japonicum	Japanese climbing fern	N	N,C, S
Lygodium microphyllum	Old World climbing fern	N	C, S
Macfadyena unguis-cati	cat's claw vine		N,C, S
Manilkara zapota	sapodilla		S
Melaleuca quinquenervia	melaleuca, paper bark	P, N, U	C, S
Melia azedarach	Chinaberry		N,C,S
Mimosa pigra	cat-claw mimosa	P, N, U	C, S
Nandina domestica	nandina, heavenly bamboo		N
Nephrolepis cordifolia	sword fern		N,C,S
Nephrolepis multiflora	Asian sword fern		C, S
Neyraudia reynaudiana	Burma reed; cane grass	N	S
Paederia cruddasiana	sewer vine, onion vine	N	S
Paederia foetida	skunk vine	N	N,C,S
Panicum repens	torpedo grass		N,C,S
Pennisetum purpureum	Napier grass		C, S
Pistia stratiotes	water lettuce	P	N,C,S
Psidium cattleianum (=P. littorale)	strawberry guava		C, S
Psidium guajava	guava		C, S
Pueraria montana (=P. lobata)	kudzu	N, U	N,C, S
Rhodomyrtus tomentosa	downy rose-myrtle	N	C, S
Rhoeo spathacea (see *Tradescantia spathacea)*			
Ruellia brittoniana	Mexican petunia		N, C, S
Sapium sebiferum	popcorn tree, Chinese tallow tree	N	N, C, S
Scaevola sericea (=Scaevola taccada var. *sericea, S. frutescens)*	scaevola, half-flower, beach naupaka		C, S
Schefflera actinophylla (=Brassaia actinophylla)	schefflera, Queensland umbrella tree		C, S
Schinus terebinthifolius	Brazilian pepper	P, N	N, C, S
Senna pendula (=Cassia coluteoides)	climbing cassia, Christmas cassia, Christmas senna		C, S
Solanum tampicense (=S. houstonii)	wetland night shade, aquatic soda apple	N, U	C, S
Solanum viarum	tropical soda apple	N, U	N, C, S
Syngonium podophyllum	arrowhead vine		C, S
Syzygium cumini	jambolan, Java plum		C, S
Tectaria incisa	incised halberd fern		S
Thespesia populnea	seaside mahoe		C, S
Tradescantia fluminensis	white-flowered wandering jew		N, C
Tradescantia spathacea (= Rhoeo spathacea, Rhoeo discolor)	oyster plant		S
Urochloa mutica (= Brachiaria mutica)	Pará grass		C, S

Competitive Power Ventures, Inc.

35 Braintree Hill Office Park
Suite 107
Braintree, MA 02184
Phone: 781-848-0253
Fax: 781-848-5804

Fax

To:	Alvaro Linero, P.E.	**From:**	Betty Deyeso for Peter Podurgiel
Fax:	850-922-6979	**Date:**	1/2/02
Phone:		**Pages:**	6
Re:	CPV Cana, Ltd Comments on Draft PSD Permit Power Generating Facility & Comments on Electric Facility	**CC:**	

☐ **Urgent** x **For Review** ☐ **Please Comment** ☐ **Please Reply** ☐ **Please Recycle**

Competitive Power Ventures, Inc.

VIA TELEFAX AND OVERNIGHT COURIER

January 2, 2002

Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Comments on CPV Cana Electric Generating Facility Draft PSD Permit, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

Pursuant to the Public Notice of Intent for the above-referenced matter, the permit applicant, CPV Cana, Ltd., submits the attached comments on the draft Prevention of Significant Deterioration (PSD) permit for the CPV Cana Power Generating Facility.

As we recently discussed with you, CPV Cana currently is in the process of working with turbine manufacturer General Electric and others to address the complex startup and shutdown emissions issues raised in the draft PSD Permit condition concerning Excess Emissions, Best Operational Standard (No Bypass), which is Condition No. 29c., as renumbered pursuant to attached comment letter, and the corresponding information, for inclusion on page BD-19 of the BACT Determination document. Due to the complexity and newness of the excess emissions Best Operational Standard issue, CPV Cana still is obtaining from its turbine manufacturers and others information that CPV Cana needs in order to prepare and submit its comments on this issue. Accordingly, CPV Cana respectfully requests the Bureau of Air Regulation to extend the 30-day period in which CPV Cana may submit comments, by 14 days, so that CPV Cana will submit its comments on the excess emissions Best Operational Standard issue to the Bureau of Air Regulation by the close of business on January 17, 2002.

The Bureau of Air Regulation determined CPV Cana's PSD permit application to be complete on October 25, 2001. Under Section 403.0876, Florida Statutes, and Section 120.60, Florida Statutes, the 90-day period in which the Department must issue (or deny) CPV Cana's permit will expire on January 23, 2002. CPV Cana hereby waives the 90-day timeframe in which the Department must issue (or deny) the permit until January 28, 2002, to afford CPV Cana and the Department sufficient time in which to resolve the excess emissions issue and any other outstanding issues. Under this waiver, the Department has until end of business on January 28, 2002, in which to issue (or deny) CPV Cana's PSD permit.

We appreciate the opportunity to work with you on this matter, and please call me if you have any questions or wish to discuss any issues concerning the CPV Cana PSD permit.

Sincerely,

Peter J. Podugiel
CPV Cana, Ltd.

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Theresa Herron, FDEP

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804

Competitive
Power Ventures, Inc.

January 2, 2002

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Comments on Draft PSD Permit for CPV Cana, Ltd. Power Generating Facility, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

Pursuant to the Public Notice of Intent for the above-referenced matter, the permit applicant, CPV Cana, Ltd., submits the following comments on the draft Prevention of Significant Deterioration ("PSD") permit, Technical Evaluation and Preliminary Determination, and BACT Determination for the CPV Cana Power Generating Facility.

I. Comments on Draft Permit

1. On page 1 of 20 in the permit file information box; on 4 of 20 in General and Administrative Requirements, Condition No. 9; and on page 5 of 20, Condition No. 11, the permit expiration date is December 31, 2004. Given that construction of the facility will take between twenty-four (24) and twenty-seven (27) months to complete and also given that construction cannot commence at this time because other permits are still being obtained, CPV Cana is concerned that the December 31, 2004 permit expiration date will not provide sufficient time to complete construction and testing of the facility. Therefore, CPV Cana requests that the permit expiration date be revised to December 31, 2005.

2. On page 2 of 20, in the Facility Description, third bullet point, the word "million" should be deleted, to accurately reflect the 975,000 gallon storage tank capacity.

3. On page 2 of 20, in the Emissions Units table, for Emissions Unit No. 004, the emission unit description should be revised to insert the word "fire" between "hp" and "water," so that the revision reads as follows: "One diesel-fired 250 hp fire water pump, one 500 kW emergency generator, and an aqueous ammonia storage tank." Similarly, the end of the last bullet under the preceding Facility Description heading should be revised to read: "...one diesel-fired 250 hp fire water pump, and a 500 kW emergency generator."

4. On page 2 of 20, in the Regulatory Classification section, in the paragraph entitled "PSD," at the beginning of the fifth (5[th]) line of that paragraph, the word "modification" should be deleted, since this is a permit for a new facility, rather than a modification of an existing facility.

5. On page 3 of 20, in the Permit Schedule section, second bullet point, the Notice of Intent for the permit was published in The Tribune on December 3, 2001.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804

6. In connection with Comment No. 1 above, regarding revision of the permit expiration date, on page 4 of 20, on page 4 of 20, General and Administrative Requirements, Condition No. 9, the construction deadline in that condition should be revised to February 28, 2005 to provide a sufficient timeframe in which to complete construction of the facility.

7. On page 8 of 20, in the Applicable Standards and Regulations, Condition No. 3.a., concerning Emissions Unit 001, the clause "power generation facilities consisting of three simple cycle combustion turbines with a nominal generating capacity of 170 MW each" immediately before the parenthetical regarding Subpart GG of 40 CFR 60, should be deleted as unnecessary, since CPV Cana is a combined cycle facility consisting of one combustion turbine and one steam turbine.

8. On page 8 of 20, in the Applicable Standards and Regulations, Condition No. 3.d., concerning Emissions Unit 004, in the first bullet point concerning Ancillary Equipment, the term "500 MW" should be changed to "500 kW" to accurately reflect the capacity of the CPV Cana facility's emergency generator.

9. On page 9 of 20, in the Applicable Standards and Regulations, Condition No. 3.d., concerning Emissions Unit 004, in the last bullet point concerning One Exhaust Stack, the sentence "A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emission Modes 5, 5Q, and 6Q." should be deleted since the bypass stack option is not an appropriate operating mode for the CPV Cana facility, and the facility will not be operated in this mode.

10. On page 9 of 20, in General Operating Requirements, Condition No. 6, the maximum heat input to the combustion turbine when firing oil should be revised from 1900 mmBtu/hr to 1898 mmBtu/hr. to accurately reflect the information provided in the permit application.

11. On page 12 of 20, Condition No. 15, the reference to Condition No. 4 should be changed to Condition No. 5 and the reference to Condition No. 26 should be changed to Condition No. 27, to correctly cross-reference the permit conditions that address fuel types and fuel sulfur limits.

12. Similarly, on page 12 of 20, Condition No. 16, the reference to Condition No. 4 should be changed to Condition No. 5 and the reference to Condition No. 26 should be changed to Condition No. 27, to correctly cross-reference the permit conditions that address fuel types and fuel sulfur limits.

13. On page 14 of 20, in the middle of Condition No. 23, there is a spacing typographical error. The topic under the heading "Compliance with the CO/NOx Emissions Limits" should be made into a separate new Condition No. 24. In connection with this revision, the references in new Condition No. 24 to Conditions No. 17, 21, and 29 should be changed to Conditions No. 18, 22, and 30, respectively.

14. Beginning with new Condition No. 24, the Conditions throughout the rest of the permit should be renumbered.

15. On page 14 of 20, in new Condition No. 25, the references to Conditions No. 17 and 20 should be changed to Conditions No. 18 and 21, respectively.

16. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section b., concerning the Best Operational Standard (Bypass Stack Option) should be deleted from the permit, since the bypass stack option is not an appropriate operating mode for the CPV Cana facility, and the facility will not be operated in this mode.

17. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section c., concerning the Best Operational Standard (No Bypass), [FILL IN INFORMATION RE: OPERATION DURING STARTUP]

18. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section e., the reference to Condition 20 should be changed to Condition 30 to accurately reflect the renumbering of the

19. On page 16 of 20, Condition No. 30 (per renumbering of Conditions), the first sentence of this condition should be revised as follows: "The owner or operator shall install, calibrate, maintain, and operate a continuous emissions monitoring (CEM) system in the combustion turbine exhaust stack (EU 001) ~~of each emissions unit~~ to measure and record the emissions of NOx and CO ~~from these emissions units~~ in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit." These revisions clarify that EU 001(the combustion turbine exhaust stack) is the only emissions unit for which CEM system monitoring is required.

20. On page 20 of 20, in Condition No. 36 (per renumbering of Conditions), the word "each" should be inserted before the term "Compliance Authority."

II. Comments on Technical Evaluation and Preliminary Determination

21. On page TE-2, in the Facility Information section, Facility Location paragraph, the following revisions should be made: First, the location is approximately 180 km, rather than 200 km, North-northeast of the Everglades National Park. Second, the proposed site is located in St. Lucie County, rather than in Port St. Lucie.

22. On page TE-3, in the Project Description section, Emissions Units table, for Emissions Unit No. 004, the emission unit description should be revised to insert the word "fire" between "hp" and "water," so that the revision reads as follows: "One 500 kW emergency generator and one diesel-fired 250 hp fire water pump."

23. On page TE-3, immediately under the Emissions Units table, the reference to "Competitive Power Ventures Cana Ltd." should be changed to "CPV Cana, Ltd."

24. On page TE-4, in the last line on the page, for consistency with the information submitted in the permit application, the tons per year (TPY) for PM/PM_{10} should be changed to 96 TPY, and the TPY for NOx should be changed to 103 TPY.

25. The following typographical errors should be corrected:

(1) On page TE-5, in the second paragraph in Section 4, Process Description, in the second sentence immediately above the photograph, the word "a" should be inserted before the word "photograph."

(2) On page TE-6, in the third paragraph, delete the stray " symbol immediately after "59° F."

(3) On page TE-6, in the Rule Applicability section, third paragraph, second sentence, insert the word "the" immediately before the word "proposed."

26. On page TE-7, in the Source Impact Analysis section, paragraph 6.1, in the last sentence, the references to Condition Nos. in the draft permit should be revised from 12 to 13, and from 16 to 17.

27. On page TE-8, the following revisions should be made to the Facility Emissions (Total TPY) and PSD Applicability Table, to accurately reflect the information provided in the application:

(1) For NOx, the Oil Firing TPY should be changed from 28 to 29, and the Total TPY should be changed from 102 to 103.

(2) For Sulfuric Acid Mist, the Gas Firing TPY should be changed from 9 to 4.

28. On page TE-8, in paragraph 6.4, paragraph 6.4.1. Description of Vicinity, should be revised to read as follows: "Refer to Figures 1 and 2 above. The CPV Cana Power Generating Facility is located approximately three (3) miles west of ~~will be in~~ the City of Port St. Lucie, which has a population of 80,000, compared to the 185,000 in St. Lucie County. The proposed project is located ~~N~~north of Jensen Beach."

29. On page TE-9, the reference in the third sentence to "southeast" should be revised to "southwest," to accurately state the location of the facility.

30. On page TE-10, in Section 6.4.3, in the list of the Major Sources of NOx in St. Lucie County, the Tons per year figure for CPV Cana should be changed from 102 to 103.

31. On pages TE-10 and TE-11, all references to CPV Gulfcoast should be changed to CPV Atlantic, and all references to CPV Cana should be followed by the insert: "(Future)". In addition, the word "major" should be deleted from the titles of the tables on each page, since many quantities listed are below the 100 TPY threshold for being considered a "major source" of air pollution, and the use of the term in a non-regulatory sense is confusing, since the air regulations specifically address and regulate "major sources."

32. On page TE-13, in the Air Quality Impact Analysis section, in the second paragraph of 6.5.1, the distance of the site from the Everglades National Park should be revised from 200 km to 180 km.

III. Comments on Appendix BD, Best Available Control Technology Determination (BACT):

33. On page BD-1, in the Background section, first paragraph, second sentence, strike the reference to Port St. Lucie, since the facility will not be located in the City of Port St. Lucie, but will instead be located in unincorporated St. Lucie County.

34. On page BD-17, in the table, the Proposed BACT Limit for CO emissions for oil firing should be corrected to 15% O_2, so that it is listed as 17 ppmvd @ 15% O_2 in the table.

35. On page BD-18, in the fourth bullet point, first line, the word "is" should be changed to "in."

36. On page BD-19, the third bullet point concerning Best Operational Standard — Startup BACT (Bypass Stack Option) should be deleted because it is not appropriate for CPV Cana and will not be used at the facility.

37. On page BD-19, in the fourth and fifth bullet points concerning an alternative Best Operational Practice and a Best Operational Standard — Startup BACT (No Bypass Stack), respectively, the following revisions should be made to reflect operating conditions during startup: [FILL IN INFORMATION]

We appreciate the opportunity to comment on the draft permit, and look forward to receipt of the final permit. Please contact me if you have any questions or wish to discuss any revisions we have requested.

Sincerely,

Peter

Peter J. Podurgiel
CPV Cana, Ltd.

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Theresa Herron, FDEP

MOYLE, FLANIGAN, KATZ, RAYMOND & SHEEHAN, P.A.
ATTORNEYS AT LAW

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Tallahassee, Florida 32301

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CATHY M. SELLERS
E-mail: csellers@moylelaw.com

West Palm Beach Office
(561) 659-7500

December 6, 2001

RECEIVED
DEC 06 2001
BUREAU OF AIR REGULATION

By Hand Delivery

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: CPV Cana Electric Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)
Affidavit of Publication

Dear Mr. Linero:

Enclosed please find the original Affidavit of Publication for the Cana PSD air construction permit. If you have any questions, please give me a call.

Sincerely,

Cathy M. Sellers

Cathy M. Sellers

CMS/jd
Enclosure
J. Heron
C. Holladay
J. Goldman, SEP
J. Worley, NPS
G. Bunyak, EPA

BEST AVAILABLE COPY

SCRIPPS HOWARD

THE TRIBUNE
ST. LUCIE COUNTY, FLORIDA

600 Edwards Road, Ft. Pierce, FL 34982

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Lynn Ferraro, General Manager; Kathy LeClair, Business Manager or Bob Rossi, Circulation Manager of The Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida; that the attached copy of advertisement was published in The Tribune in the following issues below. Affiant further says that the said Tribune is a newspaper published at Fort Pierce in said St. Lucie County, Florida and that the said newspaper has heretofore been continuously published in said St. Lucie County, Florida daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper. The Tribune has been entered as second class matter at the Post Office in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Name	Date	Price Per Day	PO #
2296875	RICHARD V. NEILL, JR.	12/03/2001	$472.00	
		Total	$472.00	

Subscribed and sworn to me before this date:

12/03/2001

Bob Rossi

Kathy Lee

Notary Public

KATHY LEE
My Comm Exp. 7/30/2002
No. CC 763706
X Personally Known [ ] Other I.D.
NOTARY PUBLIC STATE OF FLORIDA SEAL

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110103-001-CA and PSD-FL-323
CPV Cana Power Generating Facility
Combined Cycle Power Project
St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Cana Ltd. The permit is to construct a combined cycle electrical power generating plant in St. Lucie County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM10), carbon monoxide (CO), sulphur dioxide (SO2), sulfuric acid mist (SAM), and nitrogen oxides (NOx). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Cana Ltd., 35 Braintree Hill Office Park, Suite 107, Braintree, Massachusetts 02184.

The project consists of: a nominal 170 megawatt General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a separate stem-electrical generator, a 170-foot stack, a mechanical draft cooling tower, a 975,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NOx emissions will be controlled by selective catalytic reduction (SCR) to achieve 2.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM10, SO2, sulfuric acid mist, volatile organic compounds, and hazardous pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions (NH3) generated due to NOx control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10 (filterable & condensable)	96	25/15
Sulfuric Acid Mist	8	7
SO2	76	40
NOx	102	40
VOC	16	40
CO	170	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefor no Increment consumption analysis was required. Given the distance from the Everglades and the rather low emissions, the National Park Service advised the Department that it does not anticipate any significant impacts on resources from emissions from this proposed facility. Therefor a Class I analysis was not required. The Department concludes that emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards.

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 cycle submitted by the applicant and reviewed by the Department.

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

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction

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 cycle submitted by the applicant and reviewed by the Department.

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under section 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitle to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Dept. of Environmental Protection	Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	Port St. Lucie Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Avenue	1801 S.E. Hillmoor Dr., C204
Tallahassee, Florida, 32301	W. Palm Beach, Florida 33416-5425	Port St.. Lucie, Florida 34952
Telephone: 850/488-0114	Telephone: 561/681-6600	Telephone: 561/398-2806
Fax: 850/922-6979	Fax: 561/681-6755	Fax: 561/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents can be accessed at www.dep.state.fl.us/air/permitting/construction.htm by clicking on the Southeast Region of the map of Florida.

Publish: December 4, 2001

2296875

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

CPV Cana Power Generating Facility

245-Megawatt Electrical Power Plant

St. Lucie County

DEP File No. 1110103-001-AC (PSD-FL-323)

Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation

November 21, 2001

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

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

Authorized Representative: *Gary Lambert, Manager*

1.2 Reviewing and Process Schedule

09-05-01: Date of Receipt of Application
10-25-01: Application Complete
11-21-01: Distributed Intent to Issue

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The CPV Cana Power Generating Facility will be located in St. Lucie County near the central east coast of Florida. The location is approximately 200 kilometers North-northeast of the Everglades National Park. The proposed site is South of the intersection of State Road 609 and 709 in Port St. Lucie. The UTM coordinates for this facility are Zone 17; 550.9 km East; 3018.1 km North.

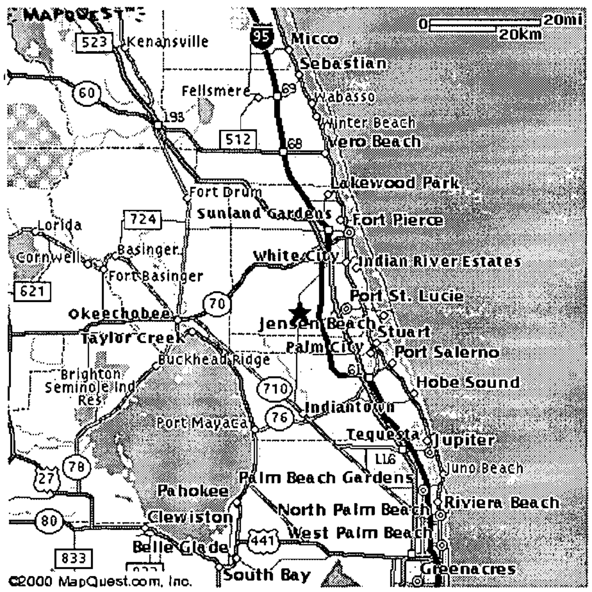

Figure 1 – Location near Port St. Lucie

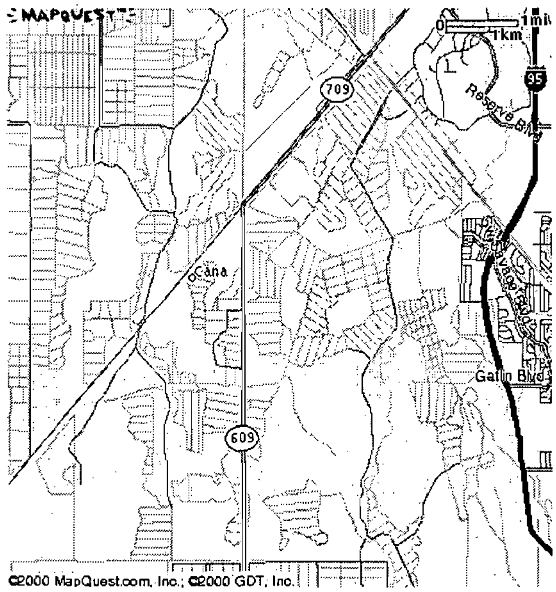

Figure 2 – Project Site west of I-95

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3. Facility Category

This new facility will generate electric power from a combined cycle unit including an unfired heat recovery steam generator (HRSG). The combustion turbine will be fired primarily with natural gas as the primary fuel, with distillate fuel as backup.

The 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 TPY. The facility is not a major source of hazardous air pollutants (HAPs). The facility is not subject to a determination of maximum achievable control technology (MACT).

The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because proposed emissions are greater than 100 TPY for **CO** the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). As a Major Facility, project emissions greater than: Significant Emission Rates given in Table 212.400-2, F.A.C., 100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 7 TPY of Sulfuric Acid Mist (SAM), 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of best available control technology (BACT).

The facility is also subject to the Title IV Acid Rain Program, 40 CFR 72 and must apply for an Acid Rain Permit at least 24 months prior to start up.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	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	Cooling	One 5-cell mechanical draft cooling tower
004	Ancillary Equipment	One 500 kW emergency generator and one diesel-fired 250 hp water pump

Competitive Power Ventures Cana Ltd. (CPV Cana) proposes to construct a combined cycle combustion turbine at their new site located in St. Lucie County. The project includes: a nominal 170 megawatt (MW) General Electric 7FA combustion turbine-electrical generator, an un-fired heat recovery steam generator (HRSG), a separate steam-electrical generator limited to less than 75 MW (gross), a 170-foot stack, a mechanical draft cooling tower, a 975,000 gallon fuel oil storage tank, and other ancillary equipment. The key components of the GE MS 7001 FA (a predecessor of the PG 7241 FA) are identified in Figure 3. An exterior view is also shown. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

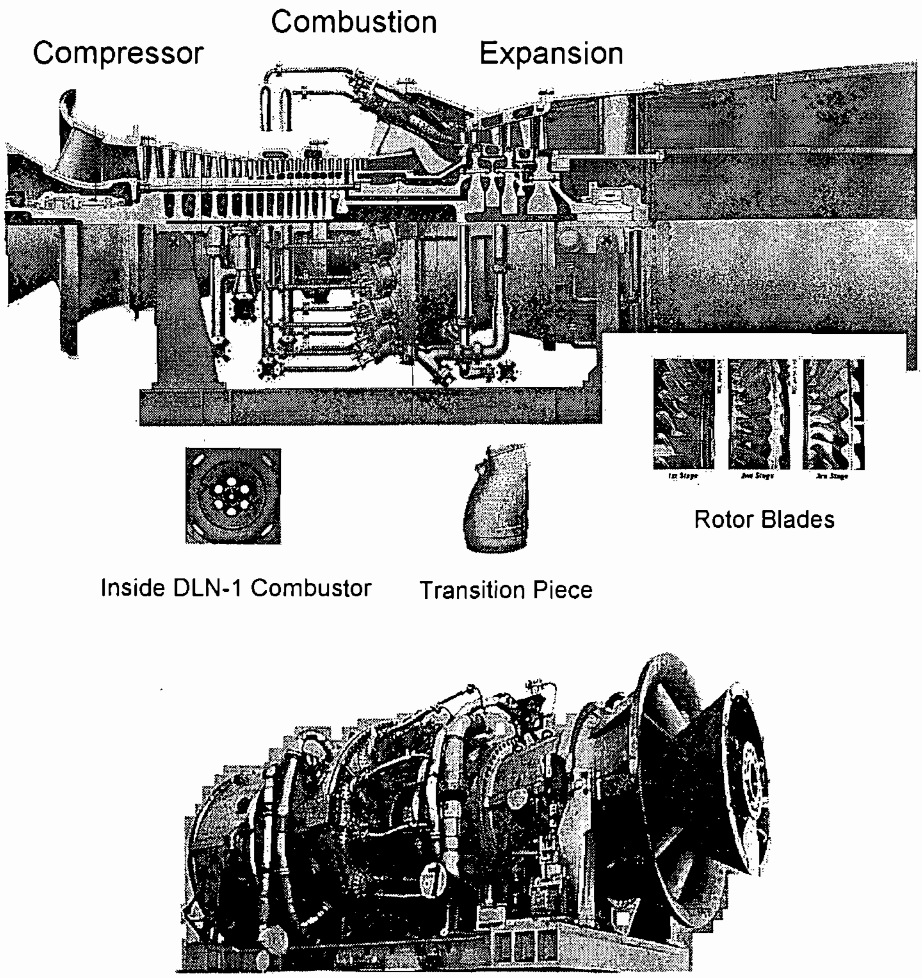

Figure 3 - Internal and External Views of Early GE 7FA

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 720 represent fuel oil operation (30 days). The turbine will have a nominal heat input rating of 1,680 million Btu per hour (mmBtu/hr), lower heating value (LHV), while firing natural gas and 1,898 mmBtu/hr, LHV, while firing fuel oil at 25 ^{o}F while operating at 100% load.

The turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors and Selective Catalytic Reduction (SCR) to control NO_X emissions to 2.5 parts per million by volume, dry, at 15% O_2 (ppmvd) while burning natural gas and 10 ppmvd while burning fuel oil.

Emission increases will occur for CO (170 TPY), SO_2 (76 TPY), SAM (8 TPY), PM/PM_{10}, (92 TPY), VOC (16 TPY), NO_X (102 TPY) and HAPs (8 TPY).

4. PROCESS DESCRIPTION

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

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 3) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Figure 4 is photograph from the GE website of a "7FA on the half-shell" as viewed from the compressor section.

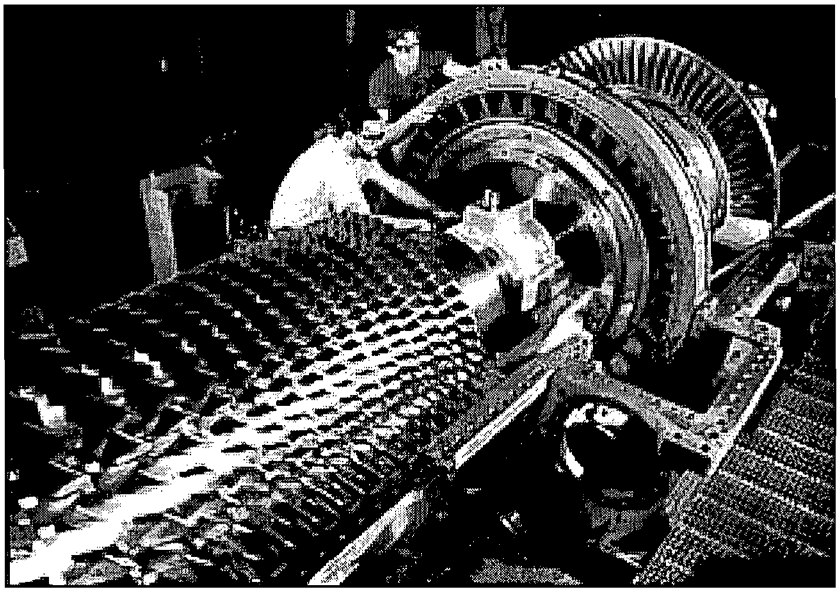

Figure 4 – Internal View of GE 7FA. (GE Website)

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the CPV project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine, which also drives an electrical generator.

Figure 5 is a process flow diagram for a combined cycle unit basically similar to the proposed CPV project. CPV will also include fuel oil back-up, SCR, and power augmentation.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To partially compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), a chilling unit or evaporative inlet fogger may be installed ahead of the combustion turbine inlet to increase air density. Neither of these features is planned for the CPV project.

Other possibilities include placing a gas-fired duct burner between the combustion turbine and the HRSG, power augmentation and peaking. *Peaking* is simply running the unit at greater than design fuel input. *Power augmentation* is accomplished by injecting some steam from the HRSG into the rotor (power) section of the combustion turbine. According to CPV, power augmentation will be employed in this project at temperatures above 59 ^{o}F "to make additional electrical output that is lost due to increasing temperature.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in St. Lucie County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SO_2, SAM and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, SO_2, SAM, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52	Subpart K, State of Florida Implementation Plan
40 CFR 60	NSPS Subparts GG and Kb
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. <u>SOURCE IMPACT ANALYSIS</u>

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, sulfuric acid mist, carbon monoxide, and negligible quantities of, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 12 through 16 of Draft Permit PSD-FL-323.

6.2 Emission Summary

The maximum potential emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TOTAL TPY) AND PSD APPLICABILITY

Pollutants	Gas Firing[1]	Gas Firing[2]	Oil Firing[3]	Ancillary Equipment	Total[4]	PSD Significance	PSD REVIEW ?
PM/PM_{10}	40	36	6	6	48[5]	25/15	Yes
SO_2	44	40	35	<2	76	40	Yes
NO_X	75	68	28	6	102	40	Yes
CO	153	143	25	2	170	100	Yes
Ozone (VOC)	13	12	3	1	16	40	No
Sulfuric Acid Mist	9	4	4	<1	8	7	Yes
Mercury	<<0.1	<<0.1	<<0.1		<0.1	0.1	No
Lead	<<0.6	<<0.6	<<0.6		<0.6	0.6	No
HAPs					8[6]	NA	NA

1. Based on 8760 hours of gas firing including 2000 hours of Power Augmentation.
2. Based on 8040 hours of gas firing including 2000 hours of Power Augmentation.
3. Based on 720 hours of fuel oil firing.
4. Based on 8040 hours of gas firing (2000 hours of Power Augmentation) and 720 hours of fuel oil firing.
5. A PM/PM_{10} total of 48 TPY includes 4 TPY from the cooling tower and ~2 TPY from other ancillary equipment. The 42 TPY includes front–half catch and sulfates only (turbine). A total of 96 TPY includes sulfates, filterables, condensables and PM/PM_{10} emissions from all ancillary equipment.
6. Less than 10 TPY for any single HAP and less than 25 TPY for all HAPs. Case-by-case MACT does not apply.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of inherently clean fuels. During gas operation, the combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN-2.6 combustors will control combustion turbine emissions not to exceed 8 ppmvd CO and 9 ppmvd NO_X @15% O_2 between 50 and 100% of full load under normal operating conditions and during gas burning. Further control for NO_X will be achieved by SCR to 2.5 (natural gas) and 10 (fuel oil) ppmvd @15% O_2. Emissions of CO during oil burning are expected not to exceed 17 ppmvd @15% O_2 at 90% to 100% of full load. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference

6.4 Existing Air Quality in the Vicinity of the project

6.4.1 Description of Vicinity

Refer to Figures 1 and 2 above. The CPV Cana Power Generating Facility will be in the City of Port St. Lucie, which has a population of 80,000 people compared to the 185,000 in St. Lucie County. The proposed project site is located North of Jensen Beach.

The proposed site is approximately 3 miles West of the Interstate I-95. Refer to Figure 5 below. The exact location is within the sector southeast of the intersection of SR 609 and SR 709. A railway runs parallel to SR 709.

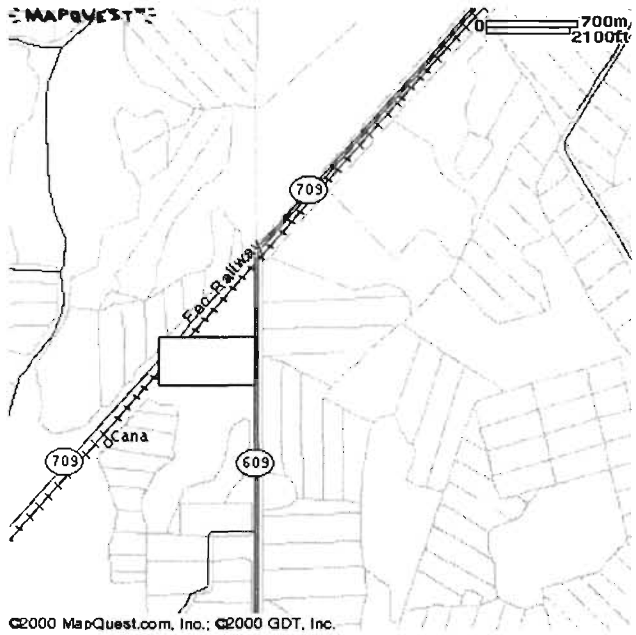

Figure 5 – CPV Cana Project Site

6.4.2 Climate

The average annual high temperature for Port St. Lucie is 83 degrees and the average low is 65 degrees. Winds are predominately out of the North and East. Refer to Figure 6 below.

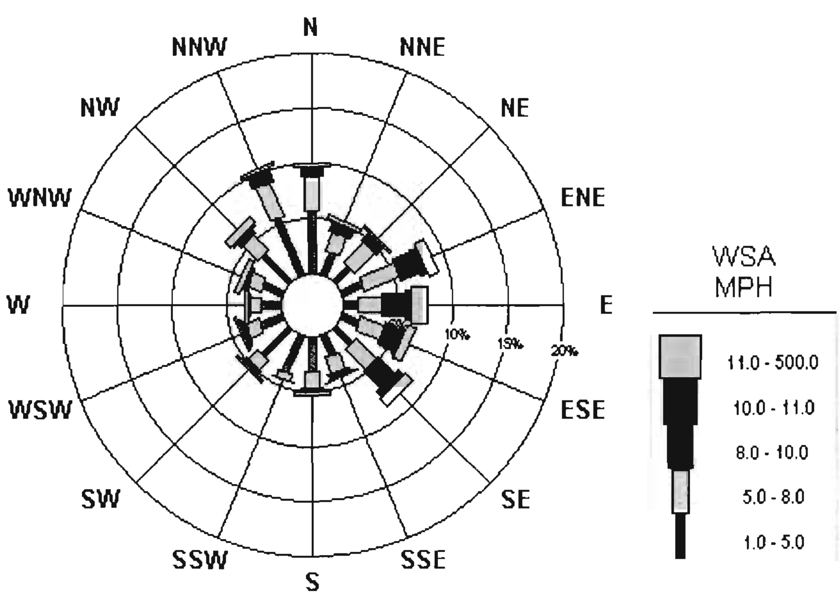

Figure 6 – St. Lucie County Wind Rose – July 2000 to July 2001

6.4.3 Major Stationary Sources in St. Lucie County

The current largest sources of air pollutants in St. Lucie County are listed below:

MAJOR SOURCES OF NO_X IN ST. LUCIE COUNTY (2000)

Owner/Company	**Site Name**	**Tons per year**
Florida Power & Light	St Lucie Nuclear Power Plant	15
Florida Gas Transmission (FGT)	FGT Station 20	323
Ft. Pierce Utilities Authority	H.D. King Power Plant	109
Tropicana Products	Tropicana Products	58
Cargill Citro Pure	Cargill Citro Pure/Ft Pierce	24
Florida Rock Industries	Fl Rock Ft. Pierce Mine	14
CPV Gulfcoast (under construction)	Gulfcoast Power Generating Facility	126
CPV Cana	**Cana Power Generating Facility**	**102**

MAJOR SOURCES OF SO_2 IN ST. LUCIE COUNTY (2000)

Owner/Company	**Site Name**	**Tons per year**
Florida Power & Light	St Lucie Nuclear Power Plant	1
Florida Gas Transmission (FGT)	FGT Station 20	6
Ft. Pierce Utilities Authority	H.D. King Power Plant	3
Dickerson Florida, In	Dickerson/Asphalt Plant #14	10
CPV Gulfcoast (under construction)	Gulfcoast Power Generating Facility	76
CPV Cana	**Cana Power Generating Facility**	**76**

MAJOR SOURCES OF VOC IN ST. LUCIE COUNTY (2000)

Owner/Company	**Site Name**	**Tons per year**
Florida Gas Transmission (FGT)	FGT Station 20	26
Ft. Pierce Utilities Authority	H.D. King Power Plant	6
Tropicana Products	Tropicana Products	1136
Cargill Citro Pure, L.	Cargil Citro Pure/Ft Pierce	131
Arch Mirror South In	Arch Mirror South	76
Maverick Boat Company	Maverick Boat Company	70
Sunshine Mirror Com	Sunshine Mirror	46
S2 Yachts, Inc	S2 Yachts	55
CPV Gulfcoast (under construction)	Gulfcoast Power Generating Facility	15
CPV Cana	**Cana Power Generating Facility**	**16**

MAJOR SOURCES OF PM/PM$_{10}$ IN ST. LUCIE COUNTY (1999)

Owner/Company	Site Name	Tons per year
Florida Power & Light	St Lucie Nuclear Power Plant	2
Ft. Pierce Utilities Authority	H.D. King Power Plant	10
Cargill Citro Pure, L.	Cargil Citro Pure/Ft Pierce	14
Dickerson Florida, Inc	Dickerson/Asphalt Plant #14	3
Florida Rock Industries	Fl Rock Ft. Pierce Mine	5/2
CPV Gulfcoast (under construction)	Gulfcoast Power Generating Facility	102
CPV Cana (Future)	**Cana Power Generating Facility**	**96**

6.4.4 Air Quality Monitoring in St. Lucie County

St. Lucie County has 4 monitors at 2 sites measuring PM, ozone, and NO_2. The 2001 St. Lucie County monitoring network is shown in Figure 7.

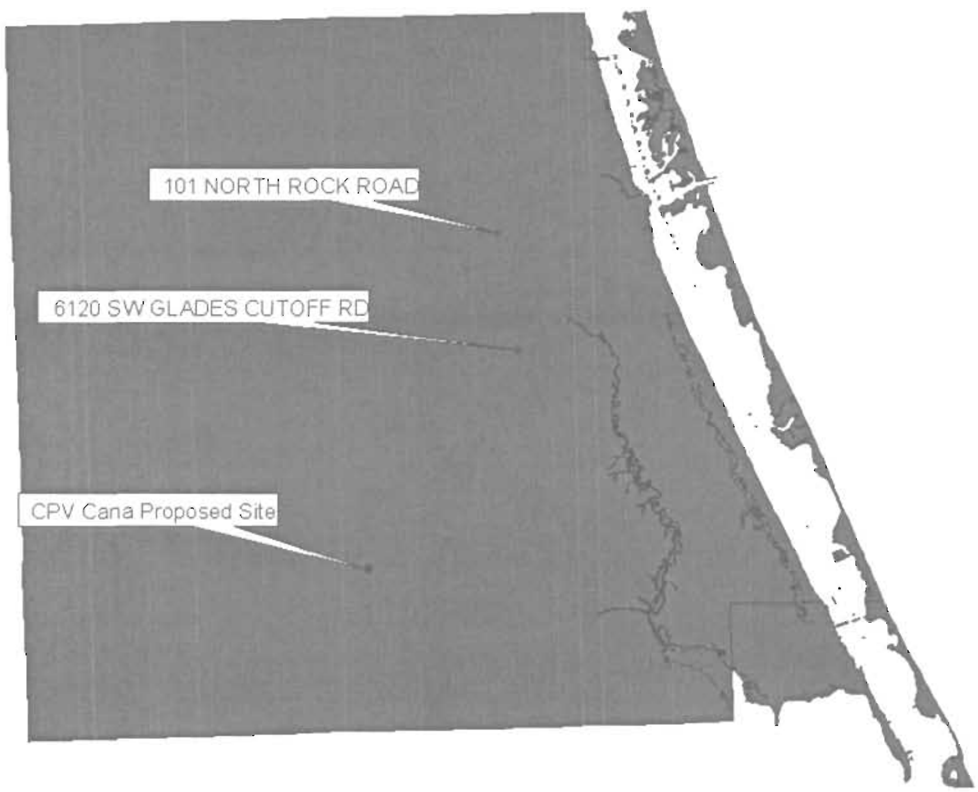

Figure 7 – St. Lucie County Monitoring Network

6.4.5 Ambient Air Quality in St. Lucie County

Measured ambient air quality is given in the following table. The highest measured values are all less than the respective National Ambient Air Quality Standards. The average measurements are all much less than the respective standards.

1999 AMBIENT AIR QUALITY NEAREST TO PROJECT SITE

Pollutant	Site Address	Averaging Period	Ambient Concentration				
			1st High	2nd High	Mean	Standard	Units
PM_{10}	6120 SW Glades Cutoff Rd., Ft. Pierce	24-hour	73	39		150 [c]	ug/m^3
		Annual			20	50 [b]	ug/m^3
SO_2	1050 15th Street West, Riviera Beach	3-hour	17	14		500 [a]	ppb
		24-hour	13	13		100 [a]	ppb
		Annual			2	20 [b]	ppb
NO_2	101 N. Rock Road, Ft. Pierce	Annual			10	53 [b]	ppb
CO	3700 Belvedere Rd., W. Palm Beach	1-hour	6	5		35 [a]	ppm
		8-hour	4	3		9 [a]	ppm
Ozone	101 N. Rock Road, Ft. Pierce	1-hour	0.083	0.083	0.044 [d]	0.12 [c]	ppm
Lead	Jog Road Incinerator, West Palm Bch	24-hour	0	0	0	1.5 [b]	ug/m^3

a - Not to be exceeded more than once per year.
b - Arithmetic mean.
c - Not to be exceeded on more than an average of one day per year over a three-year period.
d – Mean ozone value reflects the average daily 1-hour maximum reading.

6.5 Air Quality Impact Analysis

6.5.1 Introduction

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

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project predicted no significant impacts in the Class II area in the vicinity of the project. Therefore, no further applicable AAQS and PSD increment impact analyses for CO, NO_X, PM and SO_2 were required in the Class II area. The nearest PSD Class I area is the Everglades National Park (ENP) located about 200 km to the south-southwest. Due to the distance of the project from the Everglades, the applicant was not required to perform a PSD Class I air quality analysis. Also, the maximum predicted impacts for all pollutants were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

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

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.5.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. Substantial monitoring data exist for the area as discussed in the previous sections.

An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration. The table below shows that predicted impacts from the combustion turbines are substantially less than the respective de minimus levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant. Additionally, the approximate high values measured at existing ambient monitoring sites in St. Lucie County are included for comparison purposes.

Installation of additional monitors near the proposed site will probably not show any increases from the plant because of the very low impact levels. Basically, the highest contribution from the plant would be on the order of 14 percent or less of the highest measured concentrations.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMIS AMBIENT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~ 75	NO
NO_2	Annual	0.17	14	~ 20	NO
SO_2	24-hour	4.85	13	~ 35	NO
CO	8-hour	8	575	~ 4500	NO

6.5.3 Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area

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

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations from the Vero Beach Airport, Florida. The 5-year period of meteorological data was from 1990 through 1994. This station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, stability class, and mixing height.

6.5.4 Significant Impact Analysis

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class II Area. If this modeling at worst load conditions shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at and extending to 2 kilometers at 100 meter spacing from the fence line. Receptor rings were also placed at 200-meter increments out to 5 kilometers. Beyond 5 kilometers, polar receptor rings with a spacing of 500 meters were used out to 10 kilometers from the facility.

The following table shows the results of the significant impact modeling for the Class II area:

MAXIMUM PROJECT AIR QUALITY IMPACTS FROM THE CPV CANA PROJECT FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	NO
	24-Hour	4.9	5	NO
	3-Hour	15	25	NO
PM_{10}	Annual	0.2	1	NO
	24-Hour	4.3	5	NO
CO	8-Hour	8	500	NO
	1-Hour	20	2000	NO
NO_2	Annual	0.2	1	NO

The results of the significant impact modeling show that there are no significant impacts for the Class II area.

6.5.5 Additional Impacts Analysis

Impact On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the CPV Cana plant. The combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

Impact On Visibility

Pipeline Natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low NO_X, SO_2, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

The Class I Everglades National Park, where visibility impacts are normally of greater concern, is nearly 200 kilometers from the proposed site. Therefore impacts on visibility are expected to be insignificant.

Growth-Related Air Quality Impacts

According to the applicant, the project will employ between 100 and 200 workers during the various phases of construction. Most of the labor will be drawn from the local labor force. Ultimately the project will require 20 to 25 permanent employees, some of who will be drawn from the local labor force.

This project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," and the lowest air emissions per unit of electric power generating capacity.

Hazardous Air Pollutants

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

7. CONCLUSION

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

In making this preliminary determination, the Department also drafted a permit and a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, and the public.

Teresa Heron, Review Engineer
Debbie Galbraith, Meteorologist
A. A. Linero, P.E. Administrator

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110103-001-AC and PSD-FL-323

CPV Cana Power Generating Facility
Combined Cycle Power Project

St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Cana Ltd. The permit is to construct a combined cycle electrical power generating plant in Port St. Lucie in St. Lucie County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and nitrogen oxides (NO_X). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Pierce Ltd., 35 Braintree Hill Office Park, Suite 107, Braintree, Massachusetts 02184.

The project consists of: a nominal 170 megawatt General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower, a 975,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 2.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions (NH_3) generated due to NO_X control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10} (filterable & condensable)	96	25/15
Sulfuric Acid Mist	8	7
SO_2	76	40
NO_x	102	40
VOC	16	40
CO	170	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefore no increment consumption analysis was required. Given the distance from the Everglades and the rather low emissions, the National Park Service advised the Department that it does not anticipate any significant impacts on resources from emissions from this proposed facility. Therefore a Class I analysis was not required. The Department concludes that emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards.

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 cycle submitted by the applicant and reviewed by the Department.

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Dept. of Environmental Protection	Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	Port St. Lucie Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Avenue	1801 S.E. Hillmoor Dr., C 204
Tallahassee, Florida, 32301	W. Palm Beach, Florida 33416-5425	Port St. Lucie, Florida 34952
Telephone: 850/488-0114	Telephone: 561/681-6600	Telephone: 561/398-2806
Fax: 850/922-6979	Fax: 561/681-6755	Fax: 561/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. Key documents can be accessed at www.dep.state.fl.us/air/permitting/construction.htm by clicking on the Southeast Region of the map of Florida.

In the Matter of an
Application for Permit by:

Mr. Gary Lambert, Manager
CPV Cana, Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, Massachusetts 02184

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

______________________________/

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of DRAFT Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, CPV Cana, Ltd., applied on September 5, 2001 (complete October 25) to the Department to construct a combined cycle electrical power generating plant consisting of a nominal 170 MW combustion turbine-electrical generator, an unfired heat recovery steam generator, a separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower, a 975,000 gallon fuel oil storage tank, and other ancillary equipment. The project will be located at a new site in Port St. Lucie, St. Lucie County.

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

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

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

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 INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/21/01 to the person(s) listed:

Gary Lambert, CPV Atlantic, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, 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.

Victoria Gibson 11/21/01
(Clerk) (Date)

BEST AVAILABLE COPY

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

Mr. Gary Lambert, Manager
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

C. Signature

X S LeBlanc

☐ Agent
☐ Addressee

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

NOV 2

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2904

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

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

7000 2870 0000 7028 2904

OFFICIAL USE

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

Postmark
Here

Sent To
Gary Lambert

Street, Apt. No.; or PO Box No.
35 Braintree Hill Offc. Park, Ste. 107

City, State, ZIP+ 4
Braintree, MA 02184

PS Form 3800, May 2000 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

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 11/26/07

C. Signature

X

☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2898

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)

OFFICIAL USE

7000 2870 0000 7028 2898

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

Postmark Here

Sent To
Robert E. Minsky
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, May 2000 **See Reverse for Instructions**

SENDER: *COMPLETE THIS SECTION*

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

1. Article Addressed to:

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

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 11-26-01

C. Signature

X Bev Nimon

☐ Agent
☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2850

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)

OFFICIAL USE

7000 2870 0000 7028 2850

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

Postmark Here

Sent To
Doug Coward

Street, Apt. No.; or PO Box No.
2300 Virginia Ave.

City, State, ZIP+ 4
Ft. Pierce, FL 34982

PS Form 3800, May 2000 See Reverse for Instructions

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

November 21, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gary Lambert, Manager
CPV Cana, Ltd
35 Braintree Hill Office Park, Suite 107
Braintree, Massachusetts 02184

Re: DEP File No. 1110103-001-AC (PSD-FL-323)
CPV Cana Power Generating Facility
Combined Cycle Power Project

Dear Mr. Lambert:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the CPV Cana Power Generating Facility to be located in Port St Lucie, St Lucie County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Ms. Teresa Heron at 850/921-9529 or Ms. Debbie Galbraith at 850/921-9537.

Sincerely,

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

CHF/th

Enclosures

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 million 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 fire 250 hp 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 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 modification 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.

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, 2004

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

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

- xx/xx/02 Air Construction Permit Issued
- xx/xx/01 Notice of Intent to Issue published in ___________
- 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.
- Letter from EPA Region IV dated ___________
- 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, 2004. Physical construction shall be complete by June 30, 2004. 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. power generation facilities consisting of three simple cycle combustion turbines with a nominal generating capacity of 170 MW each. (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 MW 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. 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.

[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 1,900 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. 4 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. 26 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. 4 and 26 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]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 17 and 21. Continuous compliance shall be demonstrated as specified in Specific Conditon 29. [Rule 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.]

24. 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 17 and 20. [Rule 62-212.400 F.A.C. (BACT)]

25. 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)]

26. 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

27. 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.]

28. 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 (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)

   c. Best Operational Standard (No Bypass): 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 during public comment period)

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

   e. In accordance with Condition No. 29 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

29. Continuous Emission Monitoring System: The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring (CEM) system in the exhaust stack of each emissions unit to measure and record the emissions of NO_X and CO from these emissions units 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 startup*" 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.]

30. 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.]

31. 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.]

32. 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.]

33. 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

34. 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]

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

36. 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.

37. 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.

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.

APPENDIX GG

NSPS Subpart GG Requirements for Gas Turbines

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

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

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

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 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.

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

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

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

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

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

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit specifies sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

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

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

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

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 in Port St Lucie, 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.

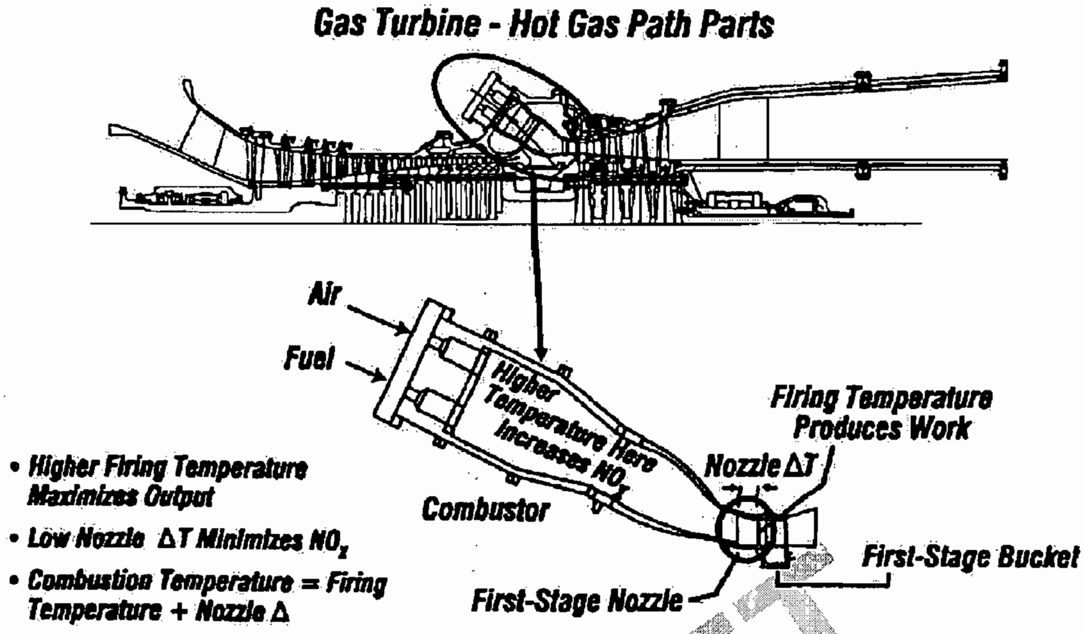

Figure 1 – Relation Between Flame Temperature and Firing Temperature

NO_X Control Techniques

Wet Injection

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.

Combustion Controls: Dry Low NO_X (DLN)

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

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

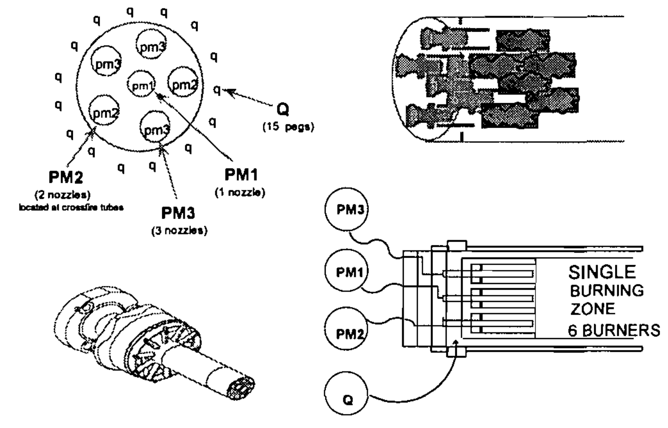

Figure 2 – DLN-2.6 Fuel Nozzle Arrangement

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.

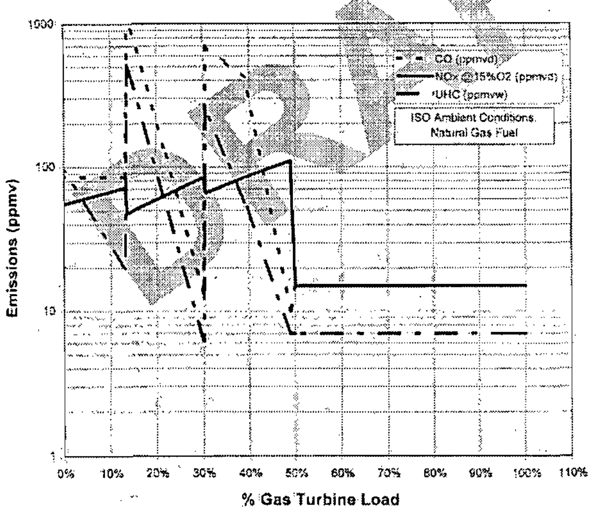

Figure 3 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

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.

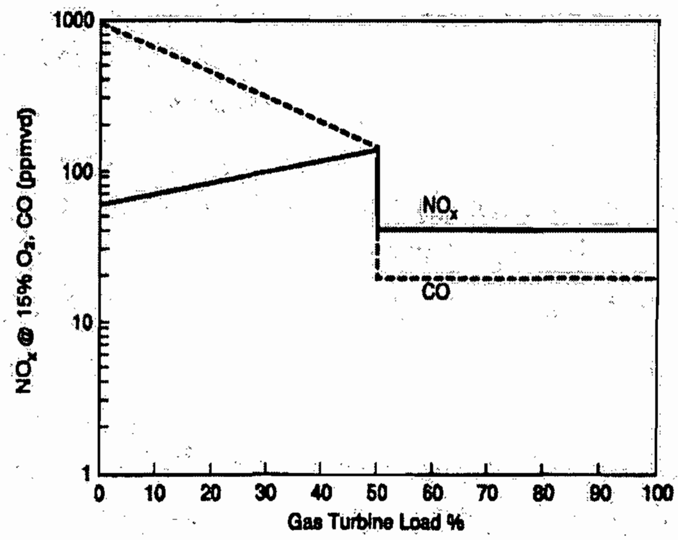

Figure 4 - Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

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.

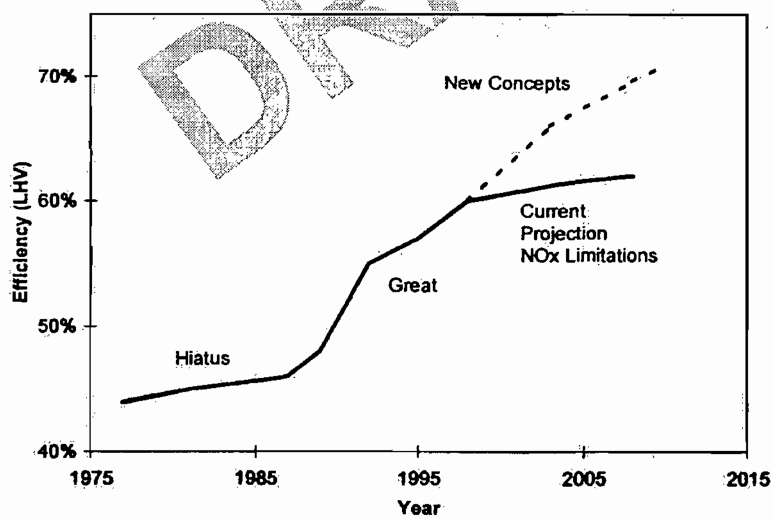

Figure 5 – Efficiency Increases in Combustion Turbines

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 temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available 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.

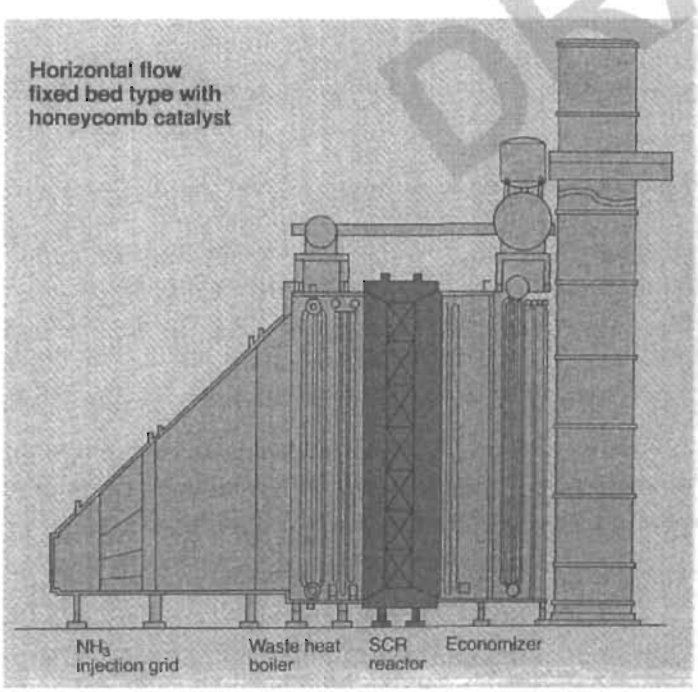

Figure 6 – SCR System within HRSG

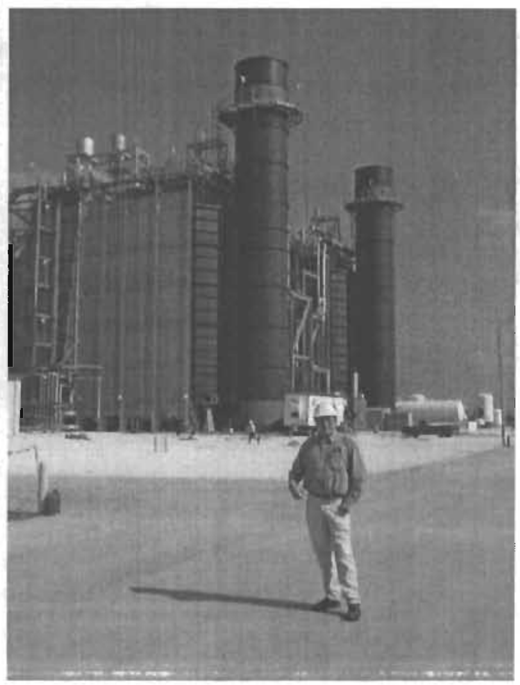

Figure 7 – FPC Hines Power Block I

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 simple cycle 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 (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 is 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.
- Best Operational Standard – Startup BACT (Bypass Stack Option):

  The combustion turbine will start up and operate as a simple cycle unit and modulate exhaust to the HRSG. This requires installation of a bypass stack and damper.

  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)

  The Department does not have a cost estimate for the additional stack and design requirements, but believes the additional power and flexibility offered by full load simple cycle operation during the cold startup of the steam cycle will defray some of the additional costs.
- If the startup BACT described above is not feasible, then the applicant will submit an alternative Best Operational Practice. 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 prior to issuance of the final permit.
- Best Operational Standard – Startup BACT (No Bypass Stack):

  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 during public comment period)
- The Department reserves the option of finalizing the Best Operational Standard for startup based on comments received during the 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.]

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: | Approved By:

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

Date:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

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Department of
Environmental Protection

Jeb Bush
Governor

Southeast District
P.O. Box 15425
West Palm Beach, Florida 33416

David B. Struhs
Secretary

NOV 1 9 2001

Certified - Return Receipt Requested 7000 ·0600 ·0024·1598·1052

Gary A. Lambert, Vice President
CPV Cana, L.L.C.
35 Braintree Hill Office, Suite 107
Braintree, MA 02184

RE: CPV Cana Ltd.
Notice of Intent to Issue
Permit Number: ES 56-0186976-001

Dear Mr. Lambert:

Enclosed are the Notice of Intent to Issue and draft Environmental Resource Permit No ES 56-0186976-001 pursuant to Part IV of Chapter 373, Florida Statutes, and Title 62, Florida Administrative Code.

If you have any questions about this document, please contact me at 561/681-6640.

Sincerely,

Indarjit Jagnarine

Indarjit Jagnarine
Professional Engineer III
Submerged Lands & Environmental
Resources Program

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
P.O. Box 15425
West Palm Beach, Florida 33416

David B. Struhs
Secretary

NOTICE OF INTENT TO ISSUE ENVIRONMENTAL RESOURCE PERMIT

In the Matter of an Application for Permit
and Water Quality Certification by:

APPLICANT: CPV Cana, Ltd.
35 Braintree Hill Office, Suite 107
Braintree, MA 02184

Attn.: Gary A. Lambert, Vice President

PROJECT: CPV Cana, Ltd.
Environmental Resource Permit Number: File No. ES 56-0186976-001
St. Lucie County

The Department of Environmental Protection gives notice of its intent to issue an environmental resource permit under Part IV of Chapter 373, Florida Statutes (F.S.), and Title 62, Florida Administrative Code (F.A.C.). A draft copy of permit is attached. Issuance of the environmental resource permit constitutes certification of compliance with state water quality standards pursuant to section 401 of the Clean Water Act, 33 U.S.C. 1341.

Where applicable, issuance of the environmental resource permit also constitutes a finding of consistency with Florida's Coastal Zone Management Program, as required by Section 307 of the Coastal Management Act.

I. DESCRIPTION OF THE PROPOSED ACTIVITY

CPV Cana, Ltd. proposes to construct and operate a peaking electric generating facility and associated infrastructure. The facility will be sited on a 61.54-acre parcel in St. Lucie County. To serve the proposed development, a surface water management system is designed to meet water quality and quantity requirements in accordance with the Environmental Resource Permit rules, regulations and criteria. No wetlands are proposed to be impacted for this project.

Activity Location: The facility is located at off Range Line Road, approximately 0.75 miles south of the intersection of Glades Cut-off and Range Line Road, St. Lucie County, in Section 01, Township 37 South, Range 38 East.

II. AUTHORITY FOR REVIEW

The Department has permitting authority under Part IV of Chapter 373, F.S., and Chapters 62-330, 62-341 and 62-343, F.A.C. The activity is not exempt from the requirement to obtain an environmental resource permit. Pursuant to operating agreements executed between the Department and the water management districts, as referenced in Chapter 62-113, F.A.C., the Department is responsible for reviewing this application.

III. BACKGROUND AND BASIS FOR ISSUANCE

On July 3, 2001, the applicant, Mr. Gary A. Lambert, Vice President, CPV Cana, Ltd., applied for an Environmental Resource Permit (ERP) to construct and operate a surface water management system to serve the proposed electric generating facility located in St. Lucie County. This permit allows for construction of the CPV Cana, Ltd. energy generating facility and a surface water management system designed to meet water quality and quantity requirements in accordance with the Environmental Resource Permit rules, regulations and criteria. As outlined in the attached draft permit, the applicant has complied with the requirements of rule 40E-4 and 40E-40, Florida Administrative Code.

Based on the above, along with the general and specific conditions of the permit, the applicant has provided reasonable assurance that the construction and operation of the activity, considering the direct, secondary, and cumulative impacts, will comply with the provisions of Part IV of Chapter 373, F.S., and the rules adopted thereunder, including the Conditions for Issuance or Additional Conditions for Issuance of an environmental resource permit, pursuant to Part IV of Chapter 373, F.S., Chapters 62-330, and Sections 40E-4.301 and 40E-4.302, F.A.C. This project meets the presumptive water quality criteria of the SFWMD's Basis of Review. The construction and operation of this facility should therefore not result in violations of water quality standards. The applicant has also demonstrated that the construction of the activity, including a consideration of the direct, secondary, and cumulative impacts, is not contrary to the public interest, pursuant to paragraph 373.414(1)(a), F.S.

IV. PUBLICATION OF NOTICE

The Department has determined that the proposed activity, because of its size, potential effect on the environment or the public, controversial nature, or location, is likely to have a heightened public concern or likelihood of request for administrative proceedings. Under section 403.815 of the Florida Statutes and rule 62-103.150 of the Florida Administrative Code, you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice must be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of sections 50.011 and 50.031 of the Florida Statutes, in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used should be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant must provide proof of publication to:

Department of Environmental Protection
Southeast District
Environmental Resources Permitting
P.O. Box 15425
West Palm Beach, FL 33401

The proof of publication shall be provided to the above address within 7 days of publication. Failure to publish the notice and provide proof of publication within the allotted time shall be grounds for denial of the permit.

V. RIGHTS OF AFFECTED PARTIES

Under this intent to issue, the permit, No. ES 56-0186976-001, is hereby granted subject to the applicant's compliance with any requirement in this intent to publish notice of this intent in a newspaper of general circulation and to provide proof of such publication in accordance with section 50.051 of the Florida Statutes. This action is final and effective on the date filed with the Clerk of the Department unless a sufficient petition for an administrative hearing is timely filed under sections 120.569 and 120.57 of the Florida Statutes as provided below. If a sufficient petition for an administrative hearing is timely filed, this intent to issue automatically becomes only proposed agency action on the application, subject to the result of the administrative review process. Therefore, on the filing of a timely and sufficient petition, this action will not be final and effective until further order of the Department. When proof of publication is provided, if required by this intent, and if a sufficient petition is not timely filed, the permit, No. ES 56-0186976-001, will be executed. Because an administrative hearing may result in the reversal or substantial modification of this action, the applicant is advised not to commence construction or other activities until the deadlines noted below for filing a petition for an administrative hearing or request for an extension of time have expired and until the permit, No: No. ES 56-0186976-001, has been executed and delivered.

A person whose substantial interests are affected by the Department's action may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received by the clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Mediation may also be pursued as specified below.

Under rule 62-110.106(4) of the Florida Administrative Code, a person whose substantial interests are affected by the Department's action may also request an extension of time to file a petition for an administrative hearing. The Department may, for good cause shown, grant the request for an extension of time. Requests for extension of time must be filed with the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, before the applicable deadline. A timely request for extension of time shall toll the running of the time period for filing a petition until the request is acted upon. If a request is filed late, the Department may still grant it upon a motion by the requesting party showing that the failure to file a request for an extension of time before the deadline was the result of excusable neglect.

If a timely and sufficient petition for an administrative hearing is filed, other persons whose substantial interests will be affected by the outcome of the administrative process have the right to petition to intervene in the proceeding. Intervention will be permitted only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-106.205 of the Florida Administrative Code.

In accordance with rules 28-106.111(2) and 62-110.106(3)(a)(4), petitions for an administrative hearing by the applicant must be filed within 21 days of receipt of this written notice. Petitions filed by any persons other than the applicant, and other than those entitled to written notice under section 120.60(3) of the Florida Statutes, must be filed within 21 days of publication of the notice or within 21 days of receipt of the written notice, whichever occurs first. Under section 120.60(3) of the Florida Statutes, however, any person who has asked the Department for notice of agency action may file a petition within 21 days of receipt of such notice, regardless of the date of publication.

The petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition for an administrative hearing or pursue mediation as provided below within the appropriate time period shall constitute a waiver of those rights.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests are or will be affected by the agency determination;

(c) A statement of when and how the petitioner received notice of the agency decision;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, including the specific facts that the petitioner contends warrant reversal or modification of the agency's proposed action;

(f) A statement of the specific rules or statutes that the petitioner contends require reversal or modification of the agency's proposed action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wishes the agency to take with respect to the agency's proposed action.

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

Under sections 120.569(2)(c) and (d) of the Florida Statutes, a petition for administrative hearing must be dismissed by the agency if the petition does not substantially comply with the above requirements or is untimely filed.

In addition to petitioning for an administrative hearing, any person who has previously filed a petition for an administrative hearing may pursue mediation. If a written mediation agreement with all parties to the proceeding (i.e., the applicant, the Department, and any person who has filed a timely and sufficient petition for a hearing) is filed with the Department within 10 days after the deadline for filing a petition for an administrative hearing, the time limitations imposed by sections 120.569 and 120.57 shall be tolled to allow mediation to proceed. The agreement must contain all the information required by rule 28-106.404. The agreement must be received by the clerk in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, before the deadline noted above. Pursuing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement.

Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. As noted above, persons seeking to protect their substantial interests that would be affected by such a final decision modified through mediation must file their petitions within 21 days of receipt or publication of this notice as provided above, or they shall be deemed to have waived their right to a proceeding under sections 120.569 and 120.57. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

This intent to issue a permit, No. ES 56-0186976-001, constitutes an order of the Department. Subject to the provisions of paragraph 120.68(7)(a) of the Florida Statutes, which may require a remand for an administrative hearing, the applicant has the right to seek judicial review of the order under section 120.68 of the Florida Statutes, by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the order is filed with the Clerk of the Department. The applicant, or any party within the meaning of section 373.114(1)(a) or 373.4275 of the Florida Statutes, may also seek appellate review of the order before the Land and Water Adjudicatory Commission under section 373.114(1) or 373.4275 of the Florida Statutes. Requests for review before the Land and Water Adjudicatory Commission must be filed with the Secretary of the Commission and served on the Department within 20 days from the date when the order is filed with the Clerk of the Department. Requests for review before the Land and Water Adjudicatory Commission must be filed with the Secretary of the Commission and served on the Department within 20 days from the date when the order is filed with the Clerk of the Department.

Executed in West Palm Beach, Florida.

RECEIVED
NOV 26 2001
BUREAU OF AIR REGULATION

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Melissa L. Meeker 11/19/01
Melissa L. Meeker Date
Director of District Management
(561) 681-6661

TR
MLM/TR/VN/ij
Copies furnished to:

USACOE
Al Linero, DEP/TLH MS 5505
South Florida Water Management District - T. Waterhouse, P.E.
South Florida Water Management District – Jeff Rosenfeld
Department of Community Affairs
Richard Stalker – ERP/Compliance & Enforcement
Department of Community Affairs
Scott Glaubitz, B.S.E. Consultants, 312 South Harbor City Blvd., Suite #4, Melbourne Fl 32901

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this **INTENT TO ISSUE** and all copies were mailed before the close of business on November 19, 2001, to the above listed persons.

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7) of the Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

V. Marion 11/19/01
Clerk Date

Prepared by Indar Jagnarine and Victor Neugebauer

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE ENVIRONMENTAL RESOURCE PERMIT

The Department of Environmental Protection gives notice of its intent to issue an Environmental Resource Permit (File No. ES 56-0186976-001) to CPV Cana, Ltd. to construct an electric generating facility and associated infrastructure. The facility will be sited on a 61.54-acre parcel in St Lucie County. To serve the proposed development, a surface water management system is designed to meet water quality and quantity requirements in accordance with the Environmental Resource Permit rules, regulations and criteria. No wetlands are proposed to be impacted for this project.

The facility is located at off Range Line Road, approximately 0.75 miles south of the intersection of Glades Cut-off and Range Line Road, St. Lucie County, in Section 01, Township 37 South, Range 38 East.

The Department will issue the permit with attached conditions unless a timely petition for an administrative hearing is filed under sections 120.569 and 120.57 of the Florida Statutes, before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received by the clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

Petitions by the applicant or any of the parties listed below must be filed within 21 days of receipt of this written notice. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within 14 days of publication of the notice or within 21 days of receipt of the written notice, whichever occurs first.

Under section 120.60(3) of the Florida Statutes, however, any person who has asked the Department for notice of agency action may file a petition within 21 days of receipt of such notice, regardless of the date of publication.

The petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition or request for mediation within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name, address, and telephone number of each petitioner; the Department permit identification number and the county in which the subject matter or activity is located;
(b) A statement of how and when each petitioner received notice of the Department action;
(c) A statement of how each petitioner's substantial interests are affected by the Department action;
(d) A statement of the material facts disputed by the petitioner, if any;
(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;
(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

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

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

In addition to requesting an administrative hearing, any petitioner may elect to pursue mediation. The election may be accomplished by filing with the Department a mediation agreement with all parties to the proceeding (i.e., the applicant, the Department, and any person who has filed a timely and sufficient petition for a hearing). The agreement must contain all the information required by rule 28-106.404. The agreement must be received by the clerk in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, within ten days after the deadline for filing a petition, as set forth above. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for holding an administrative hearing and issuing a final order. Unless otherwise agreed by the parties, the mediation must be concluded within 60 days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons seeking to protect their substantial interests that would be affected by such a modified final decision must file their petitions within 21 days of receipt of this notice, or they shall be deemed to have waived their right to a proceeding under sections 120.569 and 120.57. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at the Florida Department of Environmental Protection, Southeast District Office, 400 N. Congress Avenue, 2nd Floor, West Palm Beach.

Department of
Environmental Protection

Jeb Bush
Governor

Southeast District
P.O. Box 15425
West Palm Beach, Florida 33416

David B. Struhs
Secretary

ENVIRONMENTAL RESOURCE PERMIT

PERMITTEE:
Gary A. Lambert
Vice President
CPV Cana, Ltd.
35 Braintree Hill Office, Suite 107
Braintree, MA 02184

Permit Number: ES 56-0186976-001
Date of Issue:
Expiration Date of Construction Phase:
Project: CPV Cana, Ltd -ERP
County: St. Lucie DRAFT

This permit is issued under the authority of Part IV of Chapter 373, F.S., and Title 62, Florida Administrative Code (F.A.C.). The activity is not exempt from the requirement to obtain an Environmental Resource Permit. Pursuant to operating agreements executed between the Department and the water management districts, as referenced in Chapter 62-113, F.A.C., the Department is responsible for reviewing and taking final agency action on this activity.

ACTIVITY DESCRIPTION:

CPV Cana, Ltd.. proposes to construct and operate an electric generating facility and associated infrastructure called CPV Cana, Ltd. The facility will be sited on a 61.54-acre parcel in St. Lucie County. To serve the proposed development, stormwater runoff from the power generating facility is designed to meet State and South Florida Water Management District (SFWMD) water quality and quantity requirements. No wetlands are proposed to be impacted for this project.

ACTIVITY LOCATION:

CPV Cana, Ltd. project is located at off Range Line Road, approximately 0.75 miles south of the intersection of Glades Cut-off Road and Range Line Road, St. Lucie County, in Section 01, Township 37 South, Range 38 East.

This permit also constitutes a finding of consistency with Florida's Coastal Zone Management Program, as required by Section 307 of the Coastal Management Act.

This permit also constitutes certification of compliance with water quality standards under Section 401 of the Clean Water Act, 33 U.S.C. 1341.

A copy of this authorization also has been sent to the U.S. Army Corps of Engineers (USACOE) for review. The USACOE may require a separate permit. Failure to obtain this authorization prior to construction could subject you to enforcement action by that agency. You are hereby advised that authorizations also may be required by other federal, state, and local entities. This authorization does not relieve you from the requirements to obtain all other required permits and authorizations.

The above named permittee is hereby authorized to construct the work shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof. **This permit is subject to the limits, conditions, and locations of work shown in the attached exhibits, and is also subject to the attached General Conditions (1-19) and Specific Conditions (1-10) which are a binding part of this permit.** You are advised to read and understand these drawings and conditions prior to commencing the authorized activities, and to ensure the work is conducted in conformance with all the terms, conditions, and drawings. If you are utilizing a contractor, the contractor also should read and understand these drawings and conditions prior to commencing the authorized activities. Failure to comply with all drawings and conditions shall constitute grounds for revocation of the permit and appropriate enforcement action.

Operation of the facility is not authorized except when determined to be in conformance with all applicable rules and with the general and specific conditions of this permit, and as specifically described below.

SURFACE WATER SYSTEM DESIGN:

Project Area: 61.54 acres **Drainage Area**: 31.1 acres

Drainage Basin: SFWMD C-24

Receiving Body: Range Line Road, roadside ditch

Background: On July 3, 2001, the applicant, Mr. Gary A. Lambert, Vice President, CPV Cana Ltd. applied for an Environmental Resource Permit (ERP) to construct/operate a surface water management system to serve the proposed electric generating facility located in St. Lucie County. The proposed plant's steam generator will generate less than 75 megawatts and is, therefore, not required to be reviewed under the Florida Electrical Power Plant Siting Act.

Existing Facility: The site is an abandoned vegetable field/current pasture with one jurisdictional wetland associated with a cattle pond and two off-site jurisdictional wetlands with a small portion of each of the two wetlands encroaching into the site. The site's topography averages 26.5 to 27 feet NGVD. The site is currently zoned utility and industrial.

Proposed Facility:

Proposed Landuse Summary:

Landuse	Basin 1, acres	Basin 2, acres
Powerplant	23.3	-
Lakes (stormwater)	2.9	1.1
Swales	3.4	1
Un-developed	20.44	-
Landscape Buffer	1.3	1.9
Access Paving/Staging	-	6
Total	51.54	10.0

DRAFT

The facility's stormwater management system is designed to meet SFWMD C-24 allowable discharge criteria and water quality volumetric treatment requirements. The site is hydraulically separated into two drainage basins, Basin 1 and Basin 2. Stormwater from Basin 1 (power generating facility site) will be routed to the connected dry retention areas discharging to the on-site stormwater lakes and outfalls into Range Line Road swale via a single weir structure. Basin 2 consists of dry retention, wet detention, landscape areas, construction staging and construction employee parking. Stormwater from Basin 2 will be directed to grass retention areas to the wet detention system and outfalls into Range Line Road swale. The entrance road outside the property boundary is permitted by St. Lucie County.

There will be no chemical discharge to stormwater. All on-site chemicals or additives are stored under roof, on concrete flooring with containment and/or on skids in containment. All containment provides 110% volume.

Stormwater Management System Water Control Structure:

Identification	Structure Type	Elevation (feet NGVD)	Benchmark	Location
Basin 1	6.5 " orifice	26.0	Invert of flood Control Orifice	To Range Line Road, ditch
Basin 2	3" orifice	26.0	Invert of Flood Control Orifice	To Range Line Road, ditch

Basin Information:

Basin	Area (AC)	WSWT Elev. (ft NGVD)	Normal/Dry Ctrl Elev. (ft NGVD)	Method of Determination
Basin 1 & 2	61.54	25.5	26.0	Soil Survey

Discharge Rate: Flow control orifices will limit the discharge rate of stormwater to based on the SFWMD C-24 criteria as follows:

Design Storm Freq.: 10-yr, 3-day **Design Rainfall:** 7.34 inches

Basin	Allow Disch (cfs)	Method of Determination	Design Disch (cfs)	Design Stage (ft. NGVD)
1	1.47	Allowable Discharge – 30.25cfs/mi^2	1.41	27.91
2	.47	"	0.31	27.94

Water Quality: Treatment is provided in dry retention /detention areas computed as the first inch over the site.

Basin	Pervious Area Ac.	Impervious Area for water quality Ac.	Treatment Method	Volume Req'd (ac.ft)	Volume Prov'd (ac.-ft)
1	10.68	20.42	Dry retention	1.39	1.39
2	11.62	4.90	Dry detention	0.82	0.82

Minimum Building Floor Elevation:

The minimum elevation of paved drives/parking areas within Basin 1 is set at 30.5 feet NGVD, which is above the 10-year, 3 day stage of 27.91 feet NGVD. The minimum elevation of paved drives/parking areas within Basin 2 is set at 29.0 feet NGVD, which is above the 10-year, 3-day stage of 27.94 feet NGVD. The minimum elevation of building floors is set at 32.0 feet NGVD which is above the 100-year, 3-day, zero discharge stage of 29.69 feet NGVD.

Environmental Review: The project is located on 61.54 acres of agricultural pasture land. A cattle pond exists in the northern portion of the project site. The cattle pond is vegetated with various pasture grass species. Herbaceous wetlands exist at the border and cross over onto the project site. The on-site wetlands are dominated by Maidencane and sodgrasses. No wetland impacts are proposed. BMP'S such as slit fences and hay bails will be used to protect 40' to 50' wetland buffer areas during construction.

The upland vegetative community consists primarily of a shrub layer of Brazilian Pepper (Schinus terebinthifolius) and Wax Myrtle (Myrica cerifera). The ground cover consists primarily of Bahia (Paspalum notata) and Broomsedge (Andropogon virginicus) along with other forage grasses and sedges.

System Operation: CPV Cana, Ltd.

Water Use Permit Status: A water use permit has not been applied for. A water use permit will be submitted prior to 2002.

Water and Wastewater Supplier: Initially, Water from Floridan Aquifer will be treated for use and deep well for disposal and ultimately by the City of Port St. Lucie.

Save Our Rivers: This project is not within or adjacent to lands under consideration by the Save Our Rivers program.

Swim Basin: This project is not located within a Swim Basin

Right-of-way Permit Status: A right-of-way permit is not required from the South Florida Water Management District.

Well Field Zone of Influence: This project is not located within the zone of influence of a well-field.

GENERAL CONDITIONS:

(1) All activities authorized by this permit shall be implemented as set forth in the plans, specifications and performance criteria as approved by this permit. Any deviation from the permitted activity and the conditions for undertaking that activity shall constitute a violation of this permit and Part IV, Chapter 373, F.S.

(2) This permit or a copy thereof, complete with all conditions, attachments, exhibits, and modifications shall be kept at the work site of the permitted activity. The complete permit shall be available for review at the work site upon request by the Department staff. The permittee shall require the contractor to review the complete permit prior to commencement of the activity authorized by this permit.

(3) Activities approved by this permit shall be conducted in a manner which does not cause violations of state water quality standards. The permittee shall implement best management practices for erosion and pollution control to prevent violation of state water quality standards. Temporary erosion control shall be implemented prior to and during construction, and permanent control measures shall be completed within 7 days of any construction activity. Turbidity barriers shall be installed and maintained at all locations where the possibility of transferring suspended solids into the receiving water body exists due to the permitted work. Turbidity barriers shall remain in place at all locations until construction is completed and soils are stabilized and vegetation has been established. All practices shall be in accordance with the guidelines and specifications described in Chapter 6 of the Florida Land Development Manual; A Guide to Sound Land and Water Management (Department of Environmental Regulation, 1988), unless a project-specific erosion and sediment control plan is approved as part of the permit. Thereafter the permittee shall be responsible for the removal of the barriers. The permittee shall correct any erosion or shoaling that causes adverse impacts to the water resources.

(4) The permittee shall notify the Department of the anticipated construction start date within 30 days of the date that this permit is issued. **At least 48 hours prior to commencement** of activity authorized by this permit, the permittee shall submit to the Department an "Environmental Resource Permit Construction Commencement" notice (Form No. 62-343.900(3), F.A.C.) indicating the actual start date and the expected completion date.

(5) When the duration of construction will exceed one year, the permittee shall submit construction status reports to the Department on an annual basis utilizing an "Annual Status Report Form" (Form No. 62-343.900(4), F.A.C.). Status Report Forms shall be submitted the following June of each year.

(6) **Within 30 days after completion of construction** of the permitted activity, the permittee shall submit a written statement of completion and certification by a registered professional engineer or other appropriate individual as authorized by law, utilizing the supplied "Environmental Resource Permit As-Built Certification by a Registered Professional" (Form No. 62-343.900(5), F.A.C.). The statement of completion and certification shall be based on on-site observation of construction or review of as-built drawings for the purpose of determining if the work was completed in compliance with permitted plans and specifications. This submittal shall serve to notify the Department that the system is ready for inspection. Additionally, if deviation from the approved drawings are discovered during the certification process, the certification must be accompanied by a copy of the approved permit drawings with deviations noted. Both the original and revised specifications must be clearly shown. The plans must be clearly labeled as "as-built" or "record" drawing. All surveyed dimensions and elevations shall be certified by a registered surveyor.

(7) The operation phase of this permit shall not become effective until the permittee has complied with the requirements of condition (6) above, has **submitted a "Request for Transfer of Environmental Resource Permit Construction Phase to Operation Phase" (Form No. 62-343.900(7), F.A.C.)**; the Department determines the system to be in compliance with the permitted plans and specifications; and the entity approved by the Department in accordance with Sections 9.0 and 10.0 of the Basis of Review for Environmental Resource Permit Applications Within the South Florida Water Management District - August 1995, accepts responsibility for operation and maintenance of the system. The permit shall not be transferred to such approved operation and maintenance entity until the operation phase of the permit becomes effective. Following inspection and approval of the permitted system by the Department, the permittee shall initiate transfer of the permit to the approved responsible operating entity if different from the permittee. Until the permit is transferred pursuant to Section 62-343.110(1)(d), F.A.C., the permittee shall be liable for compliance with the terms of the permit.

(8) Each phase or independent portion of the permitted system must be completed in accordance with the permitted plans and permit conditions prior to the initiation of the permitted use of site infrastructure located within the area served by that portion or phase of the system. Each phase or independent portion of the system must be completed in accordance with the permitted plans and permit conditions prior to transfer of responsibility for operation and maintenance of the phase or portion of the system to a local government or other responsible entity.

(9) For those systems that will be operated or maintained by an entity that will require an easement or deed restriction in order to enable that entity to operate or maintain the system in conformance with this permit, such easement or deed restriction must be recorded in the public records and submitted to the Department along with any other final operation and maintenance documents required by sections 9.0 and 10.0 of the Basis of Review for Environmental Resource Permit Applications Within the South Florida Water Management District - August 1995, prior to lot or unit sales or prior to the completion of the system, whichever occurs first. Other documents concerning the establishment and authority of the operating entity must be filed with the Secretary of State where

appropriate. For those systems which are proposed to be maintained by the county or municipal entities, final operation and maintenance documents must be received by the Department when maintenance and operation of the system is accepted by the local government entity. Failure to submit the appropriate final documents will result in the permittee remaining liable for carrying out maintenance and operation of the permitted system and any other permit conditions.

(10) Should any other regulatory agency require changes to the permitted system, the permittee shall notify the Department in writing of the changes prior to implementation so that a determination can be made whether a permit modification is required.

(11) This permit does not eliminate the necessity to obtain any required federal, state, local and special district authorizations prior to the start of any activity approved by this permit. This permit does not convey to the permittee or create in the permittee any property right, or any interest in real property, nor does it authorize any entrance upon or activities on property which is not owned or controlled by the permittee, or convey any rights or privileges other than those specified in the permit and Chapter 40E-4 or Chapter 40E-40, F.A.C.

(12) The permittee is hereby advised that Section 253.77, F.S. states that a person may not commence any excavation, construction, or other activity involving the use of sovereign or other lands of the state, the title to which is vested in the Board of Trustees of the Internal Improvement Trust Fund without obtaining the required lease, license, easement, or other form of consent authorizing the proposed use. Therefore, the permittee is responsible for obtaining any necessary authorizations from the Board of Trustees prior to commencing activity on sovereignty lands or other state-owned lands.

(13) The permittee is advised that the rules of the South Florida Water Management District require the permittee to obtain a water use permit from the South Florida Water Management District prior to construction dewatering, unless the work qualifies for a general permit pursuant to subsection 40E-20.302(4), F.A.C., also known as the "No Notice" rule.

(14) The permittee shall hold and save the Department harmless from any and all damages, claims, or liabilities which may arise by reason of the construction, alteration, operation, maintenance, removal, abandonment or use of any system authorized by the permit.

(15) Any delineation of the extent of a wetland or other surface water submitted as part of the permit application, including plans or other supporting documentation, shall not be considered binding unless a specific condition of this permit or a formal determination under section 373.421(2), F.S., provides otherwise.

(16) The permittee shall notify the Department in writing within 30 days of any sale, conveyance, or other transfer of ownership or control of a permitted system or the real property on which the permitted system is located. All transfers of ownership or transfers of a permit are subject to the requirements of section 62-343.130, F.A.C. The permittee transferring the permit shall remain

liable for corrective actions that may be required as a result of any violations prior to the sale, conveyance or other transfer of the system.

(17) Upon reasonable notice to the permittee, Department authorized staff with proper identification shall have permission to enter, inspect, sample and test the system to insure conformity with the plans and specifications approved by the permit.

(18) If historical or archaeological artifacts are discovered at any time on the project site, the permittee shall immediately notify the appropriate Department office.

(19) The permittee shall immediately notify the Department in writing of any previously submitted information that is later discovered to be inaccurate.

SPECIFIC CONDITIONS:

1. **Zoning.** The site is currently zoned utility and industrial. Prior to construction of the power plant, the applicant shall obtain the required zoning approval for the proposed electric power facility.

2. **Surface water management system.** The surface water system shall be constructed as shown in the attached exhibits. The dry detention basin bottom elevation shall be at 27.0 feet NGVD.

3. There shall be no chemical discharge to stormwater. Stormwater runoff collected in secondary containment storage shall not be disposed into the stormwater system.

4. **Sedimentation Controls.** Silt screens, hay bales or other such sediment control measures shall be utilized during construction. The selected sediment control measures shall be installed around the perimeter of the area to be developed. All areas shall be stabilized and vegetated immediately after construction to prevent erosion.

5. **Maintenance of Storm Drainage System.** Maintenance of the stormwater system is the responsibility of CPV Cana Ltd. A maintenance schedule shall be implemented to ensure that the stormwater management system is functioning as designed.

6. **Exotic Species.** The permittee shall maintain the project sites free from the invasion or establishment of the plants listed on the current year's Florida Exotic Pest Plant Council's Category I Invasive Exotic Species list (copy attached).

7. **Dewatering.** Dewatering activity may require an Industrial Wastewater permit (Tim Powell @ 561/681-6684, DEP/West Palm Beach) and SFWMD approval. Within 30 days of receipt of a dewatering permit, the permittee shall submit a copy of the permit to the Department (ATTN: Stormwater Section).

8. **Additional Water Quality Requirement.** The Department reserves the right to require that additional water quality treatment methods be incorporated into the drainage system if such measures are shown to be necessary.

9. **Drawings and Attachments.** Attached Drawing exhibits and DEP forms: 62-343.900(3), (4), (5), (7), and (8) F.A.C., are hereby attached to and become part of this permit.

10. **Compliance with General Conditions.** The permittee shall be aware of and operate under the attached general limiting conditions. General conditions are binding upon the permittee and enforceable pursuant to Chapters 403 and 373 of the Florida Statutes.

Executed in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

DRAFT

Melissa L. Meeker **Date**
Director of District Management
Southeast District

MLM/TR/vn/ij

Copies furnished to:
USACOE
Al Linero, DEP/TLH
Department of Community Affairs
South Florida Water Management District - T. Waterhouse, P.E.
South Florida Water Management District – Jeff Rosenfeld
Dennis Murphy, St. Lucie County Richard Stalker, ERP/Compliance & Enforcement
Scott Glaubitz, B.S.E. Consultants, 312 South Harbor City Blvd., Suite #4, Melbourne Fl 32901

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this permit and all copies were mailed to the above listed persons before the close of business on ______________________.

FILING AND ACKNOWLEDGMENT

FILED, on this date, pursuant to 120.52(11),
Florida Statutes, with the designated Department Clerk,
receipt of which is hereby acknowledged.

____

Clerk Date

Prepared by Indar Jagnarine, P.E. and Victor Neugebauer, ES II

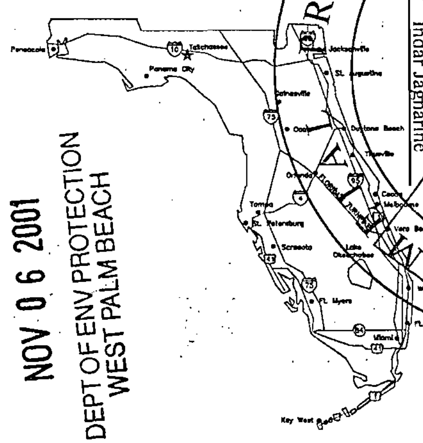
CPV CANA, LTD.

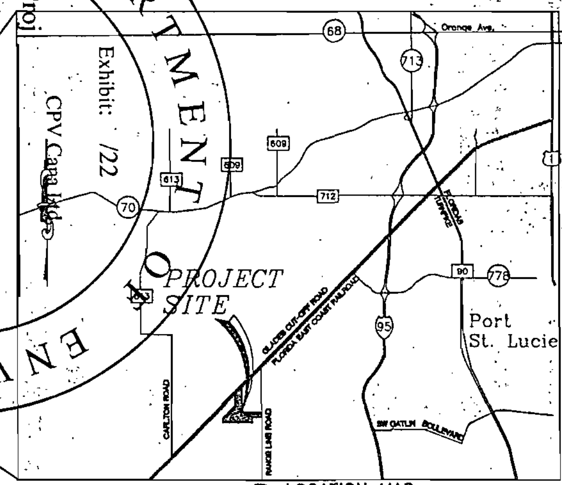
ST. LUCIE COUNTY, FLORIDA
SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST

RECEIVED
NOV 0 6 2001
DEPT OF ENV PROTECTION
WEST PALM BEACH

ENVIRONMENTAL PROTECTION DEPARTMENT OF
Proj: CPV Cana Ltd.
Exhibit: /22
ES-56-0186976-001
Date:
By: Indar Jagnarine

INDEX TO DRAWINGS





LOCATION MAP
SCALE: 1"=10,000'

ENGINEERS

B.S.E. CONSULTANTS, INC.
312 S. HARBOR CITY BLVD., SUITE 4
MELBOURNE, FLORIDA 32901
PHONE (321) 725–3674
FAX (321) 723–1159

OWNER / DEVELOPER

CPV CANA, LTD.
C/O COMPETITIVE POWER VENTURES, INC.
35 BRAINTREE HILL OFFICE PARK, SUITE 107
BRAINTREE, MA 02184
(CONTACT) PETER J. PODURGIEL
PHONE (781) 848–0253

LEGAL

MOYLE FLANIGAN KATZ RAYMOND & SHEEHAN P.A.
625 NORTH FLAGLER DRIVE, 9TH FLOOR
WEST PALM BEACH, FLORIDA 33401
PETER BRETON
PHONE (561) 822–0385

ENVIRONMENTAL PERMITTING CONSULTANT

THE LOUIS BERGER GROUP, INC.
75 SECOND AVE., SUITE 700
NEEDHAM, MA 02494
NEIL COLLINS
PHONE (781) 444–3330

ARCHITECT

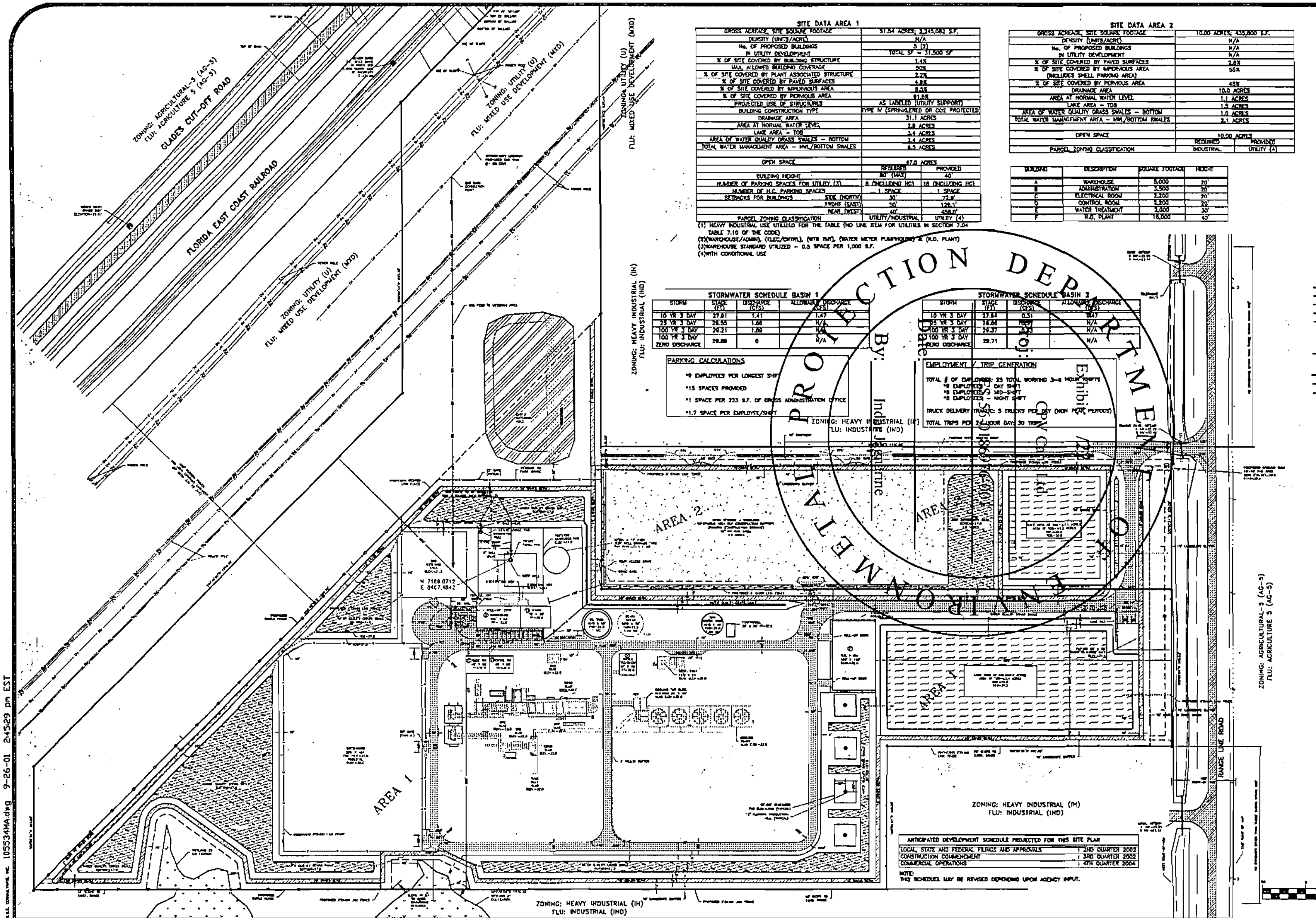
AEP PRO SERVE NORTHEAST
119 CANNETT DRIVE
SOUTH PORTLAND, ME 04106
KEITH PRICE
PHONE (207) 541–5800

REVISION: COUNTY COMMENTS – 7/20/01

SHEET 1 OF 30

PROJECT NO. 10553 DRAWING NO. 10553401

NOV 05 2001



SITE DATA AREA 1

GROSS ACREAGE, SITE SQUARE FOOTAGE	31.54 ACRES; 2,345,082 S.F.	
DENSITY (UNITS/ACRE)	N/A	
No. OF PROPOSED BUILDINGS	5 (2)	
IN UTILITY DEVELOPMENT	TOTAL SF = 31,500 SF	
% OF SITE COVERED BY BUILDING STRUCTURE	1.4%	
MAX. ALLOWED BUILDING COVERAGE	50%	
% OF SITE COVERED BY PLANT ASSOCIATED STRUCTURE	2.2%	
% OF SITE COVERED BY PAVED SURFACES	4.8%	
% OF SITE COVERED BY IMPERVIOUS AREA	8.5%	
% OF SITE COVERED BY PERVIOUS AREA	91.0%	
PROJECTED USE OF STRUCTURES	AS LABELED (UTILITY SUPPORT)	
BUILDING CONSTRUCTION TYPE	TYPE IV (SPRINKLERED OR CO2 PROTECTED)	
DRAINAGE AREA	31.1 ACRES	
AREA AT NORMAL WATER LEVEL	2.8 ACRES	
LAKE AREA – TOB	3.4 ACRES	
AREA OF WATER QUALITY GRASS SWALES – BOTTOM	3.4 ACRES	
TOTAL WATER MANAGEMENT AREA – NWL/BOTTOM SWALES	6.5 ACRES	
OPEN SPACE	47.0 ACRES	
	REQUIRED	PROVIDED
BUILDING HEIGHT	80' (MAX)	40'
NUMBER OF PARKING SPACES FOR UTILITY (3)	8 (INCLUDING HC)	16 (INCLUDING HC)
NUMBER OF H.C. PARKING SPACES	1 SPACE	1 SPACE
SETBACKS FOR BUILDINGS SIDE (NORTH)	30'	72.9'
FRONT (EAST)	50'	120.1'
REAR (WEST)	40'	458.0'
PARCEL ZONING CLASSIFICATION	UTILITY/INDUSTRIAL	UTILITY (4)

(1) HEAVY INDUSTRIAL USE UTILIZED FOR THE TABLE (NO LINE ITEM FOR UTILITIES IN SECTION 7.04 TABLE 7.10 OF THE CODE)
(2)(WAREHOUSE/ADMIN), (ELEC/CNTRL), (WTR TMT), (WATER METER PUMPHOUSE) & (R.O. PLANT)
(3)WAREHOUSE STANDARD UTILIZED – 0.5 SPACE PER 1,000 S.F.
(4)WITH CONDITIONAL USE

SITE DATA AREA 2

GROSS ACREAGE, SITE SQUARE FOOTAGE	10.00 ACRES; 435,600 S.F.	
DENSITY (UNITS/ACRE)	N/A	
No. OF PROPOSED BUILDINGS	N/A	
IN UTILITY DEVELOPMENT	N/A	
% OF SITE COVERED BY PAVED SURFACES	2.8%	
% OF SITE COVERED BY IMPERVIOUS AREA (INCLUDES SHELL PARKING AREA)	55%	
% OF SITE COVERED BY PERVIOUS AREA	45%	
DRAINAGE AREA	10.0 ACRES	
AREA AT NORMAL WATER LEVEL	1.1 ACRES	
LAKE AREA – TOB	1.5 ACRES	
AREA OF WATER QUALITY GRASS SWALES – BOTTOM	1.0 ACRES	
TOTAL WATER MANAGEMENT AREA – NWL/BOTTOM SWALES	2.1 ACRES	
OPEN SPACE	10.00 ACRES	
	REQUIRED	PROVIDED
PARCEL ZONING CLASSIFICATION	INDUSTRIAL	UTILITY (4)

BUILDING	DESCRIPTION	SQUARE FOOTAGE	HEIGHT
A	WAREHOUSE	5,000	20'
B	ADMINISTRATION	3,500	20'
C	ELECTRICAL ROOM	2,200	20'
D	CONTROL ROOM	2,200	20'
E	WATER TREATMENT	2,000	30'
F	R.O. PLANT	16,000	40'

ABBREVIATIONS

ADMIN = ADMINISTRATION
AM = AMMONIA
BFP = BOILER FEED PUMP
COND = CONDENSER
CNTRL = CONTROL
DEMIN = DEMINERALIZED
ELEC = ELECTRICAL
EW = EYE WASH
GTG = GAS TURBINE GENERATOR
HRSG = HEAT RECOVERY STEAM GENERATOR
NEUT = NEUTRALIZATION
RM = ROOM
STG = STEAM TURBINE GENERATOR
TMT = TREATMENT
TWR = TOWER
WTR = WATER

LEGEND

- GAS MAIN
- WATER MAIN
- WETLAND DELINEATION
- EXISTING OVERHEAD WIRE
- EXISTING RAILROAD TRACK
- PROPOSED SILT SCREEN FENCE
- PROPOSED CHAIN LINK FENCE
- PROPOSED CATTLE FENCE
- +32.80 = EXISTING SPOT ELEVATION
- PROPERTY LINE
- EXISTING EDGE OF PAVEMENT
- SWALE LINE
- BENCH MARK
- EXISTING UTILITY POLE
- EXISTING GUY ANCHOR
- RAILROAD SPIKE
- BUTTERFLY VALVE
- GATE VALVE
- WATER QUALITY GRASS SWALES
- LAKE AT NORMAL WATER LEVEL (NWL)
- EXISTING CATTLE POND
- EXISTING WETLANDS
- PROPOSED PAVED AREAS
- EXISTING ROAD WAYS

STORMWATER SCHEDULE BASIN 1

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.81	1.41	1.47
25 YR 3 DAY	28.55	1.66	N/A
100 YR 3 DAY	29.21	1.89	N/A
100 YR 3 DAY ZERO DISCHARGE	29.80	0	N/A

STORMWATER SCHEDULE BASIN 2

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.84	0.31	0.47
25 YR 3 DAY	28.66	[illegible]	N/A
100 YR 3 DAY	29.37	[illegible]	N/A
100 YR 3 DAY ZERO DISCHARGE	29.71		N/A

PARKING CALCULATIONS

*9 EMPLOYEES PER LONGEST SHIFT
*15 SPACES PROVIDED
*1 SPACE PER 233 S.F. OF GROSS ADMINISTRATION OFFICE
*1.7 SPACE PER EMPLOYEE/SHIFT

EMPLOYMENT / TRIP GENERATION

TOTAL # OF EMPLOYEES: 25 TOTAL WORKING 3–8 HOUR SHIFTS
*9 EMPLOYEES – DAY SHIFT
*8 EMPLOYEES – MID-SHIFT
*8 EMPLOYEES – NIGHT SHIFT

TRUCK DELIVERY TRAFFIC: 5 TRUCKS PER DAY (NON PEAK PERIODS)

TOTAL TRIPS PER 24 HOUR DAY: 30 TRIPS

ANTICIPATED DEVELOPMENT SCHEDULE PROJECTED FOR THIS SITE PLAN	
LOCAL, STATE AND FEDERAL FILINGS AND APPROVALS	: 2ND QUARTER 2002
CONSTRUCTION COMMENCEMENT	: 3RD QUARTER 2002
COMMERCIAL OPERATIONS	: 4TH QUARTER 2004

NOTE:
THIS SCHEDULE MAY BE REVISED DEPENDING UPON AGENCY INPUT.

REVISIONS		
3	COMMENTS	8/13/01
2	COUNTY COMMENTS	7/20/01
1	OWNER/CLIENT COMMENTS	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL SITE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10553.?02
SHEET 12 OF 30

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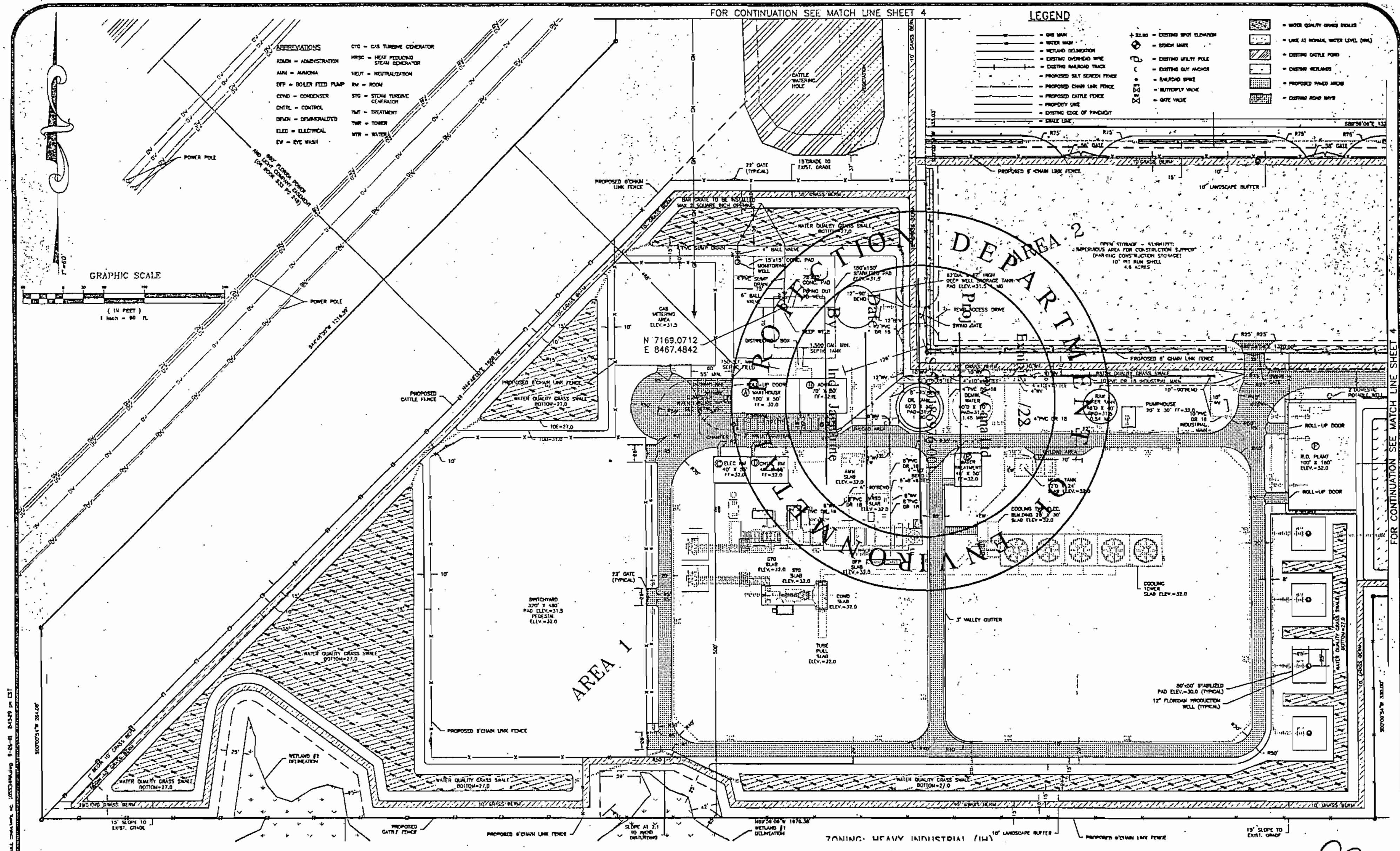
NOV 05 2001

PROTECTION DEPARTMENT OF ENVIRONMENTAL
By:
Date:
Exhibit 27
CPV Cana Ltd



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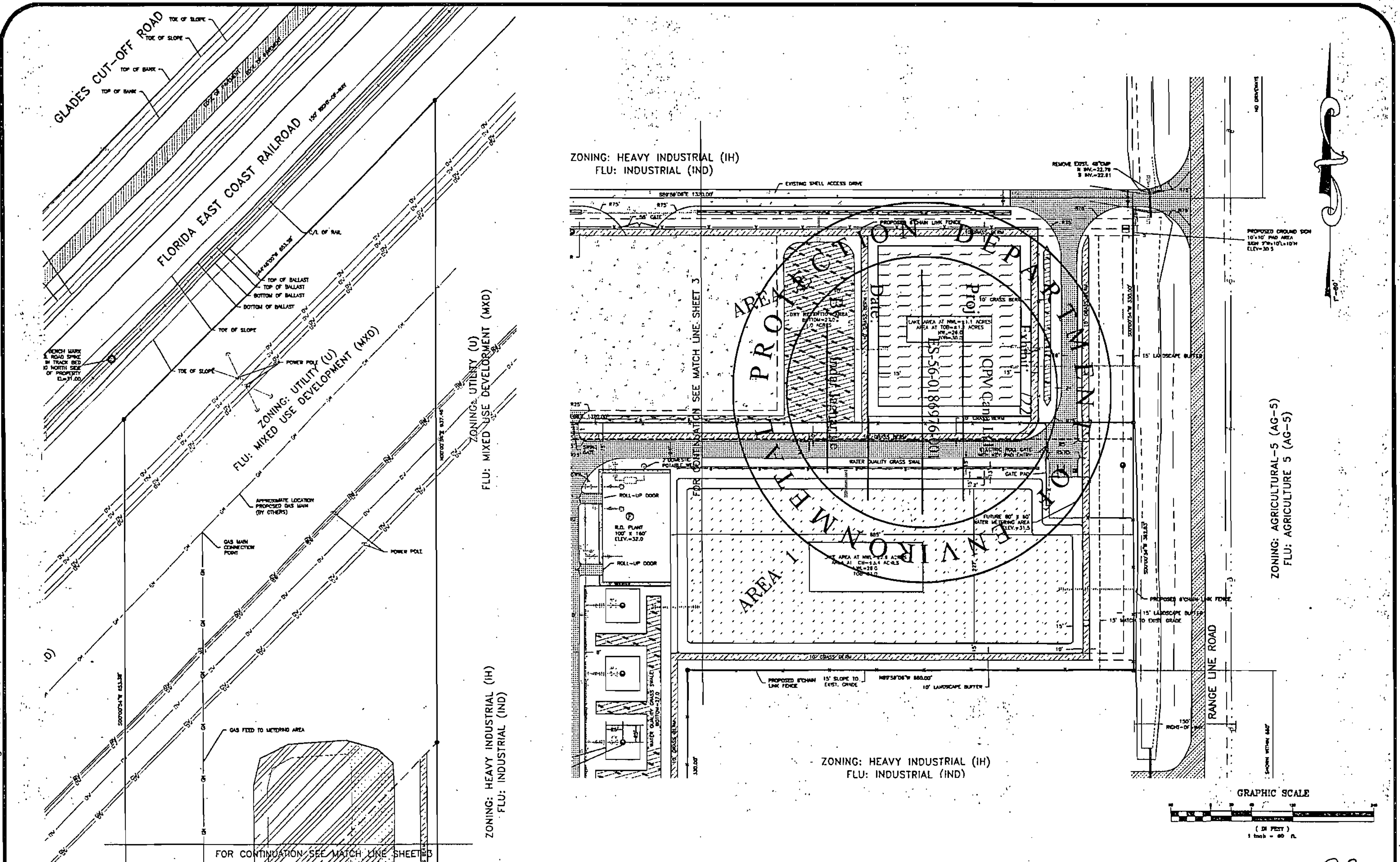
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

SITE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001



REVISIONS: 8/13/01; 7/20/01; 4/06/01. DESIGN SMG DATE 4/12/01; DRAWN BAW DATE 4/12/01; CHECKED DATE	CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	SITE PLAN AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 20 2001

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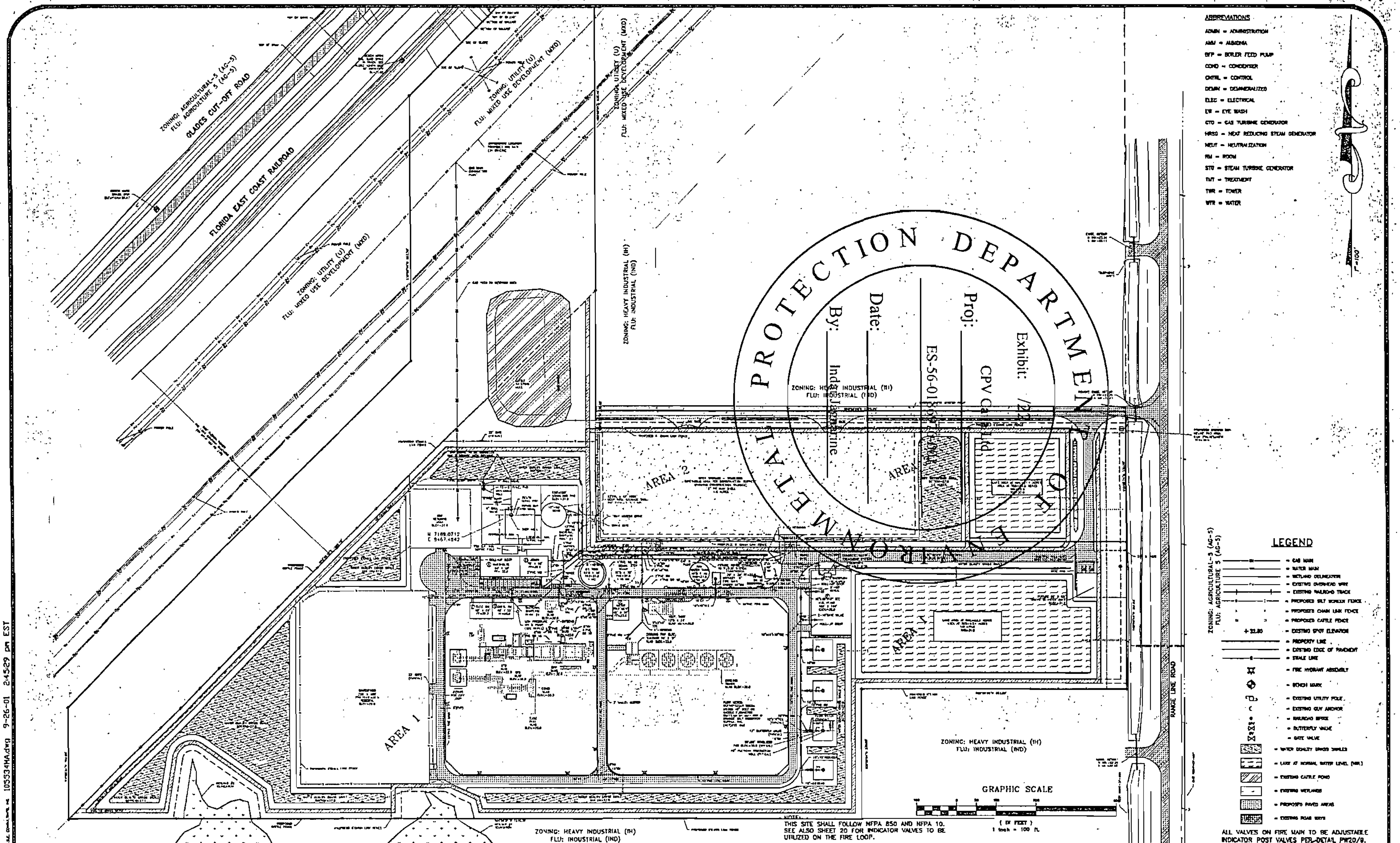

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REVISIONS		9/13/01
		7/20/01
		6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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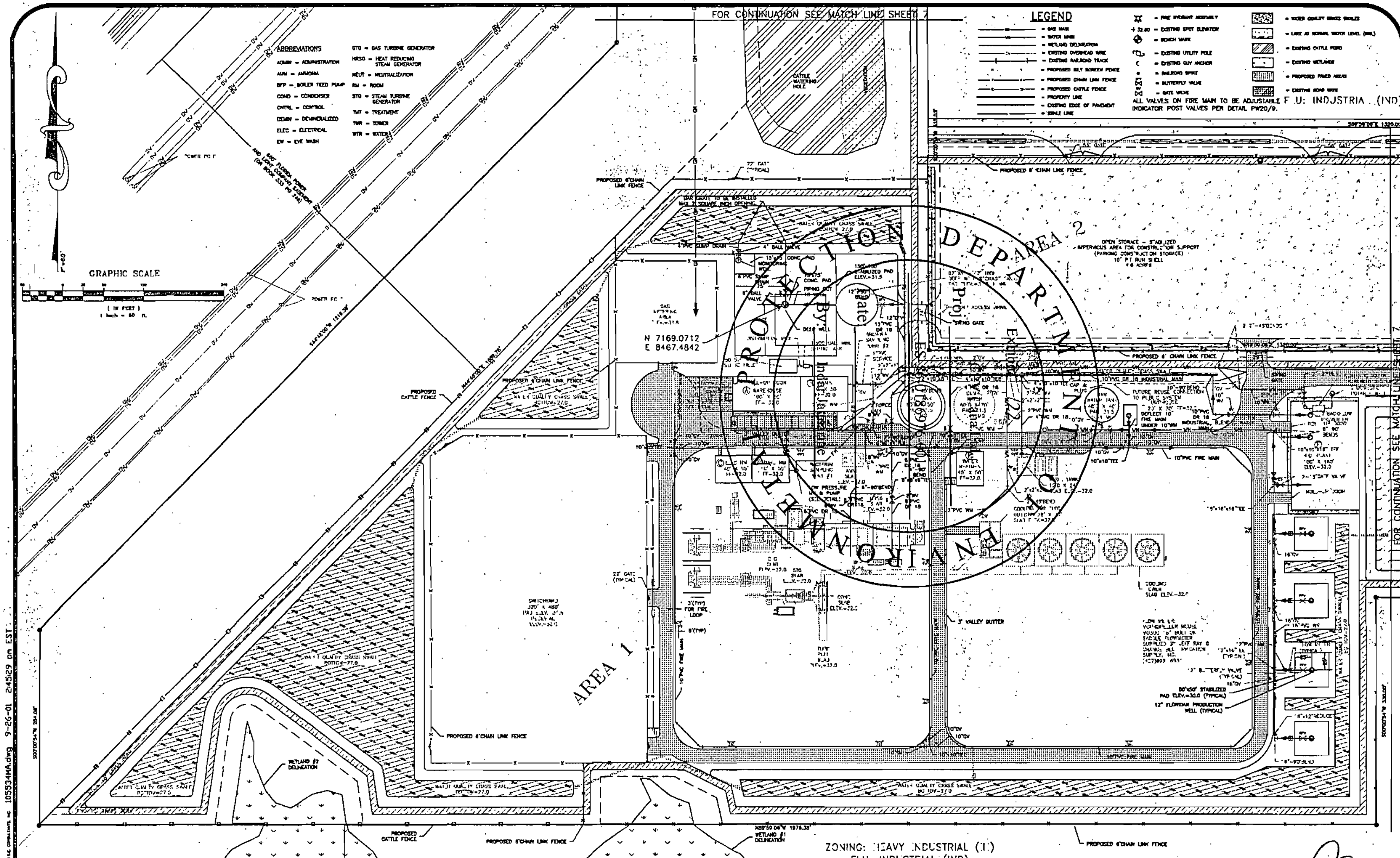
OVERALL UTILITY PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DRAWING NO. 10553405
SHEET 5 OF
PROJECT NO. 10550



REVISIONS	
ENGINEERING COMMENTS	8/13/01
COUNTY COMMENTS	7/30/01
COMMENTS	6/06/01
DESIGN SMG	DATE 4/12/01
DRAWN BAW	DATE 4/12/01
CHECKED	DATE

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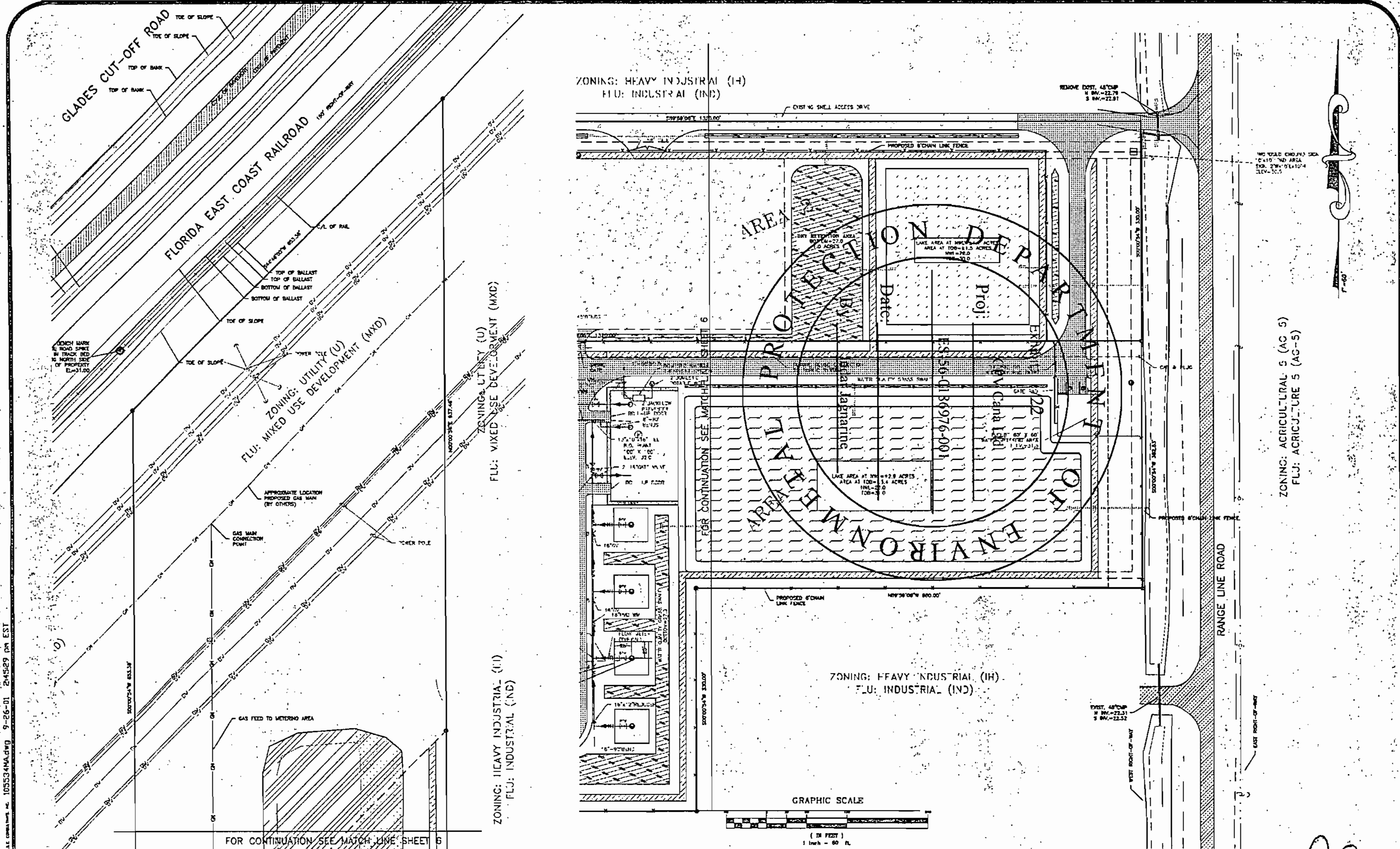
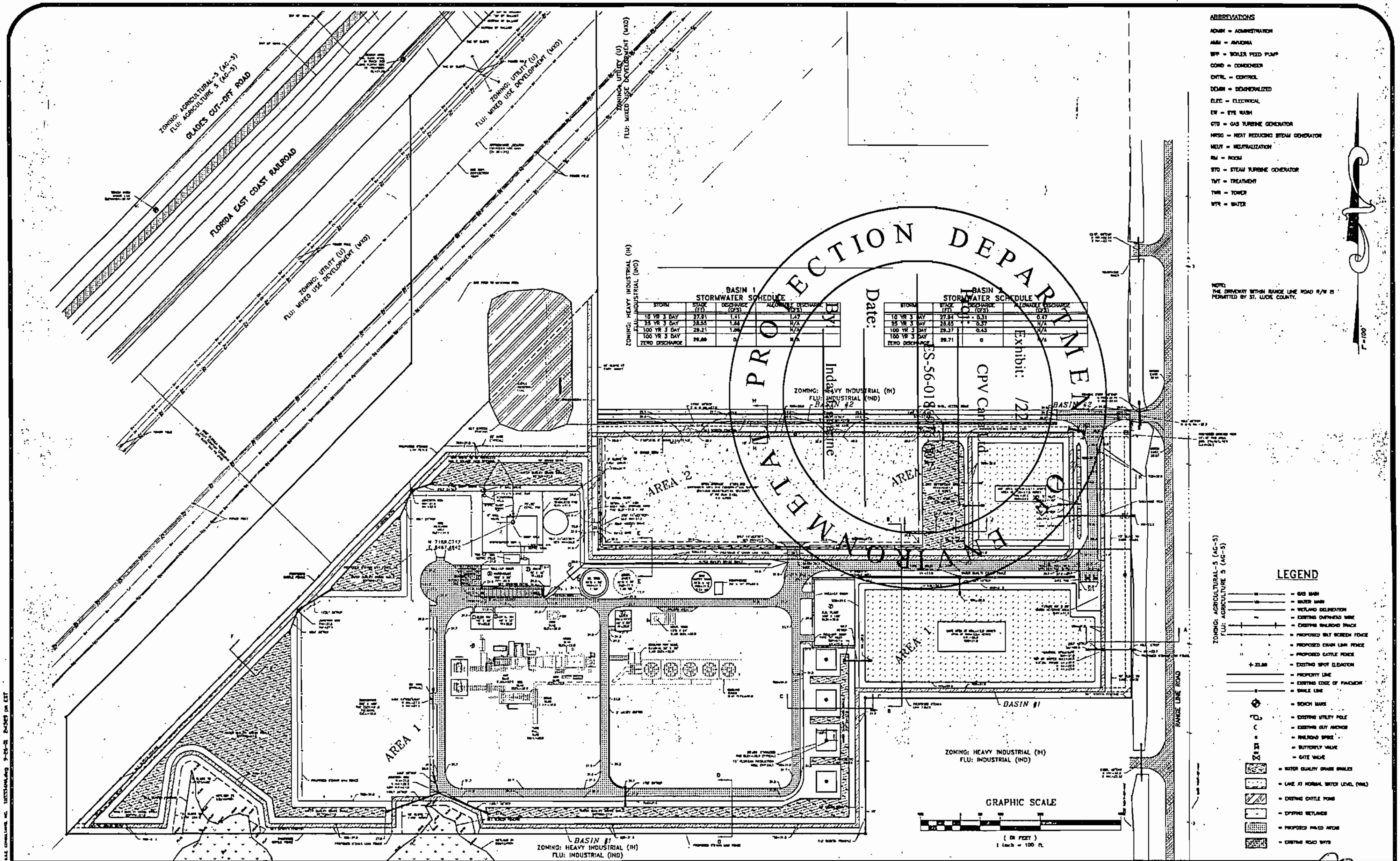
UTILITY PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001



CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	UTILITY PLAN AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001



BASIN 1
STORMWATER SCHEDULE

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.91	1.41	1.47
25 YR 3 DAY	28.53	1.64	N/A
100 YR 3 DAY	29.21	1.88	N/A
100 YR 3 DAY ZERO DISCHARGE	29.80	0	N/A

BASIN 2
STORMWATER SCHEDULE

STORM	STAGE (FT)	DISCHARGE (CFS)	ALLOWABLE DISCHARGE (CFS)
10 YR 3 DAY	27.94	0.31	0.47
25 YR 3 DAY	28.65	0.37	N/A
100 YR 3 DAY	29.37	0.43	N/A
100 YR 3 DAY ZERO DISCHARGE	29.71	0	N/A

REVISIONS		
1	ENGINEERING COMMENTS	8/12/01
2	COUNTY COMMENTS	7/20/01
3	ENGINEER/CLIENT COMMENTS	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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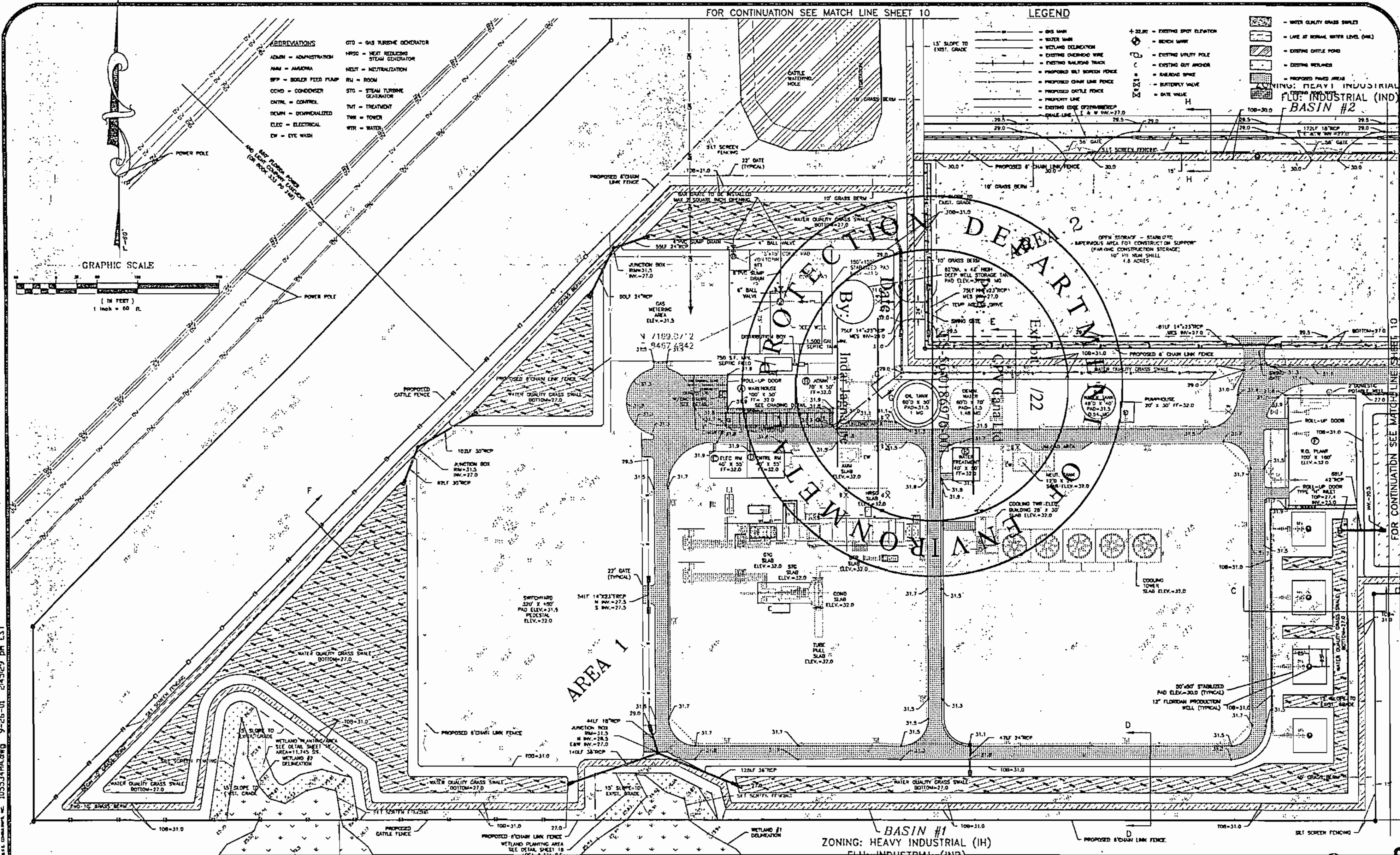
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL DRAINAGE PLAN
AREA 1—BASIN 1, AREA 2—BASIN 2

DRAWING NO. 5533-08
SHEET 8 OF 30

NOV 05 2001



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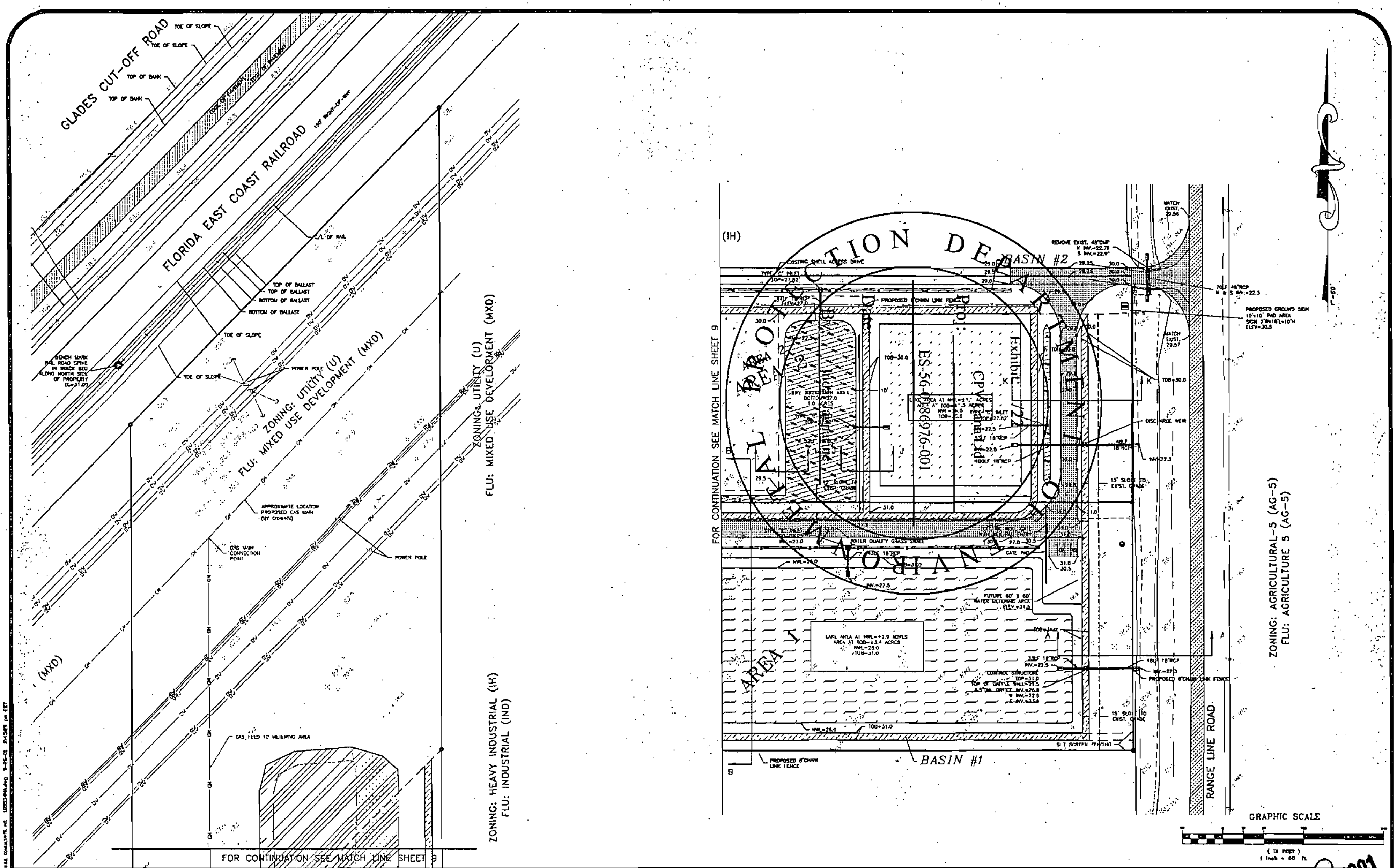
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

DRAINAGE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2



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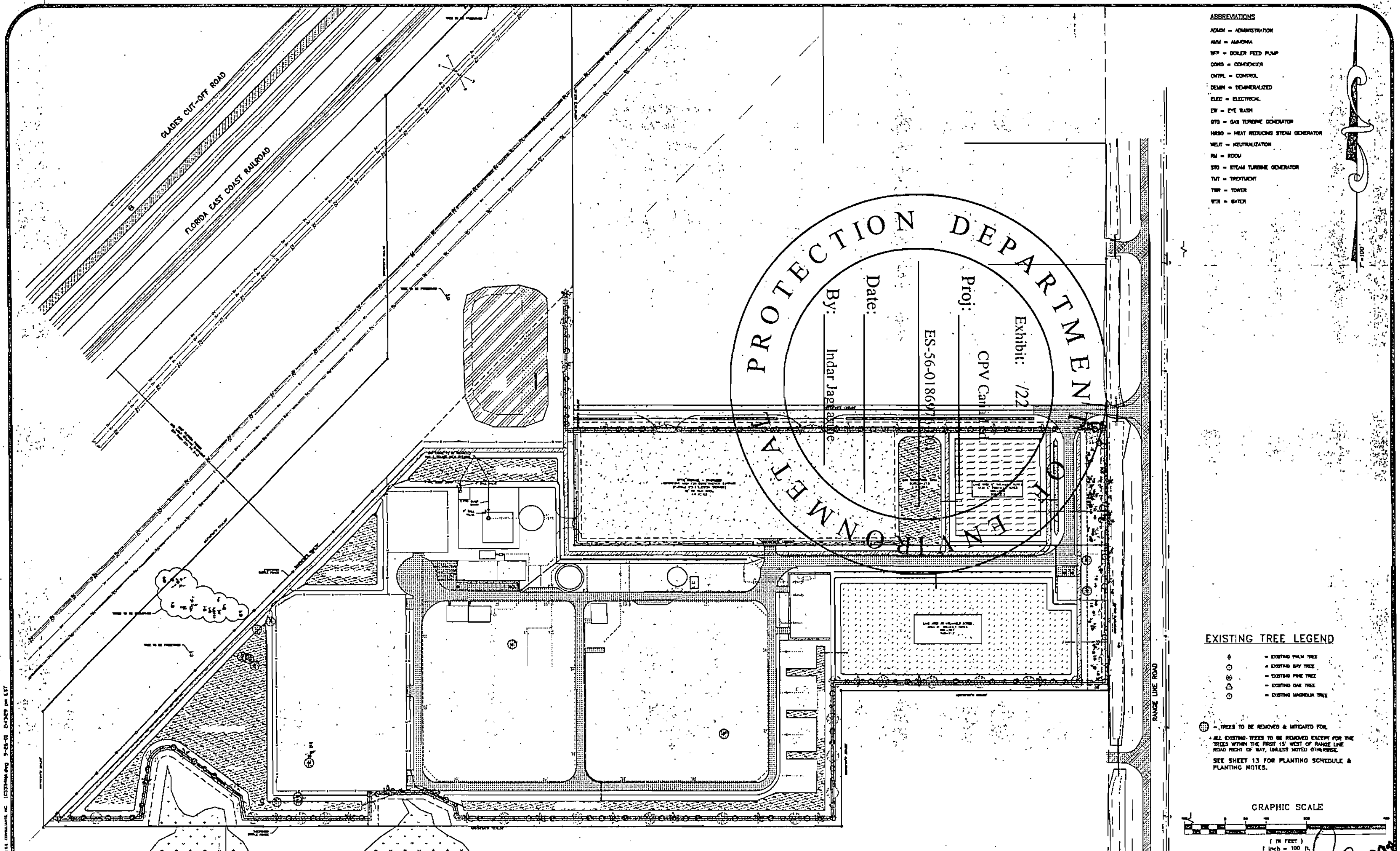
DRAINAGE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01

SHEET 10 OF 30

NOV 05 2001



REVISIONS		
4		
3	ENGINEERING COMMENTS	8/13/01
2	COUNTY COMMENTS	7/20/01
1	PERMIT/SUBMITTAL COMMENTS	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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OVERALL LANDSCAPE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

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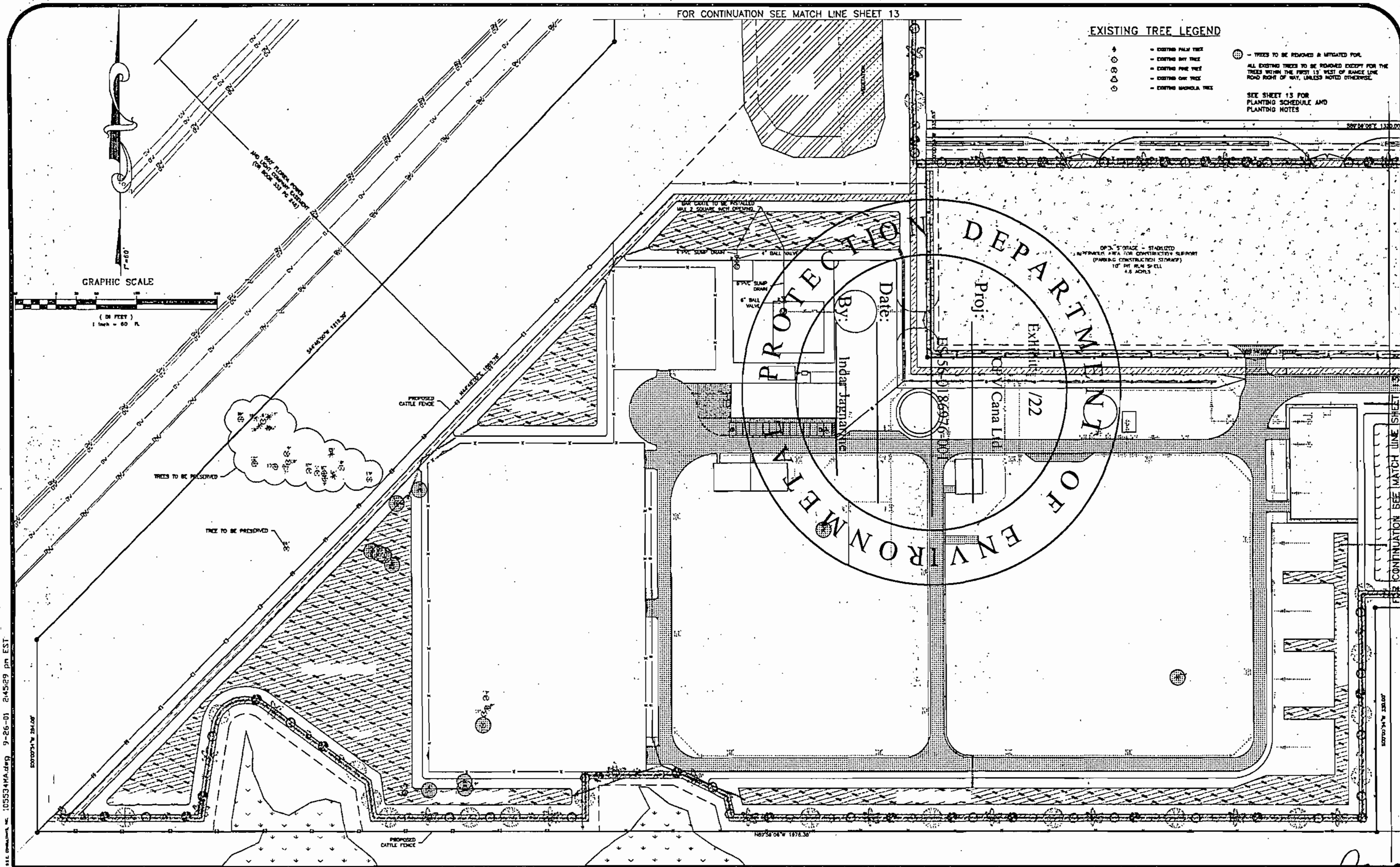

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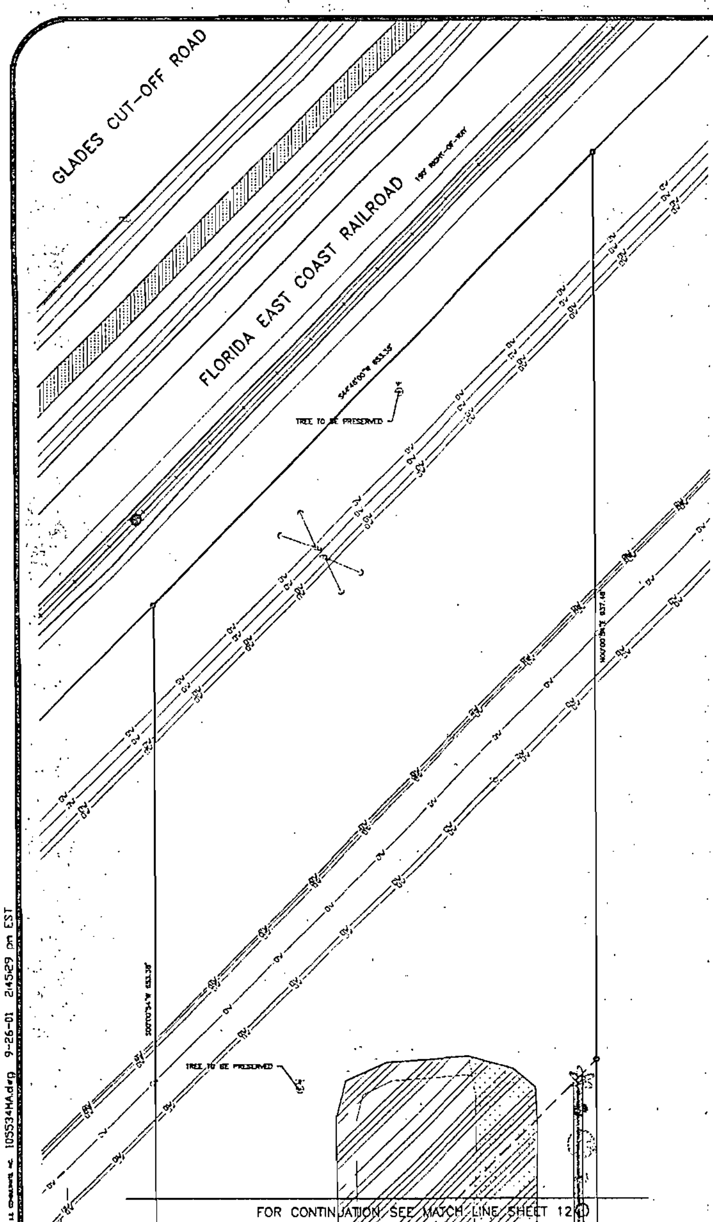
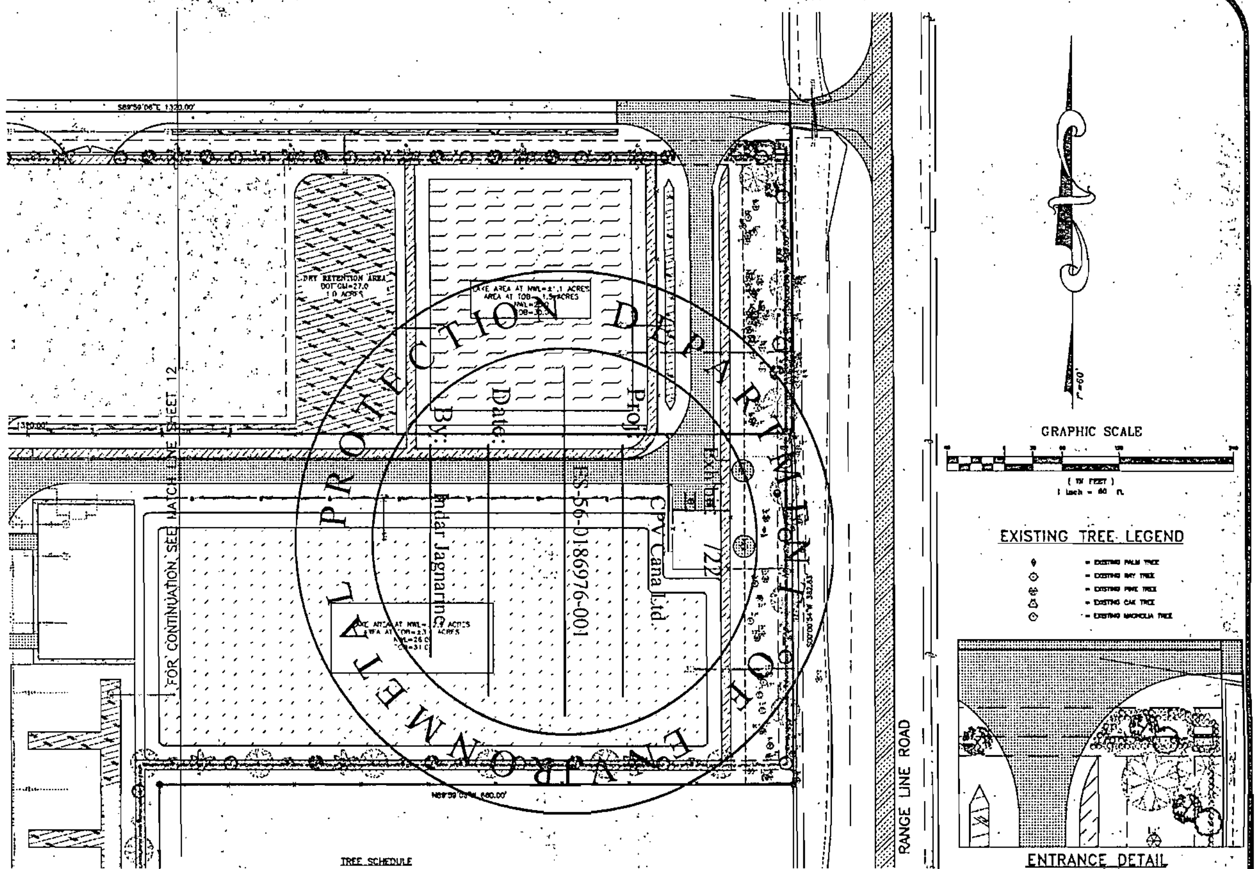
LANDSCAPE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 08 2001





TREE SCHEDULE

SYMBOL	COMMON NAME	BOTANICAL NAME	SPECIFICATION	PERIMETER QUANTITY	TERMINAL LANDSCAPE ISLAND QUANTITY
	LIVE OAK	QUERCUS VIRGINIANA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	30	1
	EAST PALATKA HOLLY	ILEX X ATTENUATA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	42	0
	SLASH PINE	PINUS ELLIOTTII	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	29	0
	CRAPE MYRTLE	LAGERSTROEMIA INDICA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	41	0
	CAROLINA CHERRY LAUREL	PRUNUS CAROLINIANA	2 1/2" CAL. @ 4.5' ABOVE GRADE, 12' HT., 5' SPREAD, 5' CLEAR TRUNK	35	2
			TOTAL	177	3

ENTRANCE DETAIL
SCALE: 1"=30'

MITIGATION SCHEDULE

TYPE OF TREE	INCHES/TREES TO BE REMOVED	PRESERVED INCHES/TREES	INCHES TO BE REPLACED
PINE, MAGNOLIA, OAK	166	766	0
PALM	1X	5	0

SHRUB SCHEDULE

SYMBOL	COMMON NAME	BOTANICAL NAME	SPECIFICATION	BUFFER QUANTITY	TERMINAL LANDSCAPE ISLAND QUANTITY
•	SNOW BERRY	CHIOCOCCA ALBA	3 GAL., 3' O.C., 24" HT.	729	23
•	OLEANDER	NERIUM OLEANDER	3 GAL., 3' O.C., 24" HT.	358	8
•	SOUTHERN WAX MYRTLE	MYRICA CERIFERA	3 GAL., 3' O.C., 24" HT.	726	19
			TOTAL	1813	50

NOTES:

1. ALL MULCHED LANDSCAPED AREAS TO BE COVERED WITH LOXON LSF LANDSCAPE FABRIC, OR EQUAL, PRIOR TO PLANTING AND MULCHING

2. ALL LANDSCAPED AREAS TO 3" MINIMUM DEPTH OF PINE MULCH.

3. TERMINAL ISLAND LANDSCAPE TO BE PLANTED AT THE PROJECT ENTRANCE. 1.6 TIMES THE REQUIRED LANDSCAPING REQUIREMENTS WAS PROVIDED.

- TREES TO BE REMOVED & MITIGATED FOR.

ALL EXISTING TREES TO BE REMOVED EXCEPT FOR THE TREES WITHIN THE FIRST 50' WEST OF RANGE LINE ROAD RIGHT OF WAY, UNLESS NOTED OTHERWISE.

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REVISIONS

4		
3	[illegible] COMMENTS	9/13/01
2	COUNTY COMMENTS	7/20/01
1	OWNER/CLIENT COMMENTS	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

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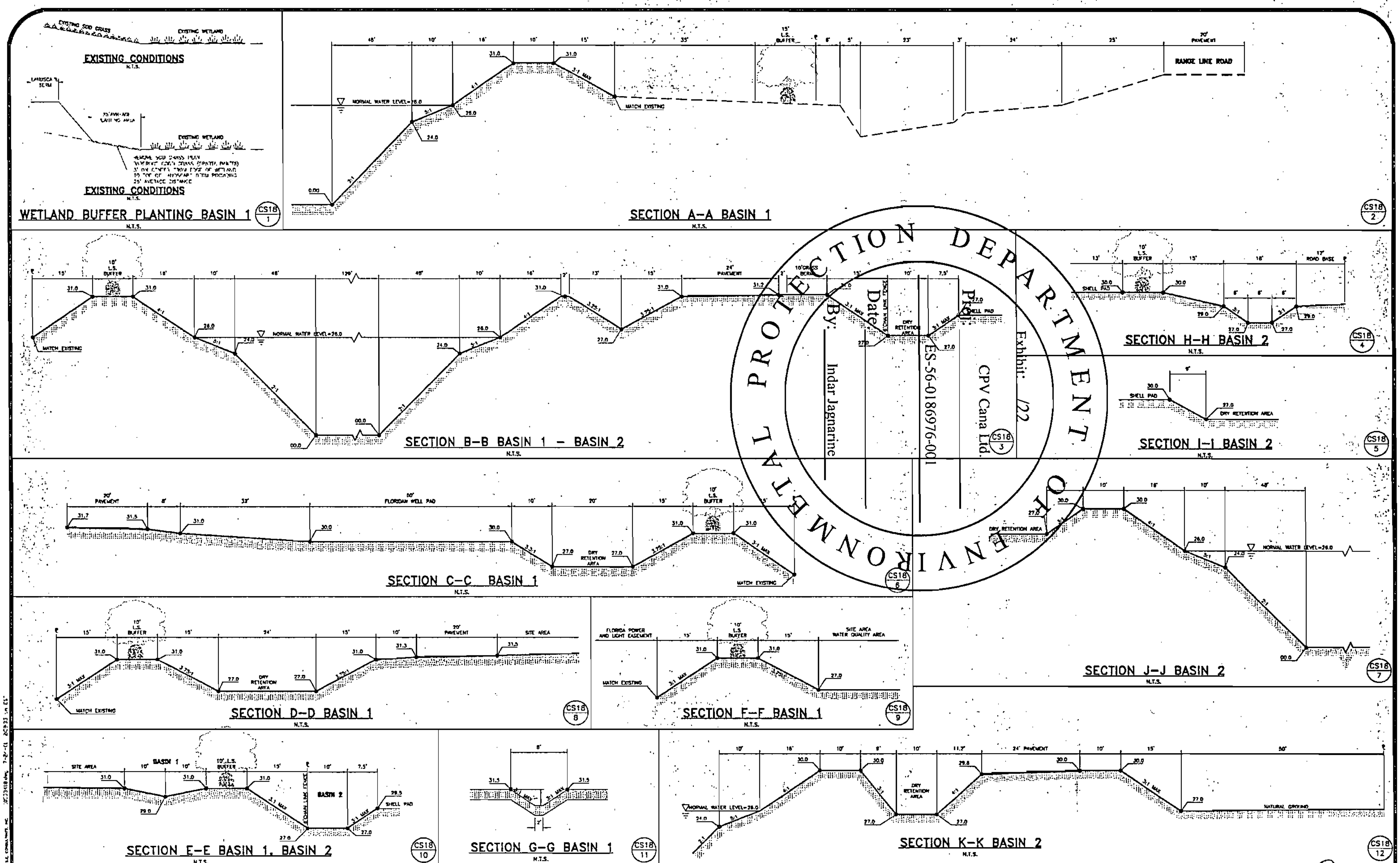
LANDSCAPE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10553416
SHEET 3 OF
PROJECT NO.

NOV 05 2001



DEPARTMENT OF ENVIRONMENTAL PROTECTION

Exhibit: 122

Proj: CPV Cana Ltd.

ES-56-0186976-001

Date

By: Indar Jagnarine

REVISIONS

COUNTY COMMENTS		7/20/01
COMMENTS		8/06/01
DESIGN SMC	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
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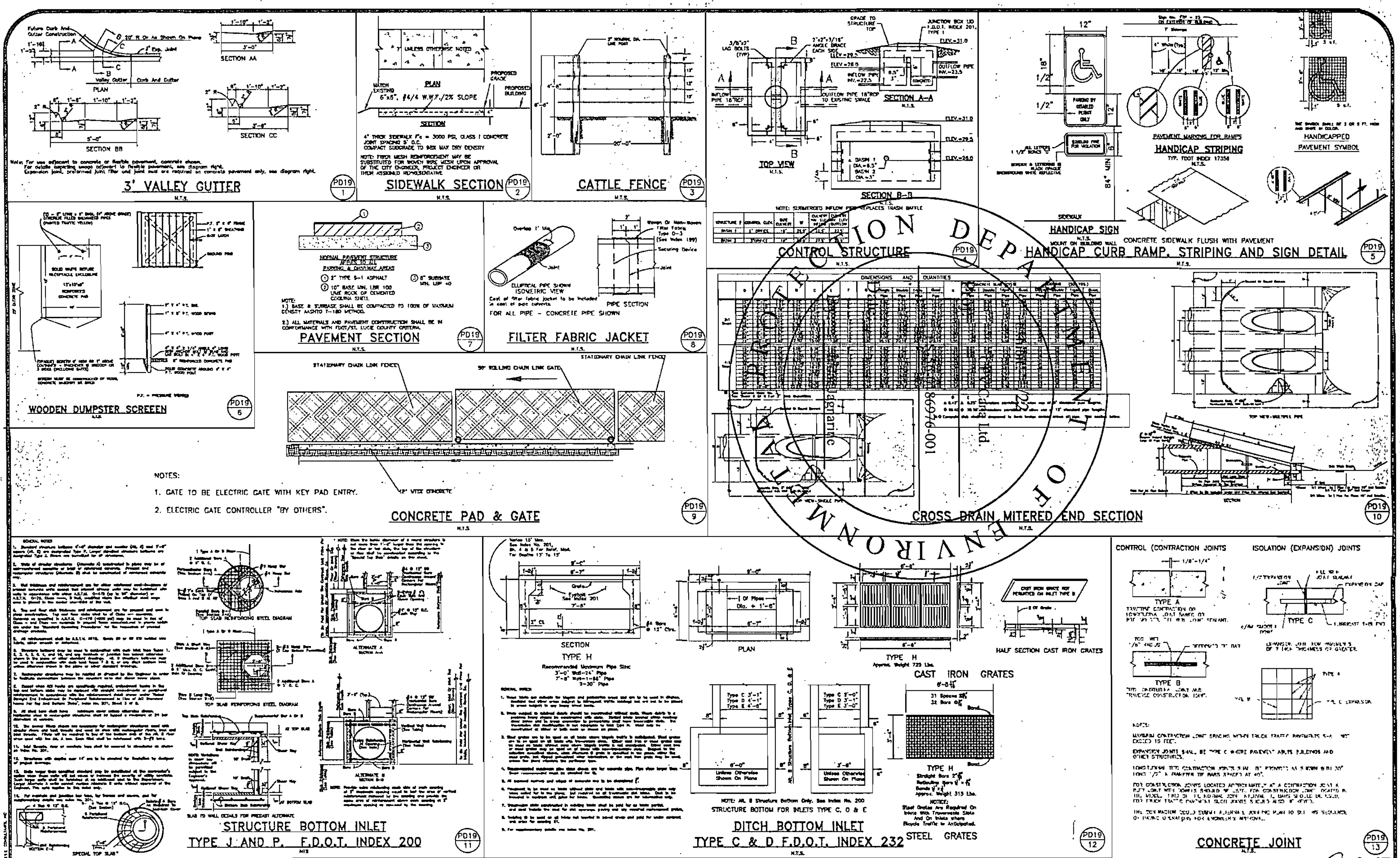
CROSS - SECTIONS
AREA 1-BASIN 1, AREA 2-BASIN 2

NOV 05 2001



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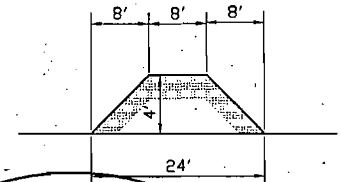
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

PAVING AND DRAINAGE DETAIL
AREA 1-BASIN 1, AREA 2-BASIN 2

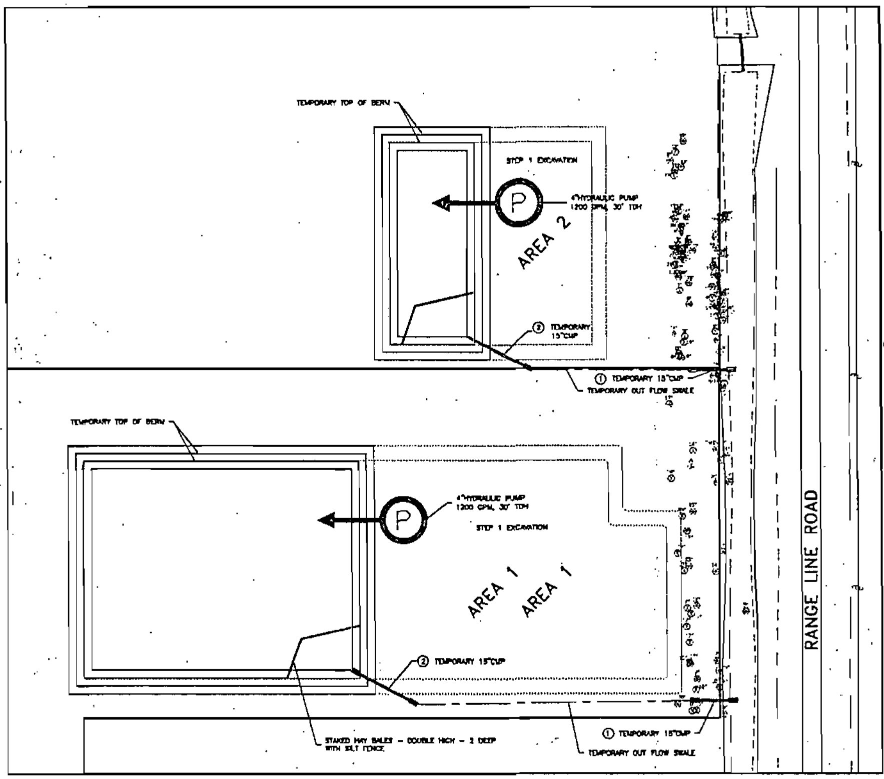
DESIGN SMG DATE 4/12/01
DRAWN BAW DATE 4/12/01

DEWATERING PLAN:

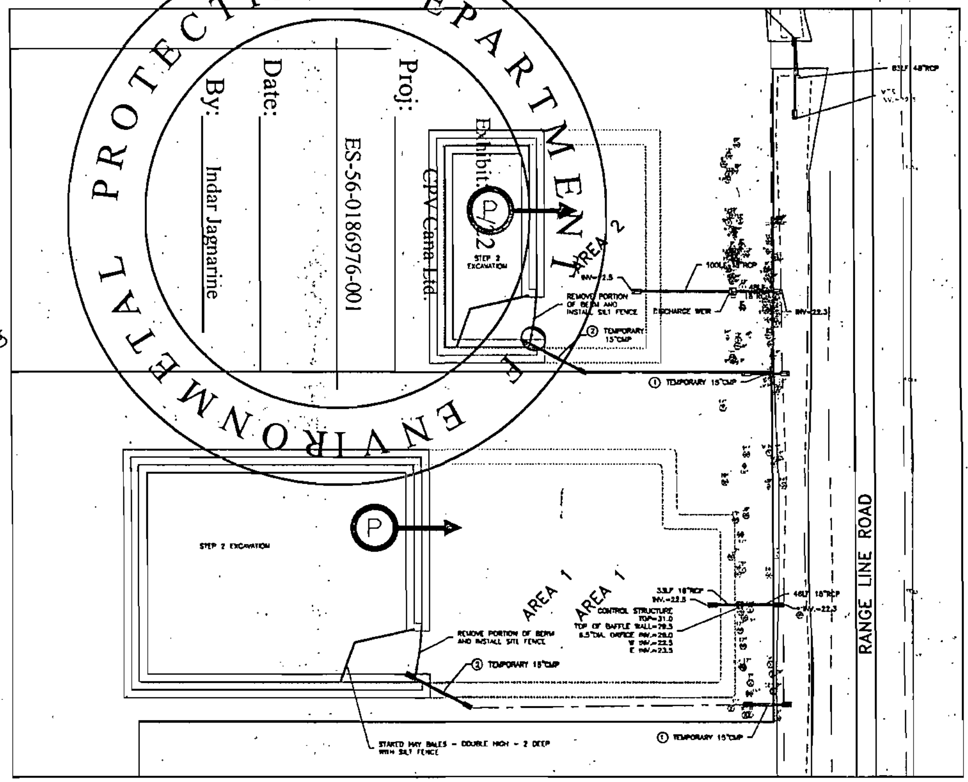
1. INSTALL TEMPORARY 15" DRAINAGE CULVERT (1) TO RANGE LINE ROAD.
2. CONSTRUCT TEMPORARY BERM AS SHOWN.
3. INSTALL TEMPORARY 15" CULVERT (2) THROUGH TEMPORARY BERM, INSTALL HAY BALES & SILT FENCE.
4. EXCAVATE EAST END OF LAKE AS SHOWN (STEP 1).
5. EXCAVATE WEST END OF LAKE AS STEP 2, DEWATER INTO EAST END OF LAKE (EXCAVATED AS STEP 1).
6. REVERSE HYDRAULIC PUMP FOR EXCAVATION OF STEP 2.
7. CONTINUE TO UTILIZE TEMPORARY CULVERTS FOR DEWATERING.
8. CONSTRUCT PERIMETER LANDSCAPE BERMS AND PERIMETER BERMS.
9. INSTALL CONTROL STRUCTURE.
10. REMOVE TEMPORARY DEWATERING CULVERTS AND FILL TEMPORARY DEWATERING SWALE.
11. COMPLETE LANDSCAPE BERM ON SOUTH SIDE OF LAKE.
12. COMPLETE LAKE EXCAVATION IN AREA OF REMOVED TEMPORARY DEWATERING CULVERTS.



TEMPORARY BERM



PHASE 1 DEWATERING



PHASE 2 DEWATERING

GRAPHIC SCALE

(IN FEET)
1 inch = 100 ft.

ENVIRONMENTAL PROTECTION DEPARTMENT
Proj: CPV Cana Ltd.
Exhibit: 2
Date:
ES-56-0186976-001
By: Indar Jagnarine

NOV 05 2001

REVISIONS		
COUNTY COMMENTS		7/20/01
DISPATCH/ELOISE COMMENTS		8/29/01
DESIGN	SMG	DATE 4/12/01
DRAWN	BAW	DATE 4/12/01
CHECKED		DATE

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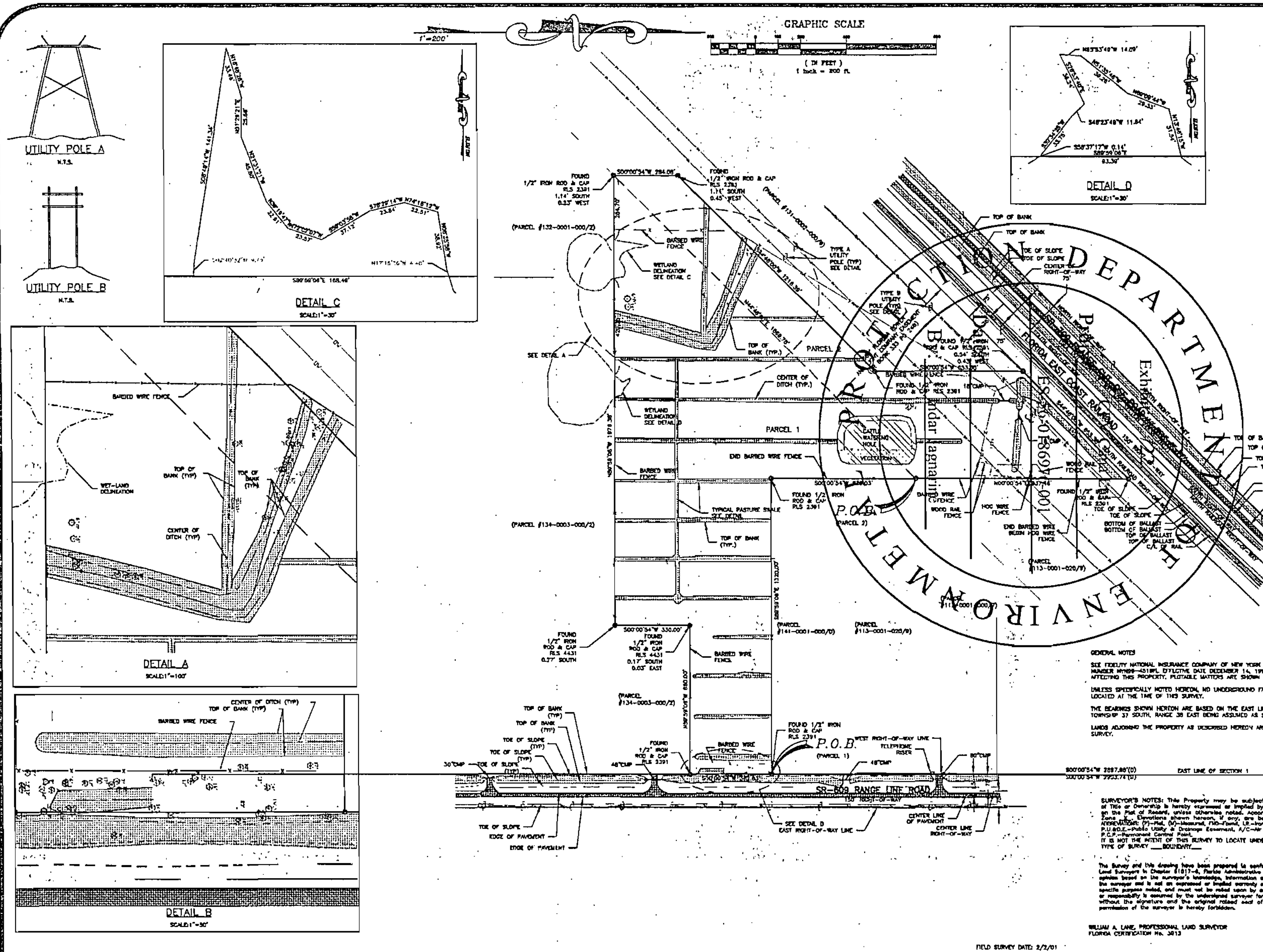
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

DEWATERING PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10533422
SHEET 12 OF



LEGAL DESCRIPTION (PARCEL 1) (O.R.B. 807, PG. 010)

COMMENCE AT THE NORTHEAST CORNER OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA; THENCE RUN S00°00'54"W ALONG THE EAST LINE OF SECTION 1, A DISTANCE OF 2897.88 FEET, TO THE POINT OF BEGINNING; THENCE RUN S00°00'54"W, ALONG THE EAST LINE OF SECTION 1, A DISTANCE OF 352.83 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 660 FEET; THENCE RUN S00°00'54"W, A DISTANCEOF 330.00 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 1978.36 FEET; THENCE RUN N44°48'00"E, ALONG THE EAST LINE OF A FLORIDA POWER AND LIGHT EASEMENT, A DISTANCE OF 1869.78 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 635.03 FEET; THENCE RUN S89°59'06"E, A DISTANCE OF 1320.00 FEET TO THE POINT OF BEGINNING; ALL LYING AND BEING IN SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA AND CONTAINING 36.06 ACRES MORE OR LESS.

LEGAL DESCRIPTION (PARCEL 2) (O.R.B. 807, PG. 010)

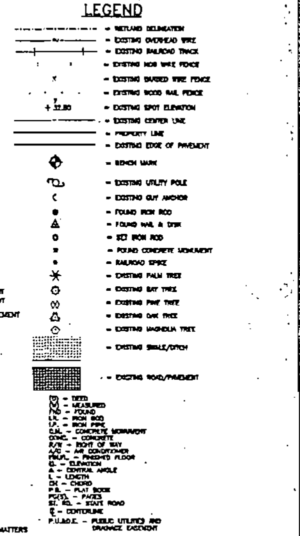
A PARCEL OF LAND IN SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST, ST. LUCIE COUNTY, FLORIDA, SAID PARCEL IS DESCRIBED AS FOLLOWS:

COMMENCE AT THE NORTHEAST CORNER OF SECTION 1, THENCE RUN S00°00'54"W, ALONG THE EAST LINE OF SECTION 1 A DISTANCE OF 2897.88 FEET; THENCE RUN N89°59'06"W, A DISTANCE OF 1320.00 FEET: THENCE RUN N00°00'54"E, A DISTANCE OF 635.03 FEET, TO THE SOUTHEASTERLY LINE OF THE 660 FOOT WIDE FLORIDA POWER AND LIGHT COMPANY EASEMENT, AS DESCRIBED IN OFFICIAL RECORDS BOOK 333, AT PAGE 248, OF THE PUBLIC RECORDS OF ST. LUCIE COUNTY, FLORIDA, AND THE POINT OF BEGINNING;

THENCE CONTINUE N00°00'54"E, A DISTANCE OF 937.46 FEET, TO THE NORTHWESTERLY LINE OF SAID EASEMENT, SAID LINE ALSO BEING THE SOUTHEASTERLY LINE OF THE 150 FOOT WIDE FLORIDA EAST COAST RAILROAD RIGHT-OF-WAY; THENCE RUN S44°48'00"W, ALONG SAID RIGHT-OF-WAY LINE A DISTANCE OF 653.38 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 653.33 FEET; THENCE RUN S44°48'00"W, A DISTANCE OF 1218.38 FEET; THENCE RUN S00°00'54"W, A DISTANCE OF 294.08 FEET, TO THE SAID SOUTHEASTERLY LINE OF THE 660 FOOT WIDE FLORIDA POWER AND LIGHT COMPANY EASEMENT; THENCE RUN N44° 48'00"W, ALONG SAID SOUTHEASTERLY LINE, A DISTANCE OF 1869.78 FEET, TO THE POINT OF BEGINNING.

THE ABOVE DESCRIBED PARCEL CONTAINS 15.4844 ACRES, MORE OR LESS.

LEGEND



GENERAL NOTES

SEE FIDELITY NATIONAL INSURANCE COMPANY OF NEW YORK TITLE COMMITMENT NUMBER [illegible]-4518FL EFFECTIVE DATE DECEMBER 14, 1999 AT 11PM, FOR MATTERS AFFECTING THIS PROPERTY. PLOTABLE MATTERS ARE SHOWN HEREON.

UNLESS SPECIFICALLY NOTED HEREON, NO UNDERGROUND FACILITIES HAVE BEEN LOCATED AT THE TIME OF THIS SURVEY.

THE BEARINGS SHOWN HEREON ARE BASED ON THE EAST LINE OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST BEING ASSUMED AS S00°00'54"W

LANDS ADJOINING THE PROPERTY AS DESCRIBED HEREON ARE NOT A PART OF THIS SURVEY.

SURVEYOR'S NOTES: This Property may be subject to easements, restrictions, or limitations, either recorded or implied. No opinion of Title or Ownership is hereby expressed or implied by the Surveyor. Bearings shown hereon are based on the Centerline of the Street as shown on the Plat of Record, unless otherwise noted. According to F.I.R.M. #12111C0275 F, Dated August 19, 1991, this property is within Flood Zone X. Elevations shown hereon, if any, are based on National Geodetic Vertical Control Datum of 1929, unless otherwise shown. ABBREVIATIONS: (P)—Plat, (M)—Measured, FND—Found, I.R.—Iron Rod, I.P.—Iron Pipe, C.M.—Concrete Monument, CONC.—Concrete, C/L—Centerline, R/W—Right of Way, P.U.&D.E.—Public Utility & Drainage Easement, A/C—Air Conditioner, Fin.Fl.—Finished Floor, Elev.—Elevation, Δ—Central Angle, L—Length, C.H.—Chord, P.C.P.—Permanent Control Point.
IT IS NOT THE INTENT OF THIS SURVEY TO LOCATE UNDERGROUND STRUCTURES.
TYPE OF SURVEY BOUNDARY

The Survey and this drawing have been prepared to conform with applicable Minimum Technical Standards as set forth by The Florida Board of Professional Land Surveyors in Chapter 61G17-6, Florida Administrative Code, pursuant to Section 472.027, Florida Statutes. This Certification is a statement of professional opinion based on the surveyor's knowledge, information and belief, which is based on the existing field evidence and documentary evidence as provided to the surveyor and is not an expressed or implied warranty or guaranty. This survey is for the sole and exclusive benefit of the parties named hereon and for the specific purpose noted, and must not be relied upon by any other individual or entity whatsoever, and is not transferable under any circumstances. No liability or responsibility is assumed by the undersigned surveyor for any other use of this survey or to any party not specifically named hereon. This drawing is not valid without the signature and the original raised seal of a Florida licensed surveyor and mapper, and reproduction of this drawing without written permission of the surveyor is hereby forbidden.

WILLIAM A. LANE, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 3013

SCOTT M. GLAUBITZ, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 41[illegible]

B.S.E. CONSULTANTS, INC. LB No. 4905

FIELD SURVEY DATE: 2/2/01

REVISIONS		
COUNTY COMMENTS (BAW)		7/20/01
DESIGN SMG	DATE	2/2/01
DRAWN BAW	DATE	2/20/01
CHECKED	DATE	

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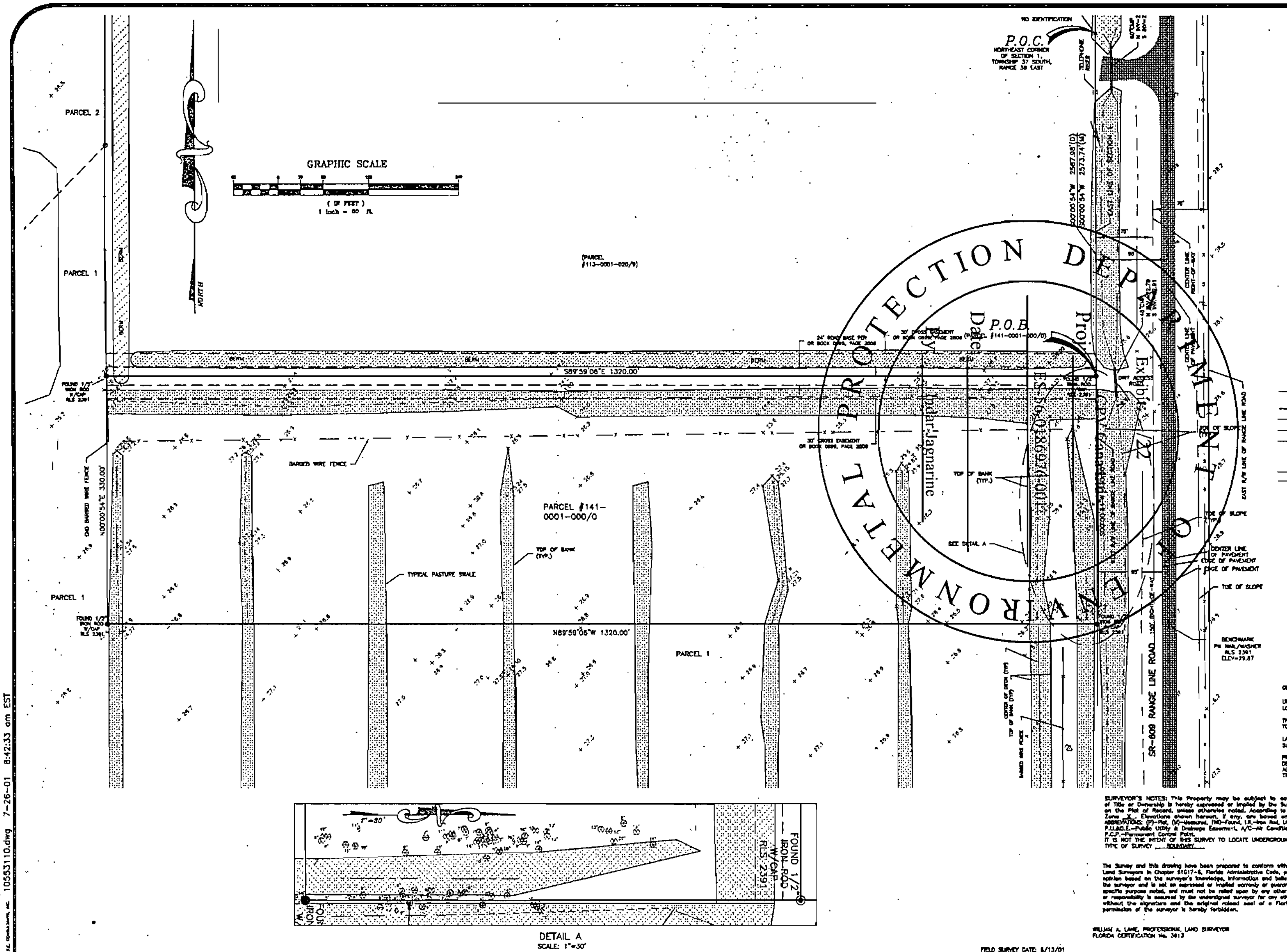
BOUNDARY SURVEY – AREA 1

DRAWING NO. 10553100
SHEET 23

PROJECT NO. 10553

10553100.dwg 7-26-01 8:39:20 am EST

NOV 2001



LEGAL DESCRIPTION (PARCEL #141-0001-000/0)

A parcel of land in Section 1, Township 37 South, Range 38 East, St. Lucie County, Florida, said Parcel is described as follows:

Commence at the NE corner of Section 1, Township 37 South, Range 38 East, St. Lucie County, Florida, thence run S00°00'54" W along the East line of said Section 1, a distance of 2567.98 feet, to the POINT OF BEGINNING, thence continue S00°00'54"W along the East line of said Section 1, a distance of 330.00 feet, thence run N89°59'08"W a distance of 1320 feet, thence run N00°00'54"E a distance of 330.00 feet, thence S89°59'08"E a distance of 1320 feet to the POINT OF BEGINNING, ALL LYING AND BEING IN Section 1, Township 37 South, Range 38 East East, St. Lucie County, Florida, and Containing 10.00 acres more or less.

LEGEND

- = WETLAND DELINEATION
- = EXISTING OVERHEAD WIRE
- = EXISTING RAILROAD TRACK
- = EXISTING HOG WIRE FENCE
- = EXISTING BARBED WIRE FENCE
- = EXISTING WOOD RAIL FENCE
- = EXISTING SPOT ELEVATION
- = EXISTING CENTER LINE
- = PROPERTY LINE
- = EXISTING EDGE OF PAVEMENT
- = BENCH MARK
- = EXISTING UTILITY POLE
- = EXISTING GUY ANCHOR
- = FOUND IRON ROD
- = FOUND NAIL & DISK
- = SET IRON ROD
- = FOUND CONCRETE MONUMENT
- = RAILROAD SPIKE
- = EXISTING PALM TREE
- = EXISTING BAY TREE
- = EXISTING PINE TREE
- = EXISTING OAK TREE
- = EXISTING MAGNOLIA TREE
- = EXISTING SWALE/DITCH
- = EXISTING ROAD/PAVEMENT

(D) - DEED
(M) - MEASURED
FND - FOUND
I.R. - IRON ROD
I.P. - IRON PIPE
C.M. - CONCRETE MONUMENT
CONC. - CONCRETE

GENERAL NOTES

UNLESS SPECIFICALLY NOTED HEREON, NO UNDERGROUND FACILITIES HAVE BEEN LOCATED AT THE TIME OF THIS SURVEY.

THE BEARINGS SHOWN HEREON ARE BASED ON THE EAST LINE OF SECTION 1, TOWNSHIP 37 SOUTH, RANGE 38 EAST BEING ASSUMED AS S00°00'54"W

LANDS ADJOINING THE PROPERTY AS DESCRIBED HEREON ARE NOT A PART OF THIS SURVEY.

PROJECT BENCHMARK IS A BRASS DISK ST. LUCIE COUNTY VERTICAL CONTROL 2000 DESIGNATION = EMMA ALONG THE NORTH SIDE OF GLADES CUT-OFF ROAD RIGHT OF WAY ALONG THE NORTH SIDE OF PROPERTY, ELEVATION 28.67 N.G.V.D. AND RAILROAD SPIKE IN TRACK BED ALONG NORTH SIDE OF PROPERTY, ELEVATION 31.00 N.G.V.D.

SURVEYOR'S NOTES: This Property may be subject to easements, restrictions, or limitations, either recorded or implied. No opinion of Title or Ownership is hereby expressed or implied by the Surveyor. Bearings shown hereon are based on the Centerline of the Street as shown on the Plat of Record, unless otherwise noted. According to F.I.R.M. #12111C0275 F, Dated August 19, 1991, this property is within Flood Zone X. Elevations shown hereon, if any, are based on National Geodetic Vertical Control Datum of 1929, unless otherwise shown. ABBREVIATIONS: (P)-Plat, (M)-Measured, FND-Found, I.R.-Iron Rod, I.P.-Iron Pipe, C.M.-Concrete Monument, CONC.-Concrete, C/L-Centerline, R/W-Right of Way, P.U.&D.E.-Public Utility & Drainage Easement, A/C-Air Conditioner, Fin.Fl.-Finished Floor, Elev.-Elevation, Δ-Central Angle, L-Length, C.H.-Chord, P.C.P.-Permanent Control Point.
IT IS NOT THE INTENT OF THIS SURVEY TO LOCATE UNDERGROUND STRUCTURES.
TYPE OF SURVEY BOUNDARY

The Survey and this drawing have been prepared to conform with applicable Minimum Technical Standards as set forth by The Florida Board of Professional Land Surveyors in Chapter 61G17-6, Florida Administrative Code, pursuant to Section 472.027, Florida Statutes. This Certification is a statement of professional opinion based on the surveyor's knowledge, information and belief, which is based on the existing field evidence and documentary evidence as provided to the surveyor and is not an expressed or implied warranty or guaranty. This survey is for the sole and exclusive benefit of the parties named hereon and for the specific purpose noted, and must not be relied upon by any other individual or entity whatsoever, and is not transferable under any circumstances. No liability or responsibility is assumed by the undersigned surveyor for any other use of this survey or to any party not specifically named hereon. This drawing is not valid without the signature and the original raised seal of a Florida licensed surveyor and mapper, and reproduction of this drawing without written permission of the surveyor is hereby forbidden.

WILLIAM A. LANE, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 3613

SCOTT M. GLAUBITZ, PROFESSIONAL LAND SURVEYOR
FLORIDA CERTIFICATION No. 4151

B.S.E. CONSULTANTS, INC. LB No. 4905

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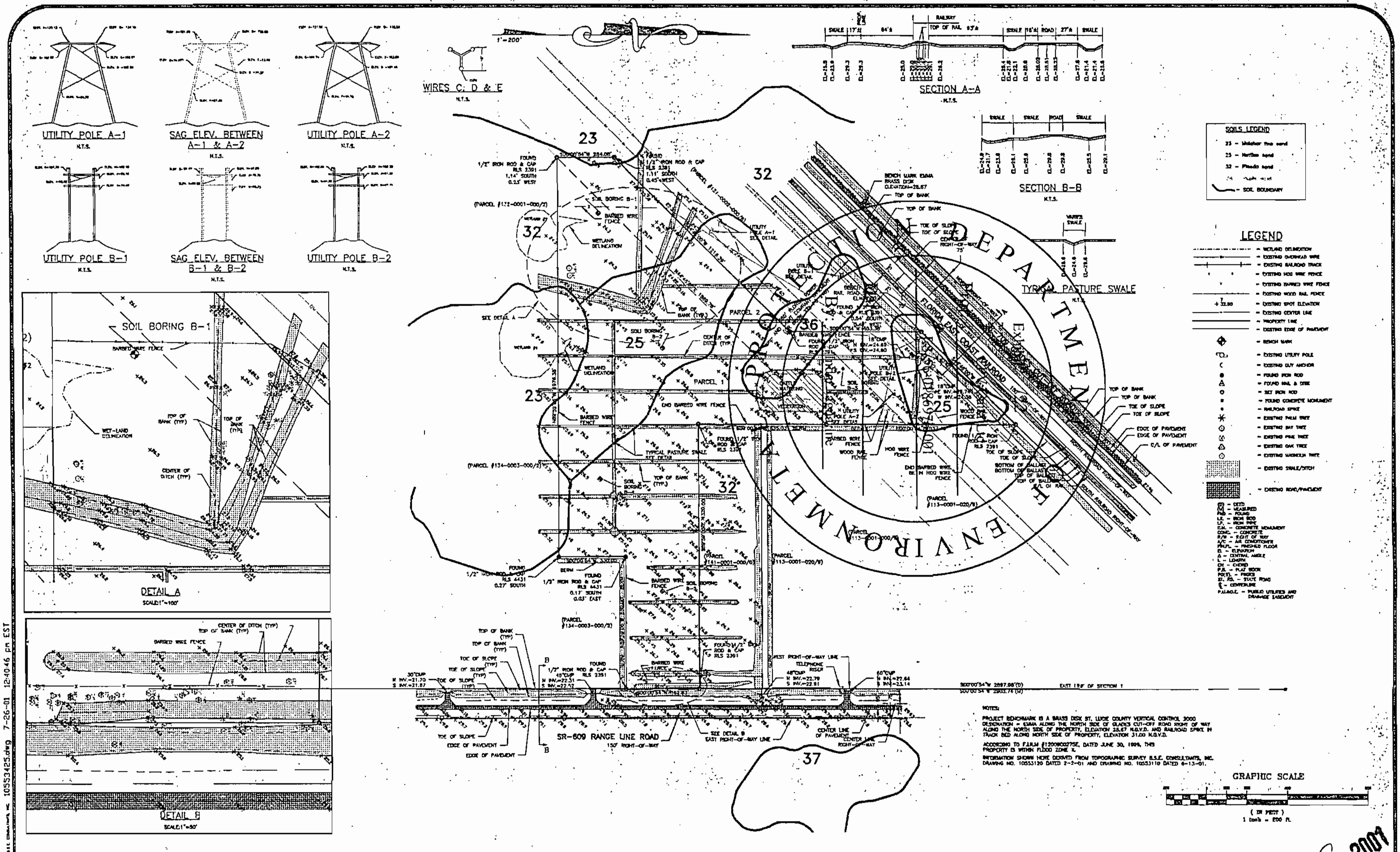
BOUNDARY & TOPOGRAPHIC SURVEY – AREA 2

REVISIONS: COUNTY COMMENTS(BAW) 7/20/01
DESIGN SMG DATE 2/2/01
DRAWN RBS DATE 6/27/01

DRAWING NO. 10553110 SHEET 2 OF 4

10553110.dwg 7-26-01 8:42:33 am EST

DEPARTMENT OF ENVIRONMENTAL PROTECTION
ES 56-0186970-001
CPV CANA
Exhibit 22
Indar Jagnarine
NOV 05 2001



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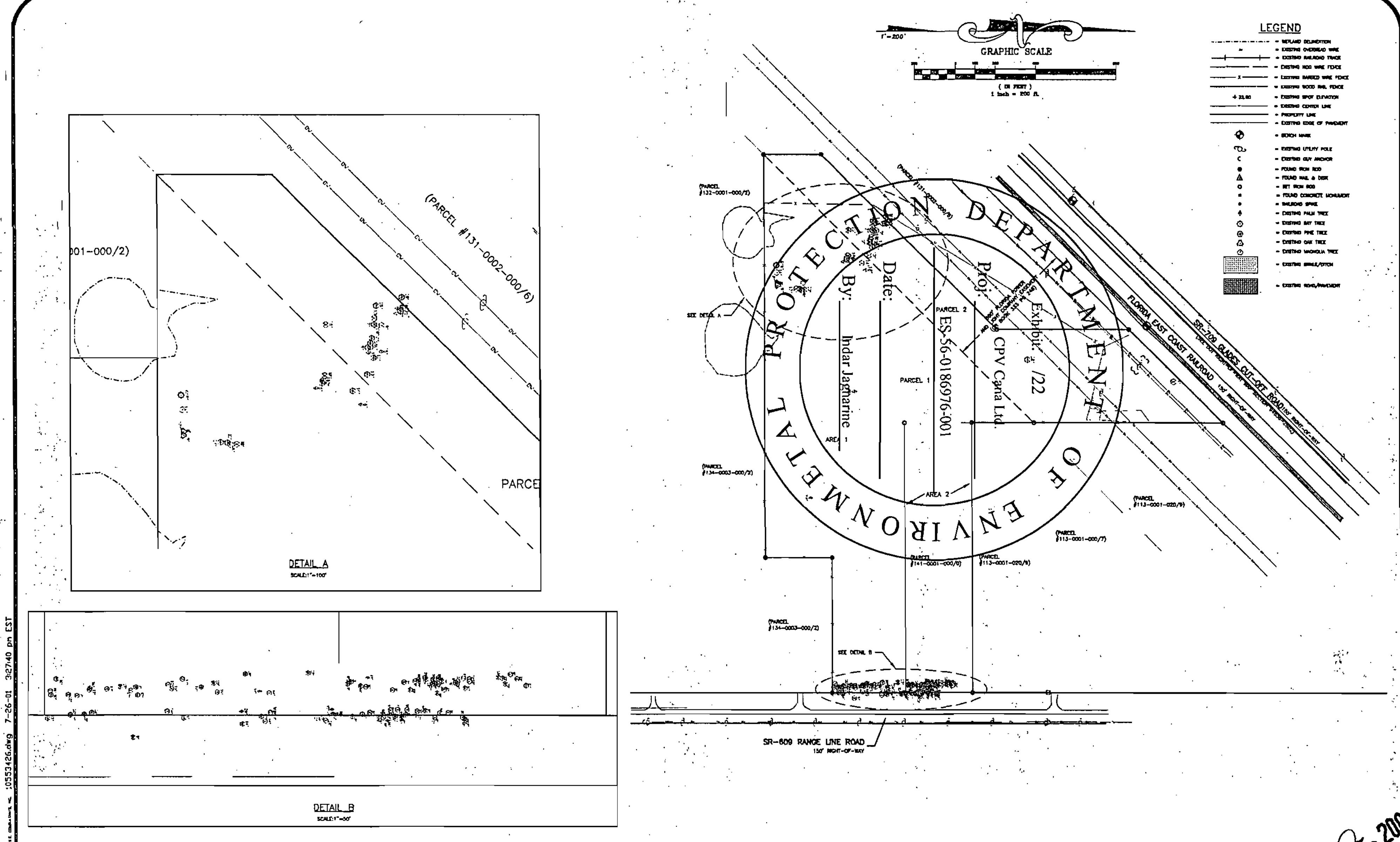
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

EXISTING CONDITIONS

10553425.dwg 7-26-01 12:40:46 pm EST

NOV 08 2001



10553426.dwg 7-26-01 3:27:40 pm EST

REVISIONS		
DESIGN	SMC	DATE 7/25/01
DRAWN	BAW	DATE 7/25/01
CHECKED		DATE

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312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

TREE SURVEY
AREA 1 & AREA 2

NOV 2001

PROJECT NO. 10553426

GENERAL NOTES

1. ALL CONSTRUCTION SHALL BE IN ACCORDANCE WITH APPLICABLE FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION AND CITY OF PORT ST. LUCIE UTILITY SYSTEMS DEPARTMENT REQUIREMENTS AND SPECIFICATIONS. IF ANY CONFLICTS EXIST BETWEEN THE STANDARDS, THE MORE STRINGENT SHALL APPLY.

2. STANDARD SEPARATION FOR ALL WATER AND/OR WASTEWATER MAINS, HORIZONTAL AND VERTICAL, SHALL BE PER FDEP REQUIREMENTS, PROVISIONS OF F.A.C. RULE 17.604 AND [illegible] STANDARDS.

3. THE CONTRACTOR SHALL CONTACT THE ENGINEER OF RECORD, THE APPROPRIATE GOVERNMENTAL JURISDICTIONAL AGENCY AND ALL UTILITY COMPANIES AT LEAST 48 HOURS PRIOR TO COMMENCEMENT OF CONSTRUCTION FOR COORDINATION OF ANY UTILITIES.

4. NO POLLUTION OR EROSION CAUSED BY THIS PROJECT WILL BE ALLOWED IN THE STORMWATER DRAINAGE SYSTEM. THE CONTRACTOR SHALL INSTALL ANY DEVICES NECESSARY TO PREVENT POLLUTION OR EROSION IN ACCORDANCE WITH FDOT ROADWAY AND TRAFFIC DESIGN STANDARDS, INDEX 102. THE COST OF POLLUTION AND EROSION CONTROL SHALL BE INCIDENTAL TO THE COST OF CONSTRUCTION.

5. CONTRACTOR SHALL MAINTAIN TRAFFIC AT ALL TIMES WHILE WORK IS IN PROGRESS. TRAFFIC CONTROL, BARRICADES, ETC. SHALL BE ACCORDANCE WITH APPLICABLE FLORIDA DEPARTMENT OF TRANSPORTATION AND OSHA STANDARDS. IF ANY CONFLICT EXISTS BETWEEN THE STANDARDS, THE MORE STRINGENT GOVERNS, AS DETERMINED BY THE ENGINEER OF RECORD.

6. NO FIELD CHANGES OR DEVIATIONS FROM DESIGN TO BE MADE WITHOUT PRIOR WRITTEN APPROVAL OF THE UTILITY AND ENGINEER OF RECORD.

7. ALL MATERIALS, CONSTRUCTION METHODS, TESTING AND DISINFECTION SHALL CONFORM TO THE REQUIREMENTS OF THE CITY OF PORT ST. LUCIE UTILITY SYSTEMS DEPARTMENT AND AWWA CURRENT STANDARDS.

8. CONTRACTOR SHALL REPAIR OR REPLACE ANY DAMAGE CAUSED BY CONSTRUCTION ACTIVITY.

9. AS-BUILT PLANS FOR WATER/SEWER MAINS SHALL BE PROVIDED BY CONTRACTOR/ENGINEER OF RECORD. A REPRODUCIBLE MYLAR COPY AND THREE (3) BLUELINE COPIES OF A CERTIFIED SURVEY. THE BLUELINE COPIES SHALL BEAR THE ORIGINAL SIGNATURE AND EMBOSSED SEAL OF THE SURVEYOR THAT PERFORMED THE AS-BUILT SURVEY. THE AS-BUILTS SHALL BE SUBMITTED AFTER THE COMPLETION OF CONSTRUCTION, PRIOR TO SUBMITTAL TO THE FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION. THE AS-BUILT [illegible]

[illegible]

INSPECTORS AUTHORITY

[illegible]

EARTHWORK

[illegible]

UTILITY EXCAVATION, BACKFILLING & COMPACTING

PART -- GENERAL

1.1 SECTION DESCRIPTION

[illegible]

UTILITY PIPE AND FITTINGS

[illegible]

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GENERAL NOTES

REVISIONS		
COUNTY COMMENTS		7/20/01
DESIGN	SMG	DATE 4/14/01
DRAWN	EAK	DATE 4/14/01
CHECKED		DATE

DRAWING NO. 0553-29
SHEET 29 OF 30
PROJECT NO. 0553

NOV 2001

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Proj: CPV Cana Ltd.
ES-56-0186976-001

UTILITY VALVES AND APPURTENANCES

PART 1—GENERAL

1.1 SECTION DESCRIPTION

1.2 SUBMITTALS

PART 2—PRODUCTS

2.1 GENERAL

2.2 Gate Valves (GV)

2.3 Butterfly Valves (BFV)

2.4 Ball Valves (BV)

2.5 Plug Valves (PV)

2.5 Check Valves (CV)

VALVE APPURTENANCES

FIRE HYDRANT ASSEMBLIES

PART 1—GENERAL

1.1 SECTION DESCRIPTION

1.2 SUBMITTALS

PART 2—PRODUCTS

2.1 FIRE HYDRANTS

PART 3—EXECUTION

3.1 FIRE HYDRANT ASSEMBLY INSTALLATION

PERFORMANCE TESTING OF PRESSURE PIPELINES

PART 1—GENERAL

1.1 SECTION DESCRIPTION

1.2 REFERENCES

1.3 SUBMITTALS

PART 2—PRODUCTS

2.1 DISINFECTION CHEMICALS

PART 3—EXECUTION

3.1 GENERAL

3.2 CLEANING

3.3 HYDROSTATIC AND LEAKAGE TESTING

3.4 DISINFECTION (Water System Only)

GRAVITY WASTEWATER COLLECTION SYSTEM

PART 1—GENERAL

1.1 SECTION DESCRIPTION

1.2 SUBMITTALS

PART 2—PRODUCTS

2.1 GRAVITY WASTEWATER MAIN

WASTEWATER MANHOLES

PART 3—EXECUTION

3.1 INSTALLATION

3.2 FIELD QUALITY CONTROL

QUALIFIED PRODUCTS LIST

TAPPING SLEEVES

BACKFLOW PREVENTERS

AIR RELEASE VALVE

CORPORATIONS

METER ANGLE VALVES

POLYETHYLENE TUBING

METER BOXES

VALVE BOXES

MANHOLE FRAME AND COVER

CONTROL PANEL FOR PUMPS AND LIFT STATIONS

PROTECTION DEPARTMENT ENVIRONMENTAL

Exhibit: /22

By: Indar Jagnarine

REVISIONS

COUNTY COMMENTS 7/20/01

DESIGN SMG DATE 4/12/01

DRAWN EAK DATE 4/12/01

CHECKED DATE

CPV CANA, LTD.

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312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

GENERAL NOTES

NOV

Form #62-343.900(3), F.A.C.
Form Title: Construction Commencement Notice
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
Construction Commencement Notice

PROJECT:______________________________ PHASE:__________

I hereby notify the Department of Environmental Protection that the construction of the surface water management system authorized by Environmental Resource Permit No.__________________ has commenced / is expected to commence on ______________ 200__, and will require a duration of approximately ______ months ______ weeks ______ days to complete. It is understood that should the construction term extend beyond one year, I am obligated to submit the Annual Status Report for Surface Water Management System Construction.

PLEASE NOTE: If the actual construction commencement date is not known, Department staff should be so notified in writing in order to satisfy permit conditions.

______________________	______________________	____________
Permittee or Authorized Agent	Title and Company	Date

______________________	______________________
Phone	Address

Form # 62-343.900(4), F.A.C.
Form Title: Annual Status Report
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
ANNUAL STATUS REPORT FORM

Florida Department of Environmental Protection
____
____
____

Permit No. ____________________ County: ____________________

Project Name: ____________________ Phase: ____________________

The following activity has occurred at the above referenced project during the past year, between June 1, 200___ and May 30, 200___.

Permit Condition / Activity	% of Completion	Date of anticipated Completion	Date of Completion

(Use Additional Sheets As Necessary)

Benchmark Description (one per major control structure): ____________________
____
____
____

____________________ ____________________
Print Name Phone

____________________ ____________________ __________
Permittee's or Authorized Agent's Signature Title and Company Date

This form shall be submitted to the above referenced Department Office during June of each year for activities whose duration of construction exceeds one year.

Form #62-343.900(5), F.A.C.
Form Title: As-Built Certification by a Registered Professional
Date: October 3, 1995

ENVIRONMENTAL RESOURCE PERMIT
AS-BUILT CERTIFICATION BY A REGISTERED PROFESSIONAL

Permit Number:______________________________

Project Name:______________________________

I hereby certify that all components of this surface water management system have been built substantially in accordance with the approved plans and specifications and are ready for inspection. Any substantial deviations (noted below) from the approved plans and specifications will not prevent the system from functioning as designed when properly maintained and operated. These determinations are based upon on-site observation of the system conducted by me or by my designee under my direct supervision and/or my review of as-built plans certified by a registered professional or other appropriate individual as authorized by law.

Name (please print)	Signature of Professional
Company Name	Florida Registration Number
Company Address	Date
City, State, Zip Code	
Telephone Number	(Affix Seal)

Substantial deviations from the approved plans and specifications:

____

____

____

____

(Note: attach two copies of as-built plans when there are substantial deviations)

Within 30 days of completion of the system, submit two copies of the form to:

____

____

____

Form #62-343.900(7), F.A.C.
Form Title: Request for Transfer to Operation Phase
Date: October 3, 1995

REQUEST FOR TRANSFER OF ENVIRONMENTAL RESOURCE PERMIT CONSTRUCTION PHASE TO OPERATION PHASE

(To be completed and submitted by the operating entity)

Florida Department of Environmental Protection

It is requested that Department Permit No. ________________________ authorizing the construction and operation of a surface water management system for the below mentioned project be transferred from the construction phase permittee to the operation phase operating entity.

PROJECT:

FROM: Name:
Address:
City:____________________________State:
Zipcode:

TO: Name:
Address:
City:____________________________State:
Zipcode:

The surface water management facilities are hearby accepted for operation and maintenance in accordance with the engineers certification and as outlined in the restrictive covenants and articles of incorporation for the operating entity. Enclosed is a copy of the document transferring title of the operating entity for the common areas on which the surface water management system is located. Note that if the operating entity has not been previously approved, the applicant should contact the Department staff prior to filing for a permit transfer.

The undersigned hearby agrees that all terms and conditions of the permit and subsequent modifications, if any, have been reviewed, are understood and are hearby accepted. Any proposed modifications shall be applied for and obtained prior to such modification.

Operating Entity ______________________________

Name ______________________________ Title ______________________________

Telephone ______________________________

Enclosure:
( ) Copy of recorded transfer of title surface water management system
( ) Copy of plat(s)
( ) Copy of recorded restrictive covenants, articles of incorporation, and certificate of incorporation

Form 62-343.900 (8)
Application for Transfer of ERP Permit
Effective Date: 8-14-96

APPLICATION FOR TRANSFER OF ENVIRONMENTAL RESOURCE PERMIT AND NOTIFICATION OF SALE OF A FACILITY OR SURFACE WATER MANAGEMENT SYSTEM

Permit No. __________ Date Issued __________ Date Expires __________

FROM (*Name of Current Permit Holder*) __________

Mailing Address __________

City __________ State ____ Zip Code __________

Telephone: (___) __________

Identification or Name of Facility/Surface Water Management System: __________

Phase of Facility/Surface Water Management System (if applicable): __________

The undersigned hereby notifies the Department of the sale or legal transfer of this facility, or surface-water management system, and further agrees to assign all rights and obligations as permittee to the applicant in the event the Department agrees to the transfer of permit.

Signature of the current permittee: __________

Title (*if any*): __________ Date: __________

TO (*Name of Proposed Permit Transferee*): __________

Mailing Address __________

City __________ State ____ Zip Code __________

Telephone: (___) __________

The undersigned hereby notifies the Department of having acquired the title to this facility, or surface-water management system. The undersigned also states he or she has examined the application and documents submitted by the current permittee, the basis of which the permit was issued by the Department, and states they accurately and completely describe the permitted activity or project. The undersigned further attests to being familiar with the permit, agrees to comply with its terms and with its conditions, and agrees to assume the rights and liabilities contained in the permit. The undersigned also agrees to promptly notify the Department of any future changes in ownership of, or responsibility for, the permitted activity or project.

Signature of the applicant (*Transferee*): __________

Title (*if any*): __________ Date: __________

Project Engineer Name (*if applicable*) __________

Mailing Address __________

City __________ State ____ Zip Code __________

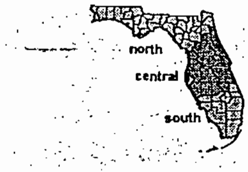
Telephone: (___) __________

Florida Exotic Pest Plant Council's 2001 List of Invasive Species

DEFINITIONS: *Exotic*—a species introduced to Florida, purposefully or accidentally, from a natural range outside of Florida. *Native*—a species whose natural range included Florida at the time of European contact (1500 AD). *Naturalized exotic*—an exotic that sustains itself outside cultivation (it has not "become" native). *Invasive exotic*—an exotic that not only has naturalized but is expanding on its own in Florida plant communities.

Abbreviations used:

for "Gov. list": **P** = Prohibited by Fla. Dept. of Environmental Protection, **N** = Noxious weed listed by Fla. Dept. of Agriculture & Consumer Services, **U** = Noxious weed listed by U.S. Department of Agriculture. for "Reg. Dis.": **N** = north, **C** = central, **S** = south, referring to each species' current distribution in general regions of Florida (not its potential range in the state). See map.



Category I - Invasive exotics that are altering native plant communities by displacing native species, changing community structures or ecological functions, or hybridizing with natives. *This definition does not rely on the economic severity or geographic range of the problem, but on the documented ecological damage caused.*

Scientific Name	Common Name	Gov. list	Reg. Dist.
Abrus precatorius	rosary pea		C, S
Acacia auriculiformis	earleaf acacia		S
Albizia julibrissin	mimosa, silk tree		N, C
Albizia lebbeck	woman's tongue		C, S
Ardisia crenata (= A. crenulata)	coral ardisia		N, C
Ardisia elliptica (=A. humilis)	shoebutton ardisia		S
Asparagus densiflorus	asparagus-fern		C, S
Bauhinia variegata	orchid tree		C, S
Bischofia javanica	bischofia		C, S
Calophyllum antillanum (=C. calaba; C. inophyllum misapplied)	santa maria (names "mast wood," "Alexandrian laurel" used in cultivation)		S
Casuarina equisetifolia	Australian pine	P	N,C,S
Casuarina glauca	suckering Australian pine	P	C, S
Cestrum diurnum	day jessamine		C, S
Cinnamomum camphora	camphor-tree		N,C,S
Colocasia esculenta	wild taro		N,C,S
Colubrina asiatica	lather leaf		S
Cupaniopsis anacardioides	carrotwood	N	C, S
Dioscorea alata	winged yam	N	N,C,S
Dioscorea bulbifera	air-potato	N	N,C,S
Eichhornia crassipes	water-hyacinth	P	N,C,S
Eugenia uniflora	Surinam cherry		C, S
Ficus microcarpa (F. nitida & F. retusa var. nitida misapplied)	laurel fig		C, S
Hydrilla verticillata	hydrilla	P, U	N,C,S
Hygrophila polysperma	green hygro	P, U	N,C,S
Hymenachne amplexicaulis	West Indian marsh grass		C, S
Imperata cylindrica (I. brasiliensis misapplied)	cogon grass	N, U	N, C, S
Ipomoea aquatica	waterspinach	P, U	C
Jasminum dichotomum	Gold Coast jasmine		C, S
Jasminum fluminense	Brazilian jasmine		C, S
Lantana camara	lantana, shrub verbena		N,C,S
Ligustrum lucidum	glossy privet		N, C
Ligustrum sinense	Chinese privet, hedge privet		N,C,S
Lonicera japonica	Japanese honeysuckle		N,C,S
Lygodium japonicum	Japanese climbing fern	N	N,C, S
Lygodium microphyllum	Old World climbing fern	N	C, S
Macfadyena unguis-cati	cat's claw vine		N,C, S
Manilkara zapota	sapodilla		S
Melaleuca quinquenervia	melaleuca, paper bark	P, N, U	C, S
Melia azedarach	Chinaberry		N,C,S
Mimosa pigra	cat-claw mimosa	P, N, U	C, S
Nandina domestica	nandina, heavenly bamboo		N
Nephrolepis cordifolia	sword fern		N,C,S
Nephrolepis multiflora	Asian sword fern		C, S
Neyraudia reynaudiana	Burma reed; cane grass	N	S
Paederia cruddasiana	sewer vine, onion vine	N	S
Paederia foetida	skunk vine	N	N,C,S
Panicum repens	torpedo grass		N,C,S
Pennisetum purpureum	Napier grass		C, S
Pistia stratiotes	water lettuce	P	N,C,S
Psidium cattleianum (=P. littorale)	strawberry guava		C, S
Psidium guajava	guava		C, S
Pueraria montana (=P. lobata)	kudzu	N, U	N,C, S
Rhodomyrtus tomentosa	downy rose-myrtle	N	C, S
Rhoeo spathacea (see *Tradescantia spathacea)*			
Ruellia brittoniana	Mexican petunia		N, C, S
Sapium sebiferum	popcorn tree, Chinese tallow tree	N	N, C, S
Scaevola sericea (=Scaevola taccada var. sericea, S. frutescens)	scaevola, half-flower, beach naupaka		C, S
Schefflera actinophylla (=Brassaia actinophylla)	schefflera, Queensland umbrella tree		C, S
Schinus terebinthifolius	Brazilian pepper	P, N	N, C, S
Senna pendula (=Cassia coluteoides)	climbing cassia, Christmas cassia, Christmas senna		C, S
Solanum tampicense (=S. houstonii)	wetland night shade, aquatic soda apple	N, U	C, S
Solanum viarum	tropical soda apple	N, U	N, C, S
Syngonium podophyllum	arrowhead vine		C, S
Syzygium cumini	jambolan, Java plum		C, S
Tectaria incisa	incised halberd fern		S
Thespesia populnea	seaside mahoe		C, S
Tradescantia fluminensis	white-flowered wandering jew		N, C
Tradescantia spathacea (= Rhoeo spathacea, Rhoeo discolor)	oyster plant		S
Urochloa mutica (= Brachiaria mutica)	Pará grass		C, S

Category II - Invasive exotics that have increased in abundance or frequency but have not yet altered Florida plant communities to the extent shown by Category I species. *These species may become ranked Category I, if ecological damage is demonstrated.*

Scientific Name	Common Name	Gov. list	Reg. Dist.
Adenanthera pavonina	red sandalwood		S
Agave sisalana	sisal hemp		C, S
Aleurites fordii (= *Vernicia fordii*)	tung oil tree		N, C
Alstonia macrophylla	devil-tree		S
Alternanthera philoxeroides	alligator weed	P	N, C, S
Antigonon leptopus	coral vine		N, C, S
Aristolochia littoralis	calico flower		N, C
Asystasia gangetica	Ganges primrose		C, S
Begonia cucullata	begonia		N, C
Broussonetia papyrifera	paper mulberry		N, C
Callisia fragrans	inch plant, spironema		C, S
Casuarina cunninghamiana	Australian pine	P	C, S
Cordia dichotoma	sebsten plum		S
Cryptostegia madagascariensis	rubber vine		C, S
Cyperus involucratus (*C. alternifolius* misapplied)	umbrella plant		C, S
Cyperus prolifer	dwarf papyrus		C
Dalbergia sissoo	Indian rosewood, sissoo		C, S
Elaeagnus pungens	thorny eleagnus		N, C
Epipremnum pinnatum cv. Aureum	pothos		C, S
Ficus altissima	false banyan		S
Flacourtia indica	governor's plum		S
Flueggea virosa	Chinese waterberry		S
Hibiscus tiliaceus	mahoe, sea hibiscus		C, S
Hiptage benghalensis	hiptage		S
Jasminum sambac	Arabian jasmine		S
Koelreuteria elegans	flamegold tree		C, S
Leucaena leucocephala	lead tree		N, C, S
Limnophila sessiliflora	Asian marshweed		N, C, S
Melinis minutiflora	molasses grass		S
Merremia tuberosa	wood-rose		S
Murraya paniculata	orange-jessamine		S
Myriophyllum spicatum	Eurasian water-milfoil	P	N, C, S
Ochrosia elliptica (=*O. parviflora*)	kopsia		C, S
Oeceoclades maculata	ground orchid		C, S
Passiflora biflora	twin-flowered passion vine		S
Passiflora foetida	stinking passion-flower		C, S
Pennisetum setaceum	green fountain grass		S
Phoenix reclinata	Senegal date palm		C, S
Phyllostachys aurea	golden bamboo		N, C
Pteris vittata	Chinese brake fern		N, C, S
Ptychosperma elegans	solitary palm		S
Rhynchelytrum repens	Natal grass		N, C, S
Ricinus communis	castor bean		N, C, S
Sansevieria hyacinthoides	bowstring hemp		C, S
Sesbania punicea	purple sesban, rattlebox		N, C, S
Solanum diphyllum	twinleaf nightshade		N, C, S
Solanum jamaicense	Jamaica nightshade		C
Solanum torvum	susumber, turkey berry	N, U	N, C, S
Syzygium jambos	rose-apple		C, S
Terminalia catappa	tropical almond		C, S
Terminalia muelleri	Australian almond		C, S
Tribulus cistoides	puncture vine, bur-nut		N, C, S
Urena lobata	Caesar's weed		N, C, S
Wedelia trilobata	wedelia		N, C, S
Wisteria sinensis	Chinese wisteria		N, C
Xanthosoma sagittifolium	malanga, elephant ear		N, C, S

The 2001 list was prepared by the FLEPPC Plant List Committee:

Daniel F. Austin (CO-CHAIR), Department of Biological Sciences, Florida Atlantic University, Boca Raton, FL 33431

Keith Bradley, Institute for Regional Conservation, 22601 S. W. 152nd Ave., Miami, FL 33170

Kathy Craddock Burks (CO-CHAIR), Bureau of Invasive Plant Management, Florida Department of Environmental Protection, 3915 Commonwealth Blvd., MS 710, Tallahassee, FL 32399

Nancy Craft Coile, Division of Plant Industry, Florida Department of Agriculture and Consumer Services, P.O. Box 147100, Gainesville, FL 32614

James G. Duquesnel, Florida Park Service, Florida Department of Environmental Protection, P.O. Box 487, Key Largo, FL 33037

David W. Hall, Consulting botanist, 6241 N. W. 23rd St., Gainesville, FL 32653

Roger L. Hammer, Department of Parks and Recreation, Miami-Dade County, 22200 S. W. 137th Ave., Miami, FL 33170

Kenneth A. Langeland, Center for Aquatic and Invasive Plants, IFAS, University of Florida, 7922 N. W. 71st St., Gainesville, FL 32606

Robert W. Pemberton, Agricultural Research Station, U.S. Department of Agriculture, 2305 College Ave., Ft. Lauderdale, FL 33314

Daniel B. Ward, Department of Botany, University of Florida, 220 Bartram Hall, Gainesville, FL 32611

Richard P. Wunderlin, Institute for Systematic Botany, Department of Biological Sciences, University of South Florida, Tampa, FL 33620

www.fleppc.org

Florida Department of
Environmental Protection

Memorandum

TO: Clair H. Fancy

THRU: A.A. Linero *aaL 11/19*

FROM: Teresa Heron

DATE: November 19, 2001

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

Attached is the draft public notice 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 million 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.

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

The proposed issue date of November 21 is Day 28. I recommend your signature and approval of this Intent to Issue.

AAL/th

Attachments

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 1110103-001-AC (PSD-FL-323)

CPV Cana Ltd.
CPV Cana Power Generating Facility
Port St. Lucie, St. Lucie County

Project type:

Project is construction of a nominal 245-megawatt combined cycle power plant with a 170 MW GE7FA combustion turbine-electrical generator, a heat recovery steam generator, a separate steam turbine-electrical generator, a 170-foot stack, a five-cell mechanical cooling tower, a nominal 1 million gallon fuel oil tank and ancillary equipment. The unit will operate maximum of 8,760 hours per year of which 2000 hours per year per unit may be in the power augmentation mode and 720 hours per year on No. 2 distillate fuel oil.

The proposed continuous (24-hour) BACT NO_X limits are 2.5 ppmvd @15% O_2 when operating on natural gas and 10 ppmvd @15% O_2 when burning fuel oil. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project are all less than the applicable significant impact limits (SILs) corresponding to the nearby Class II areas and the Class I Everglades National Park. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or Increment. The National park Service had no adverse comments regarding this project.

Based on information submitted by CPV, it was determined that the project is not subject to Sections 403.501-518, F.S., Florida Power Plant Siting Act.

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

A A Linero 11/19/01

A A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

A. A. LINERO
CERTIFICATE
NO. 26032
AAL 11/19
STATE OF
FLORIDA
REGISTERED ENGINEER

FLORIDA ELECTRICAL POWER PLANT SITING ACT APPLICABILITY DETERMINATION

CPV Cana Power Generating Facility

The meaning of electrical power plant, for the purpose of certification under the act "does not include any steam or solar electrical generating facility of less than 75 megawatts in capacity unless the applicant for such a facility elects to apply for certification under this act." [403.503(13), F.S.]

"The provisions of the act shall apply to any electrical power plant as defined herein, except that the provisions of this act shall not apply to any electrical power plant or steam generating plant of less than 75 megawatts in capacity ......" [403.506(1), F.S.]

A combined cycle plant consists of two cycles. The first is the gas turbine cycle, also known as the *Brayton Cycle*. The second is the steam turbine or *Rankine Cycle*. [Steam, its Generation and Use, Babcock & Wilcox, 1992]

For combined cycles, the Department considers the Act to apply only when electricity generated from the electrical generator operated on the Rankine cycle equals or exceeds 75 MW and not the separate electrical generator operated on the Brayton cycle.

In past permitting actions, the Department has accepted operational limitations on the gross electrical output from the steam turbine-electrical generator as the measure of capacity. [Okeelanta Cogeneration, Destec Tiger Bay, CPV Pierce]

The Department requires a clear description of the manner by which electrical power from the steam turbine-electrical generator will be limited to less than 75 MW.

In its application received by the Department on September 5, 2001, CPV stated the following:

> *"The steam turbine generator (STG) output will be limited to less than 75 MW. Control of STG output will be monitored and controlled via an automatic digital control system (DCS) to ensure the 75 MW output limit is not exceeded. A number of control options have been investigated and the most probable are described below.*
>
> *"When ambient temperature is at 59 °F or greater, excess steam generated in the HRSG will be extracted from the HRSG, bypassing the steam turbine, and injected into the CTG. This mode of operation is referred to as power augmentation. Since there is a limit on the quantity of steam that may be injected into the CTG, it may be necessary to further reduce flow to the STG to limit output or to reduce steam turbine output by other means.*
>
> *"Bypass of a portion of heat exchanger surface in the HRSG is an effective method of reducing steam production by reducing the heat recovered from the combustion turbine flue gas. The proposed design will make use of a low temperature economizer bypass to limit steam production by allowing more of the heat generated by the combustion turbine to be discharged to the atmosphere with the flue gas. This will limit STG output.*

"In many cases, application of both of these control modes will reduce steam output to the turbine to the required quantity. If additional reduction in STG output is required, raising STG discharge pressure by raising the condenser operating temperature will reduce turbine efficiency, reducing electrical output. Output of the STG may be tuned to the desired value by turning cooling tower cells on and off as necessary.

"When ambient temperature falls below 59 °F the manufacturer does not recommend injection of steam into the combustion turbine. If the low temperature economizer bypass combined with an increase cooling water temperature does not reduce STG output sufficiently, excess steam may bypass the steam turbine and be sent directly to the condenser.

"Output of the STG will be controlled automatically utilizing the methods described above through a DCS designed to ensure that the electrical power produced from steam does not exceed 74.9 MW".

The DCS will be programmed by the Engineering Procurement Construction (EPC) engineer to limit the steam turbine output to 74.9 MW. The necessary logic to automatically control steam injection to the gas turbine, cooling tower fan speed, HRSG economizer bypass control, steam bypass control, or reduce gas turbine load will be incorporated in the DCS.

The plant operator can manually lower the steam turbine output value but cannot raise the number beyond the programmed set point limit or alter the DCS logic. Depending on the DCS platform purchased, the logic and set point will either be protected by password or keylock. If the logic or set point must be changed after the plant is in commercial operation, only an authorized DCS representative or a qualified DCS engineer can make the modifications. These modifications can be made using the DCS engineering work station, which will be located in the plant control room. A shutdown of the facility is not required since the changes can be made while the plant is on-line".

The Department accepts CPV's operational description and concludes that the project is not subject to the Florida Electrical Power Plant Siting Act.

A A Linero 11/19/01

A. A. Linero, P.E. Administrator
New Source Review Section

Hamilton Oven, P.E. Administrator
Power Plant Siting Office

Competitive
Power Ventures, Inc.

RECEIVED
OCT 25 2001
BUREAU OF AIR REGULATION

October 24, 2001

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Responses to Florida DEP Comments on CPV Cana Power Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)

Reference: Letter from A. A. Linero to G. Lambert dated October 2, 2001

Dear Mr. Linero:

Enclosed please find seven copies of CPV Cana, Ltd's. response to the referenced letter. If you have any questions, please do not hesitate to contact me at (781) 848-0253.

Sincerely,

Pat [signature]

Peter J. Podurgiel
Vice President Development

Enclosures

cc: Michael Anderson, TRC
Cathy Sellers, Moyle, Flanagan
Scott Sumner, P.E. TRC
J. Heron
C. Galbraith
J. Goldman, ScD
G. Worley, EPA
J. Bunyak, NPS

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804

Responses to Florida DEP Comments on CPV Cana Power Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)

The Florida Department of Environmental Protection (DEP) notified CPV via certified mail, dated October 2, 2001, of two additional information requests needed for application completeness. The three requested items, numbered 1., 2. and 3., are restated below for completeness. CPV's response to each request is provided herein.

1. **Request:** Proposed Emissions for Sulfuric Acid Mist are 7.62 TPY. This is above the PSD limit of 7 TPY. Please complete a BACT analysis for this pollutant.

   Response: Attachment A contains Section 5.4 and Table 5-4 of the <u>CPV Cana Power Generating Facility Application for Air Permit</u> (the air permit application), which have been modified using the black-line editing function to include Sulfuric Acid Mist in the BACT analysis. It demonstrates that the use of low sulfur fuels results in the BACT emission rate limits for Sulfuric Acid Mist. For completeness, Tables 3-1 and 3-3 of the air permit application have also been modified to include sulfuric acid mist and the emissions form ancillary sources (see Request 2).

2. **Request:** Submit potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank units. Although these units may be exempted from permitting (based on emissions and capacity), we need to include them in the construction permit.

   Response: Attachment B contains the calculations of the potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank. Emissions for the fire pump and diesel emergency generator were calculated using published emissions factors and an annual operating limit of 500 hours for each piece of equipment. Emissions for diesel storage tank were calculated using the TANKS program.

3. **Request:** What is the ammonia's concentration in the storage tank (i.e. < or > 20 percent)? Please refer to 40CFR 68, Chemical Accident Provisions.

   Response: Section 3.8 of the air permit application states that the project will utilize aqueous ammonia with a concentration of less than 20 percent. It will therefore not require a Risk Management Plan (RMP) under the Chemical Accident Provisions of 40 CFR 68.

Scott G. Sumner, P.E.

25 OCTOBER 2001
Date

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature

25 OCTOBER 2001

Date

(seal)

* Attach any exception to certification statement.

Attachment A

Revisions to CPV Cana BACT Analysis

Table 3-1 New Power Generation Equipment Criteria Pollutant Emissions CPV Cana[1]	
Pollutant	**Potential Emissions[2] (Tons/Year)**
NO_x	~~96~~102
SO_2	76
CO	~~226~~228
PM/PM_{10}[3]	96
VOC	~~15~~16
H_2SO_4	7.62

1 Source: GE performance data in Appendix C.
2 Annual emission estimates based on combustion turbine operating 8760 hours at maximum hourly emission rate.
3 PM/PM_{10} value includes combustion turbines and cooling tower drift.

Table 3-3 PSD Significant Emissions Increase Level and CPV Cana Project Net Emission Rates (Pursuant to 40 CFR 52.21 (b) (23) (i))		
Pollutant	**Significant Emissions Increase Level (TPY)**	**Annual Net Emissions Increases (TPY)**
NO_x	40	~~96~~102
SO_2	40	76
CO	100	~~226~~228
PM	25	96
PM_{10}	15	96
VOC	40	~~15~~16
H_2SO_4	7	7.62

5.4 BACT Analysis for Sulfur Dioxide and Sulfuric Acid

Strategies for the control of sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low sulfur fuels or fuel sulfur removal. Post-combustion controls comprise various wet and dry flue gas de-sulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to ~~high~~ large pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low SO_2 and H_2SO_4 concentrations.

The new power generation equipment will fire natural gas as the primary fuel (0.0065% sulfur by weight) and 0.05% sulfur distillate oil as back up, which is considered BACT for SO_2 and H_2SO_4 emissions. Based on these clean fuels, the proposed maximum SO_2 and H_2SO_4 emission rates for natural gas firing ~~is~~ are 10 lb/hr and 1 lb/hr, respectively. The proposed maximum SO_2 and H_2SO_4 emission rates for distillate oil firing ~~is~~ are 99 lb/hour and 10 lb/hr, respectively.

Table 5-2 Summary of Proposed BACT Limits for the CPV Cana Project		
Pollutant	Control Technology	Proposed BACT Limit
Nitrogen Oxides	Low - NO_x Combustion Technology Selective Catalytic Reduction	2.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
Carbon Monoxide*	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation mode) 24 ppmvd (oil)
Particulate Matter-Combined-Cycle System	Inherently Clean Fuels Combustion Controls	19 lb/hr (gas) 44 lb/hr (oil)
Particulate Matter-Cooling Tower	High Efficiency Drift Eliminators	0.0005% drift
Sulfur Dioxide	Low Sulfur Fuels	10 lb/hr (gas) 99 lb/hr (oil)
Sulfuric Acid	Low Sulfur Fuels	1 lb/hr (gas) 10 lb/hr (oil)

*FDEP approved the following CO emission limits @ 15% O_2 for the CPV Pierce Project:
8 ppmvd (gas)
13 ppmvd (power augmentation mode)
17 ppmvd (oil)

Attachment B

Emissions Calculations for Ancillary Equipment

CPV Cana
Assumptions and Emission for the Fire Water Pump

Operating Hours	500
Type Fuel	Diesel
Fuel Heating Value (Btu/gal)	140,000
Gallons per Hour	13.8
Fuel Input in MMBtu per Hour	1.93
Assumed Efficiency	33%
BHP Rating	250
Annual Fuel Usage (gal/year)	6,886
Sulfur Content in Fuel	0.05%

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.310	2	0.598	0.149	
PM10	na	0.310	2	0.598	0.149	
SOx	na	0.051	1	0.097	0.024	
CO	630-08-0	0.950	1	1.832	0.458	
VOC	na	0.349	2	0.673	0.168	
NOx	na	4.410	2	8.503	2.126	
Hazardous Air Pollutants						
1,3 Butadiene	106-99-0	3.91E-05	2	7.54E-05	1.88E-05	yes
Acetaldehyde	75-07-0	7.67E-04	2	1.48E-03	3.70E-04	yes
Acrolein	107-02-8	9.25E-05	2	1.78E-04	4.46E-05	yes
Benzene	71-43-2	9.33E-04	2	1.80E-03	4.50E-04	yes
Beryllium	7440-41-7	6.90E-08	3	1.33E-07	3.33E-08	yes
Formaldehyde	50-00-0	1.18E-03	2	2.28E-03	5.69E-04	yes
Mercury	na	3.01E-07	3	5.81E-07	1.45E-07	yes
Napthalene	91-20-3	8.48E-05		1.64E-04	4.09E-05	yes
PAH	130498-29-2	1.68E-04	2	3.24E-04	8.10E-05	yes
Acenaphthene (POM)	83-32-9	1.42E-06	2	2.74E-06	6.84E-07	yes
Acenaphthylene (POM)	208-96-8	5.06E-06	2	9.76E-06	2.44E-06	yes
Anthracene (POM)	120-12-7	1.87E-06	2	3.61E-06	9.01E-07	yes
Benz(a)anthracene (POM)	56-55-3	1.68E-06	2	3.24E-06	8.10E-07	yes
Benzo(a)pyrene (POM)	50-32-8	1.88E-07	2	3.62E-07	9.06E-08	yes
Benzo(b)fluoranthene (POM)	205-99-2	9.91E-08	2	1.91E-07	4.78E-08	yes
Benzo(g,h,i)perylene (POM)	191-24-2	4.89E-07	2	9.43E-07	2.36E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	1.55E-07	2	2.99E-07	7.47E-08	yes
Chrysene (POM)	218-01-9	3.53E-07	2	6.81E-07	1.70E-07	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	5.83E-07	2	1.12E-06	2.81E-07	yes
Fluoranthene (POM)	206-44-0	7.61E-06	2	1.47E-05	3.67E-06	yes
Fluorene (POM)	86-73-7	2.92E-05	2	5.63E-05	1.41E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	3.75E-07	2	7.23E-07	1.81E-07	yes
Naphthalene (POM)	91-20-3	8.48E-05	2	1.64E-04	4.09E-05	yes
Phenanthrene (POM)	85-01-8	2.94E-05	2	5.67E-05	1.42E-05	yes
Pyrene (POM)	129-00-0	4.78E-06	2	9.22E-06	2.30E-06	yes
Toluene	108-88-3	4.09E-04	2	7.89E-04	1.97E-04	yes
Xylenes	1330-20-7	2.85E-04	2	5.50E-04	1.37E-04	yes
Other Non-Criteria Air Pollutants						
Aldehydes	na	7.00E-02	2	1.35E-01	3.37E-02	no
Propylene	115-07-1	2.58E-03	2	4.97E-03	1.24E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	3/4	2.00E-03	4.99E-04	no
Totals						
Federal HAPs					1.91E-03	
Other Non-criteria Pollutants					3.55E-02	

1. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.4-1, 5th Edition - Supplement B November, 1996.
2. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.3-1 and 3.3-2, 5th Edition - Supplement B November, 1996.
3. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
4. Emission factor for sulfuric acid is 8.9(S) ng/J.

CPV Cana
Assumptions and Emission for the Emergency Generator

Operating Hours	500
Type Fuel	Diesel
Sulfur Content of Fuel	0.05%
Fuel Heating Value (Btu/gal)	140,000
Gallon per Hour	36
Fuel Input in MMBtu per Hour	5.0
Output in kW	500
Assumed Heat Rate (Btu/kW-hr)	10,000

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.068	2	0.340	0.085	
PM10	na	0.057	2	0.287	0.072	
SOx	na	0.051	1	0.253	0.063	
CO	630-08-0	0.850	1	4.250	1.063	
VOC	na	0.090	1	0.450	0.113	
NOx	na	3.20	1	16.00	4.000	
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	2.52E-05	3	1.26E-04	3.15E-05	yes
Acrolein	107-02-8	7.88E-05	3	3.94E-04	9.85E-05	yes
Benzene	71-43-2	7.76E-04	3	3.88E-03	9.70E-04	yes
Beryllium		6.90E-08	5	3.45E-07	8.63E-08	yes
Formaldehyde	50-00-0	7.89E-05	3	3.95E-04	9.86E-05	yes
Mercury	na	3.01E-07	5	1.51E-06	3.77E-07	yes
Napthalene	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
PAH	130498-29-2	2.45E-04	4	1.22E-03	3.06E-04	yes
Acenaphthene (POM)	83-32-9	4.68E-06	4	2.34E-05	5.85E-06	yes
Acenaphthylene (POM)	208-96-8	9.23E-06	4	4.62E-05	1.15E-05	yes
Anthracene (POM)	120-12-7	1.23E-06	4	6.15E-06	1.54E-06	yes
Benz(a)anthracene (POM)	56-55-3	6.22E-07	4	3.11E-06	7.78E-07	yes
Benzo(a)pyrene (POM)	50-32-8	2.57E-07	4	1.29E-06	3.21E-07	yes
Benzo(b)fluoranthene (POM)	205-99-2	1.11E-06	4	5.55E-06	1.39E-06	yes
Benzo(g,h,i)perylene (POM)	191-24-2	3.46E-07	4	1.73E-06	4.33E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	2.18E-07	4	1.09E-06	2.73E-07	yes
Chrysene (POM)	218-01-9	1.53E-06	4	7.65E-06	1.91E-06	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	3.46E-07	4	1.73E-06	4.33E-07	
Fluoranthene (POM)	206-44-0	4.03E-06	4	2.02E-05	5.04E-06	yes
Fluorene (POM)	86-73-7	1.28E-05	4	6.40E-05	1.60E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	2.57E-07	4	1.29E-06	3.21E-07	yes
Naphthalene (POM)	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
Phenanthrene (POM)	85-01-8	4.08E-05	4	2.04E-04	5.10E-05	yes
Pyrene (POM)	129-00-0	3.71E-05	4	1.86E-04	4.64E-05	yes
Toluene	108-88-3	2.81E-04	3	1.41E-03	3.51E-04	yes
Xylenes	1330-20-7	1.93E-04	3	9.65E-04	2.41E-04	yes
Other Non-Criteria Air Pollutants						
Propylene	115-07-1	2.79E-03	3	1.40E-02	3.49E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	5/6	5.17E-03	1.29E-03	no
Totals						
Federal HAPs					2.26E-03	
Other Non-criteria Pollutants					4.78E-03	

1. Emissions based on AP-42, Table 3.4-1
2. Emissions based on AP-42, Table 3.4-2
3. Emissions based on AP-42, Table 3.4-3.
4. Emissions based on AP-42, Table 3.4-4.
5. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
6. Emission factor for sulfuric acid is 8.9(S) ng/J.

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	CPV Cana Oil Storage Tank
City:	Port St. Lucie
State:	Florida
Company:	CPV
Type of Tank:	Vertical Fixed Roof Tank
Description:	Nominal 975,000 gallon distillate oil storage tank

Tank Dimensions

Shell Height (ft):	45.00
Diameter (ft):	67.75
Liquid Height (ft):	36.15
Avg. Liquid Height (ft):	30.00
Volume (gallons):	975,000.00
Turnovers:	10.86
Net Throughput (gal/yr):	10,593,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition:	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	5.00
Radius (ft) (Dome Roof):	67.75

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Vero Beach, Florida (Avg Atmospheric Pressure = 14.75 psia)

BEST AVAILABLE COPY

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	74.75	66.07	83.43	75.49	0.0104	0.0079	0.0136	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Feb	76.48	66.73	86.23	75.49	0.0110	0.0081	0.0148	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Mar	80.20	69.09	91.31	75.49	0.0123	0.0087	0.0172	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Apr	83.37	71.04	95.69	75.49	0.0136	0.0093	0.0195	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	May	85.49	73.29	97.68	75.49	0.0144	0.0099	0.0207	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jun	86.42	75.17	97.67	75.49	0.0149	0.0105	0.0206	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jul	78.91	74.83	82.99	75.49	0.0118	0.0104	0.0134	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Aug	86.96	75.89	98.02	75.49	0.0151	0.0108	0.0209	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Sep	85.13	75.43	94.84	75.49	0.0143	0.0106	0.0190	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Oct	82.04	73.14	90.94	75.49	0.0130	0.0099	0.0170	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Nov	78.48	70.07	86.89	75.49	0.0117	0.0090	0.0151	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Dec	75.45	67.14	83.75	75.49	0.0106	0.0082	0.0137	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	418.28	446.97	865.25

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)* S. LeBlanc
B. Date of Delivery 10/9/

C. Signature
X S. LeBlanc
☐ Agent
☐ Addressee

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

BRAINTREE, MA
OCT 09 2001
USPS 02184-9998

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2669

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)

OFFICIAL USE

7000 2870 0000 7028 2669

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

Postmark Here

Sent To
Gary Lambert
Street, Apt. No.; or PO Box No.
35 Braintree Hill Office Park, 107
City, State, ZIP+ 4
Braintree, MA 02184

PS Form 3800, May 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

October 2, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: DEP File No. 1110103-001-AC (PSD-FL-323)
Proposed Nominal 245 MW Combined Cycle Power Plant

Dear Mr. Lambert:

On September 5, 2001 the Department received your application and complete fee for an air construction permit for a nominal 245 megawatts (MW) combined cycle power plant in Port St. Lucie, St. Lucie County, Florida. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Proposed Emissions for Sulfuric Acid Mist are 7.62 TPY. This is above the PSD limit of 7 TPY. Please complete a BACT analysis for this pollutant.

Submit potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank units. Although these units may be exempted from permitting (based on emissions and capacity), we need to include them in the construction permit.

What is the ammonia's concentration in the storage tank (i.e. < or > 20 percent)? Please refer to 40CFR 68, Chemical Accident Provisions.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/921-9519. Matters regarding modeling issues should be directed to Debra Galbraith (meteorologist) at 850/921-9537 and e-mail debra.galbraith@dep.state.fl.us. Matters regarding the technical information may be directed to Teresa Heron at 850/921-9529 and e-mail teresa.heron@dep.state.fl.us

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/ch

cc: Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, SWD
Scott Sumner, P.E., TRC

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 7, 2001

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: CPV Cana Power Generating Facility
St. Lucie County, Florida
DEP File No. 1110103-001-AC, PSD-FL-323

Dear Mr. Worley:

Enclosed for your review and comment is an application for a PSD source submitted by CPV Cana, Ltd. for the construction of an electrical power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Teresa Heron, review engineer, at 850/921-9529.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Teresa Heron

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 7, 2001

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: CPV Cana Power Generating Facility
St. Lucie County, Florida
DEP File No. 1110103-001-AC, PSD-FL-323

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for a PSD source submitted by CPV Cana, Ltd. for the construction of an electrical power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Teresa Heron, review engineer, at 850/921-9529.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Teresa Heron

MOYLE, FLANIGAN, KATZ, RAYMOND & SHEEHAN, P.A.
ATTORNEYS AT LAW

The Perkins House
118 North Gadsden Street
Tallahassee, Florida 32301

Telephone: (850) 681-3828
Facsimile: (850) 681-8788

CATHY M. SELLERS
E-mail: csellers@moylelaw.com

West Palm Beach Office
(561) 659-7500

September 5, 2001

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SEP 05 2001
BUREAU OF AIR REGULATION

By Hand Delivery

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: CPV Cana Power Generating Facility
Application for Air Permit

Dear Mr. Linero:

Enclosed please find seven copies of CPV Cana's Application for Air Permit. If you have any questions, please give me a call.

Sincerely,

for

Cathy M. Sellers

CMS/jd
Enclosures

cc: J. Heron
O. Galbraith
J. Goldman, SED
B. Worley, EPA
J. Bunyak, NPS

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BUREAU OF AIR REGULATION

CPV Cana Power Generating Facility
Application for Air Permit
Document ID: CPV-CA

Florida Department of Environmental Protection
Division of Air Resources Management

Prepared For:

CPV Cana, Ltd.

Prepared By:

TRC Environmental Corporation
5 Waterside Crossing
Windsor, Connecticut

August 2001

TABLE OF CONTENTS

APPENDICES

LIST OF FIGURES

Page

LIST OF TABLES

Section 1

Introduction

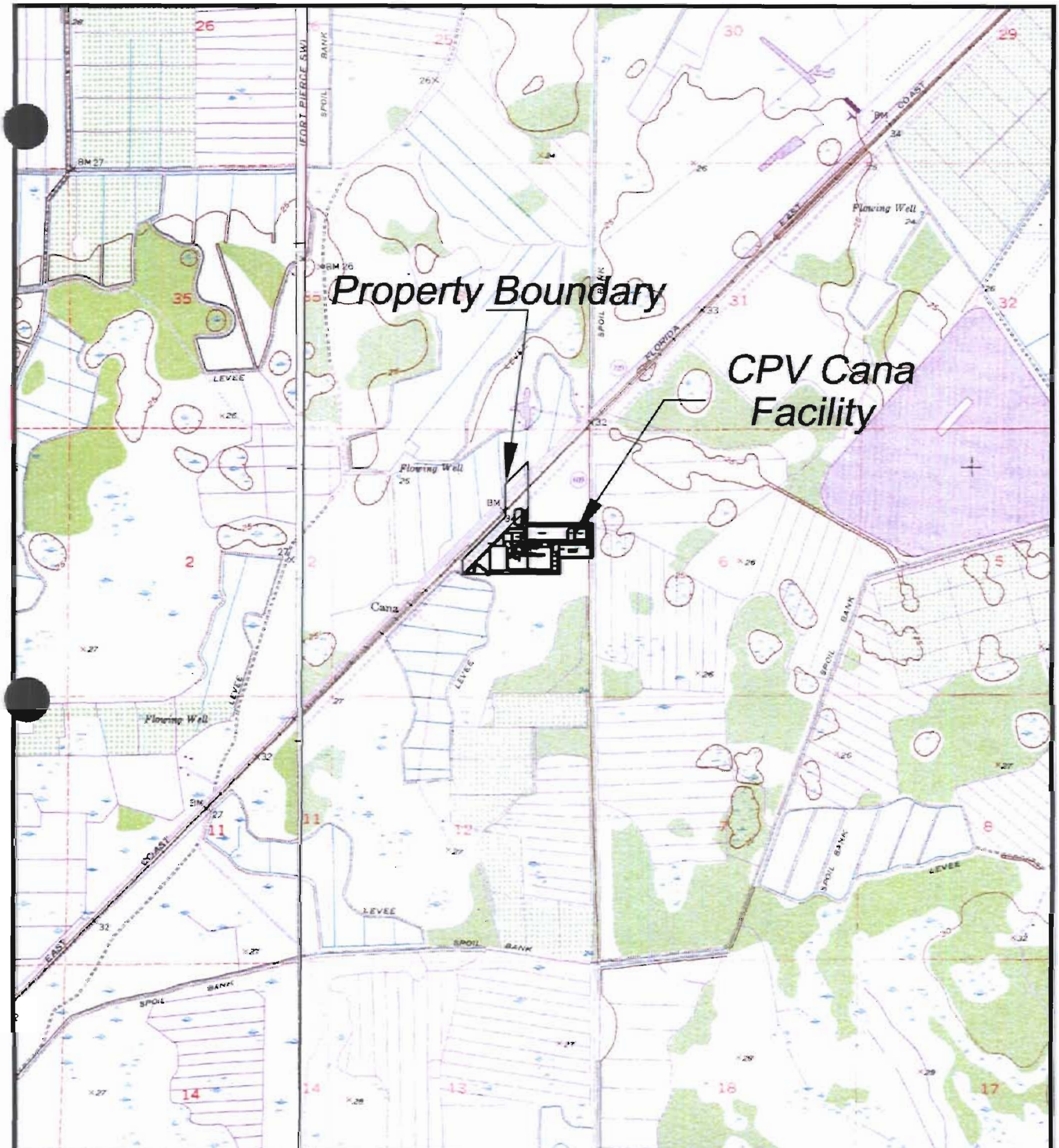
1.0 INTRODUCTION

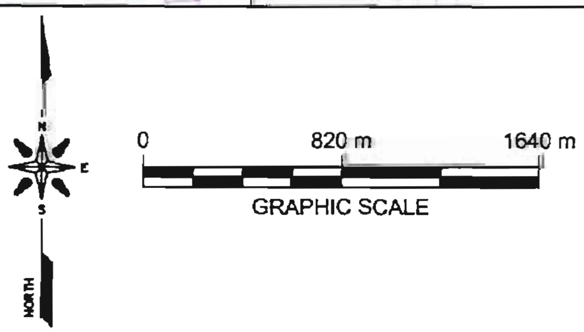
The purpose of this document is to provide the regulatory forms and technical information required to secure approval pursuant to Florida environmental regulations for construction and operation of a new electric power generation facility.

CPV Cana, Ltd. (CPV) is proposing to construct a power generation facility capable of generating a nominal net electrical output of approximately 245 megawatts (MW). The proposed facility, referred to as the CPV Cana Power Generating Facility (The Facility or Project), will be located in St. Lucie County. The proposed Facility will be sited on parcels of land bounded by Range Line Road (SR609), to the east and Glades Cut Off Road (SR709), running northeast to southwest, on the west side. The size of the parcel is approximately 61 acres. The Project equipment will be contained within a fenced portion of the parcel expected to be approximately 29 acres. The location of the site is shown on a USGS topographical map of the area given as Figure 1-1. An illustration of the proposed site showing the approximate Project boundary and fenced portion is presented as Figure 1-2.

CPV is proposing to install an electrical generating Facility consisting of a combined-cycle generating system. The combined-cycle system will be comprised of an energy efficient combustion turbine (CT), a heat recovery steam generator (HRSG) and a steam turbine. The gas turbine will provide approximately 170 MW of electrical power. The HRSG recovers otherwise lost heat from the gas turbine exhaust and provides steam energy to drive the steam turbine to provide a controlled maximum 74.9 MW of electric energy. The new power generation equipment will be designed to meet federal Best Available Control Technology (BACT) standards, as appropriate, for emissions control. The new power generation Facility includes a 170-foot stack and a 5-cell cooling tower.

The following sections of this document will provide the requisite information describing the proposed Project. Section 2.0 provides a detailed description of the proposed Facility. Section 3.0 describes the applicability of specific regulatory requirements to the CPV Project. Section 4.0 documents the air quality modeling study conducted to demonstrate compliance with ambient





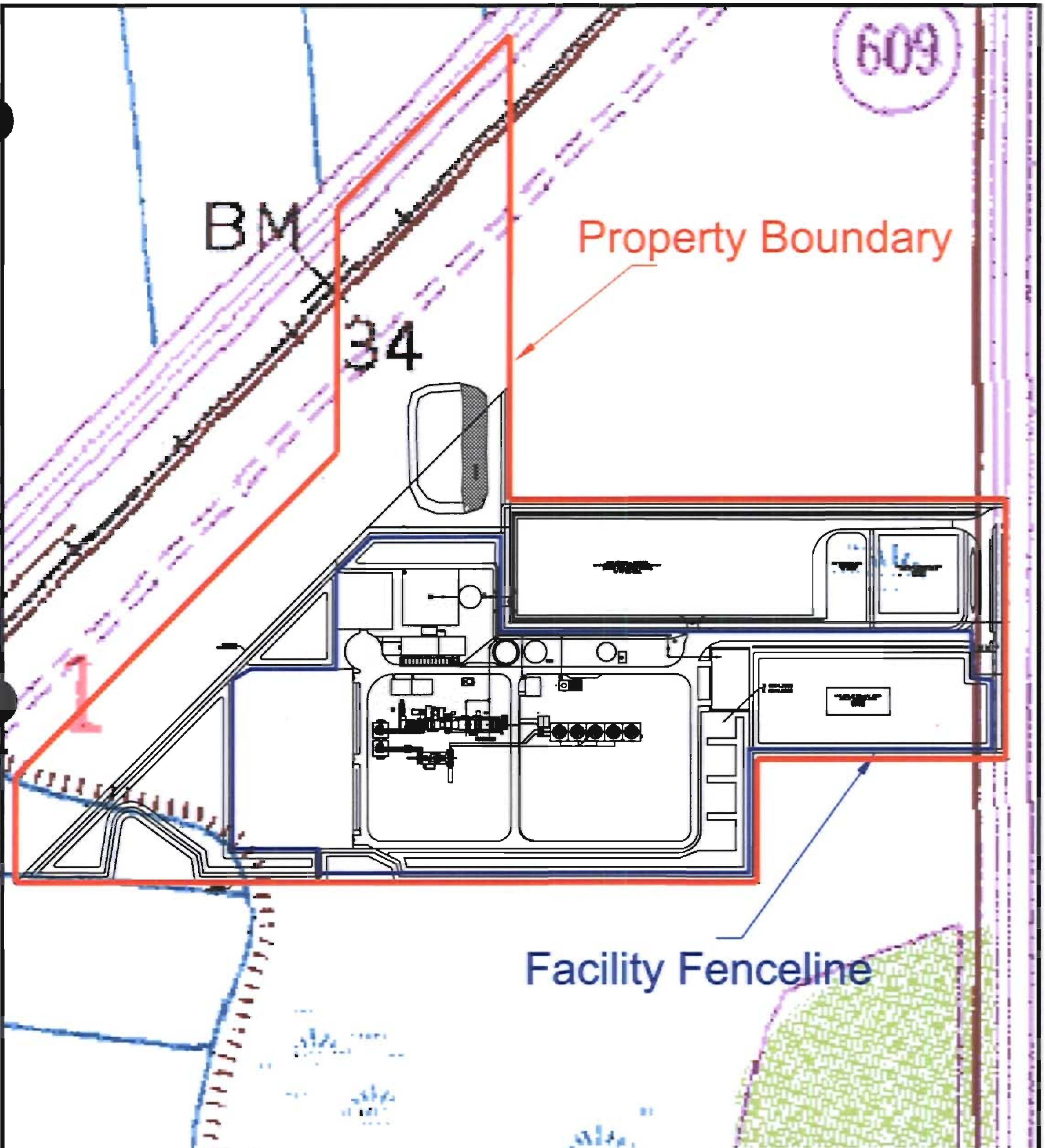
TRC Environmental Corporation

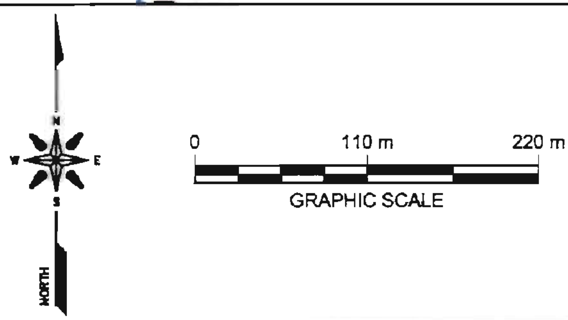
5 Waterside Crossing
Windsor, CT 06095
(860) 298 9692

CPV Cana

FIGURE 1-1
Illustration of CPV Cana
Site Location

Date: August 27, 2001 | Project No. 32543 0010





TRC Environmental Corporation
5 Waterside Crossing
Windsor, CT 06095
(860) 298 9692

CPV Cana

FIGURE 1-2

Location of CPV Cana
Property Boundary and Fenceline

Date: August 27, 2001 | Project No. 32543 0010 air quality standards and increments. Section 5.0 presents the emissions control technology assessment. The application forms are contained in Appendix A. Other appendices provide drawings, technical specifications, and data supporting the studies conducted to demonstrate compliance with applicable regulatory requirements.

Section 2

Project Description

2.0 PROJECT DESCRIPTION

CPV proposes to construct a power generation facility in St. Lucie County using state-of-the-art combined-cycle power generation technology and air pollution control systems. The major components of the Project include a combustion turbine generator, one heat recovery steam generator, one steam turbine, and state-of-the-art air pollution controls. Natural gas will be used as the primary source of fuel. To enhance overall reliability, the proposed system will also be capable of burning very low sulfur-content distillate oil as backup fuel for up to an equivalent of 30 days at full load each year.

2.1 Site Description

The CPV power generation facility will be located in southwestern St. Lucie County, Florida south of Ft. Pierce. CPV has identified a tract of land in the Cana area, bounded by SR 609 to the east and SR 709 to the west, that has been secured for the Project. The Project parcel is approximately 61 acres in size. The Project equipment will be contained within a fenced portion of the parcel with an area of approximately 29 acres. Figures 1-1 and 1-2 illustrate the proposed Project location.

2.2 Equipment Description

To maximize efficiency and energy conservation, the proposed Project will include both combustion and steam cycles. In the combustion cycle, the combustion turbine will fire natural gas as its primary fuel to produce approximately 170 MW. The system will also have a steam cycle system consisting of a HRSG and steam turbine generator. This system provides exceptional efficiency by employing the HRSG to recover otherwise lost heat from the gas turbine exhaust and using it to create steam and drive the steam turbine generator to produce an additional maximum 74.9 MW. The steam that exhausts from the steam turbine generator is cooled and condensed for re-use in the steam cycle.

The combined-cycle technology design achieves an operational efficiency on a unit of energy output per unit of energy input basis greater than the operational efficiency for peaker type simple-cycle system or older power plants.

Ancillary equipment for the Project will include:

- One diesel-fired 250 hp fire water pump,
- One 500 kW emergency generator for safe shutdown, and
- One 5-cell cooling tower

A description of each major Project component is provided below.

2.2.1 Combined-Cycle Combustion Turbine Generator

The Project will use an advanced natural gas and distillate oil fired combustion turbine generator. The combustion turbine generator to be supplied by General Electric (GE) will be equipped with GE's two-stage, lean pre-mix dry low-nitrogen oxides (NO_X) combustor.

The nominal 170 MW turbine generator is GE's Model 7241FA. Basic elements include a compressor, a dry low NO_x combustor, a power turbine, and a generator. Within the combustor, injected fuel (in this case, natural gas or distillate oil) mixes with compressed air from the compressor and burns, producing hot exhaust that drives the shaft-mounted turbine blades. Some of the rotational energy of the shaft compresses the incoming combustion air. The greater portion of the shaft's rotational energy drives the generator to produce the nominal 170 MW.

The power produced by the combustion turbine generator decreases as the ambient temperature rises. This is because the density of the air decreases with increasing temperature. Because the turbine section produces power based on mass flow, increases in ambient air temperature result in a decrease in ambient air density that reduces the mass flow rate available for power generation by the turbine. In the proposed unit, power augmentation will be employed to minimize the effect of decreasing output with increasing temperature.

During warmer ambient temperatures, the combustion turbine is power augmented to make-up electrical output that is lost due to the increasing temperatures. Power augmentation involves using steam generated in the HRSG. The steam is injected into the turbine section of the combustion turbine generator. The injected steam increases the mass flow through the turbine, thereby increasing power output. Power augmentation can only be used, however, when the ambient air temperature is above 59°F.

2.2.2 Heat Recovery Steam Generator

Exhaust gases leaving the combustion turbine retain considerable recoverable heat energy. The HRSG transfers the heat from this high temperature exhaust gas (about 1,100°F) to water in order to generate useful steam for additional generating capacity. The temperature of the exhaust gas leaving the HRSG is approximately 190°F when firing natural gas.

The major sections of the HRSG include a super heater, an evaporator, and an economizer. The HRSG will not include duct burners and it will not be supplementally fired. Other HRSG components include a Selective Catalytic Reduction (SCR) NO_x control system (with associated ammonia injection and control systems) and an exhaust stack.

2.2.3 Emission Control Equipment

The exhaust flow from the combustion turbine will pass through an SCR system before venting through a 170-foot stack. This stack height has been designed to provide sufficient emission dispersion while minimizing the potential for aerodynamic downwash of stack emissions, and limiting the effect upon visual aesthetics. The SCR control system will be capable of reducing NO_x emissions to 2.5 (ppmvd @15% O_2) when firing natural gas and 10 ppmvd @15% O_2 when firing distillate oil. The ammonia slip will be limited to 5 ppmvd @ 15% O_2 when firing each fuel.

2.2.4 Cooling Tower

A wet cooling tower will be used to cool and condense steam in the proposed combined-cycle electric generation facility. The cooling tower reduces the temperature of cooling water by air-water contact. The Facility will include a condenser and a five-cell mechanical draft cooling tower to cool the steam/water from the HRSG.

Water from the cooler side of the condenser flows down through each cooling tower cell while air flows upward. Some of the cooling water evaporates and exits with the air as water vapor. The surface area of the water is increased as it flows or trickles through the fill section, which optimizes the heat transfer capability prior to it being collected in a basin at the bottom of the tower. Airflow, induced through the tower by fans, passes upward through the fill section, where heat transfers from the water and a fraction of the water evaporates, thus cooling the remaining water. The cooled water, which is collected in the basin, is then re-circulated back to the condenser. All of this occurs in a continuous fashion. A small percentage of the water is trapped in the air as small droplets. These entrained water droplets are referred to as cooling tower drift. Most of the water trapped in the air is removed using high-efficiency drift eliminators. However, some droplets remain airborne and are released with the plume exiting the tower.

The water that is lost through the tower to the atmosphere must be replaced. In addition, as water is evaporated from the system, the dissolved solids concentration of the water remaining in circulation increases. To prevent dissolved solids from reaching levels where they would collect as scale on the exposed surfaces of the tower and condenser, some of the basin water is continuously bled off from the system. This is known as cooling tower blowdown. As with the evaporative losses, this blowdown must be replaced. The flow required to compensate for evaporative and drift losses and blowdown are known as cooling tower makeup.

Air quality impacts are expected from the mechanical draft cooling tower system due to the dissolved solids contained in the cooling tower drift, even when high efficiency drift eliminators are employed to limit the quantity of droplets in the plume. The cooling tower will be designed to achieve a drift rate of 0.0005 percent of the circulating water flow rate, which represents the state-of-the-art in drift elimination technology. Some of the solids (particulate matter) are less than 10 microns in size and constitute PM_{10} emissions. These cooling tower emissions will be in addition to combustion emissions associated with the proposed Project stack.

2.2.5 Proposed Fuel Use

The equipment will be designed to generate electricity and steam using natural gas as the primary fuel source. During periods of natural gas interruption or when market conditions warrant, very low sulfur (0.05 percent) distillate oil will be used. The annual quantity of distillate oil use is limited to the equivalent of 100 percent load operation for no more than 30 days, i.e., 720 hours. The distillate oil will be delivered to the site by truck, and stored in an above ground tank.

2.3 Project Physical Layout and Design

The new equipment associated with the Project will occupy an approximate 29-acre area footprint on the approximately 61-acre site. A site plan illustrating the Facility arrangement is contained in Appendix B.

Power Generation Equipment: The electrical generating equipment, including the gas turbine, steam turbine, HRSG and associated mechanical and electrical equipment will be located outdoors.

Support Buildings: There will be several small ancillary buildings as shown on the site plan in Appendix B, including a combination administration/warehouse building, a combination electric room/control room, a cooling tower electric building, water treatment area, pump house, and a Reverse Osmosis water plant building (R.O. plant).

Security: All operational areas of the site will be enclosed by a security fence. The electrical switchyard and the gas metering area will each be separately fenced. There will be one main gated plant entrance on the east side off of Range Line Road.

Storage Tanks: Several storage tanks will be constructed, all of which will be above ground and will meet all applicable Florida Department of Environmental Protection (FDEP) standards. One distillate oil storage tank with a capacity of 975,000 gallons will be installed. The tank will have double-wall construction with leak detection. Three water storage tanks will also be constructed: one 1.48 million gallon de-mineralized water tank, one 0.54 million gallon raw firewater storage tank and one deep well storage tank. A 12,000-gallon aqueous ammonia storage tank will be constructed for the nitrogen oxide emission control system. A concrete containment dike will be built around this tank. Finally, a 20,000-gallon neutralizer tank will be installed.

2.4 Equipment Operation

The proposed design consists of a combined-cycle power generating unit based on a single GE PG7241 (FA) combustion turbine, a 3-pressure heat recovery steam generator and a steam turbine generator (STG) designed in conjunction with the HRSG. The STG output will be limited to less than 75 MW. Control of STG output will be monitored and controlled via an automatic digital control system (DCS) to ensure the 75 MW output limit is not exceeded. A number of control options have been investigated and the most probable are described below.

When ambient temperature is at 59 degrees Fahrenheit (°F) or greater, excess steam generated in the HRSG can be extracted from the HRSG, bypassing the steam turbine, and injected into the CT. This mode of operation is referred to as power augmentation. Since there is a limit on the quantity of steam that may be injected into the CT, it may be necessary to further reduce steam flow to the STG to limit output or to reduce steam turbine output by other means.

Bypass of a portion of the heat exchange surface in the HRSG can be an effective method of reducing steam production by reducing the heat recovered from the combustion turbine flue gas. The proposed design will make use of a low temperature economizer bypass to limit steam production by allowing more of the heat generated by the combustion turbine to be discharged to the atmosphere with the flue gas. This will limit STG output.

In many cases, application of both of these control modes will reduce steam output of the turbine to the required quantity. If additional reduction in STG output is required, raising the STG discharge pressure by raising the condenser operating temperature will reduce turbine efficiency, reducing electrical output. Output of the STG may be tuned to the desired value by turning cooling tower cells on and off as necessary.

When the ambient temperature falls below 59 °F, the manufacturer does not recommend injection of steam into the combustion turbine. If the low temperature economizer bypass, combined with an increase in cooling water temperature does not reduce STG output sufficiently, excess steam may bypass the steam turbine and be sent directly to the condenser.

Output of the STG will be controlled automatically utilizing the methods described above through a DCS designed to ensure that the electrical power produced from steam does not exceed 74.9 MW. The DCS will be programmed by the Engineering Procurement Construction (EPC) engineer to limit the steam turbine output to 74.9 MW. The necessary logic to automatically control steam injection to the gas turbine, cooling tower fan speed, HRSG economizer bypass control, steam bypass control, or reduce gas turbine load will be incorporated in the DCS. The plant operator can manually lower the steam turbine output value but cannot raise the number beyond the programmed set point limit or alter the DCS logic. Depending on the DCS platform purchased, the logic and set point will either be protected by password or keylock. If the logic or set point must be changed after the plant is in commercial operation, only an authorized DCS representative or a qualified DCS engineer can make the modifications. These modifications can be made using the DCS engineering work station, which will be located in the plant control room. A shutdown of the facility is not required since the changes can be made while the plant is on-line.

2.5 Construction Schedule

The development schedule for the Project calls for obtaining all required pre-construction approvals by the first quarter of 2002. Upon financial closing, groundbreaking for the Facility would be initiated by the EPC contractor. Construction of the Project would require approximately 22 to 24 months and is scheduled to be completed in the first quarter of 2004. Start-up/testing activities would be ongoing during the later phases of construction. Commercial acceptance of the Facility by CPV would occur approximately six weeks after completion of the construction activities.

Section 3

Applicable Regulatory Requirements

3.0 APPLICABLE REGULATORY REQUIREMENTS

The proposed CPV Project must comply with air pollution control regulations administered by the Florida Department of Environmental Protection (FDEP), Division of Air Resources Management (DARM). Essential to understanding the regulatory requirements to which the Project must comply are the new power generation equipment air pollutant emission rates.

The Project will produce approximately 245 MW of electrical power. The Project's primary power generation equipment includes a new combustion turbine, HRSG, and steam turbine, operated as a combined-cycle system.

Major pollutants of interest emitted include: sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter less than 10 microns (PM_{10}), carbon monoxide (CO), and volatile organic compounds (VOC). Other pollutants including lead and regulated non-criteria air contaminants are not of concern because the new power generation equipment will fire natural gas as the primary fuel and very low-sulfur distillate oil (0.05 percent sulfur content) as the back-up fuel. The distillate oil firing will be limited to the equivalent of 30-day operation at 100 percent load.

The annual emission rates that determine regulatory applicability are the potential annual emissions of the new power generation equipment. Design data provided by the equipment manufacturer for the new power generation equipment specifies air pollutant emissions as a function of operating load and ambient temperature for both natural gas and distillate oil firing (see Appendix C). The annual potential emissions were calculated assuming 335 days of natural gas firing and 30 days of low sulfur distillate oil firing, and assuming the maximum pollutant emission rate over the range of operating conditions contained in the equipment design data. Table 3-1 shows the new power generation equipment's potential annual emissions.

Table 3-1 New Power Generation Equipment Criteria Pollutant Emissions CPV Cana[1]	
Pollutant	**Potential Emissions[2] (Tons/Year)**
NO_x	96
SO_2	76
CO	226
PM/PM_{10}[3]	96
VOC	15

[1] Source: GE performance data in Appendix C.
[2] Annual emission estimates based on combustion turbine operating 8760 hours at maximum hourly emission rate.
[3] PM/PM_{10} value includes combustion turbines and cooling tower drift.

The U.S. Environmental Protection Agency (EPA) regulations establish air quality standards and air contaminant emission limits with which all new sources must comply. These regulations affect the design and operation of the new power generation equipment. This section describes the regulations and their impact on the Project.

3.1 Ambient Air Quality Standards

EPA has developed National Ambient Air Quality Standards (NAAQS) for six pollutants, referred to as criteria pollutants, for the protection of the public health and welfare. The criteria pollutants are SO_2, NO_2, CO, PM_{10}, ozone (O_3), and lead (Pb). FDEP enforces the NAAQS as state air quality standards. FDEP has also established primary SO_2 State Ambient Air Quality Standards (SAAQS), which are more restrictive than the NAAQS. Table 3-2 shows the NAAQS and SAAQS.

Primary standards protect human health with an adequate margin of safety, and secondary standards protect public welfare (e.g., avoid damage to property or vegetation). Different averaging periods are established for the criteria pollutants based on their potential environmental effects.

Attaining and maintaining compliance with the state and national ambient air quality standards is the primary goal of all air regulations evolving from the original Clean Air Act and its subsequently enacted amendments. All areas of the nation have been classified as to their status with regard to attaining the standards. The Project site area is classified as "unclassified" or "attainment" for all criteria pollutants.

Table 3-2 Ambient Air Quality Standards and Thresholds

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)[h]		PSD Increments ($\mu g/m^3$)	Significant Impact Levels ($\mu g/m^3$)
		Primary	Secondary		
Sulfur Dioxide (SO_2)	3-hour 24-hour Annual	NA 365[a] (260) 80[g] (60)	1300[a] NA NA	512[a] 91[a] 20[g]	25 5 1
Nitrogen Dioxide (NO_2)	Annual	100[g]	100[g]	25[g]	1
Carbon Monoxide (CO)	1-hour[a] 8-hour[a]	40,000 10,000	NA NA	NA NA	2000 500
Particulate Matter (PM_{10})	24-hour Annual	150[d] 50[g]	NA NA	30[a] 17[g]	5 1
Particulate Matter ($PM_{2.5}$)	24-hour Annual	65[f] 15[eg]	NA NA	NA NA	NA NA
Ozone (O_3)	1-hour 8-hour	235[b] 157[c]	235[b] 157[c]	NA NA	NA NA
Lead (Pb)	Quarterly	1.5[g]	NA	NA	NA

a Not to be exceeded more than once per year.
b Not to be exceeded more than once per year on average.
c 3-year average of annual 4th highest concentration.
d The pre-existing form is exceedance-based. The revised form is the 99th percentile.
e Spatially averaged over designated monitors.
f The form is the 98th percentile.
g Never to be exceeded.
h $\mu g/m^3$, micrograms per cubic meter.
( ) SAAQS Concentration.

It is important to note that implementation of some proposed NAAQS, the $PM_{2.5}$ standards, and the 8-hour ozone standard have been delayed. The delay is due to recent court decisions and the need to develop additional ambient air quality data and compliance assessment procedures.

3.2 Non-attainment New Source Review

Because St. Lucie County is currently designated as "unclassifiable" or "attainment" for all criteria pollutants, the Project is not subject to non-attainment new source review.

3.3 Prevention of Significant Deterioration (PSD)

The federal PSD regulations affect areas classified as "unclassifiable" or "attainment" with respect to the NAAQS. St. Lucie County is classified as such for all criteria pollutants.

As part of an ambient air quality impact analysis, a facility classified as a new major source or major modification must demonstrate compliance with the NAAQS, and with the PSD increments shown in Table 3-2. The PSD regulations require assessments of potential impacts to soils and vegetation and to growth and visibility in the area surrounding the proposed plant.

Additionally, facilities within 100 kilometers (km) of a Class I (wilderness) area must also perform an assessment of potential impacts to Class I area(s). The Class I area closest to the Project is the Everglades National Park. This Class I area is located approximately 180 km from the Facility site, and therefore is beyond the distance for which an impact analysis is required under the PSD Rules. When advised of the proposed Facility emissions rates and distance from the Class I area, the National Park Service confirmed to DEP that an impact analysis is not required.

A new major source in "unclassifiable" or "attainment" areas that will result in net emissions increases greater than the significant emissions increase levels presented in Table 3-3 is subject to PSD review. Other pollutants for which EPA promulgated annual emission thresholds are not listed because the new equipment will burn natural gas as the primary fuel producing negligible emissions of these pollutants. The annual emission thresholds shown in Table 3-3 are exceeded for NO_x, SO_2, CO, and PM/PM_{10}. Accordingly, the proposed project's new power generation equipment is subject to PSD permitting requirements for these air pollutants.

Table 3-3 PSD Significant Emissions Increase Level and CPV Cana Project Net Emission Rates (Pursuant to 40 CFR 52.21 (b) (23) (i))

Pollutant	Significant Emissions Increase Level (TPY)	Annual Net Emissions Increases (TPY)
NO_x	40	96
SO_2	40	76
CO	100	226
PM	25	96
PM_{10}	15	96
VOC	40	15

3.4 New Source Performance Standards (NSPS)

Combustion Turbine

The new combustion turbine associated with the Project is subject to the provisions of 40 CFR Part 60 Subpart GG (New Source Performance Standards for Combustion Turbines). NSPS Subpart GG affects combustion turbines having a maximum firing capacity greater than 10 million Btu per hour and constructed after October 1977. The emission standards contained in the NSPS rule, limit flue gas concentrations of NO_x and SO_2.

The NO_x limit is 75 parts per million (ppm) (based on the turbine heat rate and the fuel bound nitrogen). The SO_2 limit is 150 ppm (or 0.8 percent sulfur in fuel). Additionally, the provisions of this subpart require the installation of a Continuous Emission Monitoring System (CEMS) to monitor fuel consumption and water to fuel ratio. Subpart GG also requires monitoring of fuel sulfur and nitrogen content and allows for the development of a custom schedule to monitor these parameters.

The new power generation equipment will combust natural gas and 0.05 percent sulfur content distillate oil. The proposed fuels contain less than 0.8 percent sulfur, complying with the NSPS requirements for SO_2.

The combined-cycle combustion turbine will generate no more than 9 ppm of NO_x prior to the addition of SCR controls and no more than 2.5 ppmvd@15% O_2 after the SCR controls when firing natural gas. Backup distillate firing will generate no more than 10 ppmvd@15% O_2 of NO_x. Therefore, the combustion turbine will comply with the requirements of NSPS Subpart GG for NO_x.

Fuel Oil Storage Tank

The Facility plans to install and operate a 975,000 gallon above ground fuel oil storage tank. Due to its size, this tank is subject to the provisions of 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction Commenced after July 23, 1984. Specifically, this Subpart requires record keeping as stated in Section 60.116b, which includes the dimensions of the tank, and an analysis showing the capacity of the vessel.

3.5 National Emission Standards for Hazardous Air Pollutants

New stationary combustion turbines are subject to 40 CFR Part 63, Subpart B – Requirements for the Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j). This regulation requires a case-by-case determination of the Maximum Achievable Control Technology (MACT) for major sources that exceed the annual emission thresholds of 10 tons per year for an individual Hazardous Air Pollutant (HAP) or 25 tons per year for total HAP emissions.

Because the Project is using clean fuels (natural gas and distillate oil), total Project HAP emissions do not exceed the regulatory thresholds. Emission calculations for HAPs are provided in Appendix C and are based on AP-42 emission factors, Fifth Edition, April 2000 for all HAPs.

Total Project emissions of each HAP are less than 10 tons per year and less than 25 total tons; therefore, the Project is not subject to this regulation.

3.6 Acid Rain Program

Title IV of the 1990 Clean Air Act amendments required EPA to establish a program to reduce emissions of acid rain-forming pollutants, called the Acid Rain Program. The overall goal of the Acid Rain Program is to achieve significant environmental benefits through reductions in SO_2 and NO_x emissions. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution.

Under the federal program, EPA allocates existing units SO_2 allowances. The affected facilities may use their allowances to cover emissions, or may trade their allowances to other units under a market-trading program. In addition, subject facilities are required to implement continuous emissions monitoring systems (CEMS) for affected units. The CEMS requirements of the Acid Rain Program include: an SO_2 concentration monitor; a NO_x concentration monitor; a volumetric flow monitor; an opacity monitor; a diluent gas (O_2 or CO_2) monitor; and a computer-based data acquisition and handling system for recording and performing calculations.

Beginning in 2000, the Federal Acid Rain Program's annual emission limitations became effective. The new combustion turbine will not be given an annual emissions budget under the Federal Acid Rain Program. The new combustion turbine will obtain SO_2 allowances through the market-trading program. The new power generation equipment incorporates the appropriate CEMS equipment in its design.

3.7 Operating Permit

The CPV Facility is subject to the Federal Clean Air Act (CAA) Title V operating permit program. The Florida DARM regulations implementing the CAA Title V program are contained in Rule 62-213. The operating permit specifies the applicable regulatory requirements with which the CPV Facility must comply and the methods used to demonstrate compliance. CPV will comply with the rule requirements as necessary.

3.8 Risk Management Plan (RMP)

In the case of a new facility, compliance with the RMP rule requires that the plan be submitted before the regulated substance is present at the facility in a quantity above the applicable regulatory threshold. Because the SCR control technology proposed for the Project will utilize aqueous ammonia with a concentration of less than 20 percent and because no other regulated substances will be present in a quantity above an applicable threshold, an RMP will not be required for the Project.

3.9 Florida Air Permit Application

The purpose of the new source permitting process is to ensure that a proposed facility will be in compliance with all applicable federal and state regulatory requirements.

The Project requires the submittal of an Air Permit Application under the Florida permitting rules. Based on the regulatory applicability review presented in the previous sections, the application for the new power generation equipment is expected to include the following analyses:

- Air quality modeling study demonstrating compliance with state and federal ambient air quality standards and increments; and
- Federal PSD review for SO_2, NO_x, PM/PM_{10}, and CO.

The Application is submitted to DARM for review and approval. The initial step in the agency review of the application is a completeness determination. Once the application is deemed complete, DARM conducts its review and issues a proposed permit for public review. A public hearing may be held and any comments addressed before issuing final approval.

Section 4

Assessment Of Impacts

4.0 ASSESSMENT OF IMPACTS

Due to limitations in the spatial and temporal coverage of air quality measurements, monitoring data normally are not sufficient to demonstrate the adequacy of emission limits for existing sources. Also, the impacts of new sources that do not yet exist can only be determined through modeling. Thus, dispersion models have become the primary analytical tools in most air quality impact assessments.

The following subsections describe the evaluation of the Project ambient air quality impacts. The air quality modeling study was conducted using data, assumptions, and procedures consistent with FDEP modeling guidelines and was based on discussions with FDEP modeling staff to determine specific model input requirements and compliance criteria.

4.1 Emission and Stack Parameters

The new power generation equipment will operate over a range of load conditions typically from 50 to 100 percent. Operation below 50 percent load will only occur briefly during startup or shutdown. The equipment vendor developed emissions and representative stack parameters for the combined-cycle system. Expected emissions for combinations of representative local ambient temperature range and load conditions for natural gas and distillate oil firing were provided to represent the range of operating conditions. These data are summarized in the following tables.

Table 4-1 contains the expected stack parameters for each of the operating conditions evaluated for the proposed power generation equipment. Table 4-2 contains the estimated emission rates for all operating scenarios modeled for the proposed power generation equipment based on vendor data currently available.

For demonstration of compliance purposes, if the maximum predicted air quality impact of the new power generation equipment for a specific pollutant and averaging time is below the modeling significance impact levels shown in Table 3-2, no additional air quality modeling is required.

Table 4-1 Stack Exhaust Parameters CPV Cana Project

Stack Height: 170 feet		
Stack Diameter: 18.5 feet		
Case ID	Temperature	Velocity
Temperature (°F)/% Load	(°F)	(feet/second)
Natural Gas		
25/50	166	40.5
25/75	172	50.4
25/100	184	65.2
59/50	173	40.0
59/75	177	48.5
59/100	186	61.5
59/100PA	181	64.4
72/50	168	39.2
72/75	172	47.2
72/100	181	59.2
72/100PA	187	63.0
97/50	175	38.3
97/75	179	45.9
97/100	188	55.8
97/100PA	183	58.3
Low Sulfur Distillate Oil		
25/50	255	46.8
25/75	258	58.0
25/100	285	78.6
59/50	255	45.8
59/75	265	56.4
59/100	284	73.8
72/50	255	45.4
72/75	265	55.4
72/100	284	71.4
97/50	259	44.1
97/75	270	53.2
97/100	284	66.0

Table 4-2 Power Generation Equipment Projected Criteria Pollutant Emissions for the CPV Cana Project (lb/hr)															
Load Condition (%)	50	75	100	50	75	100	100PA	50	75	100	100PA	50	75	100	100PA
Ambient Temperature (^{0}F)	25	25	25	59	59	59	59	72	72	72	72	97	97	97	97
Combined-Cycle Unit with Emission Controls															
Natural Gas															
SO_2	6	8	10	6	8	9	10	6	7	9	10	6	7	8	9
NO_X	11	14	14	10	13	16	17	10	13	16	16	9	12	14	15
CO	20	25	31	19	23	29	50	19	23	28	49	18	21	26	45
PM	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Distillate Oil															
SO_2	62	79	99	59	75	93	N/A	58	73	91	N/A	53	68	83	N/A
NO_X	49	63	80	47	60	75	N/A	46	58	73	N/A	42	54	67	N/A
CO	53	65	70	52	62	66	N/A	51	60	63	N/A	49	57	57	N/A
PM	41	42	44	40	42	44	N/A	40	42	44	N/A	40	41	43	N/A

PA=Power Augmentation Operating Scenario

4.2 Good Engineering Practice (GEP) Stack Height Calculation

The Project site is located in a rural setting with no existing nearby buildings that have the potential to affect plume dispersion from the combustion turbine stacks. The HRSG, associated with the combined-cycle unit, is the only structure with physical dimensions that could potentially affect plume dispersion. The HRSG height is 88 feet above grade and is connected to the stack. Appendix B contains a site drawing showing structure location and dimensions.

A mechanical draft cooling tower will be constructed at the site consisting of five cells. The combined dimensions of the five contiguous cells will be approximately 240 feet long, 50 feet wide, and 31 feet in height with fan top height of 45 feet. The fan opening at the top of each cell is approximately 32.8 feet in diameter. The cooling tower is to be located to the east of the power production equipment (see site plan in Appendix B) with the long axis oriented east to west. As the cooling towers are sources of PM_{10}, they were included in the GEP analysis.

The GEP stack height analysis was done following the procedures outlined in the Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document For the Stack Height Regulations, Revised, EPA-450/4-80-023R, June 1985).

Direction specific building downwash dimensions were determined using the EPA's BPIP software for the combustion turbine stack assuming a height of 170 feet. Each building's location and dimensions and the location of the proposed stack and cooling towers were input to calculate the maximum building downwash height and projected width for each 10-degree sector surrounding the stack or emission point. Version 3 of the Industrial Source Complex Short Term model (ISCST3) was used to predict air quality impacts. Input files for ISCST3 included the 36 pairs of effective building height and projected width values for the stack and the cooling tower cells generated by BPIP.

The GEP height regulations allow stack heights up to 65 meters without any need for a demonstration. The height of the stack for this Project will be below 65 meters, therefore, it will comply with the GEP regulations.

Appendix D-1 includes the input and output files from the GEP program and a graphic showing the location of the stacks and buildings.

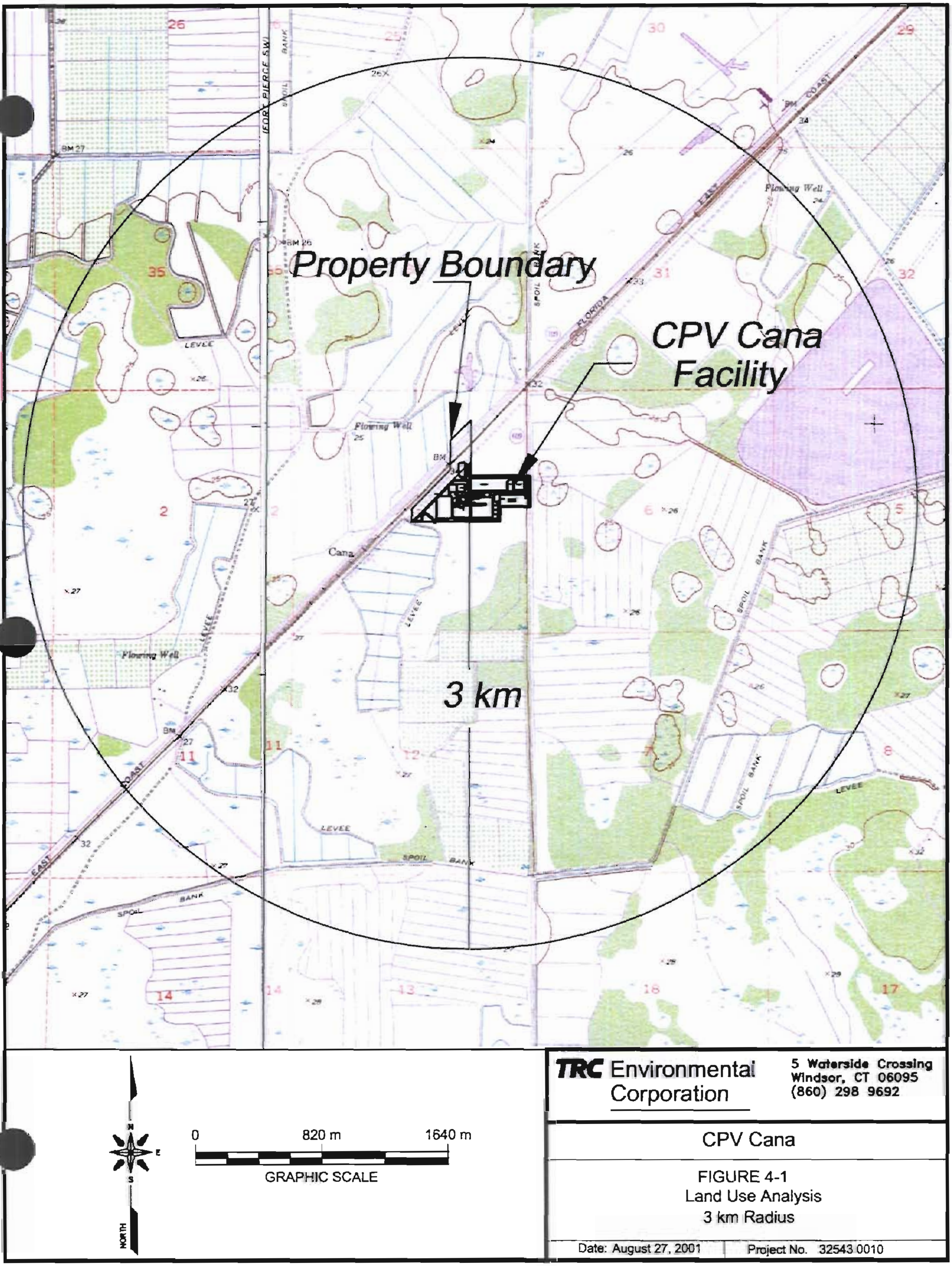
4.3 Land Use Determination

The ISCST3 model allows the option to include atmospheric dispersion coefficients characteristic of urban or rural land use. The determination of which set of dispersion coefficients to use is based on the land use within a three-kilometer (3 km) radius circle centered on the project site, referred to as the Auer method. Figure 4-1 illustrates the area within a 3 km radius considered in the land use determination.

The Project site is located in St. Lucie County, Florida, south of Ft. Pierce. The land use within three kilometers of the station is predominately rural residential and agricultural. Based on the EPA-recommended Auer technique, the land use within the 3 km circle is considered rural.

4.4 Background Air Quality

FDEP maintains a network of ambient air monitors to evaluate existing air quality throughout the state. The existing air quality in the area of the Project site is described using data available from the EPA AIRS database monitoring network.



TRC Environmental Corporation

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CPV Cana

FIGURE 4-1
Land Use Analysis
3 km Radius

Date: August 27, 2001	Project No. 32543 0010

The most recent three years (1998 to 2000) of available data from nearby monitoring locations were analyzed to determine representative ambient concentrations of the criteria pollutants of interest. The highest annual average and highest second-high short-term average concentrations were identified, as appropriate, for each air contaminant. Table 4-3 lists the monitoring stations, and the classifications of their associated land uses, selected to determine existing ambient levels in the vicinity of the Project site.

The air contaminant measurements are summarized in Table 4-4. The short-term levels, e.g., 24-hours or less, are the second highest average values for each year. As can be seen from Table 4-4, existing ambient levels of all pollutants are well below their respective NAAQS and SAAQS.

Table 4-3. Air Quality Monitoring Stations

Monitor Address	Land Use	Location Type	Monitor ID
101 North Rock Rd., Ft. Pierce	Agricultural	Rural	121111002426021
1050 15th St. W, Riviera Beach	Commercial	Suburban	120993004424011
6120 SW Glades Cutoff Rd., Ft. Pierce	Industrial	Suburban	121110012811021
3700 Belevedere Road, West Palm Beach	Residential	Suburban	120991004421011

Table 4-4 Existing Air Quality

Pollutant	Station	Averaging Time	Units	Concentration			
				NAAQS (SAAQS)	1998	1999	2000
NO_2	101 North Rock Rd., Ft. Pierce	Annual	ppm	0.053	0.012*	0.010	0.010
SO_2	1050 15th St. W, Riviera Beach	3-hour	ppm	0.5	0.012	0.014	0.012
		24-hour	ppm	0.14 (0.1)	0.004	0.013	0.008
		Annual	ppm	0.03 (0.02)	0.001	0.001	0.001
PM_{10}	6120 SW Glades Cutoff Rd., Ft. Pierce	24-hour	μg/m³	150	35	39	35
		Annual	μg/m³	50	19	20	19
CO	3700 Belevedere Road, West Palm Beach	1-hour	ppm	35	6	4	4
		8-hour	ppm	9.0	3	3	3

*Data from Monitor ID 120991004426021

4.5 Meteorological Data

Five years of hourly surface meteorological data (1990 to 1994) from Vero Beach Airport were used to model the emission impacts for the proposed Facility. This observation station is located approximately 26 miles to the north of the Project site. The meteorological data sets consist of hourly values of wind speed and direction, temperature, stability class, and mixing height.

Wind roses for the years 1990 through 1994, individually and cumulatively, are contained in Appendix D-2. The predominant winds are from the northeast through the southeast sector, occurring approximately 40 percent of the time for the combined five years of data used in the modeling. Calm winds occur on an average of about 14 percent of the time each year.

4.6 Receptors

A polar receptor grid was developed to assess the air quality impacts in the Project vicinity. Receptor rings were located at 100-meter intervals from the combustion turbine stack location (polar grid center at x=0.0, y=0.0) out to a distance of 2.0 kilometers. Receptor rings were also placed at 200-meter increments out to a distance of 5 km. From 5 km to 10 km the rings were placed at 500-meter intervals and at 1 km intervals out to 20 km distance. A total of 1980 polar receptors were used.

Receptors were also placed around the plant and fence-line at approximately 50-meter intervals for a total of 36 receptors. Polar receptors located within the fence line were then deleted, leaving a total of 1933 receptors.

A more refined receptor grid was used in the PM_{10} impact analysis to insure capture of the maximum impact from the low level cooling tower emission points. A 10 meter refined grid was generated beyond the fence line out to 100 meters in all directions.

Receptor terrain elevations were set to zero along with the stack base elevation as recommended by FDEP.

4.7 Modeling Approach

TRC conducted the modeling study after consultation with FDEP, and consistent with the preceding discussions using EPA and FDEP approved methods.

Refined modeling was conducted using the ISCST3 model to demonstrate compliance with ambient air quality standards and/or significant impact levels (SILs). ISCST3 is preferred by EPA and other agencies for refined modeling because ISCST3 can simulate atmospheric dispersion associated with multiple stacks, simple, intermediate and complex terrain, and building wake effects. Rural dispersion coefficients were used, as more than 50 percent of the land use within a three-kilometer radius circle centered on the Project site is classified as rural.

ISCST3 was run to predict concentrations using the regulatory default option, which includes:

- Stack-tip downwash;
- Buoyancy-induced dispersion;
- Final plume rise;
- Calm wind processing;
- Default wind profile exponents;
- Default vertical potential temperature gradients; and
- Use of upper bounds for super-squat buildings having an influence in the lateral dispersion of the plume.

The ISCST3 model was run with the simple terrain processing option selected as recommended by FDEP.

The modeling was conducted for each air contaminant and for the proposed power generation equipment operating scenarios using the five years of Vero Beach Airport meteorological data. If the maximum predicted impact is less than the SIL for a particular pollutant and averaging time, then no further assessment is required.

4.8 Predicted Impacts

Impacts predicted by the ISCST3 model are presented for each criteria pollutant and averaging time for the Project's emissions. The short-term air quality impacts are documented for natural gas and backup low-sulfur distillate oil firing. The annual impacts are conservatively reported as the annual maximum average concentration predicted for all operating scenarios and fuel burned.

In assessing the impacts of the proposed new combustion turbines, the ISCST3 model was run for all operating cases using case-specific emission rates. The predicted impacts were then compared to the appropriate pollutant and averaging period SILs. PM_{10} combined impacts from the combustion stack and the cooling towers were also evaluated using the ISCST3 model with appropriate model input parameters for each source. The model input and output files for each scenario modeled are provided on a CD included in Appendix D-3. A summary of the scenarios modeled and results is provided in Appendix D-4.

4.8.1 Sulfur Dioxide (SO_2)

The maximum predicted 3-hour average impact for the five years of meteorological data modeled for the stack emissions is 14.8 $\mu g/m^3$ (distillate) and 2.48 $\mu g/m^3$ (natural gas). For the 24-hour average, the model predicted maximum impacts of 4.85 $\mu g/m^3$ (distillate) and 0.95 $\mu g/m^3$ (natural gas). These impacts are well below the 3-hour and 24-hour SO_2 SILs of 25.0 and 5.0 $\mu g/m^3$, respectively.

The maximum annual average SO_2 impact is predicted to be 0.21 $\mu g/m^3$. This maximum impact is well below the annual SIL of 1.0 $\mu g/m^3$.

4.8.2 *Nitrogen Dioxide (NO_2)*

The modeled maximum annual average impact of the oil-fired and gas-fired scenarios was predicted to be 0.17 $\mu g/m^3$, which is well below the annual SIL of 1.0 $\mu g/m^3$.

4.8.3 *Carbon Monoxide (CO)*

The modeled CO impacts for low-sulfur distillate oil firing are 20 $\mu g/m^3$ and 8.18 $\mu g/m^3$ for the 1-hour and 8-hour averaging periods, respectively. The predicted CO impacts for natural gas firing are 12.8 $\mu g/m^3$ and 5.16 $\mu g/m^3$ for the 1-hour and 8-hour averaging periods, respectively. With SILs for one-hour of 2,000 $\mu g/m^3$ and for 8-hours of 500 $\mu g/m^3$, the predicted CO impacts from the proposed project are well below the SILs.

4.8.4 *Particulate Matter (PM_{10})*

The maximum predicted PM_{10} impacts for the combustion turbines for the 24-hour averaging period when firing low sulfur distillate oil is 4.26 $\mu g/m^3$ (3.48 $\mu g/m^3$ firing natural gas) and the maximum annual average is 0.17 $\mu g/m^3$. The 24-hour and annual SILs for PM_{10} are 5.0 and 1.0 $\mu g/m^3$, respectively.

The cooling towers are sources of PM_{10} emissions as dissolved solids and suspended particles in the cooling water will become airborne particles once the water from the drift droplets evaporates. A table of parameters used to develop the PM_{10} emission rates from the cooling towers is provided in Appendix C.

In addressing impacts from the cooling tower, it was assumed that the five cells operate continuously. This is a conservative assumption as the combustion turbine may not always be operating at maximum load and/or atmospheric conditions of temperature and dew point may not always require operation of all cells even when the combustion turbine is operating at full load.

With the assumptions listed above, the maximum 24-hour average impact due to the combustion turbine stack and cooling towers is 4.30 $\mu g/m^3$ at a receptor located to the northwest of the property boundary, approximately 80 meters northwest of the proposed fenced area. The maximum impact is dictated by the PM_{10} emissions for the combustion turbine stack. The maximum impact due to the cooling tower emissions is 1.64 $\mu g/m^3$ and it is predicted to occur near the southern property boundary. The combined maximum annual impact from all particulate matter sources is predicted to be 0.18 $\mu g/m^3$. Comparing these results with the applicable 24-hour and annual SILs, i.e., 5.0 and 1.0 $\mu g/m^3$, respectively, the predicted maximum impacts are below PSD significance levels.

4.9 Additional Impact Analyses

4.9.1 Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. For PSD sources, the principal visibility impacts of concern are impacts on the conditions within the nearest PSD Class I area. The proposed Project is nearly 200 km from the closest Class I area, therefore impacts on visibility are expected to be insignificant. Locally, there are no known scenic vistas, sensitive natural or other areas, e.g., major airports, that would have impaired visibility due to the insignificant impacts from the proposed facility.

4.9.2 Vegetation and Soils

As noted above, Florida and PSD regulations require analysis of air quality impacts on sensitive vegetation types with significant commercial or recreational value, or sensitive types of soil. Evaluation of impacts on sensitive vegetation is generally performed by comparison of predicted Project impacts with screening levels presented in the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980). These procedures specify that predicted concentrations used for the analysis account for Project impacts added to ambient background concentrations.

Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that demonstrated compliance with NAAQS and PSD increments assures compliance with sensitive vegetation screening levels. The exception to the foregoing is the 3-hour average sensitive vegetation screening level for sulfur dioxide (SO_2), which is 786 $\mu g/m^3$. Additionally, there is a 1-hour screening level for SO_2 (918 $\mu g/m^3$) for which there is no NAAQS equivalent. Predicted project impact levels have been demonstrated by dispersion modeling to be insignificant, well below the applicable air quality standards, and well below the vegetation sensitivity thresholds.

4.9.3 Growth

The work force expected for the Project will range from 100 to 200 jobs during various phases of construction. It is expected that a significant regional construction force is already available to build the Project. Therefore, it is expected that new housing, commercial and industrial construction will not be necessary to support the Project during the two-year construction schedule.

The Project will also require approximately 20 to 25 permanent positions. Individuals that already live in the region will perform a number of these jobs. For any new personnel moving to the area, no new housing requirements are expected. Further, due to the small number of new individuals expected to move into the area to support the Project and existence of some commercial activity in the area, new commercial construction will not be necessary to support the Project's permanent work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth is not expected.

Based on the growth expectations above, no new significant emissions from secondary growth during Project construction and operation are anticipated.

4.9.4 Class I Areas

As noted above, the Project site is nearly 200 km from the closest Class I area. The Facility emissions will not have a significant impact on any Class I area. This expectation is based on the relatively small emission rates associated with the clean fuels, i.e., natural gas and low sulfur distillate oil, proposed for this Project and the long distance to the Class I area.

4.10 Summary of Project Impacts

Emissions from the proposed Project have been evaluated using appropriate modeling methods and source data. All impacts from the Facility operation are predicted to be below the applicable air quality standards or limits and in all cases are below the significance levels established for these limits. Table 4-9 summarizes the predicted impacts relative to the applicable standards or limits. Based on these results, the proposed Facility will not have a significant impact on any of the potentially impacted areas.

Pollutant/AQRV	Averaging Period	NAAQS (μg/m³)		PSD Class II (μg/m³)				PSD Class I			
		Primary	Secondary	Increment	SILs	Predicted Impacts	Significant Impact?	Increment	SILs	Predicted Impact	Significant Impact?
Sulfur Dioxide (SO_2)	3-hour	N/A	1300[a]	512[a]	25	14.8	NO	25	1.0	N/A	N/A
	24-hour	365[a] (260)	N/A	91[a]	5	4.85	NO	5	0.2	N/A	N/A
	Annual	80[b] (60)	N/A	20[b]	1	0.21	NO	2	0.1	N/A	N/A
Nitrogen Dioxides (NO_2)	Annual	100[b]	100[b]	25[b]	1	0.17	NO	2.5	0.1	N/A	N/A
Carbon Monoxide (CO)	1-hour[a]	40,000	N/A	N/A	2000	20.0	NO	N/A	N/A	N/A	N/A
	8-hour[a]	10,000	N/A	N/A	500	8.18	NO	N/A	N/A	N/A	N/A
Particulate (PM_{10})	24-hour	150[c]	N/A	30[a]	5	4.30	NO	8	0.3	N/A	N/A
	Annual	50[b]	N/A	17[b]	1	0.18	NO	4	0.2	N/A	N/A

Table 4-5 CPV Cana Project Summary of Applicable Limits and Predicted Impacts

a Not to be exceeded more than once per year.
b Never to be exceeded.
c The pre-existing form is exceedance-based. The revised form is based on the 99th percentile statistic.

( ) SAAQS Concentration.

Section 5

Control Technology Analysis

5.0 CONTROL TECHNOLOGY ANALYSIS

A control technology analysis has been performed for the new power generation equipment based upon guidance presented in the draft EPA document, New Source Review Workshop Manual (October 1990). Control technology requirements for each pollutant depend upon the Project area's attainment status and the potential emissions of the pollutant. Air contaminants subject to non-attainment New Source Review (NSR) must apply Lowest Achievable Emission Rate (LAER) technology and those subject to PSD review must apply Best Available Control Technology (BACT).

Section 5.1 outlines the degree of control required (LAER or BACT) for each air contaminant, as determined based on the regulations discussed in Section 3.0. Section 5.2 presents an overview of the "Top-Down" BACT assessment procedure used in this analysis. The procedure used in the economic analysis for technically feasible control options is detailed in Section 5.2.2. Sections 5.3 through 5.6 present control technology determinations for CO, SO_2, PM/PM_{10} and NO_x, respectively, for the proposed power generation equipment.

Note that throughout this section, "ppm" concentration levels for gaseous pollutants are parts per million by volume, dry basis, unless otherwise noted.

5.1 Applicability of Control Technology Requirements

An applicability determination, as discussed in this section, is the process of determining the level of emissions control required for each applicable air pollutant. Control technology requirements are generally based upon the potential emissions from the new or modified source and the attainment status of the area in which the source is to be located. A detailed determination of the applicable regulations, including the control technology requirements under the PSD and non-attainment rules, is provided in Section 3.0. The following sections discuss the applicability of BACT and LAER for emissions from equipment included in this permit application.

5.1.1 PSD Contaminants Subject To BACT Under PSD Review

Pollutants subject to PSD review are subject to BACT analysis. BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental and economic impacts. Based upon the regulatory applicability analysis in Section 3.0, the proposed Facility is considered a major source for PSD purposes since potential emissions exceed the major source threshold. Therefore, individual regulated pollutants are subject to PSD review, including the BACT requirement, unless potential annual emission rate increases are below the significant emission rates presented in 40 CFR 52.21(b)(23)(i) and summarized in Table 3-3. A PSD area is defined as an attainment area. Based upon these criteria, the federal BACT requirements for the proposed project apply to SO_2, PM/PM_{10}, CO, and NO_x emissions.

5.1.2 Non-Attainment Pollutants Subject To LAER

Emissions of pollutants subject to non-attainment NSR must be limited to LAER levels. LAER is defined as either the most stringent emission limitation contained in a State Implementation Plan (SIP) (unless it is demonstrated to not be achievable) or the most stringent emission limitation which is achieved in practice by the class or category of source, whichever is the most stringent, without regard to cost. The Project location is classified as attainment or unclassifiable for all criteria pollutants. Therefore, LAER requirements, including a control technology determination, are not applicable for any pollutant.

5.2 Approach Used for the BACT Analyses

As explained in Section 5.1, the new power generation equipment is subject to federal PSD BACT requirements for emissions of CO, SO_2, PM/PM_{10}, and NO_x. As previously stated, BACT defined under federal rules is the optimum level of control applied to pollutant emissions based upon consideration of energy, economic, and environmental factors. In a BACT analysis, the energy, economic, and environmental factors associated with each alternate control technology are evaluated, from the most stringent (top) technology and then proceeding to lesser degrees of control. The BACT analyses presented here consist of up to five steps for each pollutant, as outlined below.

5.2.1 Identification of Technically Feasible Control Options

The first step is identification of available technically feasible control technology options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements that would prevail in the absence of BACT decision-making, such as Reasonably Available Control Technology (RACT) or Florida emission standards. After elimination of technically infeasible control technologies, the remaining options are to be ranked from the top down by control effectiveness.

If there is only a single feasible option, or if the applicant is proposing the most stringent alternative, no further analysis is required. If two or more technically feasible options are identified, the next three steps are applied to identify and compare the energy, economic, and environmental impacts of the options. Technical considerations and site-specific sensitive issues will often play a role in BACT determinations. If the most stringent technology is rejected as BACT, the next most stringent technology is evaluated and so on.

In order to identify options for each class of equipment, a search of the EPA RACT/BACT/LAER Clearinghouse (RBLC) has been performed. Individual searches were performed for each pollutant emitted from the new power generation equipment. Results of the RBLC searches are summarized in Appendix E.

5.2.2 Economic (Cost-Effectiveness) Analysis

The cost-effectiveness evaluation relies on engineering estimates, vendor quotations, internal costing estimates, and environmental agency costing guidelines. The EPA guidance documents used in this analysis include the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, (USEPA, EPA 450/B-96-001, Fifth Edition, February 1996) and Alternate Control Techniques Document—NO_x Emissions from Stationary Gas Turbines, (USEPA, EPA 453/R-93-007, January 1993). The basic principles and assumptions used in the economic analysis are summarized below.

The economic portion of the BACT review consists of computing the ratio of the annualized cost of each emission control option to the annual emission reduction it can produce, represented as dollars per ton. The annualized cost of each emission control option has two components; the annualized total capital investment and the annual operating and maintenance cost.

The total capital investment (TCI) is the sum of the total direct costs (TDC) and total indirect costs. Direct costs are defined as the capital investment required to purchase equipment needed for the control system. Examples of direct costs include purchased equipment costs (PEC) (i.e., the sum of the base equipment, sales tax, and freight costs) and installation. Indirect costs include costs for engineering, construction, contractor, startup, testing, and contingency.

The PEC for a technically feasible control technology is based upon vendor quotations and engineering estimates for the control system specific to the proposed unit. Assumptions used to estimate elements of the TCI are provided as follows, unless site-specific values were available:

- Sales Tax – 6.5% of base equipment cost;
- Freight - 4% of base equipment cost;
- Installation - 35% of base equipment cost;
- Engineering Costs - 5% of PEC; and
- Contingency - 3% of Direct and Indirect Costs.

These assumptions are based on recent guidance and comments provided by both EPA Region IV and FDEP for similar turbine installations. The installation costs also include engineering, construction and field expenses, contractor fees, start-up and performance testing.

The capital recovery factor (CRF) is used to convert capital cost estimates into equivalent annualized costs. In order to annualize capital costs, an interest rate and project life must be estimated. When the CRF is multiplied by the capital investment, the product is the uniform end-of-year payment necessary to repay the investment in a defined amount of years. The CRF can be calculated based upon the following equation:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where i = interest rate and n = number of years of the investment.

A 7% nominal interest rate has been selected for this evaluation. The investment life, n, has been assumed to be equal to a ten-year payback period. The TCI has been amortized over a ten-year period at a 7% interest rate. These assumptions are consistent with values presented in the OAQPS Control Cost Manual – Fifth Edition and the latest update from William Vatavuk's companion text.

The total annual operating cost is defined as the expenses associated with the annual operation of the control equipment and is the sum of the direct annual costs and indirect annual costs. Direct annual costs include operating and supervisory labor, maintenance labor, and materials required to operate the control equipment. Direct annual costs also include catalyst replacement and utility costs. Indirect annual costs include overhead, property taxes, insurance and administration (including environmental reporting) associated with the operation of the control equipment. Assumptions used to estimate elements of the annual operating cost are as follows:

- Maintenance Labor - 1% of TCI;
- Maintenance Materials - 1% of TCI;
- Overhead - 60% of labor and maintenance materials;
- Property Tax - 1% of TCI;
- Insurance - 1% of TCI; and
- Administration - 2% of TCI.

Specific costing factors for feasible alternatives are identified in the appropriate pollutant-specific section. An economic analysis is not required if the most effective emission control option is proposed or if there are no technically feasible control options. An economic impact analysis was performed as part of the NO_x control technology review process and the CO control technology review.

5.2.3 Energy Impact Analysis

The energy impacts that may be associated with a control option can normally be quantified in two ways. Increases in energy consumption resulting from increased heat rate may be shown as incremental Btus or fuel consumed per year. Also, the installation of a control option may reduce the output and/or reliability of the proposed equipment. This reduction would result in assumed loss of revenue from "lost" electric power sales to the local utility.

5.2.4 Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutant being controlled. Increases or decreases in emissions of other criteria or non-criteria air contaminants may occur with some technologies, and should also be identified. Non-air impacts, such as solid waste disposal and increased water consumption/treatment, may be an issue for some projects and control options.

5.2.5 BACT Proposal

The determination of BACT for each air pollutant and emissions unit is based on a review of the three impact categories and the technical factors that affect feasibility of the control alternatives under consideration. The methodology described above is applied to the proposed Facility for the following pollutants: CO, SO_2, PM/PM_{10} and NO_x.

5.3 BACT Analysis for Carbon Monoxide

The proposed Project will consist of a combustion turbine and a non-supplementally fired HRSG. The formation of CO in the operation of a combustion turbine is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion, including insufficient O_2 availability, poor air and fuel mixing, cold wall flame quenching, reduced combustion temperature, decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized. The following sections address BACT elements for the proposed turbine.

5.3.1 Identification of Technically Feasible Control Options

The proposed GE model 7241FA turbine has inherently low CO emissions, due to the dry low-NO_x combustion technology employed. GE 7241FA turbine CO emissions on natural gas are among the lowest offered for utility-scale units across the anticipated load range of 50% to 100% load. Turbine emissions for each unit are guaranteed to be no more than 9 ppm for this load range during gas fired operation without power augmentation, no more than 15 ppm during natural gas firing with power augmentation, and no more than 24 ppm during oil-fired operation. The part-load emissions, in particular, compare favorably to other turbine models; some combustion turbine models have CO emissions of 100 ppm or greater at the 50% load level.

After combustion control, the only practicable control method to reduce CO emissions from combustion turbine units is an oxidation catalyst. Exhaust gases from the combustion turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide. CO reduction efficiencies in the range of 80 to 90 percent can be guaranteed, although CO reduction may be somewhat less than the design value at the very low inlet concentrations that are expected for the proposed turbine. A location downstream of the turbine or within the HRSG may be identified that will provide temperatures appropriate for the effective oxidation catalyst operation. Since the temperature profile will change with changing turbine load, a catalyst would be placed for optimum performance at full-load while providing some lesser degree of control at other load points. Likewise, since catalyst temperature is critical to the oxidation process, the oxidation catalyst will not be effective during combustion turbine start-up until the catalyst temperature is elevated to the necessary level. No other technically feasible options are identified for combustion turbine CO control.

Drawbacks of the oxidation catalyst include added cost, reduced turbine output and efficiency due to increased back pressure, and the potential for increased PM_{10} and/or sulfuric acid mist emissions, as outlined in the following three subsections. For base-loaded units with the low emissions projected for these turbines, such controls may be ruled out as BACT, due to the high cost per ton of pollutant control. For this reason, the application of oxidation catalysts on turbines is limited.

The energy losses associated with the use of an oxidation catalyst for CO control include reduced electrical output due to increased back-pressure, as well as the potential for lost generating capacity associated with any unplanned shutdowns for catalyst change-out, maintenance, and replacement.

A listing of economic, energy and environmental impacts associated with the proposed technology is provided under the following three subsections followed by the detailed proposal of BACT limits for the turbine.

5.3.2 Environmental Impacts of Technically Feasible CO Controls

Based upon modeling results, all predicted CO impacts fall well below significance levels defined in the PSD regulations. Therefore, the differences in emission rates with and without the catalyst do not correlate to meaningful differences in air quality impacts. A possible benefit of using catalysts would be the oxidation of VOC as well as CO, although the proposed VOC emissions are already quite low (maximum of 1.4 parts per million by volume, wet (ppmvw) with natural gas firing, and 3.5 ppmvw with oil firing) and VOC control efficiencies have not generally been guaranteed for catalysts on combustion turbines at these low emission levels. A drawback of the higher temperature catalyst location needed to reduce VOC emissions is the increased oxidation of SO_2 to SO_3. Higher SO_3 concentrations increase the potential for formation of sulfuric acid mist and ammonium sulfate and sulfite with ammonia slip from the NO_x controls. These substances not only add to PM/PM_{10} emissions, but also may condense and stick to the ductwork and stack, resulting in corrosion and increased maintenance.

5.3.3 Energy Impact of Oxidation Catalyst

The energy losses associated with the use of an oxidation catalyst for CO control include reduced electrical output (193 kW reduction, or a total of 1,521,000 kW-hr lost per year assuming a 90% capacity factor) due to increased back-pressure. It also gives rise to the potential for lost generating capacity associated with any unplanned shutdowns for catalyst change-out, maintenance, and replacement. Alternately, the energy penalty can be expressed as an increase in fuel consumption. The increase in heat rate predicted to result from the catalyst, 9 Btu/kW-hr, corresponds to an additional 11,921 MMBtu fuel consumption per year (assuming a 90% capacity factor and 161.2 MW combustion turbine electrical output at base conditions and 72 °F).

5.3.4 Economic Impact of Oxidation Catalyst

The initial capital cost for the catalyst is $870,352, based upon an estimate from a catalyst vendor that includes installation and contingency for the GE 7FA combustion turbine. Calculations of other costs used to derive an equivalent annual cost for the technology are detailed in Appendix E. The greatest factors in the annual operating cost are periodic catalyst replacement (a three-year guarantee is typical for a catalyst), and increased fuel cost due to adverse effect on combustion turbine heat rate, or efficiency. Equivalent annual cost for this technology (annualized capital plus annual O&M costs) is $355,941 per year. The vendor guaranteed uncontrolled CO emission levels of 9 ppm during natural gas firing without power augmentation and 20 ppm during oil firing at full power can be reduced to approximately 2 ppm and 4 ppm by an oxidation catalyst. Therefore, of the uncontrolled annual emissions of 156 tons of CO per year, an oxidation catalyst would control 124.8 tons (estimated 80% control efficiency) of CO per year. The annual operating scenario used in the calculation (turbine operation at 100% load for 6,040 hours per year firing gas without power augmentation, 2,000 hours per year firing gas with power augmentation, and 720 hours per year firing oil) is conservative since it maximizes the tons of CO available for control by the catalyst. Since the catalyst vendor does not guarantee CO removal during start-up, these emissions are not included in the calculation. The resulting cost-effectiveness per turbine is $2,852 per ton, which is calculated as follows:

($355,941/yr)/(124.8 tons CO controlled/yr) = $2,852/ton CO

5.3.5 BACT Proposal

The use of advanced dry low-NO_x turbine combustion technology is proposed as BACT for CO emissions. Therefore, the proposed CO emission limits are 9 ppm during natural gas firing for operating loads greater than 50% and 15 ppm during periods of power augmentation at 100% load. During distillate fuel oil firing the proposed limit is 20 ppm at 100% load. See Appendix C for CO concentrations at other loads.

The proposed BACT emission limits for CPV Cana are the same as those approved by FDEP for the identical CPV Pierce project in Florida. For that project (and the CPV Gulfcoast and CPV Atlantic projects), FDEP concluded that the installation of an oxidation catalyst was not warranted because actual CO emission rates are expected to be much less than the proposed limits, and continuous emissions monitoring systems (CEMS) will be employed to verify this expected performance. However, in response to EPA comments regarding the previous CPV projects, FDEP established permit limits that restrict operation "… in power augmentation mode to 2000 hours unless CPV installs [an] oxidation catalyst or proves that actual performance is much better than guaranteed (thus rendering control not cost effective)".

CPV therefore also proposes to accept a temporary limit of 2000 operating hours per year in power augmentation mode and the use of CEMS to record actual CO emission rates for the CPV Cana Project. It is expected that when actual CO emission rates from the GE 7241FA combined-cycle system are demonstrated in practice to be much lower than currently guaranteed, thus confirming that installation of [an] oxidation catalyst would not be cost-effective, CPV Cana will request a permit modification and FDEP will rescind the 2000 hour limit on annual operations in the power augmentation mode.

5.4 BACT Analysis for Sulfur Dioxide

Strategies for the control of SO_2 emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low sulfur fuels or fuel sulfur removal. Post-combustion controls comprise various wet and dry flue gas de-sulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to high pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low SO_2 concentrations.

The new power generation equipment will fire natural gas as the primary fuel (0.0065% sulfur by weight) and 0.05% sulfur distillate oil as back up, which is considered BACT for SO_2 emissions. Based on these clean fuels, the proposed maximum SO_2 emission rate for natural gas firing is 10 lb/hr and for distillate oil firing is 99 lb/hour.

5.5 BACT Analysis for Particulate Matter

5.5.1 Combustion Turbine

Particulate matter (PM/PM_{10}) emissions from combustion turbines are inherently very low, arising from impurities in combustion air and fuel, primarily from noncombustible metals present in trace quantities in liquid fuels. As a practical matter, turbine fuel specifications generally require that trace metals in the liquid fuel be kept to no more than a few parts per million to mitigate the potential deleterious action of PM/PM_{10} on turbine blades. Other sources of PM/PM_{10} include minerals in the injection water and PM/PM_{10} present in the combustion air and NH_3/sulfur salt formation due to the presence of the SCR.

The use of clean burning fuels, such as natural gas, is considered to be the most effective means for controlling PM/PM_{10} emissions from combustion equipment. Post-combustion controls, such as baghouses, scrubbers, and electrostatic precipitators are impractical due to the high pressure drops associated with these units and the low concentrations of PM/PM_{10} present in the exhaust gas. A review of PM/PM_{10} emission limits for combustion turbines presented in the RBLC search shows that only good combustion techniques and low-sulfur fuel have been used as controls for PM/PM_{10} emissions.

Because the Facility plans to fire natural gas as the primary fuel and very low sulfur (0.05%) distillate oil as the back-up fuel, the combination of clean fuels and good combustion is considered BACT for PM/PM_{10} emissions. The proposed front and back half emission limits for PM/PM_{10} are 19 lb/hr during natural gas firing, and 44 lb/hr during distillate oil firing, which includes ammonium sulfates due to the SCR catalyst.

5.5.2 Cooling Tower

PM/PM_{10} emissions from the cooling towers occur because wet cooling towers provide direct contact between the cooling water and the air passing through the tower. Some of the liquid water may be entrained within the air stream and be carried out of the tower as "drift" droplets. Therefore, the PM/PM_{10} constituent (suspended and dissolved solids) of the drift droplets may be classified as an emission. Because drift droplets contain the same chemical impurities as the water circulating through the tower, these impurities can be converted into airborne emissions. To reduce drift from cooling towers, drift eliminators are usually incorporated into the tower design to prevent water droplets from leaving the tower and therefore reduce PM/PM_{10} emissions. The only alternative would be to reduce the solids content of the water, either by water treatment or by reducing the cycles of concentration. A review of PM/PM_{10} emission limits for cooling towers, presented in the RBLC search, identifies drift eliminators as the most stringent control technique option for PM/PM_{10} emissions.

Drift eliminators will be incorporated into the cooling tower design specifications, which will limit drift from the cooling tower to less than 0.0005 percent of the circulating water flow rate.

5.6 BACT Analysis for Nitrogen Oxides

The formation of NO_x is determined by the interaction of chemical and physical processes occurring within the combustion chamber of the turbine. There are two principal forms of NO_x designated as "thermal" NO_x and "fuel" NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. The major factors influencing thermal NO_x formation are temperature and residence time within the combustion zone. Fuel NO_x is formed by the oxidation of fuel-bound nitrogen. For combustion turbines, fuel NO_x is typically responsible for only a small amount of the total NO_x formed in the combustion process. Adjusting the combustion process and/or installing post-combustion controls can control NO_x formation.

Typical gas turbines are designed to operate at a fuel to air ratio of 1.0. This is the point where the highest combustion temperature and quickest combustion reactions (including NO_x

formation) occurs. Fuel-to-air ratios below 1.0 are referred to as fuel-lean mixtures (i.e., excess air in the combustion chamber) and fuel-to-air ratios above 1.0 are referred to as fuel-rich (i.e., excess fuel in the combustion chamber). The rate of NO_x production falls off dramatically as the flame temperature decreases. Very lean dry combustors can be used to control emissions.

Based upon this concept, lean combustors are designed to operate below the 1:1 ratio thereby reducing thermal NO_x formation within the combustion chamber. The lean combustors typically are two staged premixed combustors designed for use with natural gas fuel and capable of operation on liquid fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage. The GE 7241FA turbine utilizes a dry low-NO_x combustion system, which produces expected uncontrolled NO_x emissions of 9 ppm during natural gas firing without power augmentation, and 12 ppm during natural gas firing with power augmentation.

5.6.1 Identification of Technically Feasible Control Options

The "Top-Down" policy for performing a BACT analysis starts at the lowest achievable emission rate (LAER) for NO_x. To determine the most stringent permit limit, a search of the RBLC was performed. For a limit to be considered LAER, it requires more than just the issuance of a permit. If a facility was never built or operated, or has not demonstrated compliance through stack testing and/or continuous emissions monitoring, the facility's emission limits have not been demonstrated to be achievable and are not considered LAER.

$SCONO_x$ is a trade name for a proprietary NO_x control technology being marketed by Goal Line Technologies. $SCONO_X$ technology has been tested on small turbines, and installed on the GE LM 2500 turbine at the 32 MW Federal Cold Storage Cogeneration Facility in Vernon, California. The facility is owned and operated by one of the parent companies of Goal Line Technologies. The turbine at the Federal Cold Storage Cogeneration Facility fires natural gas exclusively. To date, this technology has achieved a NO_x emission rate (approximately 2.0 ppm) comparable to those considered LAER or BACT at other facilities using SCR. The NO_x emission rate would not be lower with this technology based on information provided to date.

A recent assessment of the $SCONO_x$ technology (Appendix E) determined that this technology was not technically feasible based in part on the recent experience with the technology on a small (5 MW) combustion turbine. The $SCONO_x$ system on this turbine is not able to meet the vendor guarantees.

SCR is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. SCR involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x contained within the air to form nitrogen gas (N_2) and water (H_2O) in accordance with the following chemical equations:

$$4NH_3 + 4NO + O_2 \Rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \Rightarrow 7N_2 + 12H_2O$$

The catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogeneous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path in order to achieve maximum conversion efficiency and minimum backpressure on the gas turbine. The most common configuration is a "honeycomb" design. In a typical NH_3 injection system, NH_3 is drawn from a storage tank, vaporized and injected upstream of the catalyst bed. Excess NH_3 which is not reacted in the catalyst bed and which is emitted from the stack is referred to as NH_3 slip.

An important factor that affects the performance of an SCR is operating temperature. The temperature range for standard base metal catalyst is between 400 and 800 °F.

5.6.2 Environmental Impacts of a SCR Control System

SCR is often considered BACT for NO_x emissions on natural gas-fired combined-cycle combustion turbines in ozone attainment areas. It has been argued that dry low-NO_x turbines should not apply additional SCR controls as it can have a negative environmental effect. An SCR system involves injecting anhydrous or aqueous ammonia (NH_3) into the flue gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_x contained within the air to form nitrogen gas and water. The following environmental issues are a result of the addition of SCR controls to a combustion turbine flue gas stream:

Ammonia Slip Impacts

Ammonia salts (fine particle) formation - Combustion turbines emit SO_3, which may then react with water to form sulfuric acid, which in turn reacts with ammonia slip to form ammonium salts, resulting in increased particulate matter emissions. Ammonium salts are corrosive and can stick to the heat recovery surfaces, ductwork, or the stack at low temperatures. Increased particulate emissions effect visibility and can cause human health problems.

Eutrophication – when deposited on water surfaces, oxidized or reduced nitrogen promotes the growth of aquatic plants, such as algae, and the resulting bacteria consumes the oxygen in the water.

Possible conversion to nitrous oxide (N_2O) – once deposited on soil, a small fraction of ammonia emissions may be converted by soil microbes to N_2O, which contributes to ozone formation and has other adverse environmental and health effects.

Ammonia Storage and Handling

Storage/Handling – Although not of concern at this Facility due to the selection of less than 20% aqueous ammonia, an anhydrous or aqueous ammonia storage tank will be required at a facility utilizing SCR controls. Ammonia is identified by EPA as an extremely hazardous substance. It is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose or throat. Additionally, ammonia vapors may form an explosive mixture with air.

Applicable requirements – facilities that handle over 10,000 pounds of anhydrous ammonia or more than 20,000 pounds of ammonia in an aqueous solution of 20% ammonia or greater must prepare a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases.

Catalyst Disposal

Spent catalyst waste – the catalyst in the SCR degrades over time and needs to be replaced, about once every three years. The amount of spent catalyst waste is dependent on several factors, including the amount of catalyst used in the system, the life of the catalyst, and the amount of spent catalyst recycling that occurs.

5.6.3 *Energy Impacts of a SCR Control System*

The installation of a SCR control system in the flue gas stream has several operating effects on the combustion turbine, which are discussed below.

The SCR unit causes a pressure drop in the flue gas stream and the resultant backpressure exerted on the combustion turbine. The pressure drop effect will result in an increased heat rate for the turbine. This will result in either a decrease in the turbine's power output or an increase in the turbine's fuel consumption to compensate for the heat rate increase.

The following table is a demonstration of how the proposed SCR controls effect the performance of the GE 7421FA combustion turbine:

Table 5-1 Energy Impacts of SCR Controls			
Pressure Drop Across SCR System (inches H_2O)	**Lost Output Due to Pressure Drop (kW-hr/yr)**	**Increased Heat Rate of Combustion Turbine (Btu/kW-hr)**	**Additional Fuel Consumption Due to Heat Rate Increase (MMBtu/yr)**
1.5	2,409,000	9	12,709

Notes:
1. Increased heat rate based on pressure drop. Similar project experienced a 9 Btu/kw-hr increase due to a 1.5-inch pressure drop from a control device.
2. Annual lost electrical output and additional fuel consumption based on 8,760 hours of operation and 161.2 MW combustion turbine output.

5.6.4 *Economic Impact of SCR Control System*

In addition to being technically infeasible, $SCONO_x$ control technology is significantly more expensive than SCR. An economic analysis is provided in Appendix E. The estimated levelized cost per ton of NO_x removal for the $SCONO_x$ technology is $20,604/ton per year. The SCR annualized cost per ton, which is the proposed control technology for NO_x removal, totaled $3,396/ton per year.

5.6.5 *BACT Proposal*

The $SCONO_x$ control technology is not a demonstrated technology and SCR technology is significantly less expensive than $SCONO_x$ for the same level of NO_x control. Therefore, the use of SCR technology is proposed as BACT for NO_x emissions from the combined-cycle equipment. Proposed BACT emission limits are 2.5 ppm at 15% O_2 (16.7 lb/hr) NO_x during natural gas firing and 10 ppm at 15% O_2 (80 lb/hr) NO_x during distillate oil firing. The 2.5 ppmvd NO_x limit during natural gas firing has recently been required, for the first time, as BACT by the FDEP for the similar CPV Pierce facility in Polk County.

5.7 BACT Summary

This BACT analysis was based on similar recent analyses performed and submitted with other CPV applications. The proposed BACT emission rate limits for this application are consistent with recent determinations made by the FDEP. The following table summarizes the proposed BACT limits, assuming full load operations, for the proposed Facility.

Table 5-2 Summary of Proposed BACT Limits for the CPV Cana Project		
Pollutant	Control Technology	Proposed BACT Limit
Nitrogen Oxides	Low - NO_x Combustion Technology Selective Catalytic Reduction	2.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
Carbon Monoxide*	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation mode) 24 ppmvd (oil)
Particulate Matter-Combined-Cycle System	Inherently Clean Fuels Combustion Controls	19 lb/hr (gas) 44 lb/hr (oil)
Particulate Matter-Cooling Tower	High Efficiency Drift Eliminators	0.0005% drift
Sulfur Dioxide	Low Sulfur Fuels	10 lb/hr (gas) 99 lb/hr (oil)

*FDEP approved the following CO emission limits @ 15% O_2 for the CPV Pierce Project:
8 ppmvd (gas)
13 ppmvd (power augmentation mode)
17 ppmvd (oil)

Appendix A

Air Permit Application Forms

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: CPV Cana, Ltd.	
2. Site Name: CPV Cana Power Generating Facility	
3. Facility Identification Number:	[X] Unknown
4. Facility Location: Street Address or Other Locator: south of intersection of SR 609 and 709 City: Port St. Lucie County: St. Lucie Zip Code: 34987	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: Peter J. Podurgiel, Vice President Development
2. Application Contact Mailing Address: Organization/Firm: CPV Cana, Ltd. Street Address: 35 Braintree Hill Office Park, Suite 107 City: Braintree State: MA Zip Code: 02184
3. Application Contact Telephone Numbers: Telephone: (781) 848-0253 Fax: (781) 848-5804

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	9-5-01
2. Permit Number:	1110103-001-AC
3. PSD Number (if applicable):	PSD-FL-323
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:________________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:________________________________

Operation permit number to be revised:______________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:______________________________

Reason for revision:____

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Gary Lambert, Manager of CPV Cana LLC the general partner of CPV Cana, Ltd.
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: CPV Cana, Ltd. Street Address: 35 Braintree Hill Office Park, Suite 107 City: Braintree State: MA Zip Code: 02184
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (781) 848-0253 Fax: (781) 848-5804
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✓], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Signature 8/31/01 Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: Scott G. Sumner Registration Number: 44352
2.	Professional Engineer Mailing Address: Organization/Firm: TRC Street Address: 21 Technology Drive City: Irvine State: CA Zip Code: 92618
3.	Professional Engineer Telephone Numbers: Telephone: (949) 727-9336 Fax: (949) 727-7399

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature 8-31-01

Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
--	General Electric 7241FA Combustion Turbine	AC1A	
--	Cooling Tower	AC1A	

Application Processing Fee

Check one: [ ] Attached - Amount: $____________________ [ ] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: Construction of an electrical power generation facility consisting of a combined-cycle system comprised of one nominal 170-MW General Electric 7241 FA combustion turbine and heat recovery steam generator designed to power a steam turbine with an operational controlled generating capacity of 74.9 MW.
2. Projected or Actual Date of Commencement of Construction: To be determined
3. Projected Date of Completion of Construction: To be determined

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17 East (km): 550.9 North (km): 3018.1			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 27/17/7.4 N Longitude (DD/MM/SS): 80/29/7.2 W			
3. Governmental Facility Code: 0	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters): CPV Cana, Ltd. will install a power generating unit consisting of an efficient combustion turbine with heat recovery steam generator (HRSG). The gas turbine will provide approximately 170 MW of electrical power. The HRSG recovers otherwise lost heat from the gas turbine exhaust and provides steam energy to drive a steam turbine with an operationally controlled generating capacity of 74.9 MW. The new power generation equipment will be designed to meet federal Best Available Control Technology (BACT) standards, as appropriate for emissions control. The combustion turbine, HRSG, and steam turbine will be built on a 29-acre portion of the 61-acre St. Lucie County property. The new power generation facility includes a 170-foot stack.			

Facility Contact

1. Name and Title of Facility Contact: Peter J. Podurgiel, Vice President Development
2. Facility Contact Mailing Address: Organization/Firm: CPV Cana, Ltd. Street Address: 35 Braintree Hill Office Park, Suite 107 City: Braintree State: MA Zip Code: 02184
3. Facility Contact Telephone Numbers: Telephone: (781) 848-0253 Fax: (781) 848-5804

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): Combustion turbine subject to 40 CFR Part 60 Subpart GG.	

List of Applicable Regulations

Not Applicable	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
SO2	B				Sulfur Dioxide
NOX	B				Nitrogen Oxides
PM	B				Particulate Matter
PM_{10}	B				Particulate Matter < 10 µm
CO	A				Carbon Monoxide
VOC	B				Volatile Organic Compounds

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID: CPV-CA [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: CPV-CA [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: CPV-CA [ ] Not Applicable
7. Supplemental Requirements Comment: Supplemental information includes air quality modeling study that demonstrates facility's maximum ambient air quality impacts are below Significant Impact Levels and emission control technology review that demonstrates facility's consistency with Best Available Control Technology requirements.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:________________________) [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
General Electric 107FA combustion turbine

4. Emissions Unit Identification Number:
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	First Quarter 2004	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

Construction of a combined-cycle power generation unit consisting of one nominal 170-MW General Electric 7241FA combustion turbine and heat recovery steam generator designed to power a steam turbine with an operationally controlled generating capacity of 74.9 MW.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Selective Catalytic Reduction (SCR) will be applied to the combined-cycle system.
2. Control Device or Method Code(s): 65

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric		Model Number: 7241FA
2. Generator Nameplate Rating:	170 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	1,680 (natural gas)	1,898 (distillate) MMBtu/hr	
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:	hours/day		days/week
	weeks/year		8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Maximum heat input based on lower heating values of fuels:

- Natural gas - 20,958 Btu/lb
- Distillate - 18,300 Btu/lb

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Kb
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? See CPV-CA Appendix B.	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): Exhaust through a 170-foot stack
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: V	6. Stack Height: 170 feet	7. Exit Diameter: 18.5 feet
8. Exit Temperature: See CPV-CA °F	9. Actual Volumetric Flow Rate: See CPV-CA acfm	10. Water Vapor: See CPV-CA %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates: Zone: 17	East (km): 550.9	North (km): 3018.1

14. Emission Point Comment (limit to 200 characters): See CPV-CA, Appendix C for all operating conditions.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): natural gas		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million Cubic Feet	
4. Maximum Hourly Rate: 1.91	5. Maximum Annual Rate: 16,714	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0065	8. Maximum % Ash:	9. Million Btu per SCC Unit: 881
10. Segment Comment (limit to 200 characters): Maximum Annual Rate based on operation at 8,760 hours/year		

Segment Description and Rate: Segment __2__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): distillate oil		
2. Source Classification Code (SCC): 20100101	3. SCC Units: 1000 Gallons	
4. Maximum Hourly Rate: 14.71	5. Maximum Annual Rate: 10,592	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 129.0
10. Segment Comment (limit to 200 characters): Maximum Annual Rate based on operation at 720 hours/year		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			EL
NOX	65		EL
PM			EL
PM_{10}			EL
CO			EL
VOC			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 10 (natural gas), 99 (distillate) lb/hour 75.8 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates for all operating conditions Annual emissions: [(10 lb/hr) X (335 days/year) X (24 hr/day) + (99 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 75.8 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emissions are for worst case operating load condition. See CPV-CA, Appendix C for emissions at other load conditions	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: Natural gas: 0.0065% (sulfur in fuel by weight) Distillate: 0.05% (sulfur in fuel by weight)	4. Equivalent Allowable Emissions: 10 (natural gas), 99 (distillate) lb/hour 75.8 tons/year.
5. Method of Compliance (limit to 60 characters): Fuel sampling	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Concentration limits apply for operating loads greater than 50%	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.7 (natural gas), 80 (distillate) lb/hour 95.9 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates for all operating conditions Annual emissions: [(16.7 lb/hr) X (335 days/year) X (24 hr/day) + (80 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 95.9 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: Natural Gas: 2.5 ppmvd @ 15% O_2 Distillate: 10 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions: 16.7 (natural gas), 80 (distillate) lb/hour 95.9 tons/year
5. Method of Compliance (limit to 60 characters): CEM - 3 hour block average	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Concentration limits apply for operating loads greater than 50%.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 19 (natural gas), 44 (distillate) lb/hour 92.2 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates for all operating conditions Annual emissions: [(19 lb/hr) X (335 days/year) X (24 hr/day) + (44 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 92.2 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 19 lb/hour (natural gas), 44 lb/hour (distillate)	4. Equivalent Allowable Emissions: 19 (natural gas), 44 (distillate) lb/hour 92.2 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test, USEPA Method 5	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Concentration limits apply for operating loads greater than 50%.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 19 (natural gas), 44 (distillate) lb/hour 92.2 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates for all operating conditions Annual emissions: [(19 lb/hr) X (335 days/year) X (24 hr/day) + (44 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 92.2 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 19 lb/hour (natural gas), 44 lb/hour (distillate)	4. Equivalent Allowable Emissions: 19 (natural gas), 44 (distillate) lb/hour 92.2 tons/year
5. Method of Compliance (limit to 60 characters): Annual stack test, USEPA Method 5	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Concentration limits apply for operating loads greater than 50%.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: See CPV-CA Appendix C. lb/hour 226.2 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates at 100% operating load Annual emissions: [(50 lb/hr) X (335 days/year) X (24 hr/day) + (70 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 226.2 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential annual emission rate assumes continuous power augmentation when natural gas firing.	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 50 lbs/hr (natural gas), 70 lb/hr (distillate)	4. Equivalent Allowable Emissions: 50 lbs/hr (natural gas), 70 lb/hr (distillate), 226.2 tons/year
5. Method of Compliance (limit to 60 characters): 24-hr block average demonstrated by CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): See CPV-CA Appendix C.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 3 (natural gas), 8 (distillate) lb/hour 14.9 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C Values are maximum rates for all operating conditions Annual emissions: [(3 lb/hr) X (335 days/year) X (24 hr/day) + (8 lb/hr) X (30 days/year) X (24 hr/day)]/ (2000 lb/ton) = 14.9 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.4 ppmvw as CH_4 (natural gas) 3.5 ppmvw as CH_4 (distillate)	4. Equivalent Allowable Emissions: 3 (natural gas), 8 (distillate) lb/hour 14.9 tons/year
1. Method of Compliance (limit to 60 characters): USEPA Method 25A	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Concentration limits apply for operating loads greater than 50%.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Annual testing using USEPA Method 9	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code: EM	2. Pollutant(s): NO_x, CO
3. CMS Requirement: [X] Rule	
4. Monitor Information: Manufacturer: Not yet determined Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: CPV-CA [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: CPV-CA [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Fresh Water Cooling Tower

4. Emissions Unit Identification Number: [X] No ID
ID: [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	First Quarter 2004	49	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):   High efficiency drift eliminators.
2. Control Device or Method Code(s): 15

Emissions Unit Details

1. Package Unit: Manufacturer: to be determined	Model Number:
2. Generator Nameplate Rating: MW	
3. Incinerator Information: Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		mmBtu/hr	
2. Maximum Incineration Rate:		lb/hr	tons/day
3. Maximum Process or Throughput Rate:	75,000 gal/min		
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day		7 days/week
	52 weeks/year		8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum process rate (Item 3) is cooling tower water circulation rate.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? Cooling Tower	2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: V	6. Stack Height: 45 feet	7. Exit Diameter: 32.8 feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: 17 East (km): 551.0 North (km): 3018.1	
14. Emission Point Comment (limit to 200 characters): Cooling tower consists of 5 cells. Exhaust temperature and flow rate vary with changes in ambient temperature. UTM coordinates reference the eastern most cell.	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Fresh water cooling tower re-circulation water flow rate.		
2. Source Classification Code (SCC):	3. SCC Units: 1000 gallons of water circulated	
4. Maximum Hourly Rate: 4,500	5. Maximum Annual Rate: 39,420,000	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment __2__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM/PM_{10}	**015**		**NS**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM_{10}	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.79 lb/hour 3.5 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-CA Appendix C-4 [(0.79 lb/hr) X (8760 hr/year)] / (2000 lb/ton) = 3.5 tons/year	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.0005% drift loss	4. Equivalent Allowable Emissions: 0.79 lb/hour 3.5 tons/year
5. Method of Compliance (limit to 60 characters): Cooling tower design and operation	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: [ ] Rule	
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

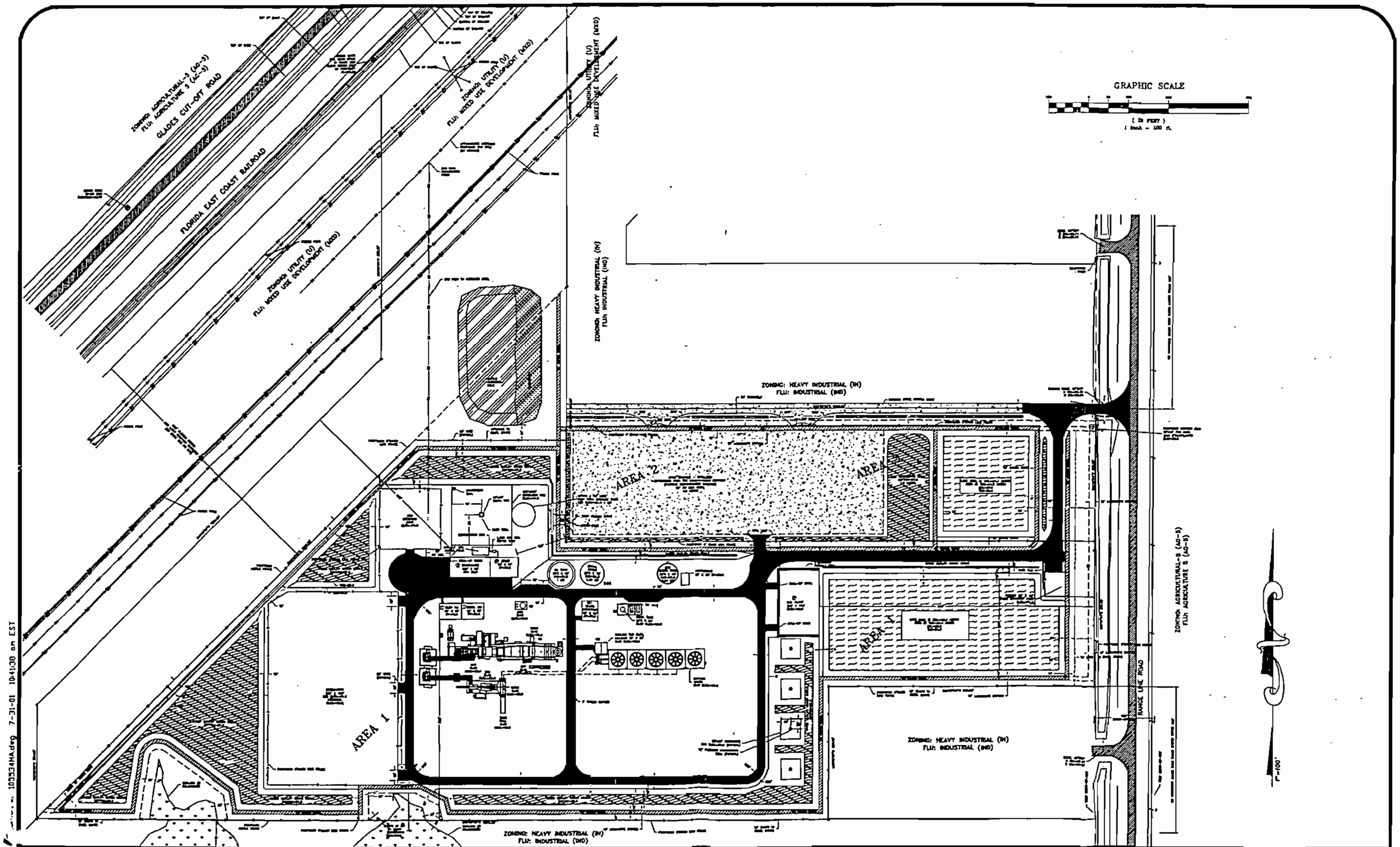
1. Process Flow Diagram [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: CPV-CA [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: CPV-CA [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

Appendix B

Engineering Drawing



CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL SITE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10553402
SHEET 2 OF 30
PROJECT NO. 10553

Appendix C

Air Pollutant Emissions

Appendix C-1

Combined-Cycle System Emissions

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60 %

50% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	11.0	pph
CO	9.0	ppmvd	CO	20.0	pph
UHC	7.0	ppmvw	UHC	10.0	pph
VOC	1.4	ppmvw	VOC	2.0	pph
SO2	1	ppmvw	SO2	6	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	8	pph	Ammonia	8	pph
O2	12.9	%	O2	12.9	%
H2O	7.5	%	H2O	7.5	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60%

75% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	14.0	pph
CO	9.0	ppmvd	CO	25.0	pph
UHC	7.0	ppmvw	UHC	12.0	pph
VOC	1.4	ppmvw	VOC	2.4	pph
SO2	1	ppmvw	SO2	8	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	10	pph	Ammonia	10	pph
O2	12.64	%	O2	12.64	%
H2O	7.69	%	H2O	7.69	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60%

100% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	14.0	pph
CO	9.0	ppmvd	CO	31.0	Pph
UHC	7.0	ppmvw	UHC	15.0	Pph
VOC	1.4	ppmvw	VOC	3.0	Pph
SO2	1	ppmvw	SO2	10	Pph
SO3	0	ppmvw	SO3	1	Pph
Sulfur Mist	1	pph	Sulfur Mist	1	Pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	Pph
PM10 Particulates	19	pph	PM10 Particulates	19	Pph
Ammonia	13	pph	Ammonia	13	Pph
O2	12.81	%	O2	12.81	%
H2O	7.53	%	H2O	7.53	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

50% Load METHANE

NOx	2.5	ppmvd@15%O2
CO	9.0	ppmvd
UHC	7.0	ppmvw
VOC	1.4	ppmvw
SO2	1	ppmvw
SO3	0	ppmvw
Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph
Ammonia	8	pph
O2	12.91	%
H2O	8.21	%

NOx	10.0	pph
CO	19.0	pph
UHC	9.0	pph
VOC	1.8	pph
SO2	6	pph
SO3	0	pph
Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph
Ammonia	8	pph
O2	12.91	%
H2O	8.21	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

75% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	13.0	pph
CO	9.0	ppmvd	CO	23.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	1.4	ppmvw	VOC	2.2	pph
SO2	1	ppmvw	SO2	8	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	10	pph	Ammonia	10	pph
O2	12.54	%	O2	12.54	%
H2O	8.54	%	H2O	8.54	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load METHANE

NOx	2.5	ppmvd@15%o2	NOx	16.0	pph
CO	9.0	ppmvd	CO	29.0	pph
UHC	7.0	ppmvw	UHC	14.0	pph
VOC	1.4	ppmvw	VOC	2.8	pph
SO2	.1	ppmvw	SO2	.9	pph
SO3	.0	ppmvw	SO3	.1	pph
Sulfur Mist	1	pph	Sulfur Mist	.1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	12	pph	Ammonia	12	pph
O2	12.59	%	O2	12.59	%
H2O	8.50	%	H2O	8.50	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>**Fuel 100% Methane**</u>
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Steam Injection for Power Augmentation (3.5% of compressor flow)
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	17.0	pph
CO	15.0	ppmvd	CO	50.0	pph
UHC	7.0	ppmvw	UHC	15.0	pph
VOC	1.4	ppmvw	VOC	3.0	pph
SO2	1	ppmvw	SO2	10	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	12	pph	Ammonia	12	pph
O2	11.67	%	O2	11.67	%
H2O	13.43	%	H2O	13.43	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

50% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	10.0	pph
CO	9.0	ppmvd	CO	19.0	pph
UHC	7.0	ppmvw	UHC	9.0	pph
VOC	1.4	ppmvw	VOC	1.8	pph
SO2	1	ppmvw	SO2	6	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	7	pph	Ammonia	7	pph
O2	12.90	%	O2	12.90	%
H2O	8.77	%	H2O	8.77	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

75% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	13.0	pph
CO	9.0	ppmvd	CO	23.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	1.4	ppmvw	VOC	2.2	pph
SO2	1	ppmvw	SO2	7	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	9	pph	Ammonia	9	pph
O2	12.48	%	O2	12.48	%
H2O	9.14	%	H2O	9.14	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load **METHANE**

NOx	2.5	ppmvd@15%O2	NOx	16.0	pph
CO	9.0	ppmvd	CO	28.0	pph
UHC	7.0	ppmvw	UHC	14.0	pph
VOC	1.4	ppmvw	VOC	2.8	pph
SO2	1	ppmvw	SO2	9	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	12	pph	Ammonia	12	pph
O2	12.47	%	O2	12.47	%
H2O	9.14	%	H2O	9.14	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:

Gas Turbine: **PG7241(FA)**

Fuel 100% Methane

Fuel LHV 20,958 Btu/lb

Sulfur emission based on 0.0065 WT% Sulfur content in the fuel

Steam Injection for Power Augmentation (3.5% of compressor flow)

Gas Turbine @ base load

Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	16.0	pph
CO	15.0	ppmvd	CO	49.0	pph
UHC	7.0	ppmvw	UHC	14.0	pph
VOC	1.4	ppmvw	VOC	2.8	pph
SO2	1	ppmvw	SO2	10	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	12	pph	Ammonia	12	pph
O2	11.49	%	O2	11.49	%
H2O	14.09	%	H2O	14.09	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70 %

50% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	9.0	pph
CO	9.0	ppmvd	CO	18.0	pph
UHC	7.0	ppmvw	UHC	9.0	pph
VOC	1.4	ppmvw	VOC	1.8	pph
SO2	1	ppmvw	SO2	6	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	7	pph	Ammonia	7	pph
O2	12.70	%	O2	12.70	%
H2O	10.68	%	H2O	10.68	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

75% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	12.0	pph
CO	9.0	ppmvd	CO	21.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	1.4	ppmvw	VOC	2.2	pph
SO2	1	ppmvw	SO2	7	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	9	pph	Ammonia	9	pph
O2	12.18	%	O2	12.18	%
H2O	11.13	%	H2O	11.13	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	14.0	pph
CO	9.0	ppmvd	CO	26.0	pph
UHC	7.0	ppmvw	UHC	13.0	pph
VOC	1.4	ppmvw	VOC	2.6	pph
SO2	1	ppmvw	SO2	8	pph
SO3	0	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	11	pph	Ammonia	11	pph
O2	12.06	%	O2	12.06	%
H2O	11.24	%	H2O	11.24	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 20,958 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Steam Injection for Power Augmentation (3.5% of compressor flow)
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load METHANE

NOx	2.5	ppmvd@15%O2	NOx	15.0	pph
CO	15.0	ppmvd	CO	45.0	pph
UHC	7.0	ppmvw	UHC	13.0	pph
VOC	1.4	ppmvw	VOC	2.6	pph
SO2	1	ppmvw	SO2	9	pph
SO3	0	ppmvw	SO3	0	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	9	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	11	pph	Ammonia	11	pph
O2	11.05	%	O2	11.05	%
H2O	16.09	%	H2O	16.09	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60%

50% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	49	pph
CO	24.0	ppmvd	CO	53.0	pph
UHC	7.0	ppmvw	UHC	10.0	pph
VOC	3.5	ppmvw	VOC	5.0	pph
SO2	11	ppmvw	SO2	62	pph
SO3	1	ppmvw	SO3	4	pph
Sulfur Mist	7	pph	Sulfur Mist	7	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	41	pph	PM10 Particulates	41	pph
Ammonia	9	pph	Ammonia	9	pph
O2	11.65	%	O2	11.65	%
H2O	9.41	%	H2O	9.41	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60%

75% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	63.0	pph
CO	24.0	ppmvd	CO	65.0	Pph
UHC	7.0	ppmvw	UHC	12.0	Pph
VOC	3.5	ppmvw	VOC	6.0	Pph
SO2	12	ppmvw	SO2	79	Pph
SO3	0	ppmvw	SO3	5	Pph
Sulfur Mist	8	pph	Sulfur Mist	8	Pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	Pph
PM10 Particulates	42	pph	PM10 Particulates	42	Pph
Ammonia	12	pph	Ammonia	12	Pph
O2	11.18	%	O2	11.18	%
H2O	10.26	%	H2O	10.26	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	25 F
Relative Humidity:	60%

100% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	80.0	pph
CO	20.0	ppmvd	CO	70.0	pph
UHC	7.0	ppmvw	UHC	16.0	pph
VOC	3.5	ppmvw	VOC	8.0	pph
SO2	11	ppmvw	SO2	99	pph
SO3	1	ppmvw	SO3	6	pph
Sulfur Mist	10	pph	Sulfur Mist	10	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	44	pph	PM10 Particulates	44	pph
Ammonia	15	pph	Ammonia	15	pph
O2	11.46	%	O2	11.46	%
H2O	10.26	%	H2O	10.26	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

50% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	47	pph
CO	24	ppmvd	CO	52	pph
UHC	7.0	ppmvw	UHC	10.0	pph
VOC	3.5	ppmvw	VOC	5	pph
SO2	11	ppmvw	SO2	59	pph
SO3	1	ppmvw	SO3	4	pph
Sulfur Mist	6	pph	Sulfur Mist	6	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	40	pph	PM10 Particulates	40	pph
Ammonia	9	pph	Ammonia	9	pph
O2	11.75	%	O2	11.75	%
H2O	9.89	%	H2O	9.89	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

75% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	60.0	pph
CO	24.0	ppmvd	CO	62.0	pph
UHC	7.0	ppmvw	UHC	12.0	pph
VOC	3.5	ppmvw	VOC	6.0	pph
SO2	12	ppmvw	SO2	75	pph
SO3	0	ppmvw	SO3	5	pph
Sulfur Mist	8	pph	Sulfur Mist	8	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	42	pph	PM10 Particulates	42	pph
Ammonia	11	pph	Ammonia	11	pph
O2	11.18	%	O2	11.18	%
H2O	10.81	%	H2O	10.81	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load Distillate

Nox	10.0	ppmvd@15%O2	NOx	75.0	pph
CO	20.0	ppmvd	CO	66.0	pph
UHC	7.0	ppmvw	UHC	15.0	pph
VOC	3.5	ppmvw	VOC	7.5	pph
SO2	11	ppmvw	SO2	93	pph
SO3	1	ppmvw	SO3	6	pph
Sulfur Mist	10	pph	Sulfur Mist	10	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	44	pph	PM10 Particulates	44	pph
Ammonia	14	pph	Ammonia	14	pph
O2	11.22	%	O2	11.22	%
H2O	11.13	%	H2O	11.13	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel Distillate</u>, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O_2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

50% Load **Distillate**

NOx	10.0	ppmvd@15%O_2	NOx	46.0	pph
CO	24.0	ppmvd	CO	51.0	pph
UHC	7.0	ppmvw	UHC	9.0	pph
VOC	3.5	ppmvw	VOC	4.5	pph
SO_2	11	ppmvw	SO_2	58	pph
SO_3	0	ppmvw	SO_3	4	pph
Sulfur Mist	6	pph	Sulfur Mist	6	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	40	pph	PM10 Particulates	40	pph
Ammonia	8	pph	Ammonia	8	pph
O_2	11.81	%	O_2	11.81	%
H_2O	10.19	%	H_2O	10.19	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel Distillate</u>, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

75% Load **Distillate**

NOx	10.0	ppmvd@15%O2	NOx	58.0	pph
CO	24.0	ppmvd	CO	60.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	3.5	ppmvw	VOC	5.5	pph
SO2	12	ppmvw	SO2	73	pph
SO3	0	ppmvw	SO3	5	pph
Sulfur Mist	8	pph	Sulfur Mist	8	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	42	pph	PM10 Particulates	42	pph
Ammonia	11	pph	Ammonia	11	pph
O2	11.17	%	O2	11.17	%
H2O	11.18	%	H2O	11.18	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	73.0	pph
CO	20.0	ppmvd	CO	63.0	pph
UHC	7.0	ppmvw	UHC	14.0	pph
VOC	3.5	ppmvw	VOC	7.0	pph
SO2	11	ppmvw	SO2	91	pph
SO3	1	ppmvw	SO3	5	pph
Sulfur Mist	10	pph	Sulfur Mist	10	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	44	pph	PM10 Particulates	44	pph
Ammonia	14	pph	Ammonia	14	pph
O2	11.09	%	O2	11.09	%
H2O	11.64	%	H2O	11.64	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

50% Load Distillate

Parameter	Value	Unit	Parameter	Value	Unit
NOx	10.0	ppmvd@15%O2	NOx	42.0	pph
CO	24.0	ppmvd	CO	49.0	pph
UHC	7.0	ppmvw	UHC	9.0	pph
VOC	3.5	ppmvw	VOC	4.5	pph
SO2	10	ppmvw	SO2	53	pph
SO3	1	ppmvw	SO3	4	pph
Sulfur Mist	6	pph	Sulfur Mist	6	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	40	pph	PM10 Particulates	40	pph
Ammonia	8	pph	Ammonia	8	pph
O2	11.91	%	O2	11.91	%
H2O	11.26	%	H2O	11.26	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

75% Load Distillate

Parameter	Value	Unit	Parameter	Value	Unit
NOx	10.0	ppmvd@15%O2	NOx	54.0	pph
CO	24.0	ppmvd	CO	57.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	3.5	ppmvw	VOC	5.5	pph
SO2	11	ppmvw	SO2	68	pph
SO3	1	ppmvw	SO3	4	pph
Sulfur Mist	7	pph	Sulfur Mist	7	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	41	pph	PM10 Particulates	41	pph
Ammonia	10	pph	Ammonia	10	pph
O2	11.15	%	O2	11.15	%
H2O	12.33	%	H2O	12.33	%

APPENDIX C-1
CPV CANA, FL
COMBINED-CYCLE GAS TURBINE
EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel Distillate, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	32 ft
Site pressure:	14.7 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	67.0	pph
CO	20.0	ppmvd	CO	57.0	pph
UHC	7.0	ppmvw	UHC	13.0	pph
VOC	3.5	ppmvw	VOC	6.5	pph
SO2	11	ppmvw	SO2	83	pph
SO3	1	ppmvw	SO3	5	pph
Sulfur Mist	9	pph	Sulfur Mist	9	pph
Front Half + Sulfates Partic.	17	pph	Front Half + Sulfates Partic.	17	pph
PM10 Particulates	43	pph	PM10 Particulates	43	pph
Ammonia	12	pph	Ammonia	12	pph
O2	10.90	%	O2	10.90	%
H2O	12.96	%	H2O	12.96	%

Appendix C-2

Annual Emissions

CPV Cana- Combined-Cycle Maximum Actual Annual Emissions									
	Units	NO_X	CO	VOC	SO_2	SO_3	PM	H_2SO_4	NH_3
		Controlled							
Capacity Factor		100%	100%	100%	100%	100%	100%	100%	100%
Natural Gas (with PA)									
Operating Period	Hours	2000	2000	2000	2000	2000	2000	2000	2000
Emission Rate	lb/hr	16.30	49.00	2.80	9.00	1.00	19.00	1.00	12.00
Annual Emissions	tons/year	16.30	49.00	2.80	9.00	1.00	19.00	1.00	12.00
Natural Gas (without PA)									
Operating Period	Hours	6040	6040	6040	6040	6040	6040	6040	6040
Emission Rate	lb/hr	15.60	28.00	2.80	9.00	1.00	19.00	1.00	12.00
Annual Emissions	tons/year	47.11	84.56	8.46	27.18	3.02	57.38	3.02	36.24
Distillate									
Operating Period	Hours	720	720	720	720	720	720	720	720
Emission Rate	lb/hr	73.00	63.00	7.00	91.00	5.00	44.00	10.00	14.00
Annual Emissions	tons/year	26.28	22.68	2.52	32.76	1.80	15.84	3.60	5.04
Total Annual Emissions	tons/year	89.69	156.24	13.78	68.94	5.82	92.22	7.62	53.28

Max. emissions at 100% load and 72F

CPV Cana- Combined-Cycle Maximum Potential Annual Emissions									
	Units	NO_X	CO	VOC	SO_2	SO_3	PM	H_2SO_4	NH_3
Capacity Factor		100%	100%	100%	100%	100%	100%	100%	100%
		Controlled							5 ppm slip
Natural Gas									
Operating Period	Hours	8040	8040	8040	8040	8040	8040	8040	8040
Emission Rate	lb/hr	16.67	50.00	3.00	10.00	1.00	19.00	1.00	13.00
Annual Emissions	tons/year	67.01	201.00	12.06	40.20	4.02	76.38	4.02	52.26
Distillate									
Operating Period	Hours	720	720	720	720	720	720	720	720
Emission Rate	lb/hr	80.00	70.00	8.00	99.00	6.00	44.00	10.00	15.00
Annual Emissions	tons/year	28.80	25.20	2.88	35.64	2.16	15.84	3.60	5.40
Total Annual Emissions	tons/year	95.81	226.20	14.94	75.84	6.18	92.22	7.62	57.66

Appendix C-3

HAP Emissions

CPV Cana
Potential Hazardous Air Pollutants Emissions
Combined Cycle Turbine

Maximum Heat Input, (Btu/hr):		Potential Operating Hours	
Distillate Fuel Oil	1,898,000,000	Distillate Fuel Oil	720
Natural Gas	1,679,900,000	Natural Gas	8,040

	Distillate Oil			Natural Gas			
Pollutant	Emission Factor lb/MMBtu	Emission Rate lb/hr	Annual Emissions TPY	Emission Factor lb/MMBtu	Emission Rate lb/hr	Annual Emissions TPY	Total Annual Emissions TPY
				(a)			
Arsenic	1.10E-05	2.09E-02	7.52E-03				7.52E-03
Beryllium	3.10E-07	5.88E-04	2.12E-04				2.12E-04
Cadmium	4.80E-06	9.11E-03	3.28E-03				3.28E-03
Chromium	1.10E-05	2.09E-02	7.52E-03				7.52E-03
Lead	1.40E-05	2.66E-02	9.57E-03				9.57E-03
Manganese	7.90E-04	1.499	0.540				5.40E-01
Mercury	1.20E-06	2.28E-03	8.20E-04				8.20E-04
Nickel	4.60E-06	8.73E-03	3.14E-03				3.14E-03
Selenium	2.50E-05	0.0475	1.71E-02				1.71E-02
Acetaldehyde				4.00E-05	0.0672	0.2701	2.70E-01
Acrolein				6.40E-06	1.08E-02	4.32E-02	4.32E-02
1,3 Butadiene	1.60E-05	3.04E-02	1.09E-02	4.30E-07	7.22E-04	2.90E-03	1.38E-02
Benzene	5.50E-05	0.1044	3.76E-02	1.20E-05	2.02E-02	0.0810	1.19E-01
Ethylbenzene				3.20E-05	0.0538	0.2161	2.16E-01
Formaldehyde	2.80E-04	0.531	0.191	7.10E-04	1.193	4.795	4.99
Napthalene	3.50E-05	0.0664	2.39E-02	1.30E-06	2.2E-03	8.78E-03	3.27E-02
PAH	4.00E-05	0.0759	2.73E-02	2.20E-06	3.70E-03	1.49E-02	4.22E-02
Propylene Oxide				2.90E-05	0.0487	0.196	1.96E-01
Toluene				1.30E-04	0.2184	0.878	8.78E-01
Xylene				6.40E-05	0.1075	0.4322	4.32E-01
					Total HAPs		7.82

Hazardous air pollutant emission factors taken from USEPA document Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, Section 3.1 Stationary Gas Turbines, dated 4/2/2000:

Table 3.1-3, Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines

Table 3.1-4, Emission Factors for Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines

Table 3.1-5, Emission Factors for Metallic Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines

Appendix C-4

Cooling Tower Particulate Emission Calculations

CPV - Cana Project Cooling Tower PM Emissions Calculations		
Parameter	**Units**	**Value**
Cooling Tower Circulating Flow*	gal/min	75,000
Drift Fraction of Circulating Flow*	percent	0.0005
Drift Rate	gal/min	0.375
Drift Rate	gal/hr	22.5
Water Density	lb/gal	8.33
Water Density Assumed for Cooling Water	lb/gal	8.33
Drift Rate	lb/min	3.12
Drift Rate	lb/hr	187.43
Convert lb/hr to g/s	g/s per lb/hr	0.126
Drift Rate	g/s	23.6
Dissolved & Suspended Solids in Water	mg/l	4200
Dissolved & Suspended Solids in Water	g/l	4.2
Convert Liters to Gallons	l/gal	3.785
Dissolved & Suspended Solids in Water	g/gal	15.90
PM Emissions	g/hr	357.7
PM Emissions	lb/hr	0.79
PM Emissions	g/s	0.099
Number of Cells		5
PM Emissions	g/s per cell	0.020
Annual Emissions	tons/year	3.45
* per Marley specification		

Appendix D

Air Quality Modeling

Appendix D-1

BPIP Input and Output Files

Appendix D-1
BPIP Input File

```
File: CANA827.GEP
         0         9         4         6     .0000METERS    1.0          UTMN 1
HRSG               1        .00
         4     26.82
-35.8     -2.6
-35.8     3.96
-3.66     3.96
-3.66     -2.6
GTG                1        .00
         8     11.89
-82.8     -6.84
-82.8     6.94
-78.5     6.94
-78.5     3.96
-35.8     3.96
-35.8     -2.60
-78.6     -2.60
-78.5     -6.86
STG                1        .00
         8      8.53
-67.6     -28.50
-67.6     -25.50
-46.5     -25.50
-43.9     -20.86
-40.4     -20.86
-40.4     -32.75
-43.9     -32.75
-46.5     -28.71
COOLT              1        .00
         4      9.45
38.6      -13.3
38.6      1.3
111.8     1.3
111.8     -13.3
ADMIN              1        .00
         4      6.10
-82.3     56.41
-82.3     71.65
-30.5     71.65
-30.5     56.41
CONTROL            1        .00
         4      6.10
-90.5     24.5
-56.9     24.5
-56.9     36.7
-90.5     36.7
WATER              1        .00
         4      9.14
18.4      23.2
18.4      38.4
30.6      38.4
30.6      23.2
PUMP               1        .00
```

```
           4      9.14
94.00      50.08
94.00      59.22
100.1      59.22
100.1      50.08
ROBLDG               1          .00
           4      6.10
169.2      12.3
169.2      61.0
199.7      61.0
199.7      12.3
DEEPWATR          .00      15.24      18.29-26.4      103.6
RAWWATER          .00      12.19      18.292.68      58.7
DEMWATER          .00      21.34      18.2926.5      59.2
FUELOIL           .00      15.24      14.6384.07      59.2
STACK1            .00      51.820          0
CELL1             .00      13.7245.9        -6.01
CELL2             .00      13.7260.6        -6.01
CELL3             .00      13.7275.2        -6.01
CELL4             .00      13.7289.8        -6.01
CELL5             .00      13.72104.5       -6.01
```

BEE-Line Software Version: 5.12

Input File - CANA827.GEP
Input File - CANA827.PIP
Output File - CANA827.TAB
Output File - CANA827.SUM
Output File - CANA827.SO

BPIP (Dated: 95086)

DATE : 08/28/01
TIME : 11:08:54
File: CANA827.GEP

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in METERS will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to 0.00 degrees with respect to True North.

File: CANA827.GEP

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
STACK1	51.82	0.00	67.05	67.05
CELL1	13.72	0.00	48.87	65.00
CELL2	13.72	0.00	48.80	65.00
CELL3	13.72	0.00	48.90	65.00
CELL4	13.72	0.00	48.92	65.00
CELL5	13.72	0.00	37.16	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 08/28/01
TIME : 11:08:54

File: CANA827.GEP

BPIP output is in meters

SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDHGT	STACK1	26.82	26.82	26.82	26.82	26.82	26.82
SO	BUILDWID	STACK1	32.79	32.45	31.11	28.84	25.68	21.75
SO	BUILDWID	STACK1	17.16	12.04	6.56	12.04	17.16	21.75
SO	BUILDWID	STACK1	25.68	28.84	31.11	32.45	32.79	32.14
SO	BUILDWID	STACK1	32.79	32.45	31.11	28.84	25.68	21.75
SO	BUILDWID	STACK1	17.16	12.04	6.56	12.04	17.16	21.75
SO	BUILDWID	STACK1	25.68	28.84	31.11	32.45	32.79	32.14

SO	BUILDHGT	CELL1	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDHGT	CELL1	9.45	9.45	11.89	26.82	21.34	9.45
SO	BUILDHGT	CELL1	9.45	12.19	21.34	21.34	21.34	9.45
SO	BUILDHGT	CELL1	9.45	15.24	15.24	15.24	9.45	9.45
SO	BUILDHGT	CELL1	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDHGT	CELL1	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDWID	CELL1	74.62	73.78	70.69	65.46	58.24	49.24
SO	BUILDWID	CELL1	38.76	27.09	13.80	12.04	18.36	49.24
SO	BUILDWID	CELL1	58.24	36.87	18.26	18.18	18.35	73.20
SO	BUILDWID	CELL1	74.62	14.60	14.67	14.63	58.24	49.24
SO	BUILDWID	CELL1	38.76	27.09	14.60	27.09	38.76	49.24
SO	BUILDWID	CELL1	58.24	65.46	70.69	73.78	74.62	73.20

SO	BUILDHGT	CELL2	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDHGT	CELL2	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDHGT	CELL2	9.45	21.34	21.34	21.34	9.45	9.45
SO	BUILDHGT	CELL2	15.24	15.24	15.24	9.45	9.45	9.45
SO	BUILDHGT	CELL2	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDHGT	CELL2	9.45	9.45	9.45	9.45	9.45	9.45
SO	BUILDWID	CELL2	74.62	73.78	70.69	65.46	58.24	49.24
SO	BUILDWID	CELL2	38.76	27.09	14.60	27.09	38.76	49.24
SO	BUILDWID	CELL2	58.24	18.31	18.26	18.18	74.62	73.20
SO	BUILDWID	CELL2	14.57	14.60	14.67	65.46	58.24	49.24
SO	BUILDWID	CELL2	38.76	27.09	14.60	27.09	38.76	49.24

```
SO BUILDWID CELL2       58.24   65.46   70.69   73.78   74.62   73.20

SO BUILDHGT CELL3        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL3        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL3        9.45   21.34   21.34    9.45    9.45   15.24
SO BUILDHGT CELL3       15.24   15.24    9.45    9.45    9.45    9.45
SO BUILDHGT CELL3        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL3        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDWID CELL3       74.62   73.78   70.69   65.46   58.24   49.24
SO BUILDWID CELL3       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL3       58.24   18.31   18.26   73.78   74.62   14.60
SO BUILDWID CELL3       14.57   14.60   70.69   65.46   58.24   49.24
SO BUILDWID CELL3       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL3       58.24   65.46   70.69   73.78   74.62   73.20

SO BUILDHGT CELL4        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL4        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL4       21.34   21.34    9.45    9.45   15.24   15.24
SO BUILDHGT CELL4        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL4        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL4        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDWID CELL4       74.62   73.78   70.69   65.46   58.24   49.24
SO BUILDWID CELL4       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL4       18.31   18.31   70.69   73.78   14.57   14.60
SO BUILDWID CELL4       74.62   73.78   70.69   65.46   58.24   49.24
SO BUILDWID CELL4       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL4       58.24   65.46   70.69   73.78   74.62   73.20

SO BUILDHGT CELL5        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL5        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL5        9.45    9.45    9.45   15.24   15.24    9.45
SO BUILDHGT CELL5        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL5        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDHGT CELL5        9.45    9.45    9.45    9.45    9.45    9.45
SO BUILDWID CELL5       74.62   73.78   70.69   65.46   58.24   49.24
SO BUILDWID CELL5       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL5       58.24   65.46   70.69   14.60   14.57   73.20
SO BUILDWID CELL5       74.62   73.78   70.69   65.46   58.24   49.24
SO BUILDWID CELL5       38.76   27.09   14.60   27.09   38.76   49.24
SO BUILDWID CELL5       58.24   65.46   70.69   73.78   74.62   73.20
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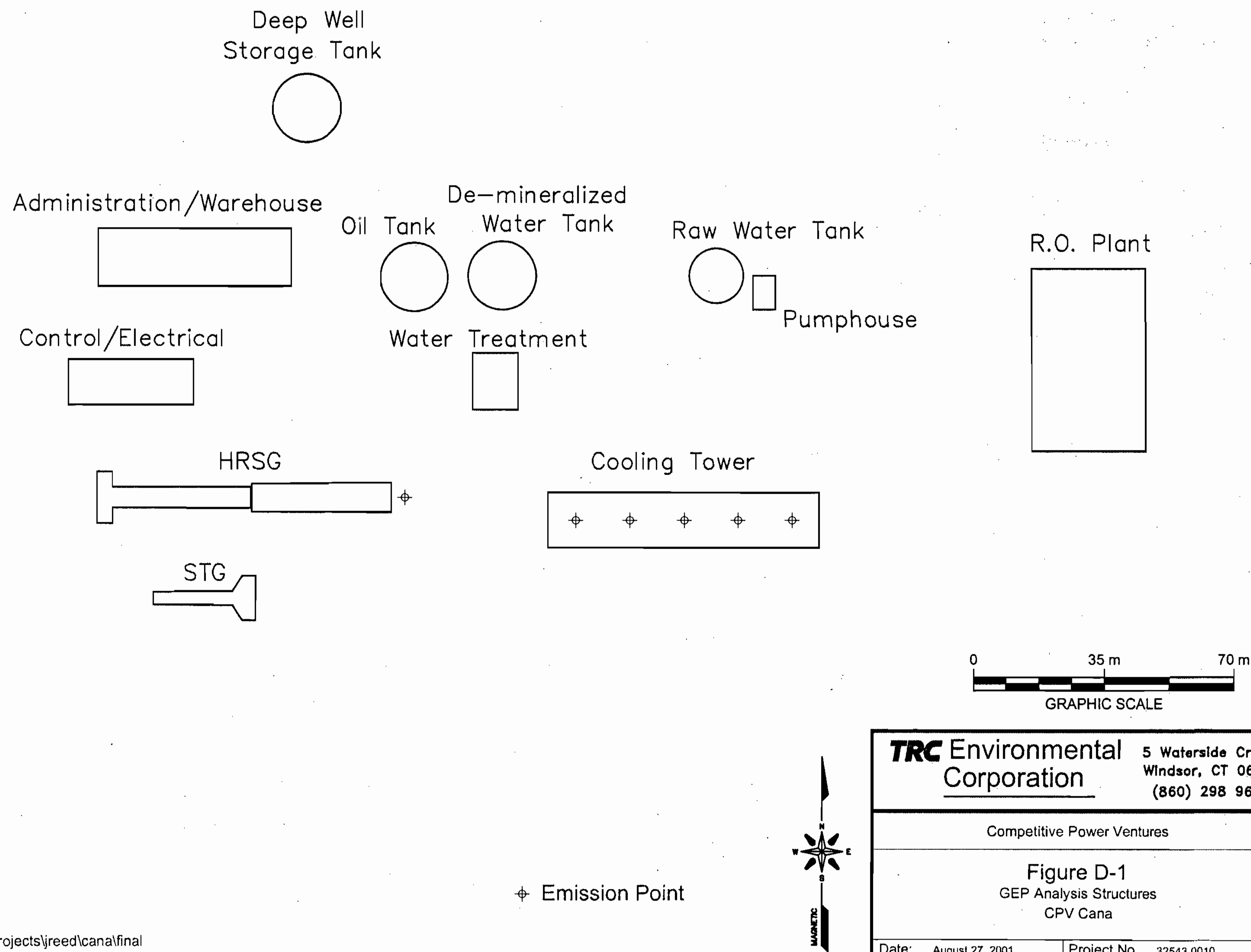


TRC Environmental Corporation
5 Waterside Crossing
Windsor, CT 06095
(860) 298 9692

Competitive Power Ventures

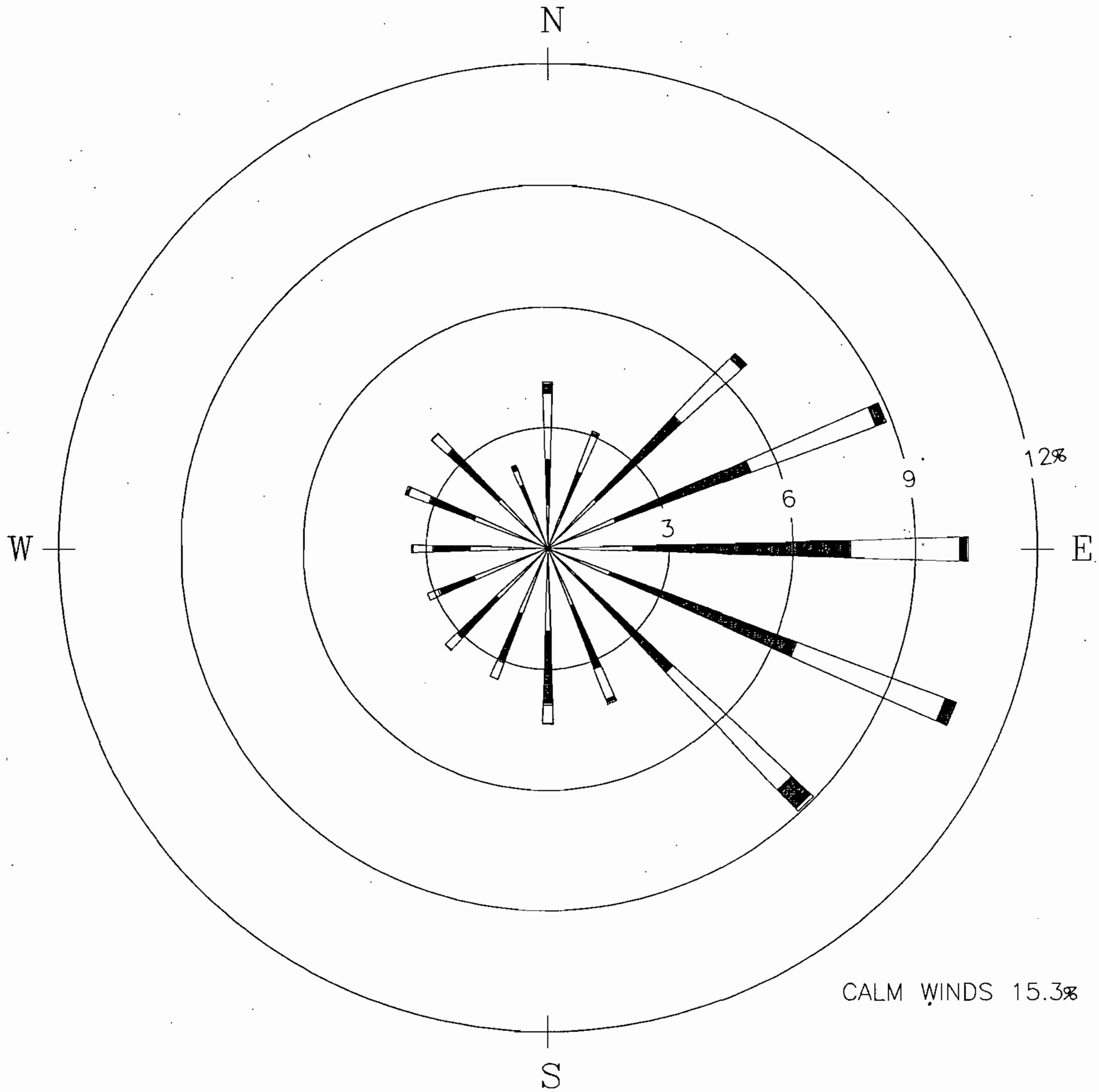
Figure D-1
GEP Analysis Structures
CPV Cana

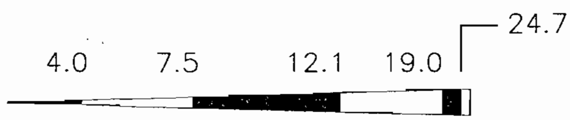
Date: August 27, 2001 | Project No. 32543 0010

j:\projects\jreed\cana\final

Appendix D-2

Vero Beach Airport
(Station I.D.:(12843) Windroses (1990-1994)





WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

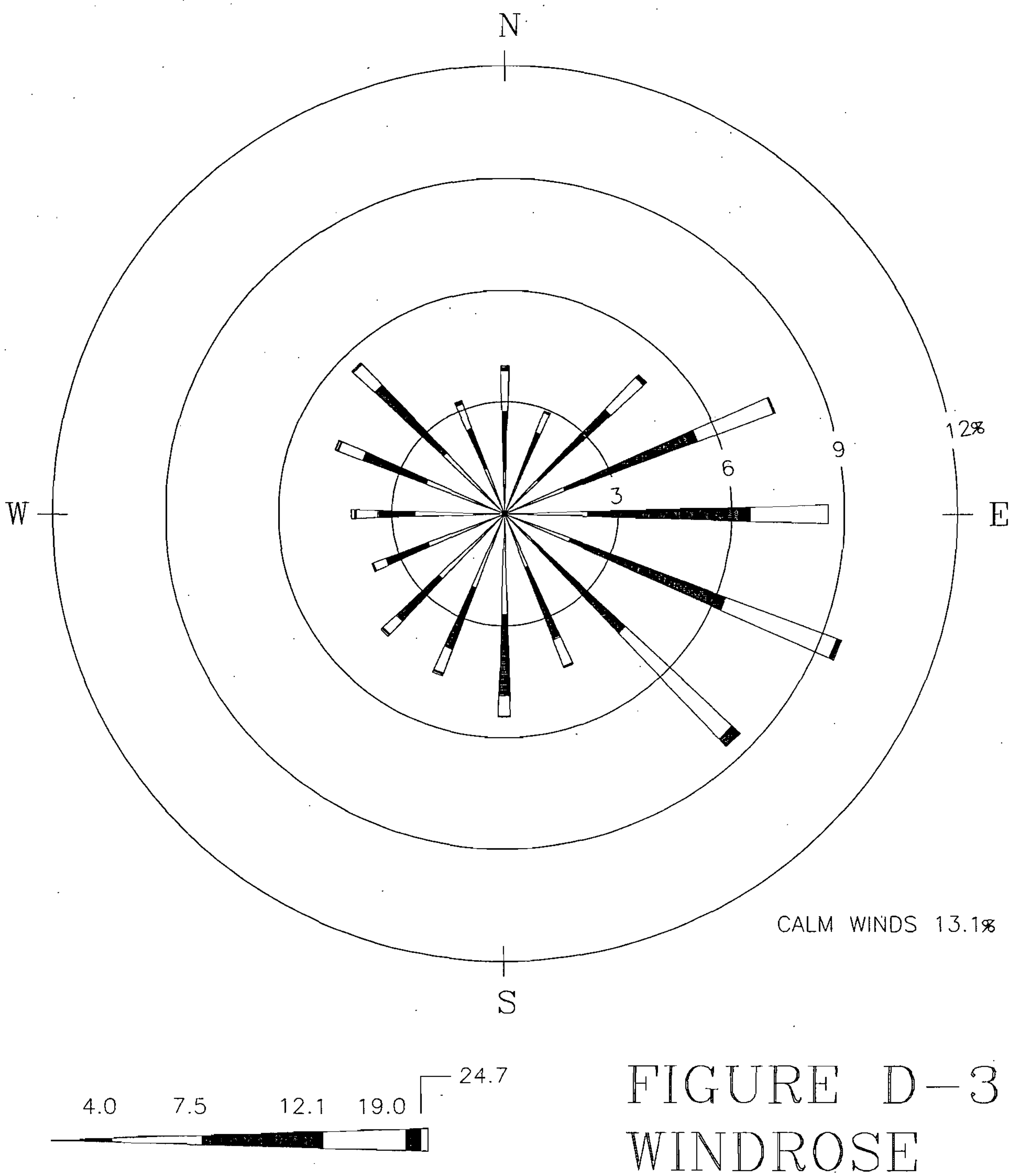
FIGURE D-2.
WINDROSE

STATION NO: 12843

PERIOD: 1990

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE – WIND IS BLOWING FROM THE NORTH 4.1 PERCENT OF THE TIME.

BEE-LINE
SOFTWARE



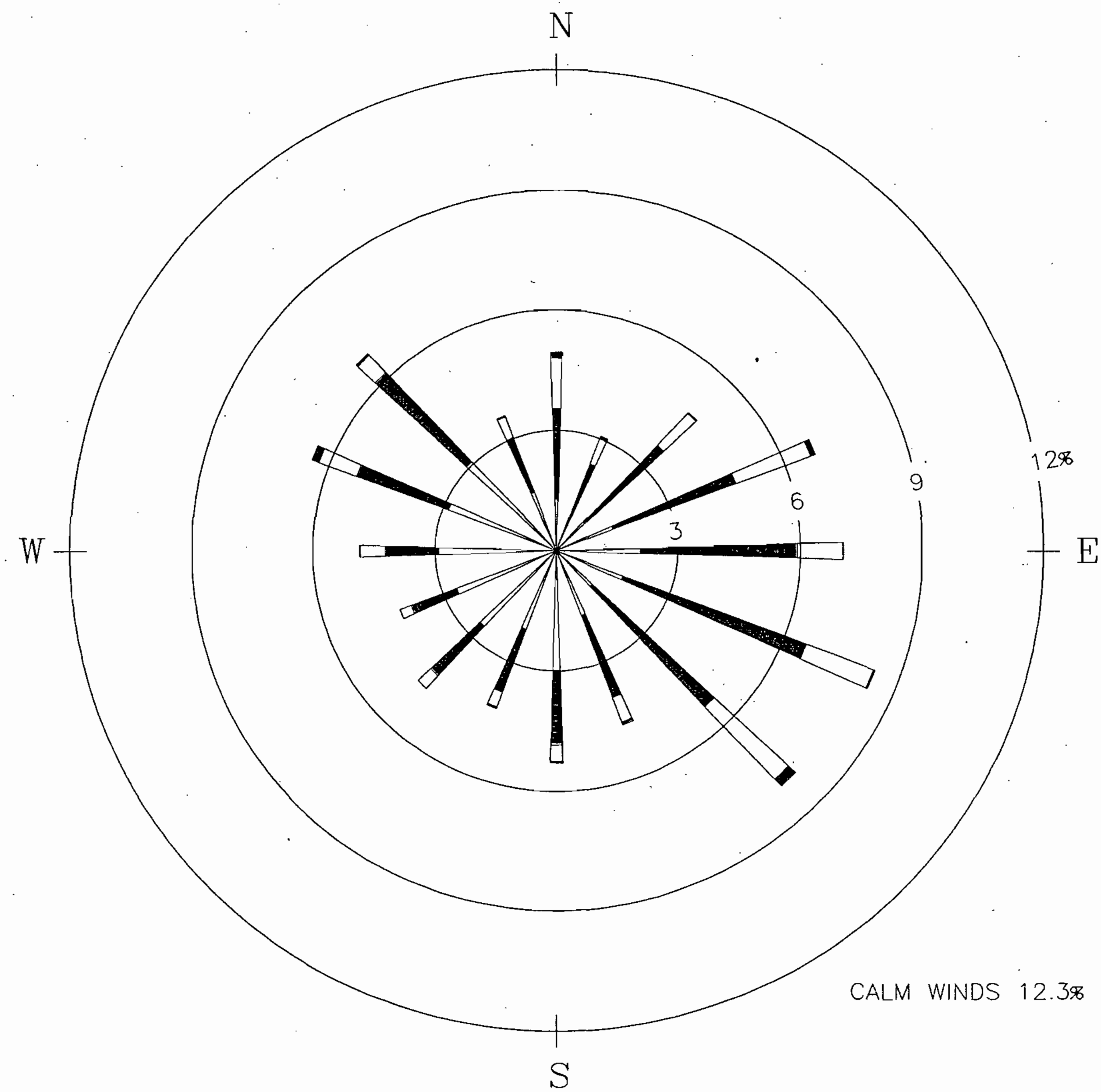
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

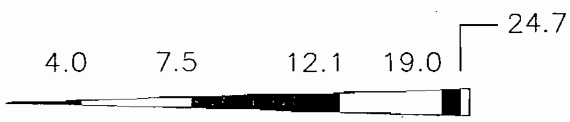
FIGURE D–3
WINDROSE

STATION NO: 12843
PERIOD: 1991

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE – WIND IS BLOWING FROM THE NORTH 4.0 PERCENT OF THE TIME.

BEE–LINE SOFTWARE





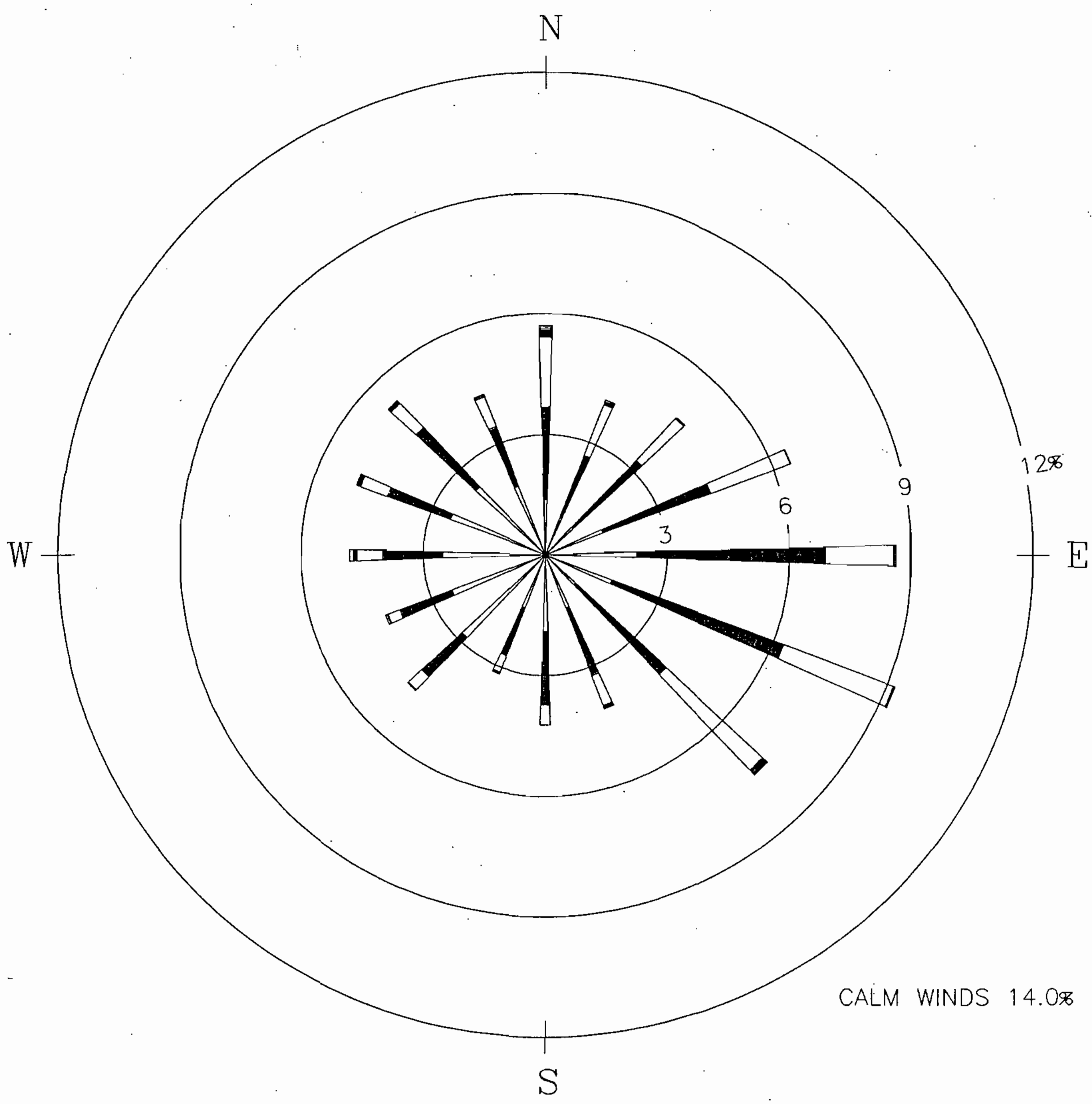
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

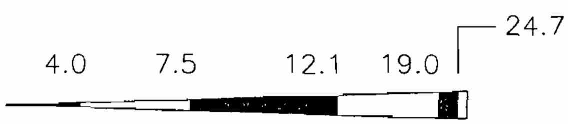
FIGURE D-4
WINDROSE

STATION NO: 12843
PERIOD: 1992

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION.
WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING.
EXAMPLE – WIND IS BLOWING FROM THE NORTH 5.0 PERCENT OF THE TIME.

BEE–LINE
SOFTWARE





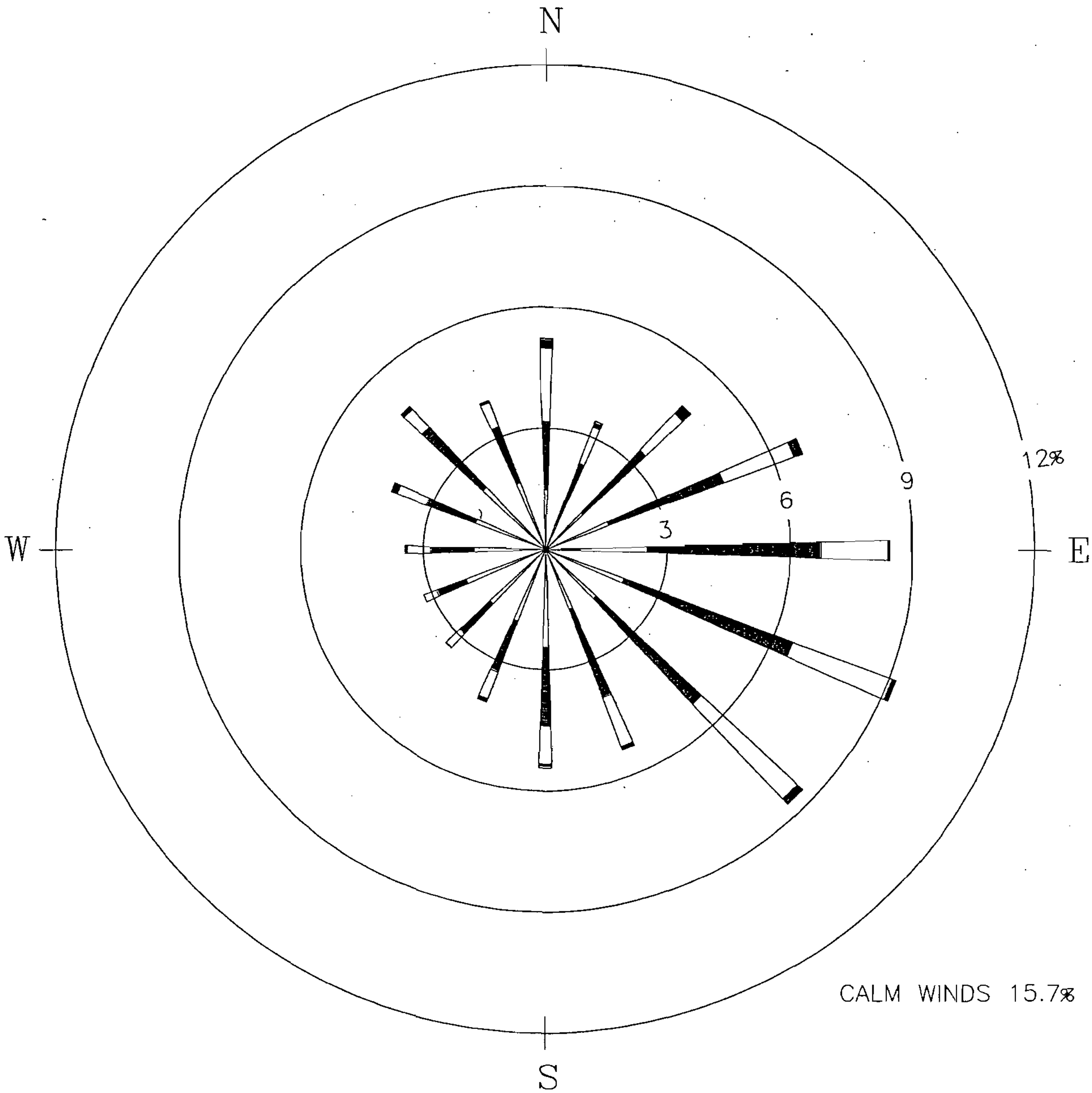
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

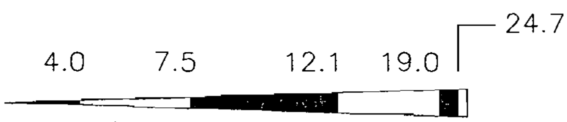
FIGURE D-5
WINDROSE

STATION NO: 12843
PERIOD: 1993

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE – WIND IS BLOWING FROM THE NORTH 5.7 PERCENT OF THE TIME.

BEE-LINE SOFTWARE





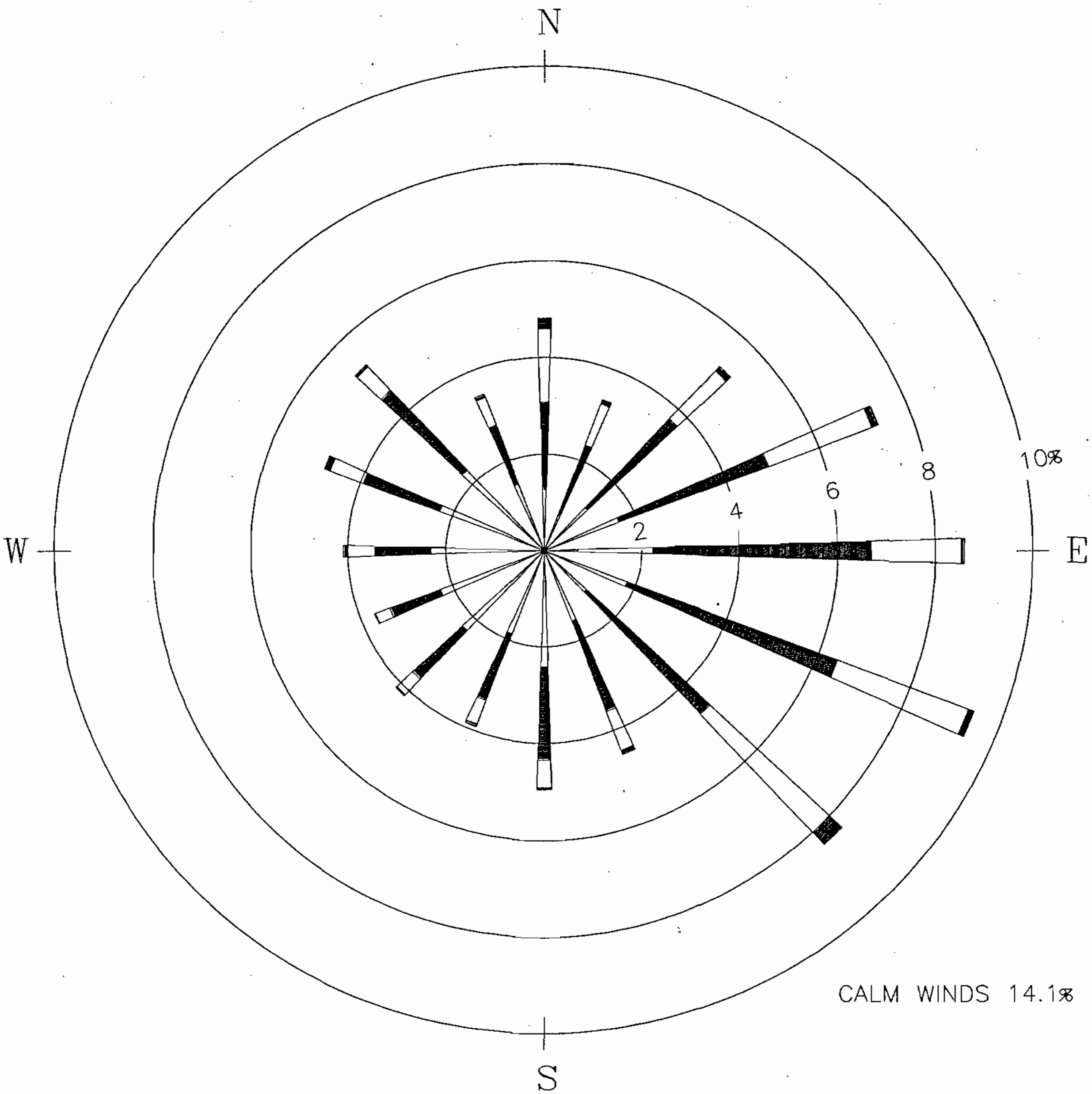
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

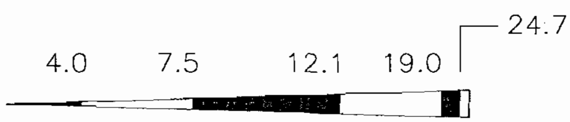
FIGURE D-6
WINDROSE

STATION NO: 12843
PERIOD: 1994

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE – WIND IS BLOWING FROM THE NORTH 5.2 PERCENT OF THE TIME.

BEE–LINE
SOFTWARE





WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

FIGURE D-7
WINDROSE

STATION NO: 12843
PERIOD: 1990-1994

NOTES:
DIAGRAM OF THE FREQUENCY OF OCCURRENCE OF EACH WIND DIRECTION. WIND DIRECTION IS THE DIRECTION FROM WHICH THE WIND IS BLOWING. EXAMPLE - WIND IS BLOWING FROM THE NORTH 4.8 PERCENT OF THE TIME.

BEE-LINE
SOFTWARE

Appendix D-3

- **Input and Output Files In Support of Class II Modeling Analyses**
- **CALPUFF/CALMET Input and Output Files in Support of Class I Modeling Analyses**

(Reference attached compact disk)

Appendix D-4

Summary of ISCST Modeling Analyses for SIL Compliance

TABLE D-4
SUMMARY OF MODELED IMPACTS
COMPETITIVE POWER VENTURES CANA PROJECT

	Operating Scenarios				Maximum Predicted Single Source Impacts ($\mu g/m^3$) Pollutant							
		Ambient			SO_2			NO_2	PM_{10}		CO	
Type of Fuel	No.	Temp. (deg F)	Evap Cooler	Load (%)	3-Hour	24-Hour	Annual	Annual	24-Hour	Annual	1-Hour	8-Hour
Natural Gas	1	25	OFF	100	1.93	0.409	0.0163	0.0228	1.62	0.0440	8.91	3.46
	2	25	OFF	75	2.38	0.782	0.0274	0.0321	2.21	0.0804	11.2	4.76
	3	25	OFF	50	2.42	0.918	0.0429	0.0790	3.41	0.165	12.8	5.17
	4	59	OFF	100	1.89	0.506	0.0153	0.0274	1.62	0.0442	8.99	3.51
	5	59	OFF	75	2.43	0.804	0.0301	0.0492	2.27	0.0879	10.7	4.48
	6	59	OFF	50	2.37	0.895	0.0417	0.0696	3.33	0.161	11.9	4.80
	7	72	OFF	100	2.06	0.549	0.0165	0.0294	1.49	0.0444	9.39	3.68
	8	72	OFF	75	2.25	0.758	0.0287	0.0534	2.44	0.0958	11.5	4.76
	9	72	OFF	50	2.49	0.950	0.0447	0.0745	3.53	0.172	12.5	5.06
	10	97	OFF	100	1.92	0.547	0.0164	0.0287	1.68	0.0494	9.15	4.01
	11	97	OFF	75	2.24	0.806	0.0340	0.0582	2.59	0.0958	10.6	4.34
	12	97	OFF	50	2.47	0.942	0.0445	0.0665	3.51	0.171	11.9	4.78
Distillate Oil	13	25	OFF	100	9.24	1.92	0.0776	0.0623	1.62	0.0428	10.2	4.08
	14	25	OFF	75	13.7	3.75	0.112	0.0891	2.40	0.0736	17.2	7.25
	15	25	OFF	50	14.8	4.85	0.201	0.159	3.93	0.163	19.6	8.08
	16	59	OFF	100	9.78	1.98	0.0782	0.0631	1.62	0.0446	10.9	4.22
	17	59	OFF	75	13.3	3.64	0.110	0.0877	2.40	0.0865	16.7	7.06
	18	59	OFF	50	14.5	4.81	0.206	0.164	3.93	0.171	20.0	8.18
	19	72	OFF	100	10.2	2.03	0.0789	0.0633	1.62	0.0446	11.1	4.22
	20	72	OFF	75	13.3	4.00	0.123	0.0974	2.46	0.0865	16.6	7.01
	21	72	OFF	50	14.5	4.82	0.208	0.165	3.99	0.175	20.0	8.15
	22	97	OFF	100	10.8	2.11	0.0791	0.0638	1.62	0.0476	11.5	4.35
	23	97	OFF	75	13.1	3.95	0.136	0.108	2.77	0.102	16.6	7.00
	24	97	OFF	50	13.6	4.68	0.200	0.158	4.30	0.184	19.9	8.05
Natural Gas - Power Augmentation	25	59	ON	100	2.01	0.425	0.0120	0.0288	1.62	0.0440	14.9	5.79
	26	72	ON	100	2.02	0.426	0.0166	0.0266	1.62	0.0440	14.7	5.71
	27	97	ON	100	2.08	0.550	0.0165	0.0275	1.68	0.0449	15.3	5.99
Maximum					14.8	4.85	0.208	0.165	4.30	0.184	20.0	8.18
Significant Impact Levels					25.0	5.00	1.00	1.00	5.00	1.00	2,000	500
PSD Increment					512	91.0	20.0	25.0	30.0	17.0	N/A	N/A
NAAQS					1,300	365	80.0	100	150	50.0	40,000	10,000

Appendix E

Control Technology Review

Appendix E-1A

RBLC Search Results for Combustion Turbine (Combined-cycle, NO_x, SO_2, CO, PM/PM_{10}, Natural Gas & Oil)

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Fuel Oil) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	ME	12/04/1998	TURBINE, COMBINED CYCLE	900	5.0	0.05% SULFUR DISTILLATE OIL #2 IS USED. EMISSION IS FROM	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PART	NEW YORK CITY	NY	06/06/1995	TURBINE, OIL FIRED	240	5.0	COMBUSTION DESIGN	BACT-PSD
UNION ELECTRIC CO	WEST ALTON	MO	05/06/1979	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION	622	9.0		BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.		GA	02/12/1992	TURBINES, 8	129	9.0	WATER INJECTION	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	133	9.2		
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	NY	06/18/1992	COMBUSTION TURBINES (2) (252 MW)	147	10.0	COMBUSTION CONTROLS	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	OSWEGO	NY	10/06/1994	GE FRAME 6 GAS TURBINE	533	10.0	NO CONTROLS	BACT-OTHER
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, OIL FIRED, 3 EA	129	10.5		BACT-PSD
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	03/06/1989	TURBINE, LM5000	54	11.0		
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	233	17.9	GOOD COMBUSTION PRACTICES	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	18.0	COMBUSTION DESIGN	BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	03/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	21.2	COMBUSTION CONTROL	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	21.3	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	129	22.2	GOOD COMBUSTION PRACTICES	BACT-PSD
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, OIL	231	22.5	WATER INJECTION	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, OIL, 1 EACH	80	25.0	COMBUSTION CONTROL	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	25.0	GOOD COMBUSTION PRACTICES	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, OIL FIRED (2 EACH)	230	25.0	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	NY	06/18/1992	COMBUSTION TURBINE (79 MW)	147	25.0	COMBUSTION CONTROL	BACT-OTHER
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (#2 FUEL OIL) (2)	149	25.4	COMBUSTOR WATER INJECTOR, WATER INJECTION	BACT-PSD
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	BURNERS, DUCT (2)	69	25.4	COMBUSTION DESIGN	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	NJ	11/01/1990	TURBINE, KEROSENE FIRED	73	26.6	CATALYTIC OXIDATION	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, FUEL OIL	116	29.6	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER CORPORATION POLK COUN	BARTOW	FL	02/25/1994	TURBINE, FUEL OIL (2)	216	30.0	GOOD COMBUSTION PRACTICES	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	30.0	WATER INJECTION	BACT-OTHER
FLORIDA POWER GENERATION	DEBARY	FL	10/18/1991	TURBINE, OIL, 6 EACH	93	30.7	GOOD COMBUSTION	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, OIL, 2 EACH	400	33.0	WET INJECTION	BACT-PSD
TECO POLK POWER STATION	BARTOW	FL	02/24/1994	TURBINE, FUEL OIL	221	40.0	GOOD COMBUSTION	BACT-PSD
UNION ELECTRIC CO	WEST ALTON	MO	05/06/1979	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION	78	71.9	GOOD COMBUSTION PRACTICES	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	92.6	COMBUSTION DESIGN	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	100.0	COMBUSTION DESIGN	BACT-PSD
FULTON COGEN PLANT	FULTON	NY	09/15/1994	GE LM5000 GAS TURBINE	63	107.0	NO CONTROLS	BACT-OTHER
CAROLINA POWER AND LIGHT	HARTSVILLE	SC	08/31/1994	STATIONARY GAS TURBINE	190	115.2	COMBUSTION DESIGN	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr

2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of CO: 1 (PPM) = (lb/mmBtu) * 423
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values

All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Fuel Oil) - NOx

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	NY	06/06/1995	TURBINE, OIL FIRED	240	10.0	FUEL SPEC: DISTILLATE #2 FUEL OIL	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74	15.0	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	VA	03/03/1992	TURBINE, COMBUSTION	140	15.0		91
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	15.0		80.8
KALAMAZOO POWER LIMITED	COMSTOCK	MI	12/03/1991	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	15.0	DRY LOW NOX TURBINES	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	60	16.0	COMBUSTION CONTROL	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	NJ	11/01/1990	TURBINE, KEROSENE FIRED	73	16.2	STEAM INJECTION AND SCR	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	20.0	WATER INJECTION WITH SCR	BACT-PSD
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	BURNERS, DUCT (2)	69	20.6	COMBUSTION CONTROL	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (#2 FUEL OIL) (2)	149	21.1	FUEL SPEC: NO. 2 FUEL OIL AS FUEL	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY	AL	03/12/1997	COMBINED CYCLE TURBINE (25 MW)	71	25.0	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT D	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.		GA	02/12/1992	TURBINES, 8	129	25.0	MAX WATER INJECTION	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, OIL FIRED (2 EACH)	230	25.0	MAXIMUM WATER INJECTION	BACT-PSD
PEPCO - CHALK POINT PLANT	EAGLE HARBOR	MD	06/25/1990	TURBINE, 105 MW OIL FIRED ELECTRIC	105	25.0	DRY PREMIX BURNER	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	OK	12/17/1992	TURBINE, COMBUSTION	58	25.0	COMBUSTION CONTROLS	BACT-OTHER
PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	VA	09/15/1993	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	146	28.9	WET INJECTION	BACT-PSD
FULTON COGEN PLANT	FULTON	NY	09/15/1994	GE LM5000 GAS TURBINE	63	36.0	WATER INJECTION	BACT
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW OIL FIRED	52	40.0	WATER INJECTION	BACT-OTHER
STAR ENTERPRISE	DELAWARE CITY	DE	03/30/1998	TURBINES, COMBINED CYCLE, 2	103	42.0	COMBUSTION CONTROL	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, OIL, 1 EACH	60	42.0	WET INJECTION	BACT-PSD
FLORIDA POWER GENERATION	DEBARY	FL	10/16/1991	TURBINE, OIL, 6 EACH	93	42.0	WET INJECTION	BACT-PSD
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, OIL	231	42.0	WATER INJECTION	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, FUEL OIL	116	42.0	WATER INJECTION	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	42.0	STEAM INJECTION	BACT-PSD
TECO POLK POWER STATION	BARTOW	FL	02/24/1994	TURBINE, FUEL OIL	221	42.0	WET INJECTION	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, FUEL OIL (2)	216	42.0	WATER INJECTION	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	129	42.0	WET INJECTION	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	OIL FIRED COMBUSTION TURBINE	74	42.0	WATER INJECTION	BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	03/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	42.0	WATER INJECTION	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	42.0	WATER INJECTION	SEE NOTES
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	42.0	WATER INJECTOR	BACT-OTHER
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	01/18/1994	GE FRAME 6 GAS TURBINE	61	42.0	STEAM INJECTION	BACT
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	49.5	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	81	55.0	DRY LOW NOX OR SCR	BACT-OTHER
PEPCO - CHALK POINT PLANT	EAGLE HARBOR	MD	06/25/1990	TURBINE, 84 MW OIL FIRED ELECTRIC	84	58.0	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
CAROLINA POWER AND LIGHT	HARTSVILLE	SC	08/31/1994	STATIONARY GAS TURBINE	190	62.0	FUEL SPEC: FUEL QUALITY	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, OIL, 2 EACH	400	65.0	LOW NOX COMBUSTORS	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW OIL FIRED ELECTRIC	140	65.0	WATER INJECTION	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	OK	12/17/1992	TURBINE, COMBUSTION	56	65.0	COMBUSTION CONTROLS	BACT-OTHER
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, OIL FIRED, 3 EA	129	65.0		BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	65.0	STEAM INJECTION & FUEL SPEC: USE OF #2 OIL	OTHER
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/08/1989	TURBINE, COMBUSTION, #7 FRAME	133	67.2		
KALAELOE PARTNERS, L.P.		HI	03/09/1990	TURBINE, LSFO, 2	225	89.0	STEAM INJECTION AT 1.3 TO 1 STEAM TO FUEL RATIO	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	69.0	WATER INJECTION; FUEL SPEC: 0.04% N FUEL OIL	BACT-PSD
PEPCO - STATION A	DICKERSON	MD	05/31/1990	TURBINE, 124 MW OIL FIRED	125	77.0	WATER INJECTION	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	MD	10/01/1989	TURBINE, OIL FIRED ELECTRIC	90	142.8	WATER INJECTION	BACT-PSD
UNION ELECTRIC CO	WEST ALTON	MO	05/06/1979	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	78	494.5	WATER INJECTION FOR NOX EMISSIONS	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr

2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of NO_2: 1 (PPM) = (lb/mmBtu) * 257
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values

All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Fuel Oil) - PM/PM10

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	lb/mmBtu[2]	CTRLDESC	BASIS
SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	NY	06/18/1992	COMBUSTION TURBINES (2) (252 MW)	147	0.004	0.5 % SULFUR DISTILLATE OIL #2 IS USED.	BACT-PSD
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	01/18/1994	GE FRAME 6 GAS TURBINE	61	0.005	FUEL SPEC: SULFUR CONTENT NOT TO EXCEE	BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.		GA	02/12/1992	TURBINES, 8	129	0.006	FUEL SPEC: FUEL LIMITED AND 0.3 % S	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	175	0.007	FUEL SPEC: SULFUR CONTENT NOT TO EXCEE	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	OSWEGO	NY	10/06/1994	GE FRAME 6 GAS TURBINE	67	0.008	FUEL SPEC: SULFUR CONTENT NOT TO EXCEE	BACT-OTHER
TECO POLK POWER STATION	BARTOW	FL	02/24/1994	TURBINE, FUEL OIL	221	0.009	GOOD COMBUSTION	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	0.009	WATER INJECTION FOR NOX EMISSIONS	BACT-PSD
TECO POLK POWER STATION	BARTOW	FL	02/24/1994	TURBINE, FUEL OIL	221	0.009	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	233	0.009	GOOD COMBUSTION PRACTICES	BACT-PSD
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, OIL	231	0.009	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	133	0.009		
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, FUEL OIL (2)	216	0.010	GOOD COMBUSTION PRACTICES	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74	0.012	FUEL SPEC: LOW SULFUR FUEL	BACT-OTHER
SAVANNAH ELECTRIC AND POWER CO.		GA	02/12/1992	TURBINES, 8	122	0.012	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	OK	12/17/1992	TURBINE, COMBUSTION	58	0.013	FUEL SPEC: USE OF DISTILLATE FUEL	BACT-OTHER
CAROLINA POWER AND LIGHT	HARTSVILLE	SC	08/31/1994	STATIONARY GAS TURBINE	190	0.014	0.05% SULFUR DISTILLATE OIL #2 USED.	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	129	0.015	GOOD COMBUSTION PRACTICES	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, OIL FIRED (2 EACH)	230	0.016	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	175	0.016	FUEL SPEC: LOW ASH FUEL, GRADE 76 #2 OIL	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	0.016	FUEL SPEC: 0.2% SULFUR FUEL OIL	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, FUEL OIL	116	0.016	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, OIL, 2 EACH	400	0.019	MAX WATER INJECTION	BACT-PSD
FLORIDA POWER GENERATION	DEBARY	FL	10/18/1991	TURBINE, OIL, 6 EACH	93	0.020	WATER INJECTION	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	80	0.023		BACT-PSD
FULTON COGEN PLANT	FULTON	NY	09/15/1994	GE LM5000 GAS TURBINE	63	0.024	FUEL SPEC: SULFUR CONTENT NOT TO EXCEE	BACT-OTHER
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, OIL, 1 EACH	80	0.025	COMBUSTION CONTROL	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (#2 FUEL OIL) (2)	149	0.026	FUEL SPEC: LOW SULFUR OIL (0.05%)	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	166	0.028	FUEL SPEC: 0.2% SULFUR FUEL OIL	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION F	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	81	0.030	COMBUSTION CONTROLS	BACT-OTHER
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #6 FRAME	64	0.033		
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, OIL FIRED, 3 EA	129	0.034		BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	ENGINE, GAS TURBINE	92	0.035		
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	0.036	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
KALAELOE PARTNERS, L.P.		HI	03/09/1990	TURBINE, LSFO, 2	225	0.044		BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	03/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	0.045	COMBUSTION CONTROL	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	0.047	GOOD COMBUSTION PRACTICES	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW OIL FIRED	52	0.050	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	0.059	PROPER COMBUSTION TECHNIQUE	BACT-OTHER
UNION ELECTRIC CO	WEST ALTON	MO	05/06/1979	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	78	0.064		BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	55.000	CLEAN FUEL	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr
2) Some lb/mmBtu values were calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Fuel Oil) - SO_2

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	lb/mmBtu[2]	CTRLDESC	BASIS
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	ME	12/04/1998	TURBINE, COMBINED CYCLE	900	0.00068	0.05% SULFUR DISTILLATE OIL #2 USED.	BACT-PSD
MOJAVE COGENERATION CO.		CA	01/12/1989	TURBINE, GAS	61	0.0012	FUEL SPEC: OIL FIRING LIMITED TO 11 H/D	BACT-PSD
TECO POLK POWER STATION	BARTOW	FL	02/24/1994	TURBINE, FUEL OIL	221	0.048	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
VIRGINIA POWER		VA	09/07/1989	TURBINE, GAS	164	0.051	FUEL SPEC: 0.06% BY WT ANN AVG S FUEL, GA	BACT-PSD
WI ELECTRIC POWER CO.	CONCORD STATION	WI	10/18/1990	TURBINES, COMBUSTION, SIMPLE CYCLE, 4	75	0.052	FUEL SPEC: 0.05% S OIL ALLOWED ONLY IF NA	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, FUEL OIL (2)	216	0.054	FUEL SPEC: LOW SULFUR FUEL OIL (MAX 0.05 9	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, FUEL OIL	116	0.056	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	0.060	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW OIL FIRED ELECTRIC	140	0.078	FUEL SPEC: LOW SULFUR OIL (0.05%)	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	OIL FIRED COMBUSTION TURBINE	74	0.090	FUEL SPEC: LOW S OIL 0.05% S	BACT-PSD
THE DEXTER CORP.	WINDSOR LOCKS	CT	09/29/1989	TURBINE, NAT GAS & #2 FUEL OIL FIRED	69	0.12	FUEL SPEC: LOW SULFUR FUEL - 0.28%	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	0.16	FUEL SPEC: 0.15% S FUEL OIL	BACT-PSD
O'BRIEN COGENERATION	HARTFORD	CT	08/08/1988	TURBINE, GAS FIRED	62	0.19	FUEL SPEC: LOW S OIL, ANNUAL FUEL LIMIT	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	156	0.19	FUEL SPEC: 0.2% SULFUR FUEL OIL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	133	0.21	FUEL SPEC: LOW S FUEL	BACT-PSD
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, OIL FIRED, 3 EA	129	0.21	FUEL SPEC: SULFUR CONTENT OF FUEL	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND*	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	0.21	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	129	0.22	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	08/17/1992	TURBINE, OIL	233	0.22	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	0.22	USING #2 OIL	OTHER
KALAELOE PARTNERS, L.P.		HI	03/09/1990	TURBINE, LSFO, 2	225	0.27		BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, OIL, 2 EACH	400	0.29	FUEL SPEC: NO. 2 FUEL OIL	BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	03/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	0.30	FUEL SPEC: LOW SULFUR FUEL (0.3% SULFUR	BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	ENGINE, GAS TURBINE	92	0.31	FUEL SPEC: LOW S OIL	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	04/15/1988	TURBINE, GE,2 EA	234	0.33	FUEL SPEC: 0.3% BY WT SULFUR LIMIT ON FUE	LAER
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	0.34	FUEL SPEC: LOW SULFUR FUEL (0.3% SULFUR	SEE NOTES
FLORIDA POWER GENERATION	DEBARY	FL	10/18/1991	TURBINE, OIL, 6 EACH	93	0.75	FUEL SPEC: #2 FUEL OIL	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr
2) Some lb/mmBtu values were calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EA	248	1.0	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, GAS FIRED (2 EACH)	227	1.8	MAXIMUM WATER INJECTION	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	77	1.8	OXIDATION CATALYST	OTHER
VIRGINIA POWER		VA	09/07/1989	TURBINE, GAS	164	2.1		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	2.7	GOOD COMBUSTION PRACTICES	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, GAS, 1 EACH	80	3.0	FUEL SPEC: NATURAL GAS	BACT-PSD
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	3.0	OXIDATION CATALYST	BACT-OTHER
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	3.0	GOOD COMBUSTION PRACTICES	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE	MI	02/08/1999	TURBINE, COMBINED CYCLE, POWER PLANT	500	3.0	CATALYTIC OXIDIZER	LAER
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	07/31/1996	COMBUSTION TURBINE WITH HEAT RECOVERY BOILE	153	3.1	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRING NO	OTHER
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	09/22/1997	TURBINE, COMBUSTION, ABB GT24	224	3.6	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, CG, 4 EACH	400	3.6	LOW NOX COMBUSTORS	BACT-PSD
AES PLACERITA, INC.		CA	03/10/1986	TURBINE & RECOVERY BOILER	65	3.7	OXIDATION CATALYST	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P	NEW YORK CITY	NY	06/06/1995	TURBINE, NATURAL GAS FIRED	240	4.0	OXIDATION CATALYST	LAER
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	4.3	COMBUSTION CONTROL	BACT-PSD
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	03/05/1985	TURBINE, GAS, 2	168	5.3		BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EA	248	5.3	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND	BACT-PSD
CROCKETT COGENERATION - C&H SUGAR	CROCKETT	CA	10/05/1993	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(F	240	5.9	ENGELHARD OXIDATION CATALYST	BACT-OTHER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	05/01/1996	COMBINED CYCLE TURBINES (2), NATURAL	471	5.9	GOOD COMBUSTION CONTROL PRACTICES. COMMITMENT	BACT-PSD
SUMAS ENERGY INC.	SUMAS	WA	06/25/1991	TURBINE, NATURAL GAS	88	6.0	CO CATALYST	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, NATURAL GAS	109	6.1	DRY LOW NOX COMBUSTOR	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	8.5	COMBUSTION CONTROL	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	8.8	COMBUSTOR DESIGN & OPERATION	OTHER
FULTON COGENERATION ASSOCIATES	FULTON	NY	01/29/1990	TURBINE, GE LM5000, GAS FIRED	63	8.9	COMBUSTION CONTROL	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	GE FRAME 6 GAS TURBINE	63	8.9	NO CONTROLS	BACT-OTHER
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERG	BUCKSPORT	ME	09/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	9.0	NONE	BACT-OTHER
FLORIDA POWER AND LIGHT	LAVOGROME REPOWER	FL	03/14/1991	TURBINE, GAS, 4 EACH	240	9.0	FUEL SPEC: NATURAL GAS AS FUEL	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	09/10/1992	GE FRAME 6 GAS TURBINE	62	9.0	NO CONTROLS	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FA	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW	81	9.5	COMBUSTION CONTROLS	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	SIEMENS V64.3 GAS TURBINE (EP #00001)	81	9.5	NO CONTROLS	BACT-OTHER
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #6 FRAME	62	9.6	COMBUSTION CONTROL	BACT-PSD
BRIDGEPORT ENERGY, LLC	BRIDGEPORT	CT	06/29/1998	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260	10.0	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL EMI	BACT-PSD
INDECK-YERKES ENERGY SERVICES	TONAWANDA	NY	06/24/1992	GE FRAME 6 GAS TURBINE (EP #00001)	54	10.0	NO CONTROLS	BACT-OTHER
LOCKPORT COGEN FACILITY	LOCKPORT	NY	07/14/1993	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	10.0	NO CONTROLS	BACT-OTHER
LONG ISLAND LIGHTING CO.		NY	11/01/1988	TURBINE, GE FRAME 7, 3 EA	75	10.0	COMBUSTION CONTROL	OTHER
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	10.0	COMPLETE COMBUSTION	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&	175	10.0		BACT-OTHER
SUNLAW/INDUSTRIAL PARK 2		CA	06/28/1985	TURBINE, GAS W/#2 FUEL OIL BACKUP, 2 EA, GE FRAN	52	10.0	MFG GUARANTEE ON CO EMISSIONS	OTHER
SYCAMORE COGENERATION CO.	BAKERSFIELD	CA	03/06/1987	TURBINE, GAS FIRED, 4 EA	75	10.0	CO OXIDIZING CATALYST, COMBUSTION CONTROL	BACT-PSD
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	04/16/1993	GE FRAME 6 GAS TURBINE	53	10.0	NO CONTROLS	BACT-OTHER
WESTPLAINS ENERGY	PUEBLO	CO	06/14/1996	SIMPLE CYCLE TURBINE, NATURAL GAS	219	10.0	DRY LOW NOX COMBUSTION SYSTEM (DLN). COMMITMENT	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	10.3	GOOD COMBUSTION	BACT-PSD
PORTSIDE ENERGY CORP.	PORTAGE	IN	05/13/1996	TURBINE, NATURAL GAS-FIRED	63	10.6	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 F	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	NY	05/02/1989	TURBINE, GR FRAME 6, 3 EA	52	10.7	COMBUSTION CONTROL	BACT-PSD
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, NAT GAS FIRED, 3 EA	129	10.9	STEAM INJECTION	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO	PROVIDENCE	RI	04/13/1992	TURBINE, GAS AND DUCT BURNER	170	11.0	NONE	BACT-PSD
SEPCO	RIO LINDA	CA	10/05/1994	TURBINE, GAS COMBINED CYCLE GE MODEL 7	115	11.6	OXIDATION CATALYST	BACT
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (NATURAL GAS) (2)	149	11.6	TURBINE DESIGN	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	08/05/1989	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	11.6	NO CONTROLS	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	03/06/1989	TURBINE, LM5000	54	11.6	COMBUSTION CONTROL	OTHER
MIDLAND COGENERATION VENTURE	MIDLAND	MI	02/16/1988	TURBINE, 12 TOTAL	123	11.8	TURBINE DESIGN	BACT-PSD
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	CHARLOTTE NC (HEADQ	FL	10/15/1999	TURBINE-GAS, COMBINED CYCLE	500	12.0	GOOD COMBUSTION	BACT-PSD
GRANITE ROAD LIMITED		CA	05/06/1991	TURBINE, GAS, ELECTRIC GENERATION	58	12.0	SCR, STEAM INJECTION	BACT-PSD
OLEANDER POWER PROJECT	BALTIMORE (HEADQUAR	FL	10/01/1999	TURBINE-GAS, COMBINED CYCLE	190	12.0	GOOD COMBUSTION	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	02/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	12.0	GOOD COMBUSTION	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	09/01/1989	TURBINE, GAS FIRED	79	12.5	COMBUSTION CONTROL	OTHER
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	NY	11/24/1992	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 M	267	13.0	COMBUSTION CONTROLS	BACT-OTHER
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	13.5	GOOD COMBUSTION PRACTICES	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
DELMARVA POWER	WILMINGTON	DE	08/23/1988	TURBINE, COMBUSTION, 2 EA	100	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJE	ROBINS AIR FORCE BAS	GA	05/13/1994	TURBINE, COMBUSTION, NATURAL GAS	80	15.0	FUEL SPEC: LOW SULFUR FUEL (.3% AVG) FUEL 0.1	BACT-PSD
HERMISTON GENERATING CO.	HERMISTON	OR	07/07/1994	TURBINES, NATURAL GAS (2)	212	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY	AL	03/12/1997	COMBINED CYCLE TURBINE (25 MW)	71	15.0	PRIMARY FUEL IS NATURAL GAS WITH BACKUP FUEL AS	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	OR	05/31/1994	TURBINES, NATURAL GAS (2)	215	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
PSI ENERGY, INC. WABASH RIVER STATION	WEST TERRE HAUTE	IN	05/27/1993	COMBINED CYCLE SYNGAS TURBINE	222	15.0	OPERATION PRACTICES AND GOOD COMBUSTION, COMBIN	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	05/01/1998	COMBINED CYCLE TURBINES (2), NATURAL	471	15.0	GOOD COMBUSTION CONTROL PRACTICES. COMMITMENT	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD	ME	05/01/1998	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	238	15.0	GE DRY LOW-NOX COMBUSTOR DESIGN. GOOD COMBUSTI	BACT-PSD
SUMAS ENERGY INC	SUMAS	WA	12/01/1990	TURBINE, GAS-FIRED	67	15.0	CO CATALYST	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	15.0	USING 15% EXCESS AIR. CO EMISSION IS BECAUSE OF N	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/04/1998	TURBINE, COMBINED CYCLE, TWO	528	15.0	USING 15 % EXCESS AIR.	BACT-PSD
LORDSBURG L.P.	LORDSBURG	NM	06/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	15.0	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AI	BACT-PSD
UNION CARBIDE CORPORATION	HAHNVILLE	LA	09/22/1995	GENERATOR, GAS TURBINE	164	15.4	NO ADD-ON CONTROL GOOD COMBUSTI	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE P	BATON ROUGE	LA	03/07/1997	TURBINE/HSRG, GAS COGENERATION	56	15.8	COMBUSTION DESIGN AND CONSTRUCTION.	BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/01/1993	GE LM-5000 GAS TURBINE	69	17.0	NO CONTROLS	BACT-OTHER
MOBILE ENERGY LLC	MOBILE	AL	01/05/1999	TURBINE, GAS, COMBINED CYCLE	188	17.8	GOOD COMBUSTION PRACTICES	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE ST	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	20.0	COMBUSTION CONTROL	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140	20.0	GOOD COMBUSTION PRACTICES	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE	ME	07/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	20.0	15% EXCESS AIR	BACT-PSD
KALAMAZOO POWER LIMITED	COMSTOCK	MI	12/03/1991	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	20.0	DRY LOW NOX TURBINES	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN	FL	01/01/1996	COMBINED CYCLE COMBUSTION TURBINE	140	20.0	DRY LNB GOOD COMBUSTION PRA	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	VA	03/03/1992	TURBINE, COMBUSTION	147	23.5	FURNACE DESIGN	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	GEISMAR	LA	02/13/1998	TURBINE GAS, GE, 7ME 7	121	25.0	GOOD EQUIPMENT DESIGN, PROPER COMBUSTION TECHN	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, NATURAL GAS (2)	189	25.0	GOOD COMBUSTION PRACTICES	BACT-PSD
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	TURBINE, GE FRAME 7, GAS FIRED	80	25.0	COMBUSTION CONTROL	BACT-PSD
OCEAN STATE POWER	BURRILLVILLE	RI	12/13/1988	TURBINE, GAS, GE FRAME 7, 4 EA	132	25.0		BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND	FL	06/01/1995	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 11	75	25.0	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE	BACT-PSD
ALABAMA POWER PLANT BARRY	BUCKS	AL	08/07/1998	TURBINES, COMBUSTION, NATURAL GAS	510	25.4	EFFICIENT COMBUSTION	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING P	LAS VEGAS	NV	09/18/1992	COMBUSTION TURBINE ELECTRIC POWER GENERATI	75	25.8	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	LAS VEGAS	NV	01/17/1991	COMBINED-CYCLE POWER GENERATION	85	26.2	CATALYTIC CONVERTER	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	04/09/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	26.3	GOOD COMBUSTION CONTROLS	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN	CO	06/30/1998	SIMPLE CYCLE TURBINE, NATURAL GAS	1122	30.0	DRY LOW NOX COMBUSTION	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	192	30.0	COMBUSTION CONTROLS, ANNUAL STACK TESTING	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	FL	07/10/1998	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALS	272	31.2	DRY LOW NOX BURNERS FOR SIMPLE CYCLE, SCR	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	02/02/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501	317	31.2	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTI	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	33.0	COMBUSTION CONTROLS.	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	04/15/1988	TURBINE, GE,2 EA	234	33.2	EQUIPMENT DESIGN	LAER
ANITEC COGEN PLANT	BINGHAMTON	NY	07/07/1993	GE LM5000 COMBINED CYCLE GAS TURBINE EP #0000	56	36.0	BAFFLE CHAMBER	SEE NOTE #4
MARCH POINT COGENERATION CO		WA	10/26/1990	TURBINE, GAS-FIRED	80	37.0	GOOD COMBUSTION	BACT-PSD
CAROLINA COGENERATION CO., INC.	NEW BERN	NC	07/11/1986	TURBINE, GAS, PEAT FIRED	52	37.0	PROPER OPERATION	BACT-PSD
CARSON ENERGY GROUP & CENTERAL VALLEY FINAN	ELK GROVE	CA	07/23/1993	TURBINE, GAS SIMPLE CYCLE LM6000	56	39.5	OXIDATION CATALYST	BACT
INDECK ENERGY COMPANY	SILVER SPRINGS	NY	05/12/1993	GE FRAME 6 GAS TURBINE EP #00001	61	40.0	NO CONTROLS	BACT-OTHER
ONEIDA COGENERATION FACILITY	ONEIDA	NY	02/26/1990	TURBINE, GE FRAME 8	52	40.0	COMBUSTION CONTROL	OTHER
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW NATURAL GAS FIRED	52	40.0	GOOD COMBUSTION PRACTICES	BACT-OTHER
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	OIL FIRED COMBUSTION TURBINE	74	42.0	FUEL SPEC: LOW S OIL 0.05% S	BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	ENGINE, GAS TURBINE	92	49.8		BACT-PSD
THE DEXTER CORP.	WINDSOR LOCKS	CT	09/29/1989	TURBINE, NAT GAS & #2 FUEL OIL FIRED	69	49.8		BACT-PSD
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	CA	08/19/1994	TURBINE, GAS, COMBINED CYCLE LM6000	53	50.0	OXIDATION CATALYST	BACT
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	05/02/1994	GAS TURBINES	75	50.6	INTERNAL COMBUSTION CONTROLS	BACT
CARSON ENERGY GROUP & CENTRAL VALLEY FINANC	ELK GROVE	CA	07/23/1993	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450	50.7	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTIO	BACT
FORMOSA PLASTICS CORPORATION	BATON ROUGE	LA	09/20/1990	TURBINE, GAS-FIRED, 2	73	53.1	COMBUSTION CONTROL	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
SIMPSON PAPER CO.		CA	06/22/1987	TURBINE, GAS	50	61.0	COMBUSTION CONTROLS	OTHER
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	02/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	61.2	GOOD COMBUSTION CONTROL	BACT-PSD
MIDWAY-SUNSET COGENERATION CO.		CA	01/27/1988	TURBINE, GE FRAME 7, 3 EA	75	69.7	GOOD COMBUSTION PRACTICES	BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/01/1993	GE LM-5000 GAS TURBINE	69	74.4	NO CONTROLS	BACT-OTHER
SYRACUSE UNIVERSITY	SYRACUSE	NY	09/01/1989	TURBINE, GAS FIRED	79	75.7	CATALYTIC OXIDATION	OTHER
GEORGIA GULF CORPORATION	PLAQUEMINE	LA	03/26/1996	GENERATOR, NATURAL GAS FIRED TURBINE	140	88.0	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr
2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of CO: 1 (PPM) = (lb/mmBtu) * 445
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - PM/PM10

FACILITY	CITY	STATE	PERMIT	PROCESS	MW	lb/mmBtu	CTRLDESC	BASIS
MIDLAND COGENERATION VENTURE	MIDLAND	MI	02/16/1988	TURBINE, 12 TOTAL	123	0.00051	FUEL SPEC: NAT GAS FUEL	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345	0.00052	NONE	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	NY	06/06/1995	TURBINE, NATURAL GAS FIRED	240	0.0013		LAER
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIF	NJ	04/01/1991	TURBINES (NATURAL GAS) (2)	149	0.0023	TURBINE DESIGN	BACT-OTHER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	05/01/1996	COMBINED CYCLE TURBINES (2), NATURAL	471	0.0024	FUEL SPEC: COMBUSTION OF PIPE LINE QUALITY GAS. CLOSE	BACT-PSD
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	03/05/1985	TURBINE, GAS, 2	168	0.0030	LOW NOX BURNERS	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	0.0033	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPL	BACT-PSD
LILCO SHOREHAM	HICKSVILLE	NY	05/10/1993	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	106	0.0035	NO CONTROLS	BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	0.0038	COMBUSTION CONTROL	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001	175	0.0039		BACT-OTHER
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	192	0.0039	FUEL SPEC: LOW ASH FUEL	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	02/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	0.0039	GOOD COMBUSTION CONTROL	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY	AL	03/12/1997	COMBINED CYCLE TURBINE (25 MW)	71	0.0044	PRIMARY FUEL IS NATURAL GAS WITH BACKUP FUEL AS DISTIL	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	LAS VEGAS	NV	01/17/1991	COMBINED-CYCLE POWER GENERATION	85	0.0044	FUEL SPEC: BURN NATURAL GAS	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	0.0047	COMBUSTION CONTROL	BACT-PSD
PACIFIC THERMONETICS, INC.	CROCKETT	CA	04/06/1989	BURNER, HRSG, 2	53	0.0048	FUEL SPEC: NAT GAS USE ONLY	OTHER
VIRGINIA POWER		VA	09/07/1989	TURBINE, GAS	164	0.0048		BACT-PSD
INDECK ENERGY COMPANY	SILVER SPRINGS	NY	05/12/1993	GE FRAME 6 GAS TURBINE EP #00001	61	0.0050	NO CONTROLS	BACT-OTHER
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	01/18/1994	GE FRAME 6 GAS TURBINE	61	0.0050	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEI	BACT-OTHER
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	02/02/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501	317	0.0050	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	RI	04/13/1992	TURBINE, GAS AND DUCT BURNER	170	0.0050	NONE	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/08/1989	TURBINE, COMBUSTION, #6 FRAME	62	0.0050	COMBUSTION CONTROL	BACT-PSD
HERMISTON GENERATING CO.	HERMISTON	OR	07/07/1994	TURBINES, NATURAL GAS (2)	212	0.0053	GOOD COMBUSTION PRACTICES	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	03/01/1995	COMBUSTION TURBINE/GENERATOR	246	0.0054	FUEL SELECTION; GOOD COMBUSTION	BACT-PSD
ANITEC COGEN PLANT	BINGHAMTON	NY	07/07/1993	GE LM5000 COMBINED CYCLE GAS TURBINE EP #0000	58	0.0055	NO CONTROLS	BACT-OTHER
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	0.0056	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, GAS, 4 EACH	400	0.0056	COMBUSTION CONTROL	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, NATURAL GAS (2)	189	0.0080	GOOD COMBUSTION PRACTICES	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, GAS, 1 EACH	80	0.0060	COMBUSTION CONTROL	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	NY	05/02/1989	TURBINE, GR FRAME 6, 3 EA	52	0.0060	COMBUSTION CONTROL	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	GE FRAME 6 GAS TURBINE	63	0.0060	STEAM INJECTION	BACT
LONG ISLAND LIGHTING CO.		NY	11/01/1988	TURBINE, GE FRAME 7, 3 EA	75	0.0060	COMBUSTION CONTROL	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	77	0.0060	TURBINE DESIGN	BACT-PSD
ONEIDA COGENERATION FACILITY	ONEIDA	NY	02/26/1990	TURBINE, GE FRAME 6	52	0.0060	COMBUSTION CONTROL	OTHER
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	04/09/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	0.0062	GOOD COMBUSTION CONTROLS	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN	FL	01/01/1996	COMBINED CYCLE COMBUSTION TURBINE	140	0.0063	DRY LNB FUEL SPEC: LOW S OIL, LIMITE	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, GAS FIRED (2 EACH)	227	0.0064	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	ME	09/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	0.0064	NONE	BACT-OTHER
LORDSBURG L.P.	LORDSBURG	NM	06/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	0.0066	WATER INJECTION	BACT-PSD
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	TURBINE, GE FRAME 7, GAS FIRED	80	0.0070	COMBUSTION CONTROL	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MV	81	0.0077	COMBUSTION CONTROLS	BACT-OTHER
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	0.0080	SCR	BACT-OTHER
FLORIDA POWER AND LIGHT	LAVOGROME	FL	03/14/1991	TURBINE, GAS, 4 EACH	240	0.0080	COMBUSTION CONTROL	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, NATURAL GAS	109	0.0081	GOOD COMBUSTION PRACTICES	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	NY	11/24/1992	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 M	267	0.0082	FUEL SPEC: USE OF NATURAL GAS	BACT-OTHER
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	11/10/1998	GENERATOR, COMBUSTION TURBINE & DUCT BURNE	249	0.0089	COMBUSTING NATURAL GAS	BACT-PSD
MOBILE ENERGY LLC	MOBILE	AL	01/05/1999	TURBINE, GAS, COMBINED CYCLE	168	0.0089	COMBUSTION OF CLEAN FUELS	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	02/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	0.0089	GOOD COMBUSTION	BACT-PSD
O'BRIEN COGENERATION	HARTFORD	CT	08/08/1988	TURBINE, GAS FIRED	62	0.0090	GOOD COMBUSTION PRACTICES	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/06/1997	TURBINE, COMBUSTION, ABB GT11N2	166	0.0094	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	09/22/1997	TURBINE, COMBUSTION, ABB GT24	224	0.0097	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON	BACT-PSD
PORTSIDE ENERGY CORP.	PORTAGE	IN	05/13/1996	TURBINE, NATURAL GAS-FIRED	63	0.0099	NONE	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	0.010	PM EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	0.010	PM EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	09/10/1992	GE FRAME 6 GAS TURBINE	62	0.010	NO CONTROLS	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	PA	11/04/1992	TURBINE (NATURAL GAS & OIL)	144	0.010	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - PM/PM10

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	lb/mmBtu[2]	CTRLDESC	BASIS
VIRGINIA POWER	CHESTERFIELD	VA	04/15/1988	TURBINE, GE,2 EA	234	0.011	EQUIPMENT DESIGN	LAER
ALABAMA POWER PLANT BARRY	BUCKS	AL	08/07/1998	TURBINES, COMBUSTION, NATURAL GAS	510	0.011	NATURAL GAS ONLY, EFFICIENT COMBUSTION	BACT-PSD
INDECK-YERKES ENERGY SERVICES	TONAWANDA	NY	06/24/1992	GE FRAME 6 GAS TURBINE (EP #00001)	54	0.012	NO CONTROLS	BACT-OTHER
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	NV	09/18/1992	COMBUSTION TURBINE ELECTRIC POWER GENERATI	75	0.012	PRECISION CONTROL FOR THE COMBUSTOR	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL	74	0.012	FUEL SPEC: LOW SULFUR FUELS	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	AL	03/16/1999	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170	0.012	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	0.014	GOOD COMBUSTION PRACTICES	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	SIEMENS V64.3 GAS TURBINE (EP #00001)	81	0.014	NO CONTROLS	BACT-OTHER
UNION CARBIDE CORPORATION	HAHNVILLE	LA	09/22/1995	GENERATOR, GAS TURBINE	164	0.014	NO CONTROL CLEAN FUEL	BACT-PSD
THE DEXTER CORP.	WINDSOR LOCKS	CT	09/29/1989	TURBINE, NAT GAS & #2 FUEL OIL FIRED	69	0.014		BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/01/1993	GE LM-5000 GAS TURBINE	69	0.014	NO CONTROLS	BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	0.016	COMBUSTION CONTROL	BACT-OTHER
MOJAVE COGENERATION CO.		CA	01/12/1989	TURBINE, GAS	61	0.017	FUEL SPEC: OIL FIRING LIMITED TO 11 H/D	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	0.017	PM IS BECAUSE OF FUEL OIL. WHEN GROSS OUTPUT IS BELO	BACT-PSD
GEORGIA GULF CORPORATION	PLAQUEMINE	LA	03/26/1996	GENERATOR, NATURAL GAS FIRED TURBINE	140	0.019	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	GEISMAR	LA	02/13/1998	TURBINE GAS, GE, 7ME 7	121	0.019	GOOD COMBUSTION PRACTICES AND USE CLEAN NATURAL G	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	0.019	CLEAN FUEL	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	05/02/1994	GAS TURBINES	75	0.020	INTERNAL COMBUSTION CONTROLS	BACT
SYRACUSE UNIVERSITY	SYRACUSE	NY	09/01/1989	TURBINE, GAS FIRED	79	0.020	COMBUSTION CONTROL	OTHER
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	04/16/1993	GE FRAME 6 GAS TURBINE	53	0.021	NO CONTROLS	BACT-OTHER
LOCKPORT COGEN FACILITY	LOCKPORT	NY	07/14/1993	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	0.021	STEAM INJECTION	BACT
KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	NY	11/05/1992	TURBINE, COMBUSTION (79 MW)	82	0.024	DRY LOW NOX OR SCR	BACT-OTHER
FULTON COGEN PLANT	FULTON	NY	09/15/1994	GE LM5000 GAS TURBINE	63	0.024	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.3% BY WEI	BACT-OTHER
FULTON COGENERATION ASSOCIATES	FULTON	NY	01/29/1990	TURBINE, GE LM5000, GAS FIRED	63	0.024		BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	0.026	FUEL SPEC: CLEAN BURNING FUEL, NAT GAS & DIST. #2 OIL	OTHER
MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	08/05/1989	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	0.028	NO CONTROLS	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	03/06/1989	TURBINE, LM5000	54	0.028		BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	0.036	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 63 MW SIMPLE-CYCLE E	248	0.036	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMP	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW OIL FIRED	52	0.050	FUEL SPECIFICATION: NO. 2 LIGHT OIL	BACT-OTHER
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	0.051	FUEL SPEC: LOW ASH CONTENT FUELS	BACT-PSD
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	09/01/1989	TURBINE, GAS FIRED	79	0.053	COMBUSTION CONTROL	OTHER
CASCO RAY ENERGY CO	VEAZIE	ME	07/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	0.060	NONE	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/04/1998	TURBINE, COMBINED CYCLE, TWO	528	0.060	NONE	BACT-PSD
WI ELECTRIC POWER CO.	CONCORD STATION	WI	10/18/1990	TURBINES, COMBUSTION, SIMPLE CYCLE, 4	75	0.065	GOOD COMBUSTION	BACT-PSD
SOUTHEAST PAPER CORP.	DUBLIN	GA	10/13/1987	TURBINE, COMBUSTION	68	0.10		OTHER

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr

2) Some lb/mmBtu values were calculated from lb/hr, lb/yr or ton/yr values

All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Fuel Oil) - VOC

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	1.0	FURNACE DESIGN	BACT-PSD
KALAELOE PARTNERS, L.P.		HI	3/9/1990	TURBINE, LSFO, 2	225	1.0		BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	ME	12/4/1998	TURBINE, COMBINED CYCLE	900	1.3	0.5 % SULFUR DISTILLATE OIL #2 IS USED.	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX	VA	9/25/1992	TURBINES (2) [EACH WITH A SF]	170	1.5	FUEL SPEC: LOW LEAD FUEL	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	1.6	FURNACE DESIGN	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	2.0	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	2.5	FUEL SPEC: LOW SULFUR OIL	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	4/11/1996	COMBUSTION TURBINE, 4 EACH	238	2.7	COMBUSTION CONTROL	BACT-PSD
FULTON COGEN PLANT	FULTON	NY	9/15/1994	GE LM5000 GAS TURBINE	63	3.0	NO CONTROLS	SEE NOTE #6
SAVANNAH ELECTRIC AND POWER CO.		GA	2/12/1992	TURBINES, 8	122	3.1	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	8/17/1992	TURBINE, OIL	233	3.6	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER CORPORATION	INTERCESSION CITY	FL	8/17/1992	TURBINE, OIL	129	3.6	GOOD COMBUSTION PRACTICES	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	3.8	FURNACE DESIGN	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	7/31/1996	COMBUSTION TURBINE WITH HEAT RECOVERY BO	153	4.0	NONE	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	4.0	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	7/1/1988	TURBINE, OIL FIRED, 3 EA	129	4.7		BACT-PSD
FLORIDA POWER GENERATION	DEBARY	FL	10/18/1991	TURBINE, OIL, 6 EACH	93	5.0	COMBUSTION CONTROL	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	5.1	GOOD COMBUSTION	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX	VA	9/25/1992	TURBINES (2) [EACH WITH A SF]	170	5.2	GOOD COMBUSTION PRACTICES	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSH	NJ	4/1/1991	TURBINES (#2 FUEL OIL) (2)	149	5.4	LOW SULFUR CONTENT FUEL, & COMBUSTION	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX	VA	9/25/1992	TURBINES (2) [EACH WITH A SF]	170	5.9	FUEL SPEC: 0.2 WT LOW SULFUR FUEL	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	6/5/1991	TURBINE, OIL, 2 EACH	400	6.0	COMBUSTION CONTROL	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	6/9/1993	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	80	6.1	NONE	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	6.3	WATER INJECTION	BACT-PSD
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	1/18/1994	GE FRAME 6 GAS TURBINE	61	6.6	NO CONTROLS	BACT-OTHER
GORDONSVILLE ENERGY L.P.	FAIRFAX	VA	9/25/1992	TURBINES (2) [EACH WITH A SF]	170	6.7	WATER INJECTION AND SCR	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	9/6/1989	TURBINE, COMBUSTION, #6 FRAME	64	6.8	COMBUSTION CONTROL	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	7.0		BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SI	BARTOW	FL	2/25/1994	TURBINE, FUEL OIL (2)	216	7.0	COMBUSTION CONTROLS.	BACT-PSD
INDECK-OSWEGO ENERGY CENTER	OSWEGO	NY	10/6/1994	GE FRAME 6 GAS TURBINE	67	7.4	NO CONTROLS	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	7.9	GOOD COMBUSTION	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/1/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	8.0	DRY LOW NOX COMBUSTOR; DESIGN, WATER I	BACT-PSD
GORDONSVILLE ENERGY L.P.	FAIRFAX	VA	9/25/1992	TURBINES (2) [EACH WITH A SF]	170	8.9	GOOD COMBUSTION PRACTICES	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	9.0	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	5/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	10.0	NONE	BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	3/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	10.1	SCR WITH AMMONIA CEM MONITORING	OTHER
BERMUDA HUNDRED ENERGY LIMITED PARTNERSH	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	140	11.1	SCR, STEAM INJ.	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	11.8	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE		KY	3/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	12.9	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	15.8	SCR	BACT-PSD
TECO POLK POWER STATION	BARTOW	FL	2/24/1994	TURBINE, FUEL OIL	221	20.7	GOOD COMBUSTION	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	4/3/1996	COMBUSTION TURBINE (2), FUEL OIL	116	30.0	OXIDATION CATALYST .16 PPM	OTHER

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr
2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of CH_4: 1 (PPM) = (lb/mmBtu) * 740
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas)-NOx

FACILITY	CITY	STATE	PERMIT	LASTUPDATE	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
CITY OF ANAHEIM GAS TURBINE PROJECT		CA	9/15/1989	5/18/1990	TURBINE, GAS, GE PGLM 5000	55	2.3	SCR, STEAM INJECTION, CO REACTOR	BACT-PSD
UNION OIL CO.	RODEO	CA	3/3/1986	5/10/1986	TURBINE, GAS & DUCT BURNER	54	2.5	SCR, STEAM INJECTION	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	NC	12/20/1991	3/24/1995	TURBINE, COMBUSTION	164	2.5	COMBUSTION CONTROL	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	ME	12/4/1998	4/19/1999	TURBINE, COMBINED CYCLE	900	2.5	SELECTIVE CATALYTIC REDUCTION. EMISSION IS FR	LAER
WESTBROOK POWER LLC	WESTBROOK	ME	12/4/1998	4/19/1999	TURBINE, COMBINED CYCLE, TWO	528	2.5	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BUR-	LAER
SEPCO	RIO LINDA	CA	10/5/1994	8/31/1999	TURBINE, GAS COMBINED CYCLE GE MODEL 7	115	2.6	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX CON	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	CA	8/19/1994	4/13/1999	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2	157	3.0	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX CO M	BACT
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	CA	8/19/1994	8/31/1999	TURBINE, GAS, COMBINED CYCLE LM6000	53	3.0	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	CA	8/19/1994	11/24/1999	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	157	3.0	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX CON	BACT
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	9/22/1997	4/19/1999	TURBINE, COMBUSTION, ABB GT24	224	3.1	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/6/1997	4/19/1999	TURBINE, COMBUSTION, ABB GT11N2	186	3.5	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON	BACT-PSD
GRANITE ROAD LIMITED		CA	5/6/1991	8/3/1993	TURBINE, GAS, ELECTRIC GENERATION	58	3.5	SCR, STEAM INJECTION	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	6/9/1993	5/29/1995	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2	77	3.5	SCR	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	NY	6/6/1995	6/30/1995	TURBINE, NATURAL GAS FIRED	240	3.5	SCR	LAER
TIVERTON POWER ASSOCIATES	TIVERTON	RI	2/13/1998	2/8/1999	COMBUSTION TURBINE, NATURAL GAS	265	3.5	SCR	LAER
RUMFORD POWER ASSOCIATES	RUMFORD	ME	5/1/1998	2/10/1999	TURBINE GENERATOR, COMBUSTION, NATURAL G	238	3.5	SCR AMMONIA INJECTION SYSTEM AND CATALYTIC REACTOR	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE	ME	7/13/1998	4/19/1999	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	3.5	SELECTIVE CATALYTIC REDUCTION	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	2/2/1998	4/19/1999	TURBINE, COMBUSTION, WESTINGHOUSE MODEL	317	3.5	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	AL	3/16/1999	4/20/1999	170 MW TURBINE W/ DUCT BURNER, HR BOILER, S	170	3.5	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT-PSD
ALABAMA POWER PLANT BARRY	BUCKS	AL	8/7/1998	8/5/1999	TURBINES, COMBUSTION, NATURAL GAS	510	3.5	NATURAL GAS, CT-DLN COMBUSTORS, DUCTBURNER, LOW N	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	3/1/1995	5/29/1995	COMBUSTION TURBINE/GENERATOR	248	3.6	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
BADGER CREEK LIMITED		CA	10/30/1989	5/18/1990	TURBINE, GAS COGENERATION	57	3.7	SCR, STEAM INJECTION	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	7/31/1996	1/12/1999	COMBUSTION TURBINE WITH HEAT RECOVERY BO	153	4.0	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING	LAER
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	5/17/1994	10/8/1997	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	4.3	NONE	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/1/1996	5/8/1998	TURBINES, COMBINED-CYCLE COGENERATION	461	4.4	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUC	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	NY	11/24/1992	9/13/1994	TURBINES, COMBUSTION (4) (NATURAL GAS) (101	287	4.5	SCR AND DRY LOW NOX	BACT-OTHER
PILGRIM ENERGY CENTER	ISLIP	NY		4/27/1995	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00	175	4.5	STEAM INJECTION FOLLOWED BY SCR	BACT
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHA	HOBBS	NM	2/15/1997	3/31/1997	COMBUSTION TURBINE, NATURAL GAS	100	4.5	DRY LOW NOX COMBUSTION	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	OR	5/31/1994	8/8/1997	TURBINES, NATURAL GAS (2)	215	4.5	SCR	BACT-PSD
HERMISTON GENERATING CO.	HERMISTON	OR	7/7/1994	1/27/1999	TURBINES, NATURAL GAS (2)	212	4.5	SCR	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	11/10/1998	4/19/1999	GENERATOR, COMBUSTION TURBINE & DUCT BUR	1988	4.5	SELECTIVE CATALYTIC REDUCTION (SCR) WITH A NOX CEM AN	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE	MI	2/8/1999	4/19/1999	TURBINE, COMBINED CYCLE, POWER PLANT	500	4.5	SCR	BACT
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	7/31/1995	5/6/1998	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE	248	4.8	FUEL SPEC: FIRING #2 FUEL OIL	BACT-PSD
KALAMAZOO POWER LIMITED	COMSTOCK -	MI	12/3/1991	3/23/1994	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	5.0	DRY LOW NOX TURBINES	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		3/24/1995	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140	5.0	DRY BURN LOW NOX BURNERS	BACT-PSD
CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING	ELK GROVE	CA	7/23/1993	4/13/1999	TURBINE, GAS, COMBINED CYCLE, GE LM6000	56	5.0	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION AL	BACT
CROCKETT COGENERATION - C&H SUGAR	CROCKETT	CA	10/5/1993	4/19/1999	TURBINE, GAS, GENERAL ELECTRIC MODEL PG72	.240	5.0	DRY LOW-NOX COMBUSTERS AND A MITSUBISHI HEAVY INDUS	BACT-OTHER
MOBILE ENERGY LLC	MOBILE	AL	1/5/1999	4/9/1999	TURBINE, GAS, COMBINED CYCLE	168	5.1	SCR & DLN COMBUSTORS DURING GAS FIRING. STEAM/W	BACT-PSD
KERN FRONT LIMITED	BAKERSFIELD	CA	11/4/1986	8/5/1999	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25	5.5	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT-OTHER
SUMAS ENERGY INC.	SUMAS	WA	6/25/1991	8/1/1991	TURBINE, NATURAL GAS	88	6.0	SCR	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	4/9/1998	8/19/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	6.0	GOOD COMBUSTION CONTROLS	BACT-PSD
BRIDGEPORT ENERGY, LLC	BRIDGEPORT	CT	6/29/1998	1/21/1999	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEME	260	6.0	DRY LOW NOX BURNER WITH SCR	BACT-PSD
AES PLACERITA, INC.		CA	7/2/1987	6/2/1988	TURBINE, GAS	66	6.2	SCR, STEAM INJECTION	BACT-PSD
SIMPSON PAPER CO.		CA	6/22/1987	6/2/1988	TURBINE, GAS	50	6.6	SCR, STEAM INJECTION	OTHER
MIDWAY - SUNSET PROJECT		CA	1/6/1987	2/19/1987	TURBINE, GAS, 3	122	7.2	H2O INJECTION	BACT-PSD
SALINAS RIVER COGENERATION COMPANY		CA	11/19/1990	3/24/1995	TURBINE,GAS, W/ HEAT RECOVERY STEAM GENE	43	7.8	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
SARGENT CANYON COGENERATION COMPANY		CA	11/19/1990	3/24/1995	TURBINE, GAS W/ HEAT RECOVERY STEAM GENE	43	8.0	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
BASF CORPORATION	GEISMAR	LA	12/30/1997	1/21/1999	TURBINE, COGEN UNIT 2, GE FRAME 6	42	8.0	STEAM INJECTION AND SCR TO LIMIT NOX TO 6 PPM FOR NATU	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	ME	9/14/1998	4/19/1999	TURBINE, COMBINED CYCLE, NATURAL GAS	175	8.0		BACT-OTHER
RICHMOND POWER ENTERPRISE PARTNERSHIP	RICHMOND	VA	12/12/1989	4/30/1990	TURBINE, GAS FIRED, 2	145	8.2	SCR, STEAM INJECTION	LAER
MOJAVE COGENERATION CO.		CA	1/12/1989	3/1/1989	TURBINE, GAS	81	8.4	FUEL SPEC: OIL FIRING LIMITED TO 11 H/D	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	NJ	11/1/1990	7/7/1993	TURBINE, NATURAL GAS FIRED	73	8.9	STEAM INJECTION AND SCR	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	4/1/1991	5/29/1995	TURBINES (NATURAL GAS) (2)	149	8.9	SCR, DRY LOW NOX BURNER	BACT-OTHER
CAROLINA POWER & LIGHT	GOLDSBORO	NC	4/11/1996	8/19/1996	COMBUSTION TURBINE, 4 EACH	238	8.9	COMBUSTION CONTROL	BACT-PSD
SUNLAW/INDUSTRIAL PARK 2		CA	6/28/1985	6/4/1986	TURBINE, GAS W/#2 FUEL OIL BACKUP, 2 EA, GE F	52	9.0	SCR, STEAM INJECTION	OTHER
BAF ENERGY		CA	7/8/1987	6/2/1988	TURBINE, GENERATOR	111	9.0	SCR, STEAM INJECTION	BACT-PSD
OCEAN STATE POWER	BURRILLVILLE	RI	12/13/1988	3/1/1989	TURBINE, GAS, GE FRAME 7, 4 EA	132	9.0	SCR, H2O INJECTION	BACT-PSD
SUMAS ENERGY INC	SUMAS	WA	12/1/1990	5/21/1991	TURBINE, GAS-FIRED	67	9.0	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	RI	4/13/1992	5/31/1992	TURBINE, GAS AND DUCT BURNER	170	9.0	SCR	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILI	BEAVER FALLS	NY	11/9/1992	9/13/1994	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79	61	9.0	DRY LOW NOX OR SCR	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	NY	11/5/1992	9/13/1994	TURBINE, COMBUSTION (79 MW)	82	9.0	DRY LOW NOX OR SCR	BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	9/1/1992	9/13/1994	TURBINE, COMBUSTION GAS (150 MW)	143	9.0	DRY LOW NOX	BACT-OTHER
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	7/31/1992	9/13/1994	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	9.0	SCR	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP		VA	5/4/1990	3/24/1995	TURBINE, COMBUSTION	158	9.0	DRY COMBUSTOR TO 25 PPM SCR TO 9 PPM USING NAT GAS	OTHER
NEVADA COGENERATION ASSOCIATES #2	LAS VEGAS	NV	1/17/1991	3/24/1995	COMBINED-CYCLE POWER GENERATION	85	9.0	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLAN	LAS VEGAS	NV	9/18/1992	3/24/1995	COMBUSTION TURBINE ELECTRIC POWER GENER	600	9.0	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	LA	3/2/1995	4/17/1995	TURBINE/HRSG, GAS COGENERATION	58	9.0	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL	LAER
MID-GEORGIA COGEN.	KATHLEEN	GA	4/3/1996	8/19/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	9.0	DRY LOW NOX BURNER WITH SCR	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas)-NOx

FORMOSA PLASTICS CORPORATION, BATON ROUGE PLAN	BATON ROUGE	LA	3/7/1997	4/28/1997	TURBINE/HSRG, GAS COGENERATION	58	9.0	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRU	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	5/7/1997	TURBINE, COMBUSTION GAS	59	9.0	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	VA	3/3/1992	5/7/1997	TURBINE, COMBUSTION	147	9.0	SCR, STEAM INJECTION	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	2/26/1995	10/6/1997	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	9.0	GOOD COMBUSTION CONTROL	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	GEISMAR	LA	2/13/1998	1/20/1999	TURBINE GAS, GE, 7ME 7	121	9.0	DRY LOW NOX TO LIMIT NOX EMISSION TO 9PPMV	BACT-PSD
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	CHARLOTTE NC (HEADQUARTERS)	FL	10/15/1999	11/11/1999	TURBINE-GAS, COMBINED CYCLE	500	9.0	DLN GE DLN2.8 BURNERS	BACT-PSD
OLEANDER POWER PROJECT	BALTIMORE (HEADQUARTERS)	FL	10/1/1999	11/11/1999	TURBINE-GAS, COMBINED CYCLE	190	9.0	DLN 2.6 GE ADVANCED DRY LOW NOX	BACT-PSD
SANTA ROSA ENERGY LLC	NORTHBROOK	FL	12/4/1998	4/16/1999	TURBINE, COMBUSTION, NATURAL GAS	241	9.8	DRY LOW NOX BURNER	BACT-PSD
LAS VEGAS COGENERATION LTD. PARTNERSHIP	NORTH LAS VEGAS	NV	10/18/1990	3/24/1995	TURBINE, COMBUSTION COGENERATION	50	10.0	H2O INJECTION/SCR	BACT-PSD
TAMPA ELECTRIC COMPANY (TEC)	APOLLO BEACH	FL	10/15/1999	2/21/2000	TURBINE, COMBUSTION, SIMPLE CYCLE	165	10.5	DLN GE DLN2.6	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	OLDMANS TOWNSHIP	NJ	2/23/1990	4/30/1993	TURBINE, NATURAL GAS FIRED	125	11.8	STEAM INJECTION AND SCR	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	2/25/1994	1/13/1995	TURBINE, NATURAL GAS (2)	189	12.0	DRY LOW NOX COMBUSTOR	BACT-PSD
KALAMAZOO POWER LIMITED	COMSTOCK	MI	12/3/1991	3/23/1994	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	15.0	DRY LOW NOX TURBINES	BACT-PSD
PEPCO - CHALK POINT PLANT	EAGLE HARBOR	MD	6/25/1990	7/20/1994	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84	15.0	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	1/13/1995	TURBINE,GAS	152	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	4/7/1993	1/13/1995	TURBINE, NATURAL GAS	109	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
TIGER BAY LP	FT. MEADE	FL	5/17/1993	1/13/1995	TURBINE, GAS	202	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	4/11/1995	5/29/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2	74	15.0	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COM	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND	FL	6/1/1995	5/20/1996	COMBINED CYCLE COMBUSTION TURBINE (TOTAL	75	15.0	DRY LOW NOX BURNER	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN	FL	1/1/1996	5/31/1996	COMBINED CYCLE COMBUSTION TURBINE	140	15.0	DRY LNB STAGED COMBUSTION	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STAT	HOBBS	NM	11/4/1996	12/30/1996	COMBUSTION TURBINE, NATURAL GAS	100	15.0	DRY LOW NOX COMBUSTION	BACT-PSD
ALABAMA POWER COMPANY	MCINTOSH	AL	12/17/1997	4/24/1998	COMBUSTION TURBINE W/ DUCT BURNER (COMBI	100	15.0	DRY LOW NOX BURNERS	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	5/1/1996	5/19/1998	COMBINED CYCLE TURBINES (2), NATURAL	471	15.0	DRY LOW NOX COMBUSTION SYSTEMS FOR TURBINES AND D	BACT-PSD
WESTPLAINS ENERGY	PUEBLO	CO	6/14/1996	2/11/1999	SIMPLE CYCLE TURBINE, NATURAL GAS	219	15.0	DRY LOW NOX COMBUSTION SYSTEM (DLN). COMMITMENT TO	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	6/23/1999	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	180	15.0	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF NATU	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY	DE	3/30/1998	1/20/1999	TURBINES, COMBINED CYCLE, 2	103	18.0	NITROGEN INJECTION WHILE FIRING SYNGAS AND STEAM INJ	LAER
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	5/2/1994	10/31/1994	GAS TURBINES	75	20.5	INTERNAL COMBUSTION CONTROLS	BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	SC	12/11/1989	3/24/1995	INTERNAL COMBUSTION TURBINE	110	21.7	WATER INJECTION	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO	EAGLE HARBOR	MD	10/1/1989	3/24/1995	TURBINE, NATURAL GAS FIRED ELECTRIC	90	22.0	WATER INJECTION	BACT-PSD
PACIFIC THERMONETICS, INC.	CROCKETT	CA	12/10/1985	2/28/1986	TURBINE, GAS, FRAME 7, 2 EA	127	25.0	QUIET COMBUSTOR. FUEL SPEC: NATURAL GAS FIRING L IMIT	BACT-PSD
PG & E, STATION T	SAN FRANCISCO	CA	8/25/1986	2/19/1987	TURBINE, GAS, GE LM5000	50	25.0	STEAM INJECTION AT STEAM/FUEL RATIO = 1.7/1	BACT-PSD
SYRACUSE UNIVERSITY	SYRACUSE	NY	9/1/1989	12/31/1989	TURBINE, GAS FIRED	79	25.0	STEAM INJECTION	OTHER
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	5/18/1990	TURBINE, GE FRAME 7, GAS FIRED	80	25.0	STEAM INJECTION	BACT-PSD
MARCH POINT COGENERATION CO		WA	10/26/1990	5/21/1991	TURBINE, GAS-FIRED	80	25.0	MASSIVE STEAM INJECTION	BACT-PSD
PEPCO - STATION A	DICKERSON	MD	5/31/1990	7/20/1994	TURBINE, 124 MW NATURAL GAS FIRED	125	25.0	WATER INJECTION	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	7/25/1991	3/24/1995	TURBINE, GAS, 1 EACH	80	25.0	WET INJECTION	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	3/5/1991	3/24/1995	TURBINE, NAT GAS & #2 OIL	192	25.0	H2O INJECTION & LOW NOX COMBUSTION, ANNUAL STACK TE	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	6/5/1991	3/24/1995	TURBINE, GAS, 4 EACH	400	25.0	LOW NOX COMBUSTORS	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	GA	5/13/1994	3/24/1995	TURBINE, COMBUSTION, NATURAL GAS	80	25.0	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	GA	5/13/1994	3/24/1995	TURBINE, COMBUSTION, NATURAL GAS	80	25.0	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	7/26/1992	3/24/1995	TURBINE, GAS FIRED (2 EACH)	227	25.0	MAXIMUM WATER INJECTION	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	3/24/1995	TURBINE, 38 MW NATURAL FAS FIRED	52	25.0	WATER INJECTION	BACT-OTHER
WI ELECTRIC POWER CO.	CONCORD STATION	WI	10/16/1990	3/24/1995	TURBINES, COMBUSTION, SIMPLE CYCLE, 4	75	25.0	H2O INJECTION	BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/1/1993	3/31/1995	GE LM-5000 GAS TURBINE	69	25.0	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	BACT
ANITEC COGEN PLANT	BINGHAMTON	NY	7/7/1993	4/27/1995	GE LM5000 COMBINED CYCLE GAS TURBINE EP #0	56	25.0	NO CONTROLS	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	4/27/1995	SIEMENS V84.3 GAS TURBINE (EP #00001)	81	25.0	WATER INJECTION	BACT
GEORGIA GULF CORPORATION	PLAQUEMINE	LA	3/26/1996	4/21/1997	GENERATOR, NATURAL GAS FIRED TURBINE	140	25.0	CONTROL NOX USING STEAM INJECTION	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY	AL	3/12/1997	5/31/1997	COMBINED CYCLE TURBINE (25 MW)	71	25.0	FUEL OIL SULFUR CONTENT <=0.05% BY WEIGHT DRY LOW NO	BACT-PSD
UNION CARBIDE CORPORATION	HAHNVILLE	LA	9/22/1995	5/31/1997	GENERATOR, GAS TURBINE	184	25.0	DRY LOW NOX COMBUSTOR	BACT-PSD
LORDSBURG L.P.	LORDSBURG	NM	6/16/1997	9/29/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	25.0	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR S	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN	CO	6/30/1998	5/19/1998	SIMPLE CYCLE TURBINE, NATURAL GAS	1122	25.0	DRY LOW NOX COMBUSTION	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	FL	7/10/1998	4/18/1999	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL	272	25.0	DRY LOW NOX BURNERS FOR SIMPLE CYCLE, SCR WHE	BACT-PSD
DELMARVA POWER	WILMINGTON	DE	9/27/1990	3/24/1995	TURBINE, COMBUSTION	100	27.1	LOW NOX BURNER	BACT-PSD
ONEIDA COGENERATION FACILITY	ONEIDA	NY	2/26/1990	5/18/1990	TURBINE, GE FRAME 6	52	32.0	COMBUSTION CONTROL	OTHER
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	3/5/1985	6/30/1987	TURBINE, GAS, 2	168	33.2		BACT-PSD
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	9/1/1989	12/31/1989	TURBINE, GAS FIRED	79	36.0	WATER INJECTION	OTHER
FULTON COGENERATION ASSOCIATES	FULTON	NY	1/29/1990	5/16/1990	TURBINE, GE LM5000, GAS FIRED	83	36.0	H2O INJECTION	BACT-PSD
MIDWAY-SUNSET COGENERATION CO.		CA	1/27/1988	6/22/1988	TURBINE, GE FRAME 7, 3 EA	75	38.4	H2O INJECTION, QUIET COMBUSTOR™	BACT-PSD
O'BRIEN COGENERATION	HARTFORD	CT	6/8/1988	4/30/1990	TURBINE, GAS FIRED	62	39.0	WATER INJECTION	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	4/15/1988	6/3/1988	TURBINE, GE,2 EA	234	42.0	STEAM INJECTION W/MAXIMIZATION (NSPS SUBPART GG)	LAER
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	7/1/1988	10/15/1988	TURBINE, NAT GAS FIRED, 3 EA	129	42.0		BACT-PSD
DELMARVA POWER	WILMINGTON	DE	6/23/1988	3/17/1989	TURBINE, COMBUSTION, 2 EA	100	42.0	LOW NOX BURNER, WATER INJECTION	BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	4/30/1990	ENGINE, GAS TURBINE	92	42.0	STEAM INJECTION	BACT-PSD
THE DEXTER CORP.	WINDSOR LOCKS	CT	9/29/1989	4/30/1990	TURBINE, NAT GAS & #2 FUEL OIL FIRED	69	42.0	STEAM INJECTION	BACT-PSD
VIRGINIA POWER		VA	9/7/1989	4/30/1990	TURBINE, GAS	184	42.0	H2O INJECTION, RECORD KEEPING OF FUEL N2 CONTENT	BACT-PSD
MIDLAND COGENERATION VENTURE	MIDLAND	MI	2/16/1988	5/1/1990	TURBINE, 12 TOTAL	123	42.0	STEAM INJECTION	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	NY	5/2/1989	5/18/1990	TURBINE, GR FRAME 6, 3 EA	52	42.0	STEAM INJECTION	BACT-PSD
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	3/6/1989	5/18/1990	TURBINE, LM5000	54	42.0	H2O INJECTION	BACT-PSD
FLORIDA POWER AND LIGHT	LAVOGROME	FL	3/14/1991	3/24/1995	TURBINE, GAS, 4 EACH	240	42.0	COMBUSTION CONTROL	BACT-PSD

MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	8/5/1989	3/30/1995	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	42.0	WATER INJECTION	BACT
INDECK-YERKES ENERGY SERVICES	TONAWANDA	NY	6/24/1992	3/31/1995	GE FRAME 6 GAS TURBINE (EP #00001)	54	42.0	STEAM INJECTION	BACT
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	9/10/1992	4/27/1995	GE FRAME 6 GAS TURBINE	62	42.0	WATER INJECTION	BACT
LEDERLE LABORATORIES	PEARL RIVER	NY		4/27/1995	(2) GAS TURBINES (EP #S 00101&102)	14	42.0	STEAM INJECTION	BACT-PSD
LOCKPORT COGEN FACILITY	LOCKPORT	NY	7/14/1993	4/27/1995	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	42.0	STEAM INJECTION	BACT
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	6/30/1995	GE FRAME 6 GAS TURBINE	83	42.0	STEAM INJECTION	BACT
CITY UTILITIES OF SPRINGFIELD	SPRINGFIELD	MO	3/4/1991	10/6/1997	GENERATION OF ELECTRICAL POWER	73	42.0	WATER INJECTION	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	SPRINGFIELD	MO	3/6/1991	10/6/1997	GENERATION OF ELECTRICAL POWER	94	42.0	WATER INJECTION	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	9/6/1989	9/29/1989	TURBINE, COMBUSTION, #7 FRAME	131	44.8	H2O INJECTION	BACT-PSD
LONG ISLAND LIGHTING CO.		NY	11/1/1988	3/1/1989	TURBINE, GE FRAME 7, 3 EA	75	55.0	WATER INJECTION	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN	MEHOOPANY	PA	5/31/1995	11/27/1995	TURBINE, NATURAL GAS	73	55.0	STEAM INJECTION	RACT
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	4/16/1993	3/31/1995	GE FRAME 6 GAS TURBINE	53	80.0	STEAM INJECTION	BACT
ALASKA ELECTRICAL GENERATION & TRANSMISSION	BIG LAKE	AK	3/18/1987	8/10/1987	TURBINE, NAT GAS FIRED	80	75.0	H2O INJECTION	BACT-PSD
CONTINENTAL ENERGY ASSOC.	HAZELTON	PA	7/28/1986	6/1/1989	TURBINE, NAT GAS	98	75.0	STEAM INJECTION	BACT-PSD
SOUTHEAST PAPER CORP.	DUBLIN	GA	10/13/1987	6/16/1993	TURBINE, COMBUSTION	68	100.0	STEAM INJECTION	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr
2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of NO_2: 1 (PPM) = (lb/mmBtu) * 271
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	lb/mmBtu[2]	CTRLDESC	BASIS
ECOELECTRICA, L.P.	PENUELAS	PR	10/1/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	0.000014	MAINTAIN EACH TURBINE IN GOOD WORKIN	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	5/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345	0.00011	LOW SULFUR CONTENT & COMBUSTION CO	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS	MEHOOPANY	PA	5/31/1995	TURBINE, NATURAL GAS	73	0.00014	STEAM INJECTION	RACT
PUERTO RICO ELECTRIC POWER AUTHORI	ARECIBO	PR	7/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE	248	0.00035	MAINTAIN EACH TURBINE IN GOOD WORKIN	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	4/11/1996	COMBUSTION TURBINE, 4 EACH	238	0.00052	COMBUSTION CONTROL	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION T	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	0.00053	COMBUSTION CONTROL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	9/6/1969	TURBINE, COMBUSTION, #6 FRAME	62	0.00058	FUEL SPEC: LOW S FUEL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	9/6/1989	TURBINE, COMBUSTION, #7 FRAME	131	0.00059	FUEL SPEC: LOW S FUEL	BACT-PSD
FLORIDA POWER CORPORATION POLK COU	BARTOW	FL	2/25/1994	TURBINE, NATURAL GAS (2)	189	0.00066	FUEL SPEC: LOW SULFUR IN NATURAL GAS	BACT-PSD
CAROLINA POWER AND LIGHT CO.	DARLINGTON	SC	9/23/1991	TURBINE, I.C.	80	0.00078	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	3/5/1985	TURBINE, GAS, 2	168	0.00085		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	5/2/1994	GAS TURBINES	75	0.0011	INTERNAL COMBUSTION CONTROLS	BACT
SC ELECTRIC AND GAS COMPANY - HAGOO	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	0.0011	GOOD COMBUSTION PRACTICES	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	9/22/1997	TURBINE, COMBUSTION, ABB GT24	224	0.0022	DRY LOW NOX COMBUSTION TECHNOLOGY	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/6/1997	TURBINE, COMBUSTION, ABB GT11N2	166	0.0023	DRY LOW NOX COMBUSTION TECHNOLOGY	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	2/2/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL	317	0.0023	DRY LOW NOX COMBUSTION TECHNOLOGY	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	0.0032	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE	ME	7/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	0.0060		BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	2/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	0.0060	FUEL SPEC: NATURAL GAS FIRED	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/4/1998	TURBINE, COMBINED CYCLE, TWO	528	0.0060		BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CL	BUCKSPORT	ME	9/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	0.0086		BACT-OTHER
MIDLAND COGENERATION VENTURE	MIDLAND	MI	2/16/1988	TURBINE, 12 TOTAL	123	0.016	FUEL SPEC: NAT GAS FUEL	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	6/5/1991	TURBINE, GAS, 4 EACH	400	0.029	FUEL SPEC: NATURAL GAS AS FUEL	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	0.033	FUEL SPEC: LOW SULFUR IN NATURAL GAS	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNER	CHESAPEAKE	VA	3/5/1991	TURBINE, NAT GAS & #2 OIL	192	0.057	FUEL SPEC: LOW SULFUR FUEL & NAT GAS	BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	5/4/1990	TURBINE, COMBUSTION	158	0.059	FUEL SPEC: LOW SULFUR FUELS, NAT GAS	OTHER
DELMARVA POWER	WILMINGTON	DE	9/27/1990	TURBINE, COMBUSTION	100	0.070	FUEL SPEC: SULFUR IN FUEL	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr

2) Some lb/mmBtu values were calculated from lb/hr, lb/yr or ton/yr values

All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - VOC

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
WESTBROOK POWER LLC	WESTBROOK	ME	12/4/1998	TURBINE, COMBINED CYCLE, TWO	528	0.40	NONE	BACT-PSD
PATOWMACK POWER PARTNERS, LIMITED	LEESBURG	VA	9/15/1993	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	146	0.60	FUEL SPEC: CLEAN FUELS	BACT-PSD
FLORIDA POWER AND LIGHT	LAVOGROME	FL	3/14/1991	TURBINE, GAS, 4 EACH	240	1.0	COMBUSTION CONTROL	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE	ME	7/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	1.0	LOW NOX BURNER	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION T	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	1.2	COMBUSTION CONTROL	BACT-PSD
VIRGINIA POWER		VA	9/7/1989	TURBINE, GAS	164	1.2		BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PAR	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	147	1.4	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	5/1/1996	COMBINED CYCLE TURBINES (2), NATURAL	471	1.4	GOOD COMBUSTION CONTROL PRACTICES.	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PAR	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	147	1.5	FURNACE DESIGN	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 000	175	1.6		BACT-OTHER
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	6/5/1991	TURBINE, GAS, 4 EACH	400	1.6	COMBUSTION CONTROL	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CL	BUCKSPORT	ME	9/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	1.7	NONE	BACT-OTHER
TIVERTON POWER ASSOCIATES	TIVERTON	RI	2/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	2.0	GOOD COMBUSTION	BACT-PSD
SACRAMENTO COGENERATION AUTHORITY	SACRAMENTO	CA	8/19/1994	TURBINE, SIMPLE CYCLE LM6000 GAS	53	2.0	OXIDATION CATALYST	BACT
DOSWELL LIMITED PARTNERSHIP		VA	5/4/1990	TURBINE, COMBUSTION	158	2.7	COMBUSTOR DESIGN & OPERATION, GAS	OTHER
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	9/22/1997	TURBINE, COMBUSTION, ABB GT24	224	2.7	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON NOX CON	BACT-PSD
UNION OIL CO. OF CALIFORNIA	KENAI	AK	8/4/1989	TURBINE, SOLAR CENTAUR WEST	550	2.9		BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/6/1997	TURBINE, COMBUSTION, ABB GT11N2	166	3.0	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON NOX CON	BACT-PSD
TAMPA ELECTRIC COMPANY (TEC)	APOLLO BEACH	FL	10/15/1999	TURBINE, COMBUSTION, SIMPLE CYCLE	165	3.0	GOOD COMBUSTION	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION T	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	156	3.1	COMBUSTION CONTROL	BACT-PSD
SEPCO	RIO LINDA	CA	10/5/1994	TURBINE, GAS COMBINED CYCLE GE MODEL 7	115	3.1	OXIDATION CATALYST	BACT
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	7/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	3.5	OXIDATION CATALYST	BACT-OTHER
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSH	NJ	4/1/1991	TURBINES (NATURAL GAS) (2)	149	3.6	TURBINE DESIGN	OTHER
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	3.9	GOOD COMBUSTION PRACTICES	BACT-PSD
NEWARK BAY COGENERATION PARTNERSI	NEWARK	NJ	6/9/1993	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2	77	4.0	TURBINE DESIGN	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	7/31/1996	COMBUSTION TURBINE WITH HEAT RECOVERY BO	153	4.0	OXIDATION CATALYST WHEN FIRING NO. 2 OIL EMISSION LIMIT = 4.4 PPM	LAER
COMMONWEALTH ATLANTIC LTD PARTNER	CHESAPEAKE	VA	3/5/1991	TURBINE, NAT GAS & #2 OIL	192	4.0	COMBUSTION CONTROLS, ANNUAL STACK TESTING	BACT-PSD
OCEAN STATE POWER	BURRILLVILLE	RI	12/13/1988	TURBINE, GAS, GE FRAME 7, 4 EA	132	4.1		BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORI	ARECIBO	PR	7/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE	248	4.3	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT (	BACT-PSD
MOBILE ENERGY LLC	MOBILE	AL	1/5/1999	TURBINE, GAS, COMBINED CYCLE	168	4.7	GOOD COMBUSTION PRACTICE	BACT-PSD
LONG ISLAND LIGHTING CO.		NY	11/1/1986	TURBINE, GE FRAME 7, 3 EA	75	4.7	COMBUSTION CONTROL	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/1/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	5.0	COMBUSTION CONTROLS	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND	PROVIDENCE	RI	4/13/1992	TURBINE, GAS AND DUCT BURNER	170	5.0	NONE	BACT-PSD
PATOWMACK POWER PARTNERS, LIMITED	LEESBURG	VA	9/15/1993	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	146	5.0	GOOD COMBUSTION OPERATING PRACTICES	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORI	ARECIBO	PR	7/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE	248	5.1	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT (	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASS	MOSELL	MS	4/9/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	5.2	GOOD COMBUSTION CONTROLS	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGEN	BEAVER FALLS	NY	11/9/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79	81	5.5	COMBUSTION CONTROLS	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	SIEMENS V64.3 GAS TURBINE (EP #00001)	81	5.5	NO CONTROLS	BACT-OTHER
CROCKETT COGENERATION - C&H SUGAR	CROCKETT	CA	10/5/1993	TURBINE, GAS, GENERAL ELECTRIC MODEL PG72	240	6.0	ENGELHARD OXIDATION CATALYST	BACT-OTHER
MID-GEORGIA COGEN.	KATHLEEN	GA	4/3/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	6.0	COMPLETE COMBUSTION	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PAR	CHESTERFIELD	VA	3/3/1992	TURBINE, COMBUSTION	147	6.0	SCR, STEAM INJECTION	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	11/10/1998	GENERATOR, COMBUSTION TURBINE & DUCT BUR	249	6.2	NATURAL GAS COMBUSTION	BACT-PSD
ANITEC COGEN PLANT	BINGHAMTON	NY	7/7/1993	GE LM5000 COMBINED CYCLE GAS TURBINE EP #0	56	6.2	NO CONTROLS	BACT-OTHER
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	GE FRAME 6 GAS TURBINE	63	6.2	NO CONTROLS	BACT-OTHER
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	2/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	69	6.3	GOOD COMBUSTION CONTROL	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	9/10/1992	GE FRAME 6 GAS TURBINE	62	6.9	NO CONTROLS	BACT-OTHER
FLORIDA POWER CORPORATION POLK CO	BARTOW	FL	2/25/1994	TURBINE, NATURAL GAS (2)	189	7.0	GOOD COMBUSTION PRACTICES	BACT-PSD
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	TURBINE, GE FRAME 7, GAS FIRED	80	7.0	COMBUSTION CONTROL	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	4/15/1988	TURBINE, GE,2 EA	234	7.1		LAER
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	9/6/1989	TURBINE, COMBUSTION, #6 FRAME	62	7.5	COMBUSTION CONTROL	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	3/1/1995	COMBUSTION TURBINE/GENERATOR	246	7.5	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
FULTON COGENERATION ASSOCIATES	FULTON	NY	1/29/1990	TURBINE, GE LM5000, GAS FIRED	63	7.8	COMBUSTION CONTROL	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	8.2	GOOD COMBUSTION	BACT-PSD
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	4/16/1993	GE FRAME 6 GAS TURBINE	53	8.6	NO CONTROLS	BACT-OTHER
SC ELECTRIC AND GAS COMPANY - HAGOO	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	8.9	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	6/5/1991	TURBINE, CG, 4 EACH	400	9.0	COMBUSTION CONTROL	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATIO	LOCKPORT	NY	5/2/1989	TURBINE, GR FRAME 6, 3 EA	52	9.4	COMBUSTION CONTROL	BACT-PSD
LOCKPORT COGEN FACILITY	LOCKPORT	NY	7/14/1993	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	9.4	NO CONTROLS	BACT-OTHER
UNION OIL CO. OF CALIFORNIA	KENAI	AK	8/4/1989	TURBINE, GTM SOLAR SATURN, 4 EA	163	9.9		BACT-PSD
ONEIDA COGENERATION FACILITY	ONEIDA	NY	2/26/1990	TURBINE, GE FRAME 6	52	10.1	COMBUSTION CONTROL	OTHER

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - VOC

WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	5/2/1994	GAS TURBINES	75	11.2	INTERNAL COMBUSTION CONTROLS	BACT
UNION OIL CO. OF CALIFORNIA	KENAI	AK	8/4/1989	TURBINE, ELECT. GENERATOR, 4 EA	138	11.7		BACT-PSD
ALABAMA POWER PLANT BARRY	BUCKS	AL	8/7/1998	TURBINES, COMBUSTION, NATURAL GAS	510	11.7	EFFICIENT COMBUSTION	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	BOILER, CIRCULATING FLUIDIZED COMBUSTION	86	11.8	GOOD COMBUSTION	BACT-PSD
ALABAMA POWER COMPANY - THEODORE	THEODORE	AL	3/16/1999	170 MW TURBINE W/ DUCT BURNER, HR BOILER, S	170	12.5	EFFICIENT COMBUSTION	BACT-PSD
MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	8/5/1989	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	15.6	NO CONTROLS	BACT-OTHER
COMMONWEALTH ATLANTIC LTD PARTNER	CHESAPEAKE	VA	3/5/1991	TURBINE, NAT GAS & #2 OIL	175	16.0	COMBUSTION CONTROL, ANNUAL STACK TESTING	BACT-PSD
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	9/1/1989	TURBINE, GAS FIRED	79	21.8	COMBUSTION CONTROL	OTHER
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	23.4	VOC EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	25.0	GOOD COMBUSTION	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 6,000 Btu/KW-hr
2) Some PPM values were calculated using a conversion factor based on the F-Factor and molecular weight of CH_4: 1 (PPM) = (lb/mmBtu) * 780
lb/mmBtu values were also calculated from lb/hr, lb/yr or ton/yr values
All turbines less than 50 MW and above 100 PPM were removed from this list

Appendix E-1B

RBLC Search Results – Cooling Towers – PM/PM_{10}

RACT/BACT/LAER Clearinghouse Search Results
Cooling Towers - PM/PM10

FACILITY	CITY	STATE	PERMIT	PROCESS	EMISSIONS	UNIT	CTRLDESC	% EFF	BASIS
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	09/04/1992	COOLING TOWER, MECHANICAL DRAFT	0.9	LB/H	DRIFT ELIMINATOR		BACT-PSD
TEXACO REFINING AND MARKETING, INC.	BAKERSFIELD	CA	01/19/1996	COOLING TOWER	1.3	LB/H	CELLULAR TYPE DRIFT ELIMINATOR	75.0	BACT-OTHER
CROWN/VISTA ENERGY PROJECT (CVEP)	WEST DEPTFORD	NJ	10/01/1993	COOLING TOWER (2)	5.9	LB/H	DRIFT ELIMINATOR	0.0	BACT-PSD
FLORIDA POWER CORPORATION	CRYSTAL RIVER	FL	08/30/1990	COOLING TOWER, 4 EACH	0.004	% OF CIRC WAT	DRIFT ELIMINATOR		BACT-PSD

Appendix E-2

Environmental Review Of The Canal Station Redevelopment Project

Excerpt from::

ENVIRONMENTAL REVIEW OF THE
CANAL STATION REDEVELOPMENT PROJECT

Tech Environmental, Inc.

June 20, 2000

The SCONOx system uses a catalyst bed to oxidize NO to NO_2 and absorb the NO_2 onto the surface of the catalyst during the "oxidation/absorption" cycle. The catalyst is divided into a number of sections, each of which is equipped with isolation dampers so that some sections can be regenerated while the plant is operating. A catalyst "regeneration" cycle is required periodically and involves passing hydrogen gas mixed with steam over the catalyst surface, producing nitrogen gas and water vapor. Since hydrogen and nitrogen are present in a high temperature environment, the formation of ammonia during the regeneration cycle is likely, since these conditions are similar to the Haber process of nitrogen fixation used to chemically create ammonia.[8] Neither Goal Line nor AAP have presented any test data to prove that SCONOx does not emit ammonia.

[8] Hiller and Herber, Principles of Chemistry, McGraw-Hill, 1960, p. 246.

Since small amounts of sulfur dioxide (SO_2) will blind (contaminate) the catalyst bed and cause it to stop working, SO_2 must be removed upstream of the SCONOx catalyst, and this is accomplished using the SCOSOx system. SCOSOx uses an oxidation/absorption cycle with a separate catalyst and a regeneration cycle with hydrogen gas just as the SCONOx system does.

The sulfur is not however permanently removed from the exhaust gas, but instead is most often re-emitted downstream of the SCONOx catalyst in the form of hydrogen sulfide (H_2S) and SO_2 according to Goal Line's technical literature.[9] The regeneration chemistry favors H_2S when operating temperatures are below 500° F, and it favors SO_2 when temperatures are highest. H_2S is an exceptionally poisonous gas and is hazardous at low concentrations. If a SCONOx/SCOSOx system were to be used on Unit 2, the 134 tons per year of potential SO_2 emissions from the combustion turbines could convert to 71 tons per year of H_2S if the regeneration cycle did not consistently operate at temperatures above 500° F. Even at high temperatures, some H_2S emissions may occur. Goal Line and AAP have presented no information on H_2S concentrations in the exhaust gas leaving a SCONOx/SCOSOx system.

A recent BACT analysis for a large (350 MW) combustion turbine project in the State[10] documented that SCONOx may impose an energy penalty twice that of SCR on a large power-generating unit, namely a 4 MW penalty for the SCONOx system (equipment electrical use, regeneration gas steam, and performance loss due to pressure drop). Coupled with the fact that the claimed zero-ammonia benefit of SCONOx remains undemonstrated and the likelihood that SCONOx creates another toxic air pollutant, hydrogen sulfide (H_2S), it has not been proven that SCONOx, on balance, offers environmental and energy benefits over SCR.

SCONOx is installed on only two turbine facilities at present: a single 30 MW gas turbine in Vernon, California owned and operated by a partner in the SCONOx technology and a 5 MW gas turbine at the Genetics Institute (G.I.). Only the Genetics Institute plant is providing independent information on how SCONOx is performing on a commercial turbine application.

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[9] MacDoonald, R. and Debbage, L., "The SCONOx Catalytic Absorption System for Natural Gas Fired Power Plants," presented at Power-Gen International '97 Dallas, TX, December, 1997, page 8.

[10] Cabot LNG Corporation, "Supplemental BACT Analysis on SCONOx for the Island End Cogeneration Plant," DEP Application MBR-97-COM-014, January 25, 2000.

And, given the overly optimistic information Goal Line has disseminated over the past year about the performance and commercial availability of SCONOx, we believe the Genetics Institute test data provide the best source of reliable information on how well SCONOx performs.

At the Northeast Energy and Commerce Association (NECA) meeting that was held on May 16-17, 2000 in Boxboro, the Manager for Environmental Engineering and Compliance at the Genetics Institute, Mr. Robert McGinnis, gave a presentation on how SCONOx is working at his facility. Although it has been nine months since SCONOx was installed and this is the simplest commercial application for SCONOx (a small combustion turbine), there are still unresolved problems with the SCONOx system, and it is not consistently meeting the NO_x emissions limits promised by Goal Line and written into the facility's permit. In addition, we note that no SCONOx system has ever been built or installed for large (100 MW) turbines.

During the NECA conference, G.I. gave conference attendees a tour of the plant. At the time, the turbine was burning natural gas and the SCONOx system was emitting 9 ppm of NO_x, or 360% of the 2.5 ppm permit limit. Mr. McGinnis has since determined that the turbine combustors were not properly tuned and the inlet concentration of NO_x to the SCONOx system was about 50% higher than it was designed for. This incident has, however, revealed that the SCONOx system does not consistently achieve the 90% NO_x removal rates demonstrated in practice by SCR systems. Mr. McGinnis notes that when the inlet concentration to SCONOx is 20 ppm of NO_x, the outlet concentration is about 2 ppm (90% removal). However, higher inlet concentrations cause a substantial degradation in SCONOx performance. When fired with distillate oil, the turbine emits about 50 ppm, and SCONOx, thus far, emits 20 ppm of NO_x, only a 60% removal rate. So far, the SCONOx system has been exceeding the ultimate 15 ppm NO_x limit for oil-firing in the DEP permit.

If the turbine was not running twice as clean as the manufacturer's guarantee (only 50 ppm of NO_x versus the guaranteed emissions of 96 ppm), NO_x emissions from the SCONOx system would be even higher. This same situation carries over to gas-fired operation. Mr. McGinnis notes that here again the turbine is generally cleaner than expected, emitting only 17 ppm of NO_x versus 25 ppm guaranteed and helping to lower the NO_x emitted by SCONOx.

In the past year, the SCONOx unit at G.I. has had a recurring problem with leaking dampers. Goal Line has redesigned the dampers three times. Goal Line has also been washing the catalyst blocks (there are 45 separate modules in the system for this single 5 MW turbine) every 2 to 2-1/2 months, which is more frequently than G.I. expected. Washing involves catalyst block removal, soaking in a potassium carbonate solution, and reinstallation of each block. Not only does catalyst washing involve substantial costs in terms of labor and wastewater disposal, during this maintenance period the turbine unit has to be shutdown. Availability of the turbine unit has been as low as 75% during some months according to G.I. The loss of electrical generation for unscheduled maintenance (e.g., to wash catalysts in order to stay within permit limits) greatly concerns G.I. and raises questions about the commercial reliability of SCONOx for much larger turbines in electric generating stations. Mr. McGinnis summed up the situation by stating that after nine months of experimentation, it is not clear if SCONOx will really work as promised over the long term.

One of the first steps of a BACT analysis, is to determine if a control technology option is "technically feasible." According to U.S. EPA guidance,[11] to be technically feasible a control technology must have been commercially demonstrated, i.e., installed and operated successfully on a source similar to the one under review. As discussed above, SCONOx has not been installed and operated on any large (100+ MW) turbine project similar to the Canal Redevelopment Project, and in the only independent commercial installation to date (a small 5 MW turbine), it has not yet been successful in consistently meeting permit limits. Thus, it is concluded that SCONOx is not technically feasible for the repowering of Unit 2 at Canal Station.

In summary, while SCONOx is a promising new technology being developed for commercial use, it is not the Best Available Control Technology for the repowering of Canal Unit 2 because:

[11] U.S. EPA, "New Source Review Workshop Manual," Research Triangle Park, NC, 1990.

(1) The only independent commercial application of SCONOx on a combustion turbine has not consistently met its ultimate permit emission limits,

(2) The only independent commercial application of SCONOx on a combustion turbine has not demonstrated a level of reliability, availability and performance equal to that of SCR,

(3) SCONOx has never been built for, installed and operated on a large (100+ MW) turbine unit,

(4) SCONOx is not technically feasible for the Project by EPA guidelines,

(5) It has not been proven that SCONOx, on balance, offers environmental and energy benefits over SCR.

Appendix E-3

- **Engelhard – Budgetary Proposal for CO Catalyst**
- **SCR Cost Information**
- **SCONO$_x$ Cost Information**

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com

DATE: August 2, 2000		NO. PAGES	3
TO:	TRC ENVIRONMENTAL ATTN: Dave Shotts	via e-mail	
ATTN:	ENGELHARD Nancy Ellison		
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841	

RE: GE 7FA Combined Cycle Project
CO Catalyst - Engelhard Budgetary Proposal EPB00893

We provide Engelhard Budgetary Proposal EPB00893 for One (1) Engelhard **Camet**® CO Catalyst system for the above project. This is per e-mail request on August 1, 2000.

Catalyst selection and pricing are based on:

- Given Data for Siemens V84.2 combustion turbine;
- CO reductionfrom noted inlet levels to 2 ppmvd @ 15% O_2 (NG) and 4 ppmvd @ 15% O_2 (Oil);
- Three (3) year Performance Guarantee - expected life 5 – 7 years;
- Meet assumed HRSG inside liner dimensions of 67 ft H x 26 ft W;
- Scope: Normal to HRSG supplier - Catalyst modules with internal frame and tongue seals with interface engineering only.
- By others: Duct / catalyst housing (including any transitions), internal insulation, grooved internal liner sheets, and frame supports and bottom pedestals are provided by others, along with catalyst loading door, personnel manway and sample ports.

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

TRC
CO Oxidation Catalyst – GE 7FA Combined Cycle
Engelhard Budgetary Proposal EPB00893
August 2, 2000

ENGELHARD CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEM

Engelhard Corporation, ("Engelhard"), offers to supply the **CAMET®** metal substrate catalytic oxidation system ("CO System") based upon Buyer's technical data and site conditions provided.

DELIVERABLES: Equipment and services consisting of:

1. Catalyst modules;
2. Removable and replaceable sample catalysts;
3. Internal support frame and internal tongue seals;
4. Drawings showing installation details, loadings, and support requirements;
5. Installation and operating manuals;
6. Technical service for inspection of equipment installation performed by others - Five (5) days total and two (2) trips are provided.

BUDGET PRICE: Per Unit Delivery: FOB, plant gate, job site

CO System	**$ 560,000 – Per Turbine**
Replacement CO Catalyst Modules	**$ 480,000 – Per Turbine**

SPENT CATALYST

Engelhard agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is not a hazardous material. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Twelve (12) months from date of start up or eighteen (18) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.
Expected Life:	Five – Seven Years

DOCUMENT / MATERIAL DELIVERY SCHEDULE

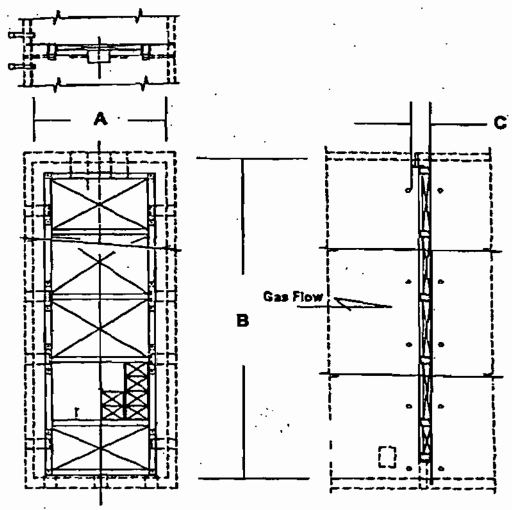
Drawings for Approval	3 – 4 weeks after notice to proceed with complete engineering specifications and Engelhard receipt of all engineering details.
Frame and Seals	16 weeks after release
Catalyst Modules	20 - 24 weeks after release

CO SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7FA Combustion Turbine
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Gas Velocities must be within $\pm$25% of the mean velocity at the catalyst face
Temperature (At catalyst face):	All Gas Temperatures must be within $\pm 20^{\circ}F$ of given average temperatures at all points at the catalyst face
CO Concentration (At catalyst face):	See Performance Data
CO Outlet:	To 2 ppmvd @ 15% O_2 (NG) / 4 ppmvd @ 15% O_2 (NG)

ENGELHARD

TRC
CO Oxidation Catalyst – GE 7FA Combined Cycle
Engelhard Budgetary Proposal EPB00893
August 2, 2000



CATALYST MODULES

The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Two of the modules are provided with four (4) replaceable test buttons; eight (8) total buttons provided.

INTERNAL SUPPORT FRAME & SEALS

The internal support frame and internal tongue seals are fabricated from standard structural steel members and shapes. Mechanical tongue and groove expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and liner sheet grooves, both designed by Engelhard.

Dimensions:

Inside Liner Width	(A)	26 ft
Inside Liner Height	(B)	67 ft
Catalyst + frame depth	(C)	18" est.

Table A - Performance Data

Refer to separate attachment – file TRC-GE7FA-DATA-080200-ENGELHARD-CO-0.xls

From: Howard Hurwitz [hhurwitz@roe.com]
Sent: Tuesday, July 25, 2000 8:46 AM
To: llabrie@trccos.com
Cc: sfinnerty@cpowerventures.com; Nabil Keddis
Subject: SCR cost information

Larry: Information from Engelhard Corporation, supplier of SCR catalyst for combustion turbine applications, is as follows

Scope of Supply
Internal catalyst support frames - installed inside internally insulated casing (by others)
NOxCat SCR catalyst modules
Ammonia Delivery System including AIG, manifold with flow control valves, air dilution skid, controls, etc.

Excluding
Ammonia Storage Tank
HRSG Casing
Field piping
Foundations
Utilities

Cost Information

SCR System Described Above - $950,000
Ammonia Storage Tank - $110,000

Replacement Catalyst (3 year life guarantee) - $520,000

Please let me know if this is sufficient information.

Howard Hurwitz
Burns and Roe Enterprises
(201) 986-4311

From: Nabil Keddis [nkeddis@roe.com]
Sent: Wednesday, July 26, 2000 9:29 AM
To: llabrie@trccos.com
Cc: Sfinnrty@cpowerventures.com
Subject: CPV- Gule Coast Project; Cost Estimate for Sconox Equipment

Lari:

The following information was verbally provided by ABB, as a cost estimate basis for the SCONOx equipment (manufactured by Goalline), based on the following parameters:

a) Natural Gas firing

Emission: NOx

Current: 9.0 ppmvd, 61.00 lb/hr

Required: 3.0 ppmvd, 20.00 lb/hr

Estimated Cost: $ 14,000,000.00

b) Oil Firing (with water injection)

Emission: NOx

Current: 42.0 ppmvd, 341.00 lb/hr

Required: 10.0 ppmvd, 81.00 lb/hr

Estimated Cost: $ 16,000,000.00

The delivery schedule for the equipment is: 8 - 10 months.

The estimated cost of installation is: $ 1,500,000.00

Duration for installation is approximately 60 (sixty) days.

As soon as I receive ABB quotation I'll forward a copy to you and Sean.

Appendix E-4

- **Table E-1 – CPV Cana CO Catalyst**
- **Table E-2 – CPV Cana SCR to Achieve 2.5 ppm NO_x**
- **Table E-3 – CPV Cana SCONOX to Achieve 2.5 ppm NO_x**

Table E-1. CANA
CO Catalyst

COST COMPONENT	COST
DIRECT COSTS	
Purchased Equipment Costs	
CO System (equipment cost based on Engelhard budgetary quote)	$560,000
Sales Tax (6.5% of equipment costs)	$36,400
Freight (4% of equipment costs)	$28,000
Purchased Equipment Costs (PEC)	$624,400
Direct Installation Costs	
Foundation, handling, electrical, piping, insulation, and painting (35% of PEC)	$196,000
Direct Installation Costs	$196,000
TOTAL DIRECT COSTS (TDC)	$820,400
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	$31,220
Contingency (3% of PEC)	$18,732
Construction, Contractor, Startup, Testing (included in installation cost)	0
TOTAL INDIRECT COSTS	$49,952
TOTAL CAPITAL INVESTMENT (TCI)	$870,352
DIRECT ANNUAL COSTS	
100% Capacity factor	
8,760 Equivalent Operating Hours per Year (per CTG)	
720 Oil-Fired operating hours/year	
Maintenance Materials and Labor (2% of TCI)	$17,407
Annualized Catalyst Replacement Cost	$182,905
$ 480,000 Replacement Cost	
3 years catalyst life	
7.00% Interest Rate	
0.381 Capital Recovery Factor	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)	$38,127
1.41E+09 Annual CTG output, kW-hr (based on 8760 hours)	
9 Btu/kW-hr heat rate penalty	
12,709 MMBtu/yr natural gas	
3.00 $/MMBtu natural gas	
Catalyst Disposal	$16,667
$ 50,000 at the end of catalyst guaranteed life	
TOTAL DIRECT ANNUAL COSTS	$255,106
INDIRECT ANNUAL COSTS	
Overhead (60% of labor and maintenance materials)	$10,444
Property Tax (1% of TCI)	$8,704
Insurance (1% of TCI)	$8,704
Administration (2% of TCI)	$17,407
TOTAL INDIRECT ANNUAL COSTS	$45,258
TOTAL ANNUAL COSTS	$300,364
CAPITAL RECOVERY FACTOR, CFR = $[i \times (1+i)^n]/[(1+i)^n - 1]$	
10 Equipment Life (years)	
7% Interest Rate	
Capital Recovery Factor	0.1424
CAPITAL RECOVERY COSTS	
TOTAL CAPITAL REQUIREMENT	$870,352
CATALYST REPLACEMENT COST	-$480,000
TOTAL CAPITAL REQUIREMENT MINUS CATALYST REPLACEMENT COST	$390,352
TOTAL ANNUALIZED CAPITAL REQUIREMENT	$55,577
TOTAL ANNUALIZED COST **(Total annual O&M cost and annualized capital cost)**	$355,941
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	156.0
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6040 hr/yr (no power augmentation)/ 15 ppm on gas for 2000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	
TONS OF CO REMOVED PER YEAR	124.8
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS **($ per ton of CO removed)**	2,852

Table E-2 Response to Comments: CPV Cana SCR to achieve 2.5 ppm NOx	
COST COMPONENT	**COST**
DIRECT COSTS	
Purchased Equipment Costs	
SCR Catalyst System (equipment cost)	1,187,500
Sales Tax (6.5% of equipment costs)	77,188
Freight (4% of equipment costs)	47,500
Purchased Equipment Costs (PEC)	1,312,188
TOTAL DIRECT COSTS (TDC)	1,312,188
INDIRECT COSTS	
Engineering Costs (5% of PEC)	65,609
Contingency (3% of PEC)	39,366
Construction, Contractor, Startup, Testing (18% of PEC)	236,194
TOTAL CAPITAL INVESTMENT (TCI)	**1,653,356**
DIRECT ANNUAL COSTS	
Maintenance Materials and Labor (2% of TCI)	33,067
Ammonia Cost	29,151
Incremental Electrical Cost	
Catalyst Pressure Derate	216,810
1.5 inch H2O pressure drop	
275 kw/inch H2Opressure drop	
100% capcity factor	
0.06 $/kW-hr	
Deminimus Water Injection During Fuel Oil Firing	
Catalyst Replacment (based on total SCR catalyst replacement cost every 3 years)	297,220
Catalyst Disposal (Amortized Over 3 Year Period)	14,289
TOTAL ANNUAL DIRECT COSTS	590,538
INDIRECT ANNUAL COSTS	
Overhead (60% of maintenance materials and labor)	19,840
Property Tax (1% of TCI)	16,534
Insurance (1% of TCI)	16,534
Administration (2% of TCI)	33,067
TOTAL INDIRECT ANNUAL COSTS	85,975
TOTAL ANNUAL INVESTMENT	**676,513**
CAPITAL RECOVERY FACTOR, CFR = $[i \times (1+i)^n]/[(1+i)^n - 1]$	
10 Equipment Life (years)	
7% Interest Rate	
Capital Recovery Factor	0.1424
CAPITAL RECOVERY COSTS	
TOTAL CAPITAL REQUIREMENT	**1,653,356**
TOTAL ANNUAL CAPITAL REQUIREMENT	**235,401**
TOTAL ANNUALIZED COST **(Total annual O&M cost and annualized capital cost)**	**911,913**
BASELINE POTENTIAL NOx EMISSIONS (TPY) FROM TURBINE (emissions based on 100% load at 72°F, 6,040 hrs no PA, 2,000 hr w/PA, 720 hr oil)	
Uncontrolled	**358.0**
Controlled	**89.5**
Annual Tons of NOx Removed	**268.5**
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS **($ per ton of NOx removed)**	**3,396**

Table E-3. CPV CANA
SCONOX to achieve 2.5 ppm NOx

COST COMPONENT		COST
DIRECT COSTS		
Purchased Equipment Costs		
SCONOX System		16,000,000
Sales Tax (6.5% of equipment costs)		1,040,000
Freight (4% of equipment costs)		640,000
Subtotal-Purchased Equipment Costs (PEC)		17,680,000
Direct Installation Costs		
Construction		1,700,000
TOTAL DIRECT COSTS (TDC)		19,380,000
INDIRECT INSTALLATION COSTS		
Engineering Costs (5% of PEC)		884,000
Contingency (3% of PEC)		530,400
Construction, Contractor, Startup, Testing (18% of PEC)		3,182,400
TOTAL CAPITAL INVESTMENT (TCI)		**23,446,400**
DIRECT ANNUAL COSTS		
Maintenance Materials and Labor		331,400
Regeneration Natural Gas and Steam		406,400
Catalyst Pressure Derate		129,360
Catalyst Replacment		190,000
TOTAL ANNUAL DIRECT COSTS		1,057,160
INDIRECT ANNUAL COSTS		
Overhead (60% of maintenance materials and labor)		198,840
Property Tax (1% of TCI)		234,464
Insurance (1% of TCI)		234,464
Administration (2% of TCI)		468,928
TOTAL INDIRECT ANNUAL COSTS		1,136,696
TOTAL ANNUAL INVESTMENT		**2,193,856**
CAPITAL RECOVERY FACTOR, CFR = $[i \times (1+i)^n]/[(1+i)^n - 1]$		
10 Equipment Life		
7% Interest Rate		
Capital Recovery Factor		0.1424
CAPITAL RECOVERY COSTS		
TOTAL CAPITAL REQUIREMENT		**23,446,400**
TOTAL ANNUAL CAPITAL REQUIREMENT		**3,338,240**
TOTAL ANNUALIZED COST **(Total annual O&M cost and annualized capital cost)**		**5,532,096**
BASELINE POTENTIAL NO_x EMISSIONS (TPY) FROM TURBINE		
Emissions based on 100% load at 72°F, 6040 hrs no PA, 2000 hrs w/PA, 720 hr:	**Uncontrolled**	**358**
	Controlled	**90**
ANNUAL TONS OF NOx REMOVED		***269***
COST-EFFECTIVENESS		
ENVIRONMENTAL BASIS		
(\$ per ton of NO_x removed)		**20,604**

February 17, 2004

RECEIVED
FEB 19 2004
BUREAU OF AIR REGULATION

Mr. Al Linero
Florida Department of Environmental Protection
Division of Air Resource Management
2600 Blair Stone Road MS 5500
Tallahassee, Florida 32399-2400

RE: CPV Cana, Ltd.
Air Construction Permit 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

Competitive Power Ventures, Inc. ("CPV") has obtained air permit 1110103-001-AC (PSD-FL-323) for its proposed CPV Cana, Ltd. ("CPV Cana") project. Per our discussion last week, I am writing to inform you that CPV has determined that it will no longer pursue development of the CPV Cana project. Please remove the site from the Division of Air Resources data bases.

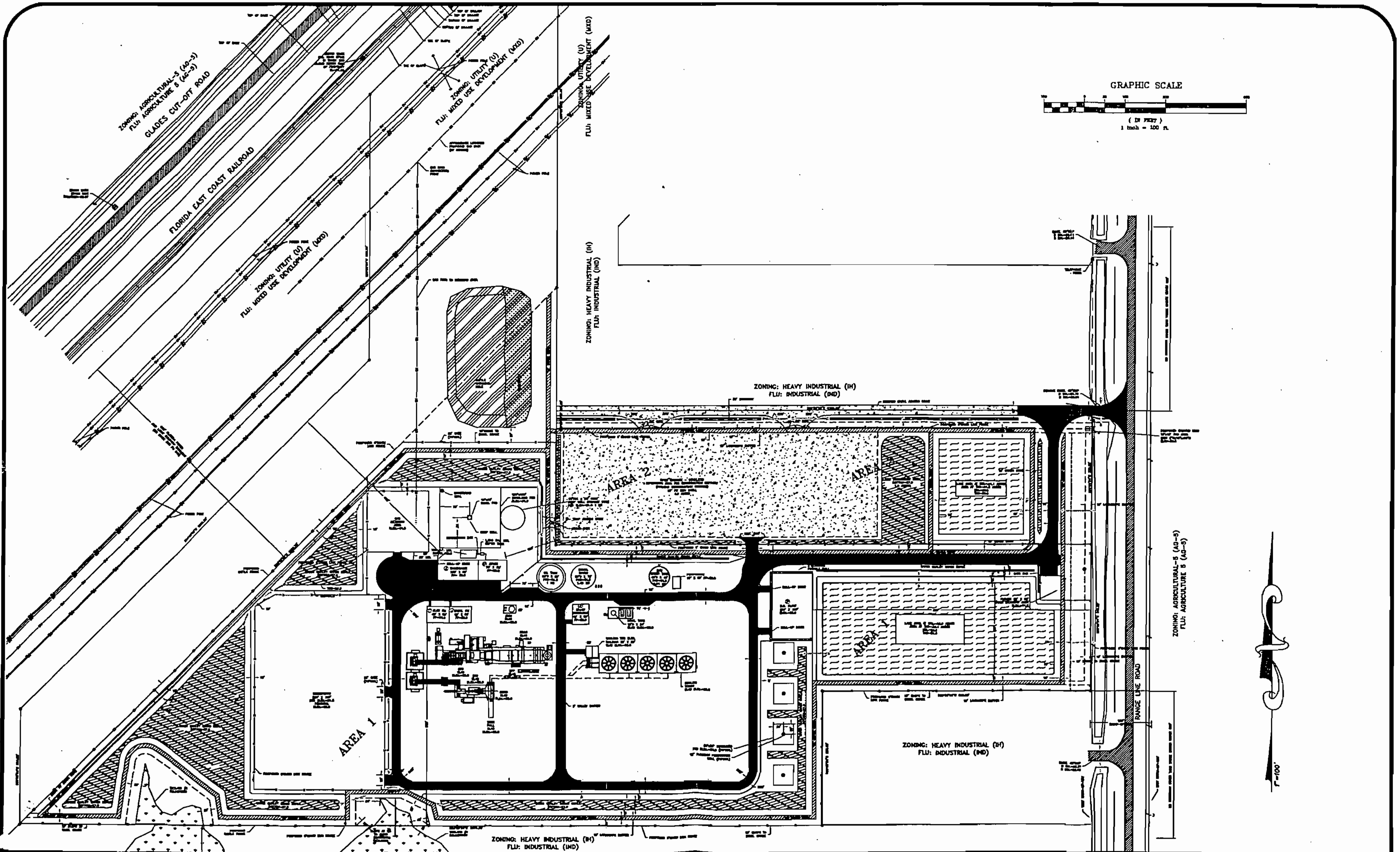
If you require any additional information, please feel free to contact me at (781) 848-0253.

Sincerely,

Patricia A. DiOrio
Director
Competitive Power Ventures, Inc.

cc: Cathy M. Sellers, Moyle Flanigan
Gary A. Lambert, Jr, CPV
Peter J. Podurgiel, CPV

CPV
COMPETITIVE POWER VENTURES, INC.
35 BRAINTREE HILL OFFICE PARK
SUITE 107
BRAINTREE, MA 02184
T/ 781 848-0253
F/ 781 848-5804
W/ WWW.CPV.COM



105534HA.dwg 7-31-01 10:41:38 am EST

REVISIONS		
COUNTY COMMENTS		7/20/01
DESIGN SMC	DATE 4/12/01	
DRAWN BAW	DATE 4/12/01	

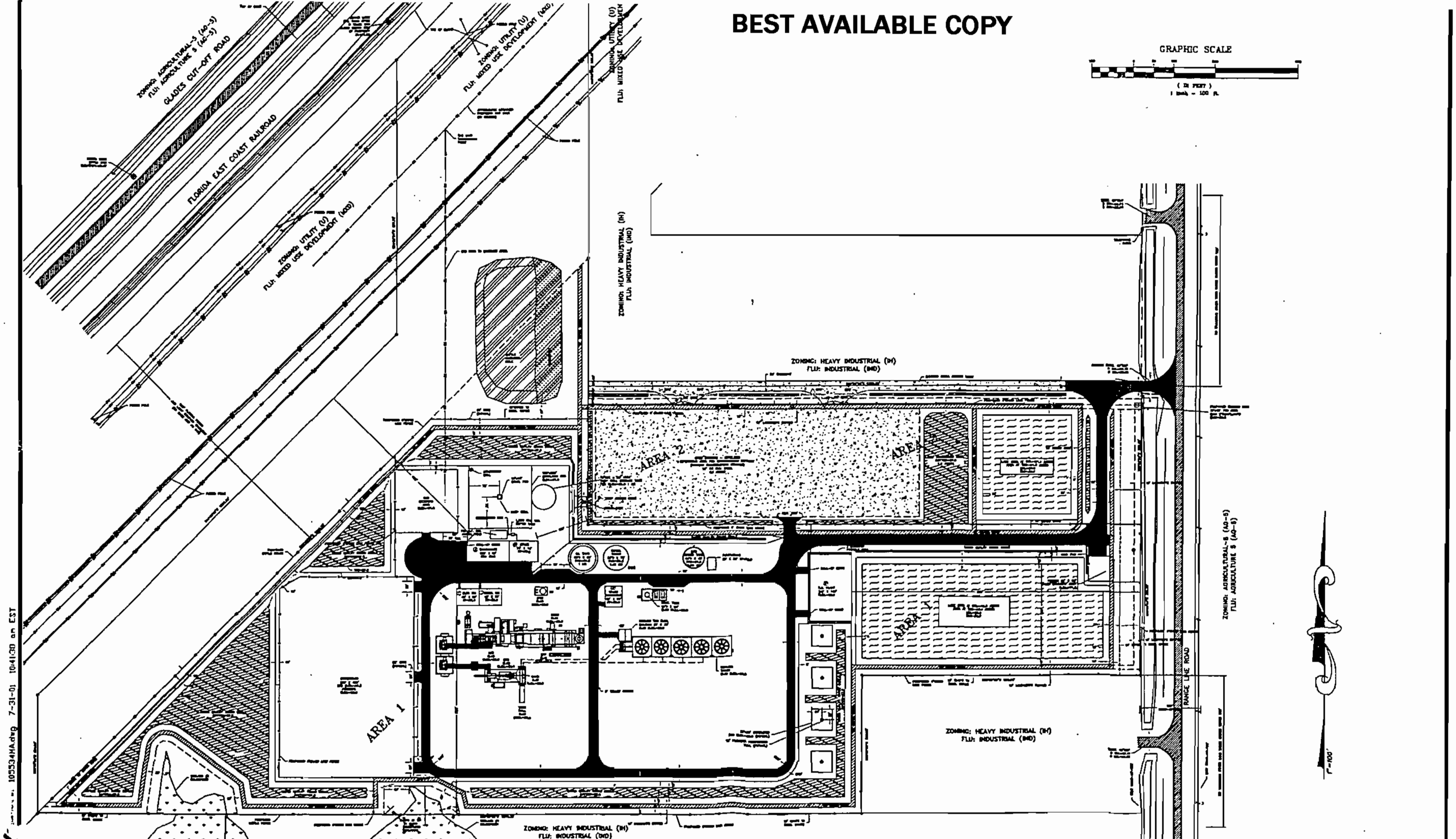
CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

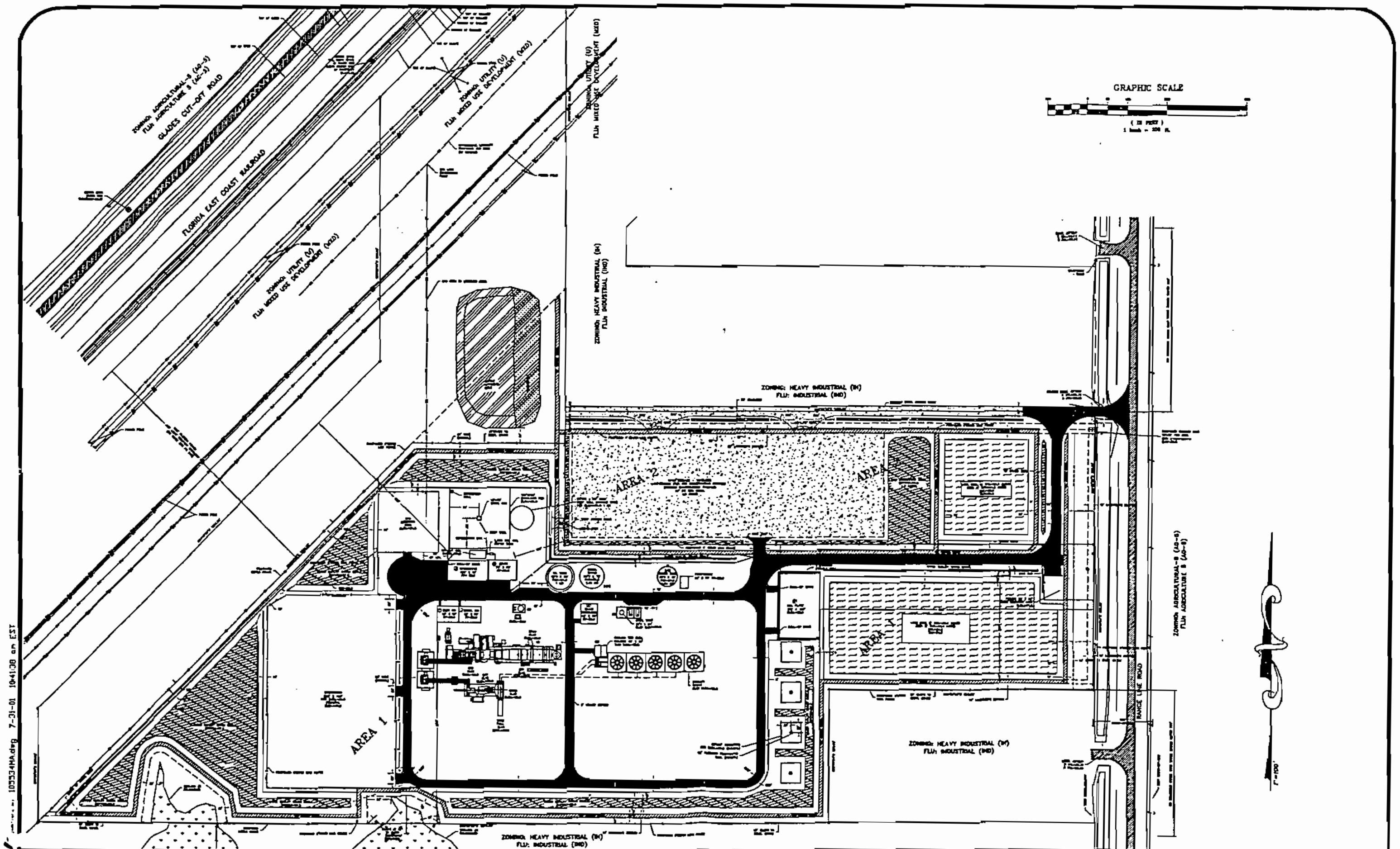
OVERALL SITE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

DRAWING NO. 10553402
SHEET 2 OF 30
PROJECT NO. 10553

BEST AVAILABLE COPY



CPV CANA, LTD.	B.S.E. CONSULTANTS, INC. CONSULTING, ENGINEERING, LAND SURVEYING 312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674	OVERALL SITE PLAN AREA 1–BASIN 1, AREA 2–BASIN 2	SHEET 2 OF 30 PROJECT NO. 10553



CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL SITE PLAN
AREA 1–BASIN 1, AREA 2–BASIN 2

10553402
SHEET 2 OF 30
10553

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)* S. LeBlanc

B. Date of Delivery 10/9/

C. Signature

X S. LeBlanc

☐ Agent
☐ Addressee

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

BRAINTREE, MA
OCT 09 2001
USPS

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

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

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 2669

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

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

7000 2870 0000 7028 2669

OFFICIAL USE

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

Postmark Here

Sent To
Gary Lambert
Street, Apt. No.; or PO Box No.
35 Braintree Hill Office Park, 107
City, State, ZIP+4
Braintree, MA 02184

PS Form 3800, May 2000 See Reverse for Instructions

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1. Article Addressed to:

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

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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

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Robert E. Minsky
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121 SW Port St. Lucie Blvd.
City, State, ZIP+ 4
Port St. Lucie, FL 34984-5099

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Gary Lambert
Street, Apt. No.; or PO Box No.
35 Braintree Hill Offc. Park, Ste. 107
City, State, ZIP+ 4
Braintree, MA 02184

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1 Article Addressed to:

Mr. Gary Lambert, Manager
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

C. Signature
X S LeBlanc ☐ Agent ☐ Addressee

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BUREAU OF AIR REGULATION

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

7001 0320 0001 3692 8574

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The Honorable Robert E. Minsky

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City, State, ZIP+4 Port St. Lucie, FL 34984-5099

PS Form 3800, January 2001 See Reverse for Instructions

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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

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B. Date of Delivery 1/22/02

C. Signature
X Karen Phillips

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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BUREAU OF AIR REGULATION

Dept. of Environmental Protection
Division of Air Resources Mgt.
Bureau of Air Regulation, NSR
2600 Blair Stone Rd., MS 5505
Tallahassee, FL 32399-2400

SENDER: *COMPLETE THIS SECTION*

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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 J 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

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PS Form 3800, January 2001 See Reverse for Instructions

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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

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B. Date of Delivery 1-22-02

C. Signature
X Lora H. McComas ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
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2. Article Number *(Copy from service label)* 7001 0320 0001 3692 8567

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

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Mr. Doug Coward, Chair OFFICIAL USE

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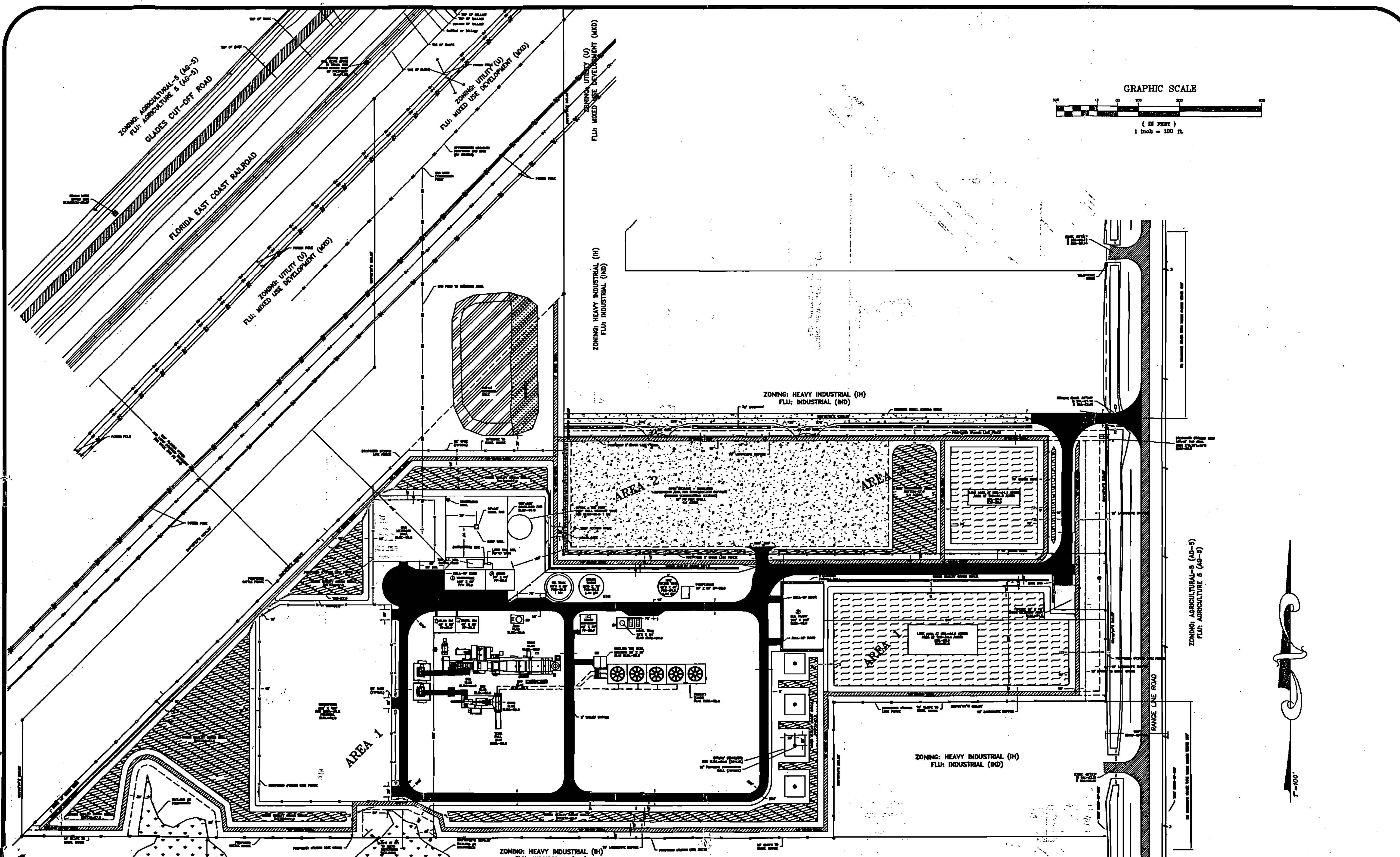
Street, Apt. No.; or PO Box No.
City, State, ZIP+4 ~~2300 Virginia Ave.~~ Ft. Pierce, FL 34982

PS Form 3800, January 2001 See Reverse for Instructions



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REVISIONS		
3	COUNTY COMMENTS	7/20/01
2	ENGINEER/CLIENT COMMENTS	6/08/01
DESIGN SMG	DATE	4/12/01
DRAWN BAW	DATE	4/12/01
CHECKED	DATE	

CPV CANA, LTD.

B.S.E. CONSULTANTS, INC.
CONSULTING, ENGINEERING, LAND SURVEYING
312 S. Harbor City Blvd. Suite 4, Melbourne, Florida (321) 725-3674

OVERALL SITE PLAN
AREA 1-BASIN 1, AREA 2-BASIN 2

DRAWING NO. 10553402
SHEET 2 OF 30
PROJECT NO. 10553

Competitive
Power Ventures, Inc.

VIA TELEFAX AND OVERNIGHT COURIER

January 2, 2002

RECEIVED
JAN 03 2002
BUREAU OF AIR REGULATION

Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Comments on CPV Cana Electric Generating Facility Draft PSD Permit, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

Pursuant to the Public Notice of Intent for the above-referenced matter, the permit applicant, CPV Cana, Ltd., submits the attached comments on the draft Prevention of Significant Deterioration (PSD) permit for the CPV Cana Power Generating Facility.

As we recently discussed with you, CPV Cana currently is in the process of working with turbine manufacturer General Electric and others to address the complex startup and shutdown emissions issues raised in the draft PSD Permit condition concerning Excess Emissions, Best Operational Standard (No Bypass), which is Condition No. 29c., as renumbered pursuant to attached comment letter, and the corresponding information, for inclusion on page BD-19 of the BACT Determination document. Due to the complexity and newness of the excess emissions Best Operational Standard issue, CPV Cana still is obtaining from its turbine manufacturers and others information that CPV Cana needs in order to prepare and submit its comments on this issue. Accordingly, CPV Cana respectfully requests the Bureau of Air Regulation to extend the 30-day period in which CPV Cana may submit comments, by 14 days, so that CPV Cana will submit its comments on the excess emissions Best Operational Standard issue to the Bureau of Air Regulation by the close of business on January 17, 2002.

The Bureau of Air Regulation determined CPV Cana's PSD permit application to be complete on October 25, 2001. Under Section 403.0876, Florida Statutes, and Section 120.60, Florida Statutes, the 90-day period in which the Department must issue (or deny) CPV Cana's permit will expire on January 23, 2002. CPV Cana hereby waives the 90-day timeframe in which the Department must issue (or deny) the permit until January 28, 2002, to afford CPV Cana and the Department sufficient time in which to resolve the excess emissions issue and any other outstanding issues. Under this waiver, the Department has until end of business on January 28, 2002, in which to issue (or deny) CPV Cana's PSD permit.

We appreciate the opportunity to work with you on this matter, and please call me if you have any questions or wish to discuss any issues concerning the CPV Cana PSD permit.

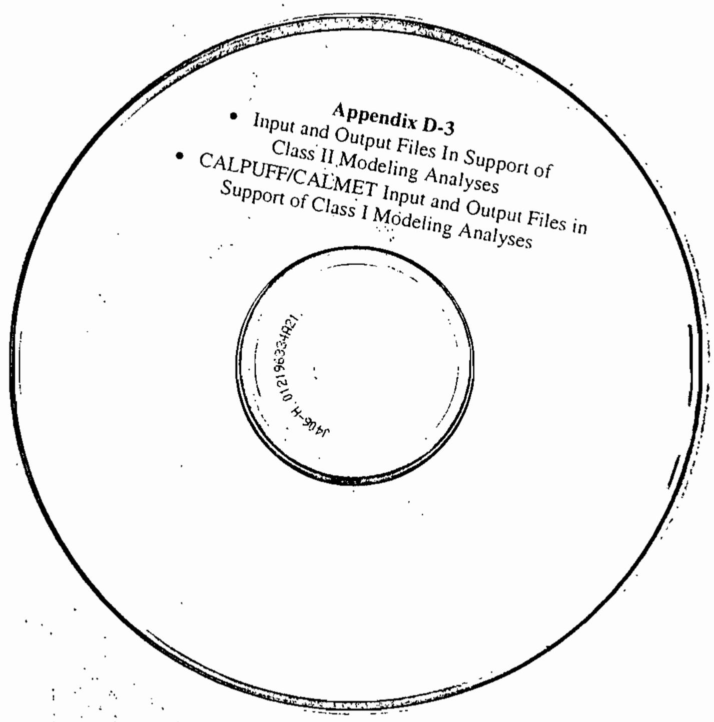
Sincerely,

Peter

Peter J. Podurgiel
CPV Cana, Ltd.

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Theresa Herron, FDEP

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804


Appendix D-3
• Input and Output Files In Support of Class II Modeling Analyses
• CALPUFF/CALMET Input and Output Files in Support of Class I Modeling Analyses

Competitive
Power Ventures, Inc.

January 2, 2002

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Comments on Draft PSD Permit for CPV Cana, Ltd. Power Generating Facility, DEP File No. 1110103-001-AC (PSD-FL-323)

Dear Mr. Linero:

Pursuant to the Public Notice of Intent for the above-referenced matter, the permit applicant, CPV Cana, Ltd., submits the following comments on the draft Prevention of Significant Deterioration ("PSD") permit, Technical Evaluation and Preliminary Determination, and BACT Determination for the CPV Cana Power Generating Facility.

I. Comments on Draft Permit

1. On page 1 of 20 in the permit file information box; on 4 of 20 in General and Administrative Requirements, Condition No. 9; and on page 5 of 20, Condition No. 11, the permit expiration date is December 31, 2004. Given that construction of the facility will take between twenty-four (24) and twenty-seven (27) months to complete and also given that construction cannot commence at this time because other permits are still being obtained, CPV Cana is concerned that the December 31, 2004 permit expiration date will not provide sufficient time to complete construction and testing of the facility. Therefore, CPV Cana requests that the permit expiration date be revised to December 31, 2005.

2. On page 2 of 20, in the Facility Description, third bullet point, the word "million" should be deleted, to accurately reflect the 975,000 gallon storage tank capacity.

3. On page 2 of 20, in the Emissions Units table, for Emissions Unit No. 004, the emission unit description should be revised to insert the word "fire" between "hp" and "water," so that the revision reads as follows: "One diesel-fired 250 hp fire water pump, one 500 kW emergency generator, and an aqueous ammonia storage tank." Similarly, the end of the last bullet under the preceding Facility Description heading should be revised to read: "...one diesel-fired 250 hp fire water pump, and a 500 kW emergency generator."

4. On page 2 of 20, in the Regulatory Classification section, in the paragraph entitled "PSD," at the beginning of the fifth (5th) line of that paragraph, the word "modification" should be deleted, since this is a permit for a new facility, rather than a modification of an existing facility.

5. On page 3 of 20, in the Permit Schedule section, second bullet point, the Notice of Intent for the permit was published in The Tribune on December 3, 2001.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804

6. In connection with Comment No. 1 above, regarding revision of the permit expiration date, on page 4 of 20, on page 4 of 20, General and Administrative Requirements, Condition No. 9, the construction deadline in that condition should be revised to February 28, 2005 to provide a sufficient timeframe in which to complete construction of the facility.

7. On page 8 of 20, in the Applicable Standards and Regulations, Condition No. 3.a., concerning Emissions Unit 001, the clause "power generation facilities consisting of three simple cycle combustion turbines with a nominal generating capacity of 170 MW each" immediately before the parenthetical regarding Subpart GG of 40 CFR 60, should be deleted as unnecessary, since CPV Cana is a combined cycle facility consisting of one combustion turbine and one steam turbine.

8. On page 8 of 20, in the Applicable Standards and Regulations, Condition No. 3.d., concerning Emissions Unit 004, in the first bullet point concerning Ancillary Equipment, the term "500 MW" should be changed to "500 kW" to accurately reflect the capacity of the CPV Cana facility's emergency generator.

9. On page 9 of 20, in the Applicable Standards and Regulations, Condition No. 3.d., concerning Emissions Unit 004, in the last bullet point concerning One Exhaust Stack, the sentence "A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emission Modes 5, 5Q, and 6Q." should be deleted since the bypass stack option is not an appropriate operating mode for the CPV Cana facility, and the facility will not be operated in this mode.

10. On page 9 of 20, in General Operating Requirements, Condition No. 6, the maximum heat input to the combustion turbine when firing oil should be revised from 1900 mmBtu/hr to 1898 mmBtu/hr. to accurately reflect the information provided in the permit application.

11. On page 12 of 20, Condition No. 15, the reference to Condition No. 4 should be changed to Condition No. 5 and the reference to Condition No. 26 should be changed to Condition No. 27, to correctly cross-reference the permit conditions that address fuel types and fuel sulfur limits.

12. Similarly, on page 12 of 20, Condition No. 16, the reference to Condition No. 4 should be changed to Condition No. 5 and the reference to Condition No. 26 should be changed to Condition No. 27, to correctly cross-reference the permit conditions that address fuel types and fuel sulfur limits.

13. On page 14 of 20, in the middle of Condition No. 23, there is a spacing typographical error. The topic under the heading "<u>Compliance with the CO/NOx Emissions Limits</u>" should be made into a separate new Condition No. 24. In connection with this revision, the references in new Condition No. 24 to Conditions No. 17, 21, and 29 should be changed to Conditions No. 18, 22, and 30, respectively.

14. Beginning with new Condition No. 24, the Conditions throughout the rest of the permit should be renumbered.

15. On page 14 of 20, in new Condition No. 25, the references to Conditions No. 17 and 20 should be changed to Conditions No. 18 and 21, respectively.

16. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section b., concerning the Best Operational Standard (Bypass Stack Option) should be deleted from the permit, since the bypass stack option is not an appropriate operating mode for the CPV Cana facility, and the facility will not be operated in this mode.

17. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section c., concerning the Best Operational Standard (No Bypass), [FILL IN INFORMATION RE: OPERATION DURING STARTUP]

18. On page 15 of 20, in Condition No. 29 (per renumbering of Conditions), section e., the reference to Condition 20 should be changed to Condition 30 to accurately reflect the renumbering of the

19. On page 16 of 20, Condition No. 30 (per renumbering of Conditions), the first sentence of this condition should be revised as follows: "The owner or operator shall install, calibrate, maintain, and operate a continuous emissions monitoring (CEM) system in the combustion turbine exhaust stack (EU 001) ~~of each emissions unit~~ to measure and record the emissions of NOx and CO ~~from these emissions units~~ in a manner sufficient to demonstrate compliance with the CEM emission standards of this permit." These revisions clarify that EU 001(the combustion turbine exhaust stack) is the only emissions unit for which CEM system monitoring is required.

20. On page 20 of 20, in Condition No. 36 (per renumbering of Conditions), the word "each" should be inserted before the term "Compliance Authority."

II. Comments on Technical Evaluation and Preliminary Determination

21. On page TE-2, in the Facility Information section, Facility Location paragraph, the following revisions should be made: First, the location is approximately 180 km, rather than 200 km, North-northeast of the Everglades National Park. Second, the proposed site is located in St. Lucie County, rather than in Port St. Lucie.

22. On page TE-3, in the Project Description section, Emissions Units table, for Emissions Unit No. 004, the emission unit description should be revised to insert the word "fire" between "hp" and "water," so that the revision reads as follows: "One 500 kW emergency generator and one diesel-fired 250 hp fire water pump."

23. On page TE-3, immediately under the Emissions Units table, the reference to "Competitive Power Ventures Cana Ltd." should be changed to "CPV Cana, Ltd."

24. On page TE-4, in the last line on the page, for consistency with the information submitted in the permit application, the tons per year (TPY) for PM/PM_{10} should be changed to 96 TPY, and the TPY for NOx should be changed to 103 TPY.

25. The following typographical errors should be corrected:

(1) On page TE-5, in the second paragraph in Section 4, Process Description, in the second sentence immediately above the photograph, the word "a" should be inserted before the word "photograph."

(2) On page TE-6, in the third paragraph, delete the stray " symbol immediately after "59° F."

(3) On page TE-6, in the Rule Applicability section, third paragraph, second sentence, insert the word "the" immediately before the word "proposed."

26. On page TE-7, in the Source Impact Analysis section, paragraph 6.1, in the last sentence, the references to Condition Nos. in the draft permit should be revised from 12 to 13, and from 16 to 17.

27. On page TE-8, the following revisions should be made to the Facility Emissions (Total TPY) and PSD Applicability Table, to accurately reflect the information provided in the application:

(1) For NOx, the Oil Firing TPY should be changed from 28 to 29, and the Total TPY should be changed from 102 to 103.

(2) For Sulfuric Acid Mist, the Gas Firing TPY should be changed from 9 to 4.

28. On page TE-8, in paragraph 6.4, paragraph 6.4.1. Description of Vicinity, should be revised to read as follows: "Refer to Figures 1 and 2 above. The CPV Cana Power Generating Facility is located approximately three (3) miles west of ~~will be in~~ the City of Port St. Lucie, which has a population of 80,000, compared to the 185,000 in St. Lucie County. The proposed project is located ~~N~~north of Jensen Beach."

29. On page TE-9, the reference in the third sentence to "southeast" should be revised to "southwest," to accurately state the location of the facility.

30. On page TE-10, in Section 6.4.3, in the list of the Major Sources of NOx in St. Lucie County, the Tons per year figure for CPV Cana should be changed from 102 to 103.

31. On pages TE-10 and TE-11, all references to CPV Gulfcoast should be changed to CPV Atlantic, and all references to CPV Cana should be followed by the insert: "(Future)". In addition, the word "major" should be deleted from the titles of the tables on each page, since many quantities listed are below the 100 TPY threshold for being considered a "major source" of air pollution, and the use of the term in a non-regulatory sense is confusing, since the air regulations specifically address and regulate "major sources."

32. On page TE-13, in the Air Quality Impact Analysis section, in the second paragraph of 6.5.1, the distance of the site from the Everglades National Park should be revised from 200 km to 180 km.

III. Comments on Appendix BD, Best Available Control Technology Determination (BACT):

33. On page BD-1, in the Background section, first paragraph, second sentence, strike the reference to Port St. Lucie, since the facility will not be located in the City of Port St. Lucie, but will instead be located in unincorporated St. Lucie County.

34. On page BD-17, in the table, the Proposed BACT Limit for CO emissions for oil firing should be corrected to 15% O_2, so that it is listed as 17 ppmvd @ 15% O_2 in the table.

35. On page BD-18, in the fourth bullet point, first line, the word "is" should be changed to "in."

36. On page BD-19, the third bullet point concerning Best Operational Standard — Startup BACT (Bypass Stack Option) should be deleted because it is not appropriate for CPV Cana and will not be used at the facility.

37. On page BD-19, in the fourth and fifth bullet points concerning an alternative Best Operational Practice and a Best Operational Standard — Startup BACT (No Bypass Stack), respectively, the following revisions should be made to reflect operating conditions during startup: [FILL IN INFORMATION]

We appreciate the opportunity to comment on the draft permit, and look forward to receipt of the final permit. Please contact me if you have any questions or wish to discuss any revisions we have requested.

Sincerely,

Peter J. Podurgiel
CPV Cana, Ltd.

cc: Gary Lambert, CPV
Michael Anderson, TRC
Keith Price, AEP Pro Serv
Cathy Sellers, Moyle Flanigan
Theresa Herron, FDEP

MOYLE, FLANIGAN, KATZ, RAYMOND & SHEEHAN, P.A.
ATTORNEYS AT LAW

The Perkins House
118 North Gadsden Street
Tallahassee, Florida 32301

Telephone: (850) 681-3828
Facsimile: (850) 681-8788

CATHY M. SELLERS
E-mail: csellers@moylelaw.com

West Palm Beach Office
(561) 659-7500

December 6, 2001

RECEIVED

DEC 06 2001

BUREAU OF AIR REGULATION

By Hand Delivery

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: CPV Cana Electric Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)
Affidavit of Publication

Dear Mr. Linero:

Enclosed please find the original Affidavit of Publication for the Cana PSD air construction permit. If you have any questions, please give me a call.

Sincerely,

Cathy M. Sellers

Cathy M. Sellers

CMS/jd
Enclosure
cc: J. Koerner
C. Holladay
I. Goldman, SED
G. Worley, EPA
J. Bunyak, NPS

SCRIPPS HOWARD

THE TRIBUNE

ST. LUCIE COUNTY, FLORIDA

600 Edwards Road, Ft. Pierce, FL 34982

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Lynn Ferraro, General Manager; Kathy LeClair, Business Manager or Bob Rossi, Circulation Manager of The Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida; that the attached copy of advertisement was published in The Tribune in the following issues below. Affiant further says that the said Tribune is a newspaper published at Fort Pierce in said St. Lucie County, Florida and that the said newspaper has heretofore been continuously published in said St. Lucie County, Florida daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose ot securing this advertisement tor publication in the said newspaper.
The Tribune has been entered as second class matter at the Post Office in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Name	Date	Price Per Day	PO #
2296875	RICHARD V. NEILL, JR.	12/03/2001	$472.00	
		Total	$472.00	

Subscribed and sworn to me before this date:

12/03/2001

Kathy Lee
Notary Public

KATHY LEE
NOTARY PUBLIC STATE OF FLORIDA
My Comm Exp. 7/30/2002
No. CC 763706
[ ] Personally Known [ ] Other I.D.
SEAL

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110103-001-CA and PSD-FL-323
CPV Cana Power Generating Focility
Cambined Cycle Power Project
St. Lucie Caunty

The Deportment of Environmentol Protection (Deportment) gives notice of its intent to issue an oir construction permit to CPV Cono Ltd. The permit is to construct o combined cycle electricol power generoting plant in St. Lucie County. A Best Available Control Technology (BACT) determination was required pursuont to Rule 62-212.400, F.A.C., Prevention af Significant Deteriaratian of Air Quality (PSD), for emissions of particulote matter (PM/PM10), carbon monoxide (CO), sulphur dioxide (SO2), sulfuric acid mist (SAM), and nitrogen oxides (NOx). A maximum achievable control technology (MACT) determination far hozordous oir pollutants was not required. The applicont's nome and address are CPV Cano Ltd., 35 Brointree Hill Office Pork, Suite 107, Braintree, Mossochusetts 02184.

The project consists of: a nominal 170 megawatt Generol Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a separate stem-electrical generator, a 170-faot stack, a mechonicol draft cooling tower, a 975,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NOx emissions will be controlled by selective cotalytic reduction (SCR) to achieve 2.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel ail. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM10, SO2, sulfuric acid mist, volotile organic compounds, and hazardous pollutants (HAP) will be controlled to very low levels by good combustion ond use of inherently clean pipeline quality noturol gas ond low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions (NH3) generated due to NOx control will be limited to 5 ppmvd.

The following table summarizes the maximum emissians (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	*Maximum Potential Emissions*	*PSD Significant Emission Rate*
PM/PM10 (filterable & condensoble)	96	25/15
Sulfuric Acid Mist	8	7
SO2	76	40
NOx	102	40
VOC	16	40
CO	170	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to propased emissions from the project ore less than the applicable PSD Class II significont impact levels for all applicable pollutants. Therefor no increment consumption onalysis was required. Given the distonce from the Everglades ond the rother low emissions, the National Park Service advised the Department that it does not anticipate any significant impacts on resources from emissions from this proposed facility. Therefor a Class I onalysis was not required. The Department concludes that emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards..

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 cycle submitted by the applicant and reviewed by the Department.

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

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

The Department will issue the permit with the attached conditions unless o timely petition for an administrative hearing is filed pursuant to Section 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a heoring ore set forth below. Mediotion is not avoilable in the proceeding.

A person whose substantial interests are offected by the proposed permitting decision may petition for an administrative proceeding (hearing) under section 120.569 and 120.57 of the Florida Statutes. The petition must contain the information *set forth below and must be filed (received) in the Office of General Counsel of the Department at* 3900 Commonwealth Boulevard, Moil Stotion #35, Tallahossee, Florido 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons *ather than those entitle to written natice under section* 120.60(3) of the Florida Statutes *must* be filed within fourteen days of publicotion of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice af agency actian may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail o copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determinatian (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approvol of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

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

Dept. of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida, 32301 Telephone: 850/488-0114 Fax: 850/922-6979	Dept. of Environmental Protection Southeast District Office 400 North Congress Avenue W. Palm Beach, Florida 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6755	Dept. of Environmental Protection Port St. Lucie Branch Office 1801 S.E. Hillmaor Dr., C204 Port St. Lucie, Florida 34952 Telephone: 561/398-2806 Fax: 561/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the informotion submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, *New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or coll* 850/488-0114, for additional information. Key documents can be accessed at www.dep.state.fl.us/air/permitting/construction.htm by clicking an the Southeast Region of the map of Florida.

Publish: December 4, 2001

2296875

Competitive
Power Ventures, Inc.

October 24, 2001

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Responses to Florida DEP Comments on CPV Cana Power Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)

Reference: Letter from A. A. Linero to G. Lambert dated October 2, 2001

Dear Mr. Linero:

Enclosed please find seven copies of CPV Cana, Ltd's. response to the referenced letter. If you have any questions, please do not hesitate to contact me at (781) 848-0253.

Sincerely,

Peter J. Podurgiel
Vice President Development

Enclosures

cc: Michael Anderson, TRC
Cathy Sellers, Moyle, Flanagan
Scott Sumner, P.E. TRC

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253 FAX: (781) 848-5804

Responses to Florida DEP Comments on CPV Cana Power Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)

The Florida Department of Environmental Protection (DEP) notified CPV via certified mail, dated October 2, 2001, of two additional information requests needed for application completeness. The three requested items, numbered 1., 2. and 3., are restated below for completeness. CPV's response to each request is provided herein.

1. **Request:** Proposed Emissions for Sulfuric Acid Mist are 7.62 TPY. This is above the PSD limit of 7 TPY. Please complete a BACT analysis for this pollutant.

   Response: Attachment A contains Section 5.4 and Table 5-4 of the <u>CPV Cana Power Generating Facility Application for Air Permit</u> (the air permit application), which have been modified using the black-line editing function to include Sulfuric Acid Mist in the BACT analysis. It demonstrates that the use of low sulfur fuels results in the BACT emission rate limits for Sulfuric Acid Mist. For completeness, Tables 3-1 and 3-3 of the air permit application have also been modified to include sulfuric acid mist and the emissions form ancillary sources (see Request 2).

2. **Request:** Submit potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank units. Although these units may be exempted from permitting (based on emissions and capacity), we need to include them in the construction permit.

   Response: Attachment B contains the calculations of the potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank. Emissions for the fire pump and diesel emergency generator were calculated using published emissions factors and an annual operating limit of 500 hours for each piece of equipment. Emissions for diesel storage tank were calculated using the TANKS program.

3. **Request:** What is the ammonia's concentration in the storage tank (i.e. < or > 20 percent)? Please refer to 40CFR 68, Chemical Accident Provisions.

   Response: Section 3.8 of the air permit application states that the project will utilize aqueous ammonia with a concentration of less than 20 percent. It will therefore not require a Risk Management Plan (RMP) under the Chemical Accident Provisions of 40 CFR 68.

Scott G. Sumner, P.E.

25 October 2001
Date

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature — Date: 25 OCTOBER 2001

(seal) SCOTT G. S... No. 44352 STATE OF ... REGISTERED ENG...

* Attach any exception to certification statement.

Attachment A

Revisions to CPV Cana BACT Analysis

Table 3-1 New Power Generation Equipment Criteria Pollutant Emissions CPV Cana[1]	
Pollutant	**Potential Emissions[2] (Tons/Year)**
NO_x	~~96~~102
SO_2	76
CO	~~226~~228
PM/PM_{10}[3]	96
VOC	~~15~~16
H_2SO_4	7.62

1 Source: GE performance data in Appendix C.
2 Annual emission estimates based on combustion turbine operating 8760 hours at maximum hourly emission rate.
3 PM/PM_{10} value includes combustion turbines and cooling tower drift.

Table 3-3 PSD Significant Emissions Increase Level and CPV Cana Project Net Emission Rates (Pursuant to 40 CFR 52.21 (b) (23) (i))		
Pollutant	**Significant Emissions Increase Level (TPY)**	**Annual Net Emissions Increases (TPY)**
NO_x	40	~~96~~102
SO_2	40	76
CO	100	~~226~~228
PM	25	96
PM_{10}	15	96
VOC	40	~~15~~16
H_2SO_4	7	7.62

5.4 BACT Analysis for Sulfur Dioxide and Sulfuric Acid

Strategies for the control of sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low sulfur fuels or fuel sulfur removal. Post-combustion controls comprise various wet and dry flue gas de-sulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to ~~high~~ large pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low SO_2 and H_2SO_4 concentrations.

The new power generation equipment will fire natural gas as the primary fuel (0.0065% sulfur by weight) and 0.05% sulfur distillate oil as back up, which is considered BACT for SO_2 and H_2SO_4 emissions. Based on these clean fuels, the proposed maximum SO_2 and H_2SO_4 emission rates for natural gas firing ~~is~~ are 10 lb/hr and 1 lb/hr, respectively. The proposed maximum SO_2 and H_2SO_4 emission rates for distillate oil firing ~~is~~ are 99 lb/hour and 10 lb/hr, respectively.

Table 5-2 Summary of Proposed BACT Limits for the CPV Cana Project		
Pollutant	Control Technology	Proposed BACT Limit
Nitrogen Oxides	Low - NO_x Combustion Technology Selective Catalytic Reduction	2.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
Carbon Monoxide*	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation mode) 24 ppmvd (oil)
Particulate Matter-Combined-Cycle System	Inherently Clean Fuels Combustion Controls	19 lb/hr (gas) 44 lb/hr (oil)
Particulate Matter-Cooling Tower	High Efficiency Drift Eliminators	0.0005% drift
Sulfur Dioxide	Low Sulfur Fuels	10 lb/hr (gas) 99 lb/hr (oil)
Sulfuric Acid	Low Sulfur Fuels	1 lb/hr (gas) 10 lb/hr (oil)

*FDEP approved the following CO emission limits @ 15% O_2 for the CPV Pierce Project:
8 ppmvd (gas)
13 ppmvd (power augmentation mode)
17 ppmvd (oil)

Attachment B

Emissions Calculations for Ancillary Equipment

CPV Cana
Assumptions and Emission for the Fire Water Pump

Operating Hours	500
Type Fuel	Diesel
Fuel Heating Value (Btu/gal)	140,000
Gallons per Hour	13.8
Fuel Input in MMBtu per Hour	1.93
Assumed Efficiency	33%
BHP Rating	250
Annual Fuel Usage (gal/year)	6,886
Sulfur Content in Fuel	0.05%

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.310	2	0.598	0.149	
PM10	na	0.310	2	0.598	0.149	
SOx	na	0.051	1	0.097	0.024	
CO	630-08-0	0.950	1	1.832	0.458	
VOC	na	0.349	2	0.673	0.168	
NOx	na	4.410	2	8.503	2.126	
Hazardous Air Pollutants						
1,3 Butadiene	106-99-0	3.91E-05	2	7.54E-05	1.88E-05	yes
Acetaldehyde	75-07-0	7.67E-04	2	1.48E-03	3.70E-04	yes
Acrolein	107-02-8	9.25E-05	2	1.78E-04	4.46E-05	yes
Benzene	71-43-2	9.33E-04	2	1.80E-03	4.50E-04	yes
Beryllium	7440-41-7	6.90E-08	3	1.33E-07	3.33E-08	yes
Formaldehyde	50-00-0	1.18E-03	2	2.28E-03	5.69E-04	yes
Mercury	na	3.01E-07	3	5.81E-07	1.45E-07	yes
Napthalene	91-20-3	8.48E-05		1.64E-04	4.09E-05	yes
PAH	130498-29-2	1.68E-04	2	3.24E-04	8.10E-05	yes
Acenaphthene (POM)	83-32-9	1.42E-06	2	2.74E-06	6.84E-07	yes
Acenaphthylene (POM)	208-96-8	5.06E-06	2	9.76E-06	2.44E-06	yes
Anthracene (POM)	120-12-7	1.87E-06	2	3.61E-06	9.01E-07	yes
Benz(a)anthracene (POM)	56-55-3	1.68E-06	2	3.24E-06	8.10E-07	yes
Benzo(a)pyrene (POM)	50-32-8	1.88E-07	2	3.62E-07	9.06E-08	yes
Benzo(b)fluoranthene (POM)	205-99-2	9.91E-08	2	1.91E-07	4.78E-08	yes
Benzo(g,h,i)perylene (POM)	191-24-2	4.89E-07	2	9.43E-07	2.36E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	1.55E-07	2	2.99E-07	7.47E-08	yes
Chrysene (POM)	218-01-9	3.53E-07	2	6.81E-07	1.70E-07	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	5.83E-07	2	1.12E-06	2.81E-07	yes
Fluoranthene (POM)	206-44-0	7.61E-06	2	1.47E-05	3.67E-06	yes
Fluorene (POM)	86-73-7	2.92E-05	2	5.63E-05	1.41E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	3.75E-07	2	7.23E-07	1.81E-07	yes
Naphthalene (POM)	91-20-3	8.48E-05	2	1.64E-04	4.09E-05	yes
Phenanthrene (POM)	85-01-8	2.94E-05	2	5.67E-05	1.42E-05	yes
Pyrene (POM)	129-00-0	4.78E-06	2	9.22E-06	2.30E-06	yes
Toluene	108-88-3	4.09E-04	2	7.89E-04	1.97E-04	yes
Xylenes	1330-20-7	2.85E-04	2	5.50E-04	1.37E-04	yes
Other Non-Criteria Air Pollutants						
Aldehydes	na	7.00E-02	2	1.35E-01	3.37E-02	no
Propylene	115-07-1	2.58E-03	2	4.97E-03	1.24E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	3/4	2.00E-03	4.99E-04	no
Totals						
Federal HAPs					1.91E-03	
Other Non-criteria Pollutants					3.55E-02	

1. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.4-1, 5th Edition - Supplement B November, 1996.
2. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.3-1 and 3.3-2, 5th Edition - Supplement B November, 1996.
3. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
4. Emission factor for sulfuric acid is 8.9(S) ng/J.

CPV Cana
Assumptions and Emission for the Emergency Generator

Operating Hours	500
Type Fuel	Diesel
Sulfur Content of Fuel	0.05%
Fuel Heating Value (Btu/gal)	140,000
Gallon per Hour	36
Fuel Input in MMBtu per Hour	5.0
Output in kW	500
Assumed Heat Rate (Btu/kW-hr)	10,000

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.068	2	0.340	0.085	
PM10	na	0.057	2	0.287	0.072	
SOx	na	0.051	1	0.253	0.063	
CO	630-08-0	0.850	1	4.250	1.063	
VOC	na	0.090	1	0.450	0.113	
NOx	na	3.20	1	16.00	4.000	
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	2.52E-05	3	1.26E-04	3.15E-05	yes
Acrolein	107-02-8	7.88E-05	3	3.94E-04	9.85E-05	yes
Benzene	71-43-2	7.76E-04	3	3.88E-03	9.70E-04	yes
Beryllium		6.90E-08	5	3.45E-07	8.63E-08	yes
Formaldehyde	50-00-0	7.89E-05	3	3.95E-04	9.86E-05	yes
Mercury	na	3.01E-07	5	1.51E-06	3.77E-07	yes
Napthalene	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
PAH	130498-29-2	2.45E-04	4	1.22E-03	3.06E-04	yes
Acenaphthene (POM)	83-32-9	4.68E-06	4	2.34E-05	5.85E-06	yes
Acenaphthylene (POM)	208-96-8	9.23E-06	4	4.62E-05	1.15E-05	yes
Anthracene (POM)	120-12-7	1.23E-06	4	6.15E-06	1.54E-06	yes
Benz(a)anthracene (POM)	56-55-3	6.22E-07	4	3.11E-06	7.78E-07	yes
Benzo(a)pyrene (POM)	50-32-8	2.57E-07	4	1.29E-06	3.21E-07	yes
Benzo(b)fluoranthene (POM)	205-99-2	1.11E-06	4	5.55E-06	1.39E-06	yes
Benzo(g,h,i)perylene (POM)	191-24-2	3.46E-07	4	1.73E-06	4.33E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	2.18E-07	4	1.09E-06	2.73E-07	yes
Chrysene (POM)	218-01-9	1.53E-06	4	7.65E-06	1.91E-06	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	3.46E-07	4	1.73E-06	4.33E-07	
Fluoranthene (POM)	206-44-0	4.03E-06	4	2.02E-05	5.04E-06	yes
Fluorene (POM)	86-73-7	1.28E-05	4	6.40E-05	1.60E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	2.57E-07	4	1.29E-06	3.21E-07	yes
Naphthalene (POM)	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
Phenanthrene (POM)	85-01-8	4.08E-05	4	2.04E-04	5.10E-05	yes
Pyrene (POM)	129-00-0	3.71E-05	4	1.86E-04	4.64E-05	yes
Toluene	108-88-3	2.81E-04	3	1.41E-03	3.51E-04	yes
Xylenes	1330-20-7	1.93E-04	3	9.65E-04	2.41E-04	yes
Other Non-Criteria Air Pollutants						
Propylene	115-07-1	2.79E-03	3	1.40E-02	3.49E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	5/6	5.17E-03	1.29E-03	no
Totals						
Federal HAPs					2.26E-03	
Other Non-criteria Pollutants					4.78E-03	

1. Emissions based on AP-42, Table 3.4-1
2. Emissions based on AP-42, Table 3.4-2
3. Emissions based on AP-42, Table 3.4-3.
4. Emissions based on AP-42, Table 3.4-4.
5. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
6. Emission factor for sulfuric acid is 8.9(S) ng/J.

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	CPV Cana Oil Storage Tank
City:	Port St. Lucie
State:	Florida
Company:	CPV
Type of Tank:	Vertical Fixed Roof Tank
Description:	Nominal 975,000 gallon distillate oil storage tank

Tank Dimensions

Shell Height (ft):	45.00
Diameter (ft):	67.75
Liquid Height (ft):	36.15
Avg. Liquid Height (ft):	30.00
Volume (gallons):	975,000.00
Turnovers:	10.86
Net Throughput (gal/yr):	10,593,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition:	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	5.00
Radius (ft) (Dome Roof):	67.75

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Vero Beach, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	74.75	66.07	83.43	75.49	0.0104	0.0079	0.0136	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Feb	76.48	66.73	86.23	75.49	0.0110	0.0081	0.0148	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Mar	80.20	69.09	91.31	75.49	0.0123	0.0087	0.0172	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Apr	83.37	71.04	95.69	75.49	0.0136	0.0093	0.0195	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	May	85.49	73.29	97.68	75.49	0.0144	0.0099	0.0207	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jun	86.42	75.17	97.67	75.49	0.0149	0.0105	0.0206	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jul	78.91	74.83	82.99	75.49	0.0118	0.0104	0.0134	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Aug	86.96	75.89	98.02	75.49	0.0151	0.0108	0.0209	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Sep	85.13	75.43	94.84	75.49	0.0143	0.0106	0.0190	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Oct	82.04	73.14	90.94	75.49	0.0130	0.0099	0.0170	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Nov	78.48	70.07	86.89	75.49	0.0117	0.0090	0.0151	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Dec	75.45	67.14	83.75	75.49	0.0106	0.0082	0.0137	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	418.28	446.97	865.25

Competitive
Power Ventures, Inc.

RECEIVED
OCT 25 2001
BUREAU OF AIR REGULATION

October 24, 2001

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32399

Re: Responses to Florida DEP Comments on CPV Cana Power Generating Facility
DEP File No. 1110103-001-AC (PSD-FL-323)

Reference: Letter from A. A. Linero to G. Lambert dated October 2, 2001

Dear Mr. Linero:

Enclosed please find seven copies of CPV Cana, Ltd's. response to the referenced letter. If you have any questions, please do not hesitate to contact me at (781) 848-0253.

Sincerely,

Peter J. Podurgiel
Vice President Development

Enclosures

cc: Michael Anderson, TRC
Cathy Sellers, Moyle, Flanagan
Scott Sumner, P.E. TRC

Responses to Florida DEP Comments on CPV Cana Power Generating Facility DEP File No. 1110103-001-AC (PSD-FL-323)

The Florida Department of Environmental Protection (DEP) notified CPV via certified mail, dated October 2, 2001, of two additional information requests needed for application completeness. The three requested items, numbered 1., 2. and 3., are restated below for completeness. CPV's response to each request is provided herein.

1. **Request:** Proposed Emissions for Sulfuric Acid Mist are 7.62 TPY. This is above the PSD limit of 7 TPY. Please complete a BACT analysis for this pollutant.

   Response: Attachment A contains Section 5.4 and Table 5-4 of the CPV Cana Power Generating Facility Application for Air Permit (the air permit application), which have been modified using the black-line editing function to include Sulfuric Acid Mist in the BACT analysis. It demonstrates that the use of low sulfur fuels results in the BACT emission rate limits for Sulfuric Acid Mist. For completeness, Tables 3-1 and 3-3 of the air permit application have also been modified to include sulfuric acid mist and the emissions form ancillary sources (see Request 2).

2. **Request:** Submit potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank units. Although these units may be exempted from permitting (based on emissions and capacity), we need to include them in the construction permit.

   Response: Attachment B contains the calculations of the potential emissions for the fire pump and the diesel emergency generator as well as the diesel storage tank. Emissions for the fire pump and diesel emergency generator were calculated using published emissions factors and an annual operating limit of 500 hours for each piece of equipment. Emissions for diesel storage tank were calculated using the TANKS program.

3. **Request:** What is the ammonia's concentration in the storage tank (i.e. $<$ or $>$ 20 percent)? Please refer to 40CFR 68, Chemical Accident Provisions.

   Response: Section 3.8 of the air permit application states that the project will utilize aqueous ammonia with a concentration of less than 20 percent. It will therefore not require a Risk Management Plan (RMP) under the Chemical Accident Provisions of 40 CFR 68.

SCOTT G. SUMNER CERTIFICATE No. 44532 STATE OF FLORIDA REGISTERED ENGINEER

Scott G. Sumner, P.E.

25 OCTOBER 2001
Date

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature | 25 October 2001
Date

(seal)

* Attach any exception to certification statement.

Attachment A

Revisions to CPV Cana BACT Analysis

Table 3-1 New Power Generation Equipment Criteria Pollutant Emissions CPV Cana[1]	
Pollutant	**Potential Emissions[2] (Tons/Year)**
NO_x	~~96~~102
SO_2	76
CO	~~226~~228
PM/PM_{10}[3]	96
VOC	~~15~~16
H_2SO_4	7.62

1 Source: GE performance data in Appendix C.
2 Annual emission estimates based on combustion turbine operating 8760 hours at maximum hourly emission rate.
3 PM/PM_{10} value includes combustion turbines and cooling tower drift.

Table 3-3 PSD Significant Emissions Increase Level and CPV Cana Project Net Emission Rates (Pursuant to 40 CFR 52.21 (b) (23) (i))		
Pollutant	**Significant Emissions Increase Level (TPY)**	**Annual Net Emissions Increases (TPY)**
NO_x	40	~~96~~102
SO_2	40	76
CO	100	~~226~~228
PM	25	96
PM_{10}	15	96
VOC	40	~~15~~16
H_2SO_4	7	7.62

5.4 BACT Analysis for Sulfur Dioxide and Sulfuric Acid

Strategies for the control of sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low sulfur fuels or fuel sulfur removal. Post-combustion controls comprise various wet and dry flue gas de-sulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to ~~high~~ large pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low SO_2 and H_2SO_4 concentrations.

The new power generation equipment will fire natural gas as the primary fuel (0.0065% sulfur by weight) and 0.05% sulfur distillate oil as back up, which is considered BACT for SO_2 and H_2SO_4 emissions. Based on these clean fuels, the proposed maximum SO_2 and H_2SO_4 emission rates for natural gas firing ~~is~~ are 10 lb/hr and 1 lb/hr, respectively. The proposed maximum SO_2 and H_2SO_4 emission rates for distillate oil firing ~~is~~ are 99 lb/hour and 10 lb/hr, respectively.

Table 5-2 Summary of Proposed BACT Limits for the CPV Cana Project		
Pollutant	Control Technology	Proposed BACT Limit
Nitrogen Oxides	Low - NO_x Combustion Technology Selective Catalytic Reduction	2.5 ppmvd @ 15% O_2 (gas) 10 ppmvd @ 15% O_2 (oil)
Carbon Monoxide*	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation mode) 24 ppmvd (oil)
Particulate Matter-Combined-Cycle System	Inherently Clean Fuels Combustion Controls	19 lb/hr (gas) 44 lb/hr (oil)
Particulate Matter-Cooling Tower	High Efficiency Drift Eliminators	0.0005% drift
Sulfur Dioxide	Low Sulfur Fuels	10 lb/hr (gas) 99 lb/hr (oil)
Sulfuric Acid	Low Sulfur Fuels	1 lb/hr (gas) 10 lb/hr (oil)

*FDEP approved the following CO emission limits @ 15% O_2 for the CPV Pierce Project:
8 ppmvd (gas)
13 ppmvd (power augmentation mode)
17 ppmvd (oil)

Attachment B

Emissions Calculations for Ancillary Equipment

CPV Cana

Assumptions and Emission for the Fire Water Pump

Operating Hours	500
Type Fuel	Diesel
Fuel Heating Value (Btu/gal)	140,000
Gallons per Hour	13.8
Fuel Input in MMBtu per Hour	1.93
Assumed Efficiency	33%
BHP Rating	250
Annual Fuel Usage (gal/year)	6,886
Sulfur Content in Fuel	0.05%

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.310	2	0.598	0.149	
PM10	na	0.310	2	0.598	0.149	
SOx	na	0.051	1	0.097	0.024	
CO	630-08-0	0.950	1	1.832	0.458	
VOC	na	0.349	2	0.673	0.168	
NOx	na	4.410	2	8.503	2.126	
Hazardous Air Pollutants						
1,3 Butadiene	106-99-0	3.91E-05	2	7.54E-05	1.88E-05	yes
Acetaldehyde	75-07-0	7.67E-04	2	1.48E-03	3.70E-04	yes
Acrolein	107-02-8	9.25E-05	2	1.78E-04	4.46E-05	yes
Benzene	71-43-2	9.33E-04	2	1.80E-03	4.50E-04	yes
Beryllium	7440-41-7	6.90E-08	3	1.33E-07	3.33E-08	yes
Formaldehyde	50-00-0	1.18E-03	2	2.28E-03	5.69E-04	yes
Mercury	na	3.01E-07	3	5.81E-07	1.45E-07	yes
Napthalene	91-20-3	8.48E-05		1.64E-04	4.09E-05	yes
PAH	130498-29-2	1.68E-04	2	3.24E-04	8.10E-05	yes
Acenaphthene (POM)	83-32-9	1.42E-06	2	2.74E-06	6.84E-07	yes
Acenaphthylene (POM)	208-96-8	5.06E-06	2	9.76E-06	2.44E-06	yes
Anthracene (POM)	120-12-7	1.87E-06	2	3.61E-06	9.01E-07	yes
Benz(a)anthracene (POM)	56-55-3	1.68E-06	2	3.24E-06	8.10E-07	yes
Benzo(a)pyrene (POM)	50-32-8	1.88E-07	2	3.62E-07	9.06E-08	yes
Benzo(b)fluoranthene (POM)	205-99-2	9.91E-08	2	1.91E-07	4.78E-08	yes
Benzo(g,h,i)perylene (POM)	191-24-2	4.89E-07	2	9.43E-07	2.36E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	1.55E-07	2	2.99E-07	7.47E-08	yes
Chrysene (POM)	218-01-9	3.53E-07	2	6.81E-07	1.70E-07	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	5.83E-07	2	1.12E-06	2.81E-07	yes
Fluoranthene (POM)	206-44-0	7.61E-06	2	1.47E-05	3.67E-06	yes
Fluorene (POM)	86-73-7	2.92E-05	2	5.63E-05	1.41E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	3.75E-07	2	7.23E-07	1.81E-07	yes
Naphthalene (POM)	91-20-3	8.48E-05	2	1.64E-04	4.09E-05	yes
Phenanthrene (POM)	85-01-8	2.94E-05	2	5.67E-05	1.42E-05	yes
Pyrene (POM)	129-00-0	4.78E-06	2	9.22E-06	2.30E-06	yes
Toluene	108-88-3	4.09E-04	2	7.89E-04	1.97E-04	yes
Xylenes	1330-20-7	2.85E-04	2	5.50E-04	1.37E-04	yes
Other Non-Criteria Air Pollutants						
Aldehydes	na	7.00E-02	2	1.35E-01	3.37E-02	no
Propylene	115-07-1	2.58E-03	2	4.97E-03	1.24E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	3/4	2.00E-03	4.99E-04	no
Totals						
Federal HAPs					1.91E-03	
Other Non-criteria Pollutants					3.55E-02	

1. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.4-1, 5th Edition - Supplement B November, 1996.
2. Emissions based on AP-42 Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources; Tables 3.3-1 and 3.3-2, 5th Edition - Supplement B November, 1996.
3. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
4. Emission factor for sulfuric acid is 8.9(S) ng/J.

CPV Cana
Assumptions and Emission for the Emergency Generator

Operating Hours	500
Type Fuel	Diesel
Sulfur Content of Fuel	0.05%
Fuel Heating Value (Btu/gal)	140,000
Gallon per Hour	36
Fuel Input in MMBtu per Hour	5.0
Output in kW	500
Assumed Heat Rate (Btu/kW-hr)	10,000

	CAS#	Emission Factor (lbs/MMBtu)	Source	Short Term Emissions (lb/hr)	Long Term Emissions (ton/yr)	Federal HAP
Criteria Air Pollutants						
PM	na	0.068	2	0.340	0.085	
PM10	na	0.057	2	0.287	0.072	
SOx	na	0.051	1	0.253	0.063	
CO	630-08-0	0.850	1	4.250	1.063	
VOC	na	0.090	1	0.450	0.113	
NOx	na	3.20	1	16.00	4.000	
Hazardous Air Pollutants						
Acetaldehyde	75-07-0	2.52E-05	3	1.26E-04	3.15E-05	yes
Acrolein	107-02-8	7.88E-05	3	3.94E-04	9.85E-05	yes
Benzene	71-43-2	7.76E-04	3	3.88E-03	9.70E-04	yes
Beryllium		6.90E-08	5	3.45E-07	8.63E-08	yes
Formaldehyde	50-00-0	7.89E-05	3	3.95E-04	9.86E-05	yes
Mercury	na	3.01E-07	5	1.51E-06	3.77E-07	yes
Napthalene	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
PAH	130498-29-2	2.45E-04	4	1.22E-03	3.06E-04	yes
Acenaphthene (POM)	83-32-9	4.68E-06	4	2.34E-05	5.85E-06	yes
Acenaphthylene (POM)	208-96-8	9.23E-06	4	4.62E-05	1.15E-05	yes
Anthracene (POM)	120-12-7	1.23E-06	4	6.15E-06	1.54E-06	yes
Benz(a)anthracene (POM)	56-55-3	6.22E-07	4	3.11E-06	7.78E-07	yes
Benzo(a)pyrene (POM)	50-32-8	2.57E-07	4	1.29E-06	3.21E-07	yes
Benzo(b)fluoranthene (POM)	205-99-2	1.11E-06	4	5.55E-06	1.39E-06	yes
Benzo(g,h,i)perylene (POM)	191-24-2	3.46E-07	4	1.73E-06	4.33E-07	yes
Benzo(k)fluoranthene (POM)	207-08-9	2.18E-07	4	1.09E-06	2.73E-07	yes
Chrysene (POM)	218-01-9	1.53E-06	4	7.65E-06	1.91E-06	yes
Dibenzo(a,h)anthracene (POM)	53-70-3	3.46E-07	4	1.73E-06	4.33E-07	
Fluoranthene (POM)	206-44-0	4.03E-06	4	2.02E-05	5.04E-06	yes
Fluorene (POM)	86-73-7	1.28E-05	4	6.40E-05	1.60E-05	yes
Indeno(1,2,3-cd)pyrene (POM)	193-39-5	2.57E-07	4	1.29E-06	3.21E-07	yes
Naphthalene (POM)	91-20-3	1.30E-04	4	6.50E-04	1.63E-04	yes
Phenanthrene (POM)	85-01-8	4.08E-05	4	2.04E-04	5.10E-05	yes
Pyrene (POM)	129-00-0	3.71E-05	4	1.86E-04	4.64E-05	yes
Toluene	108-88-3	2.81E-04	3	1.41E-03	3.51E-04	yes
Xylenes	1330-20-7	1.93E-04	3	9.65E-04	2.41E-04	yes
Other Non-Criteria Air Pollutants						
Propylene	115-07-1	2.79E-03	3	1.40E-02	3.49E-03	no
Sulfuric Acid	7664-93-9	1.03E-03	5/6	5.17E-03	1.29E-03	no
Totals						
Federal HAPs					2.26E-03	
Other Non-criteria Pollutants					4.78E-03	

1. Emissions based on AP-42, Table 3.4-1
2. Emissions based on AP-42, Table 3.4-2
3. Emissions based on AP-42, Table 3.4-3.
4. Emissions based on AP-42, Table 3.4-4.
5. Emissions based on Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxics Compounds and Sources: October, 1990, EPA-450/2-90-011.
6. Emission factor for sulfuric acid is 8.9(S) ng/J.

TANKS 4.0
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	CPV Cana Oil Storage Tank
City:	Port St. Lucie
State:	Florida
Company:	CPV
Type of Tank:	Vertical Fixed Roof Tank
Description:	Nominal 975,000 gallon distillate oil storage tank

Tank Dimensions

Shell Height (ft):	45.00
Diameter (ft):	67.75
Liquid Height (ft):	36.15
Avg. Liquid Height (ft):	30.00
Volume (gallons):	975,000.00
Turnovers:	10.86
Net Throughput (gal/yr):	10,593,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition:	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	5.00
Radius (ft) (Dome Roof):	67.75

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Vero Beach, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	74.75	66.07	83.43	75.49	0.0104	0.0079	0.0136	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Feb	76.48	66.73	86.23	75.49	0.0110	0.0081	0.0148	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Mar	80.20	69.09	91.31	75.49	0.0123	0.0087	0.0172	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Apr	83.37	71.04	95.69	75.49	0.0136	0.0093	0.0195	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	May	85.49	73.29	97.68	75.49	0.0144	0.0099	0.0207	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jun	86.42	75.17	97.67	75.49	0.0149	0.0105	0.0206	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jul	78.91	74.83	82.99	75.49	0.0118	0.0104	0.0134	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Aug	86.96	75.89	98.02	75.49	0.0151	0.0108	0.0209	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Sep	85.13	75.43	94.84	75.49	0.0143	0.0106	0.0190	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Oct	82.04	73.14	90.94	75.49	0.0130	0.0099	0.0170	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Nov	78.48	70.07	86.89	75.49	0.0117	0.0090	0.0151	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Dec	75.45	67.14	83.75	75.49	0.0106	0.0082	0.0137	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	418.28	446.97	865.25