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September 5, 2001

RECEIVED
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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
G. Worley, EPA
J. Bunyak, NPS

TRC

Customer-Focused Solutions

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

Section **Page**

APPENDICES

LIST OF FIGURES

Page

LIST OF TABLES

Section 1

Introduction

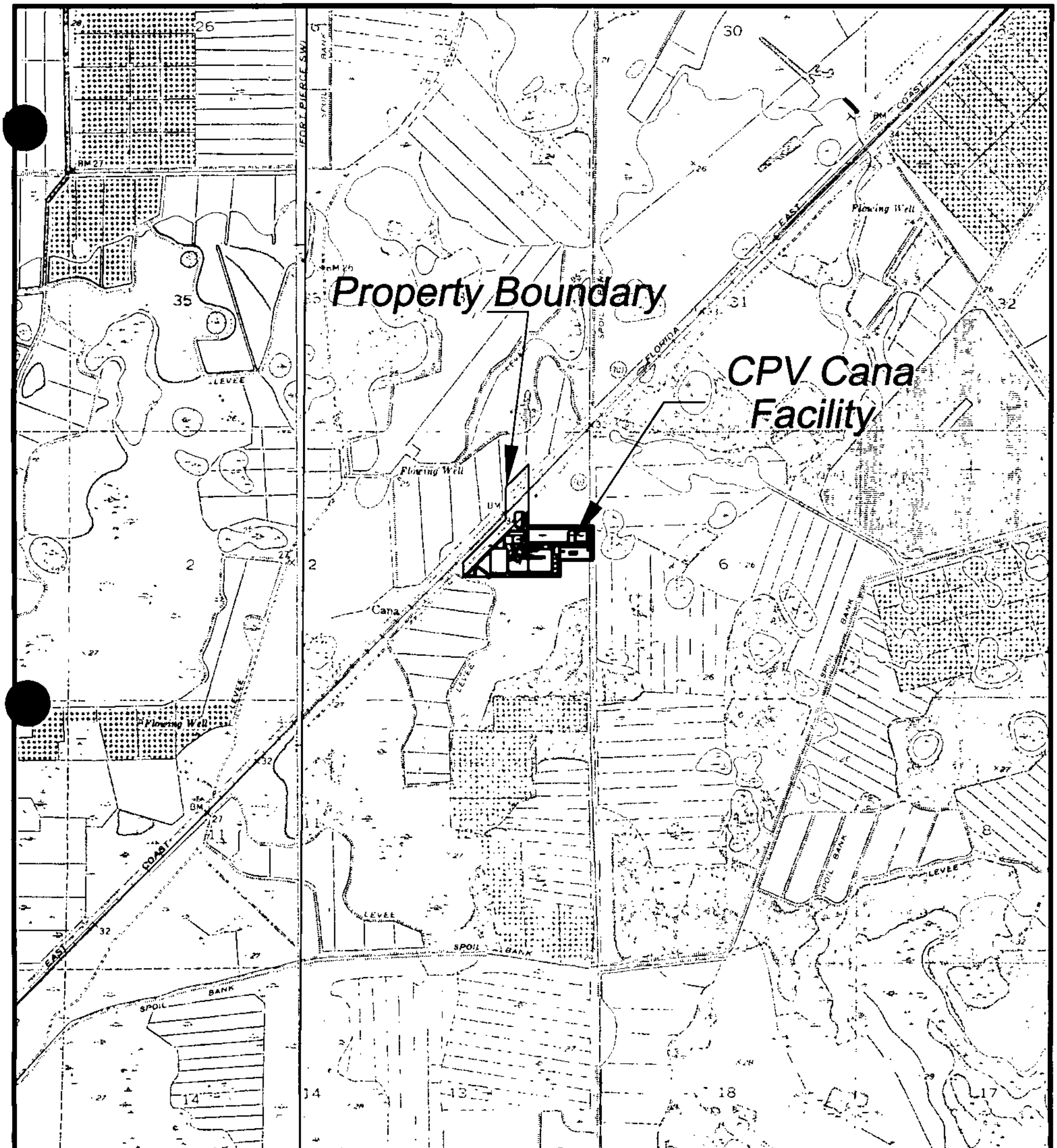
1.0 INTRODUCTION

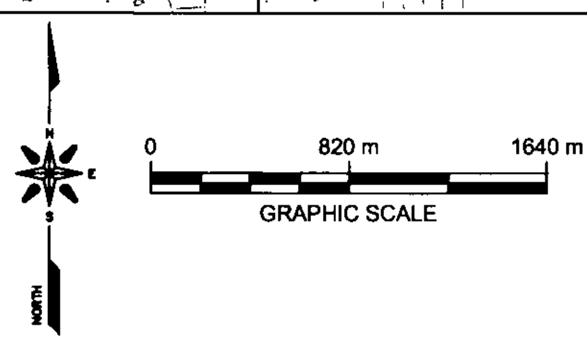
The purpose of this document is to provide the regulatory forms and technical information required to secure approval pursuant to Florida environmental regulations for construction and operation of a new electric power generation facility.

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

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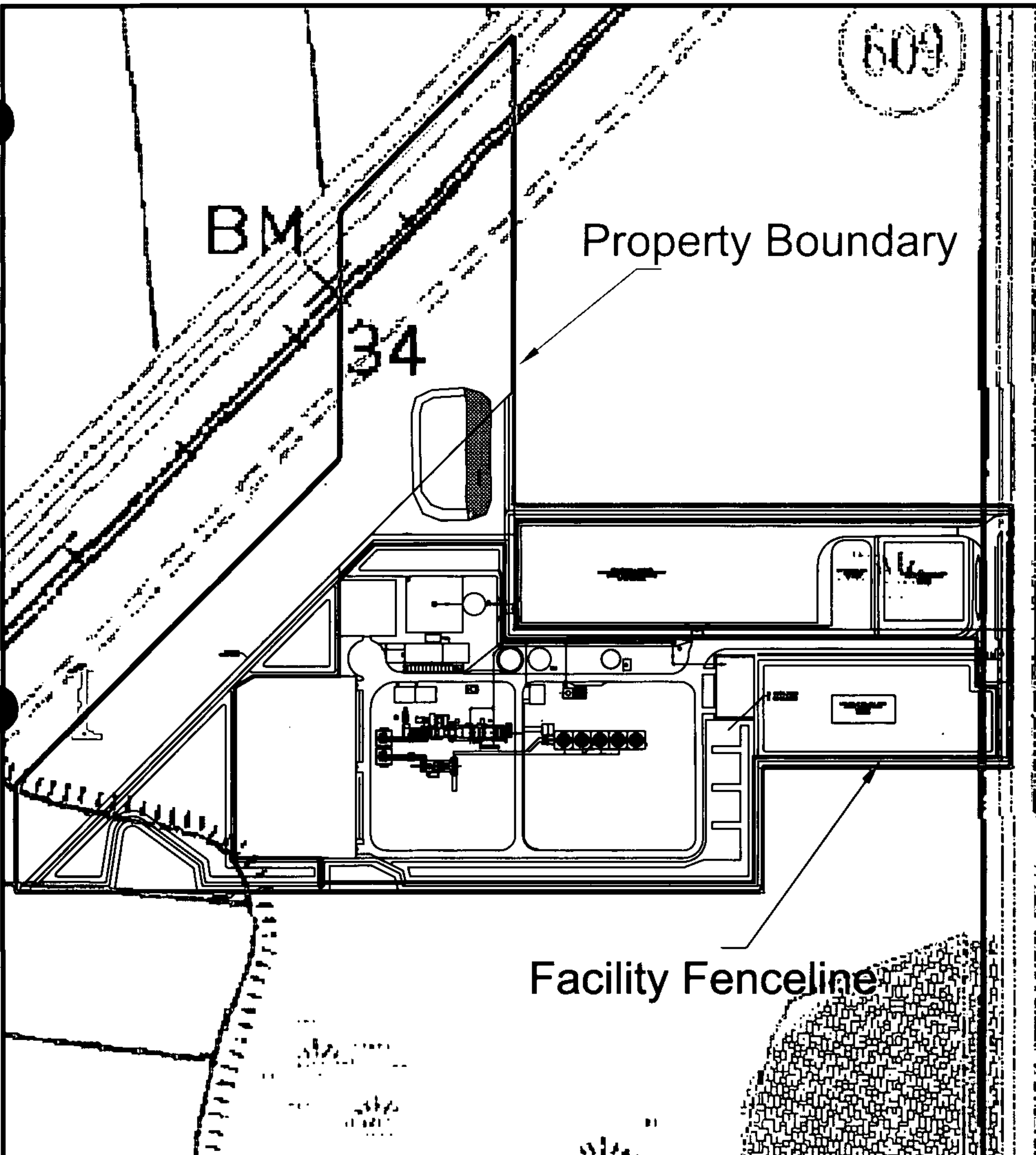
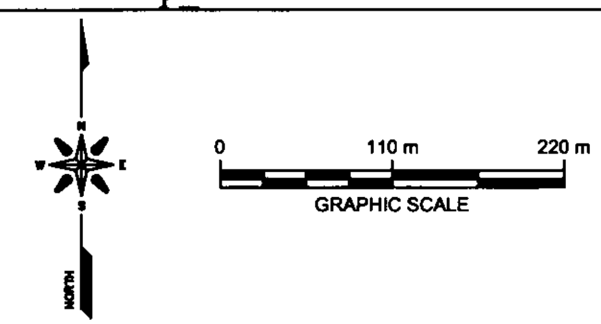
CPV Cana

FIGURE 1-1
Illustration of CPV Cana
Site Location

Date: August 27, 2001	Project No. 32543 0010





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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] Primary	NAAQS ($\mu g/m^3$)[h] Secondary	PSD Increments ($\mu g/m^3$)	Significant Impact Levels ($\mu g/m^3$)
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.

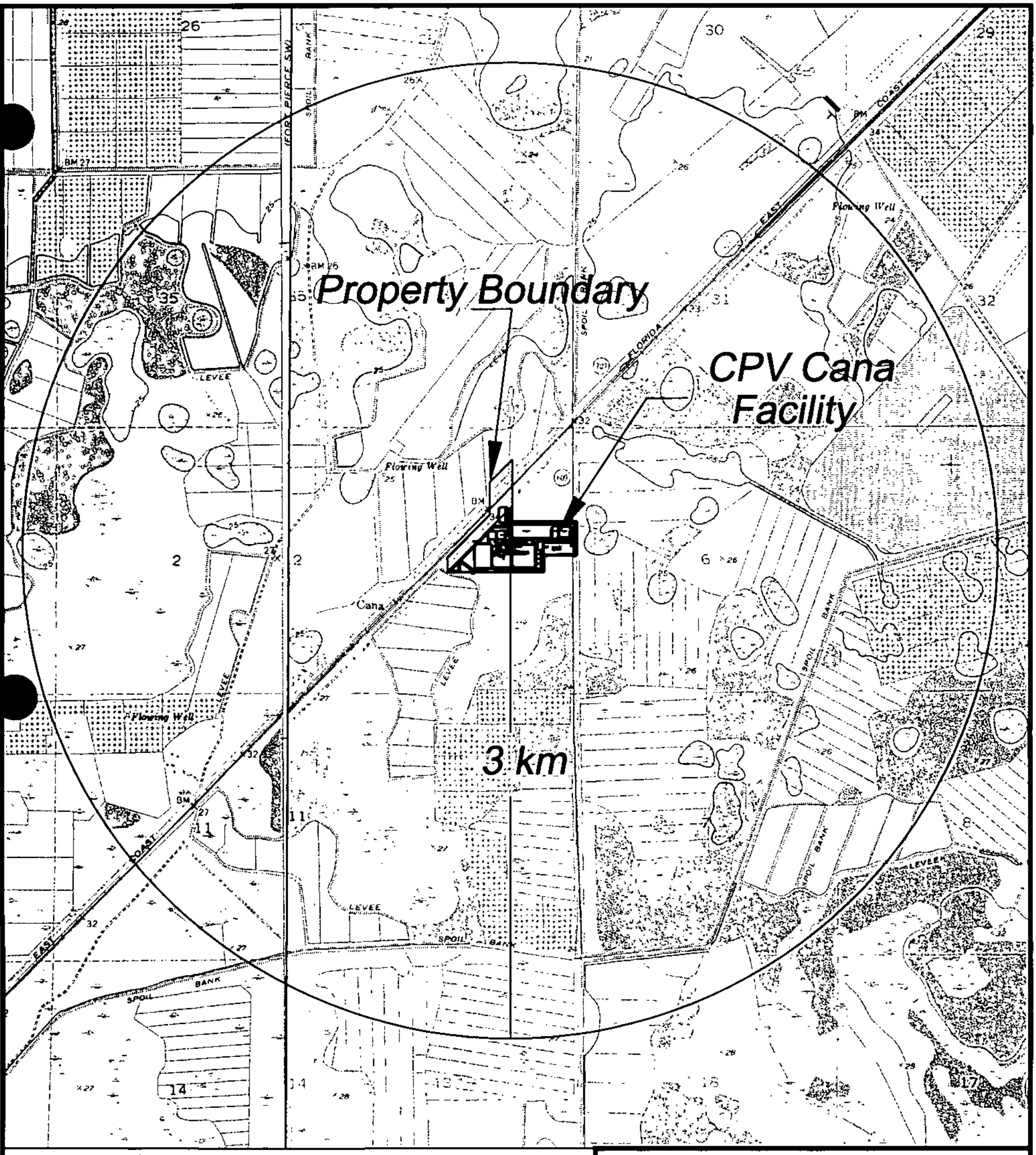
4.3 Land Use Determination

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

5 Waterside Crossing
Windsor, CT 06095
(860) 298 9692

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.

Table 4-5 CPV Cana Project Summary of Applicable Limits and Predicted Impacts											
Pollutant/AQRV	Averaging Period	NAAQS ($\mu g/m^3$)		PSD Class II ($\mu g/m^3$)				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

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 Signature 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: [signature] Date: 8-31-01

(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 weeks/year	days/week 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:

Emissions Unit Information Section ___1___ of ___2___

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

<table>
<tr><td colspan="2">1. Identification of Point on Plot Plan or Flow Diagram? Cooling Tower</td><td colspan="2">2. Emission Point Type Code:</td></tr>
<tr><td colspan="4">3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):</td></tr>
<tr><td colspan="4">4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:</td></tr>
<tr><td>5. Discharge Type Code: V</td><td colspan="2">6. Stack Height:
45 feet</td><td>7. Exit Diameter:
32.8 feet</td></tr>
<tr><td>8. Exit Temperature:
°F</td><td colspan="2">9. Actual Volumetric Flow Rate:
acfm</td><td>10. Water Vapor:
%</td></tr>
<tr><td colspan="2">11. Maximum Dry Standard Flow Rate:
dscfm</td><td colspan="2">12. Nonstack Emission Point Height:
feet</td></tr>
<tr><td colspan="4">13. Emission Point UTM Coordinates:
Zone: 17 East (km): 551.0 North (km): 3018.1</td></tr>
<tr><td colspan="4">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.</td></tr>
</table>

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

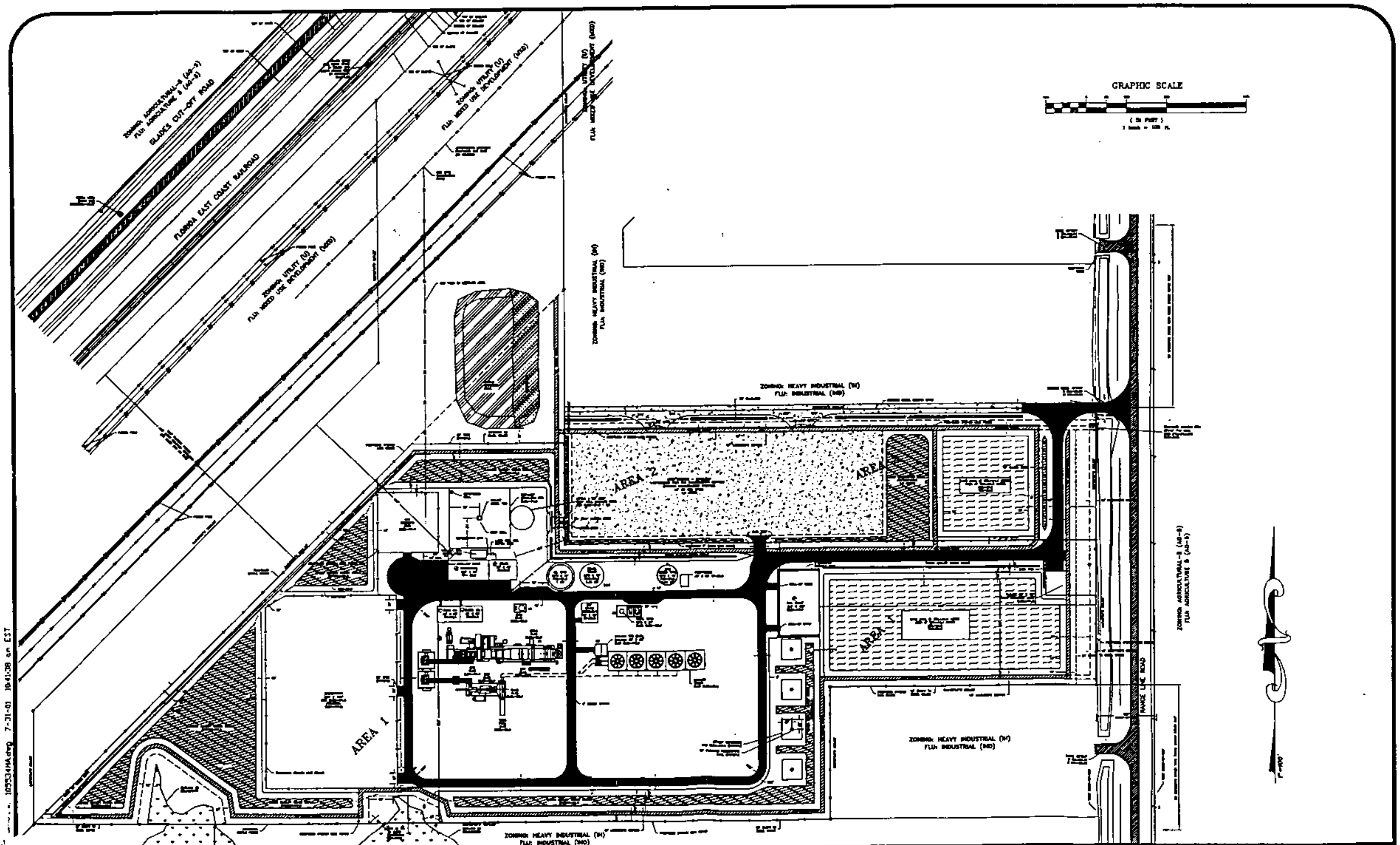
1. Process Flow Diagram [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:_______ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: CPV-CA [ ] Not Applicable [ ] 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

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)**
<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:	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)**
<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:	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)**
<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 @ 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)**
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:	59 F
Relative Humidity:	74%

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	8	pph	Ammonia	8	pph
O2	12.91	%	O2	12.91	%
H2O	8.21	%	H2O	8.21	%

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:	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)**
<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:	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)**
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:	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)**
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:	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.	19	pph	Front Half + Sulfates Partic.	9	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	1.1	pph	Ammonia	1.1	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	1.1	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)**
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:	72 F
Relative Humidity:	73%

50% Load Distillate

NOx	10.0	ppmvd@15%O2	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
SO2	1.1	ppmvw	SO2	58	pph
SO3	0	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	11.81	%	O2	11.81	%
H2O	10.19	%	H2O	10.19	%

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:	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

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

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

J:/projects/cpv cana/Final Revision/PotandAct Emissions.xls

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
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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

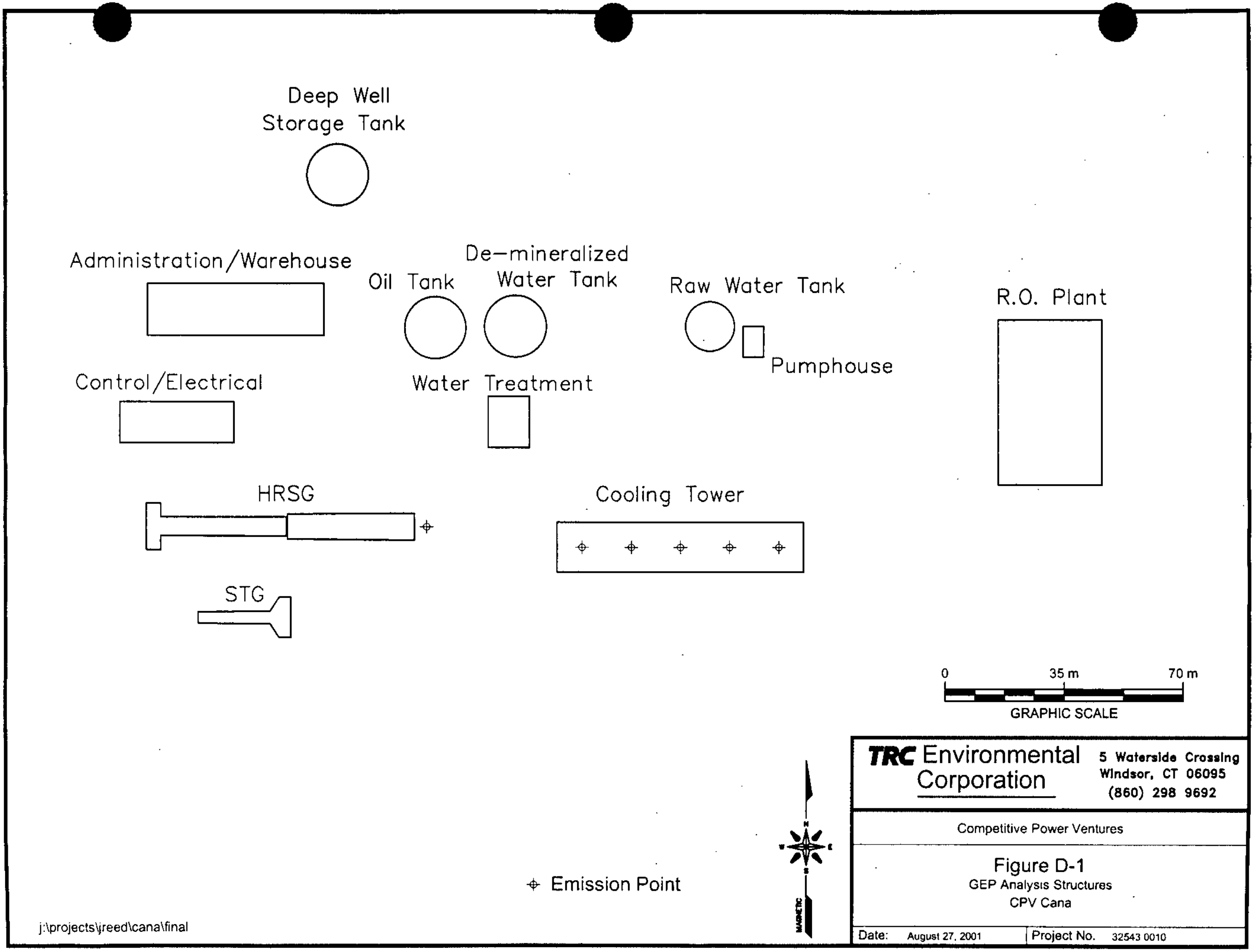
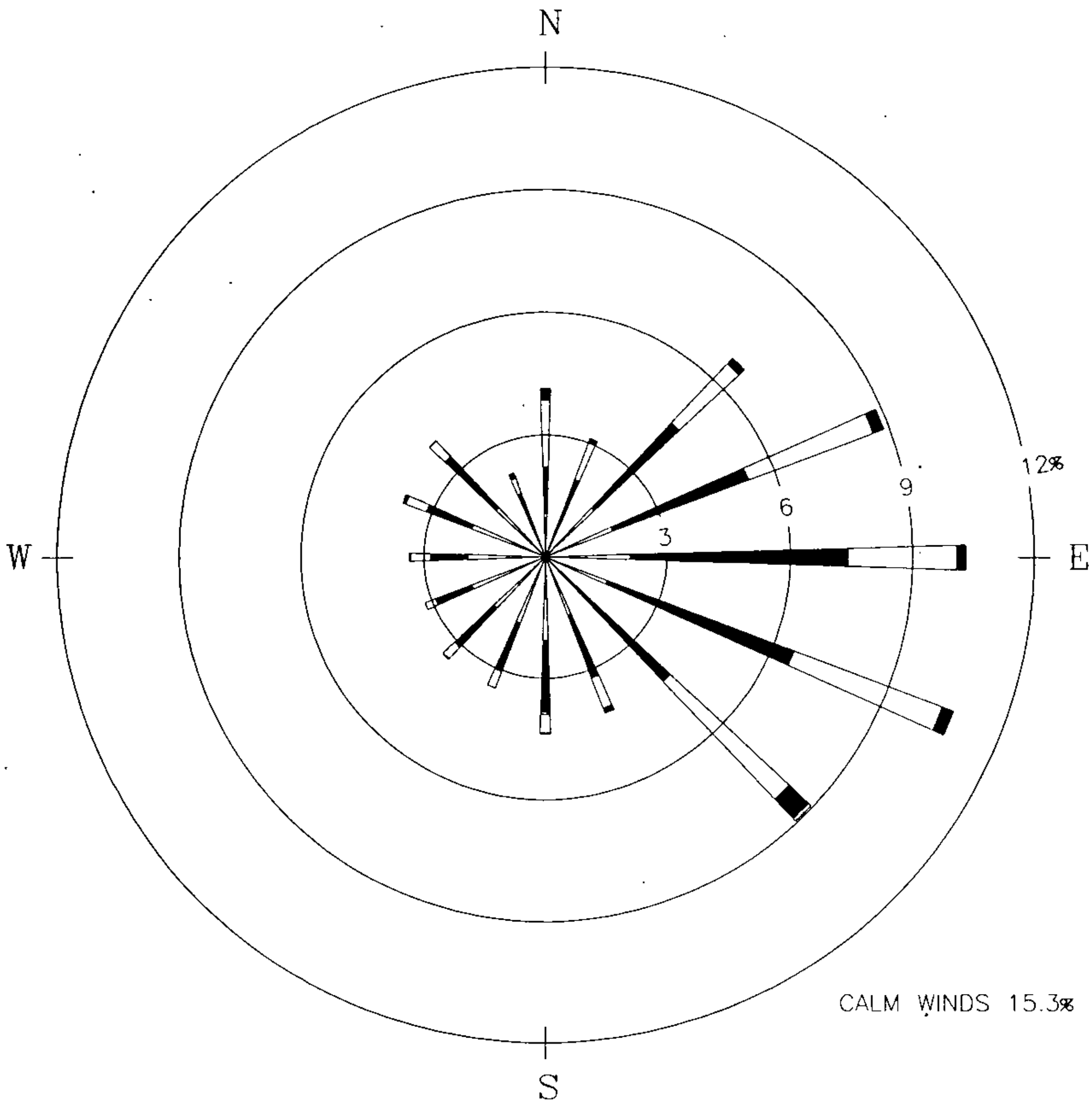
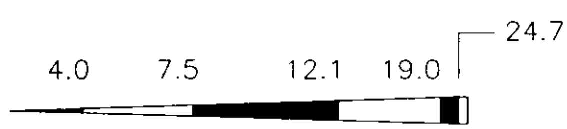


Figure D-1
GEP Analysis Structures
CPV Cana

Appendix D-2

Vero Beach Airport
(Station I.D.:(12843) Windroses (1990-1994)



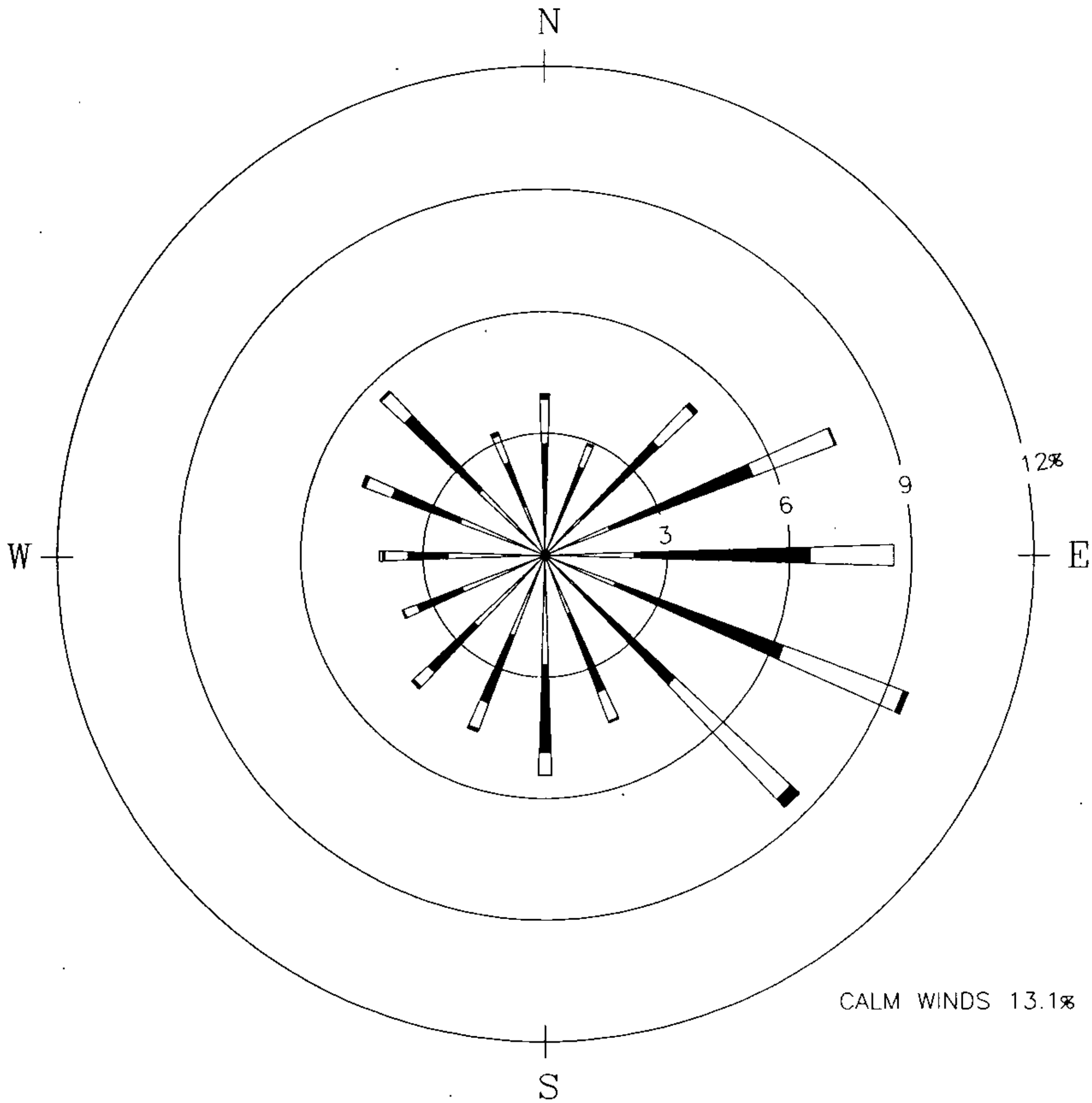


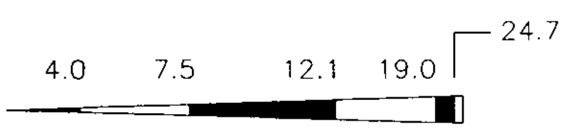
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

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





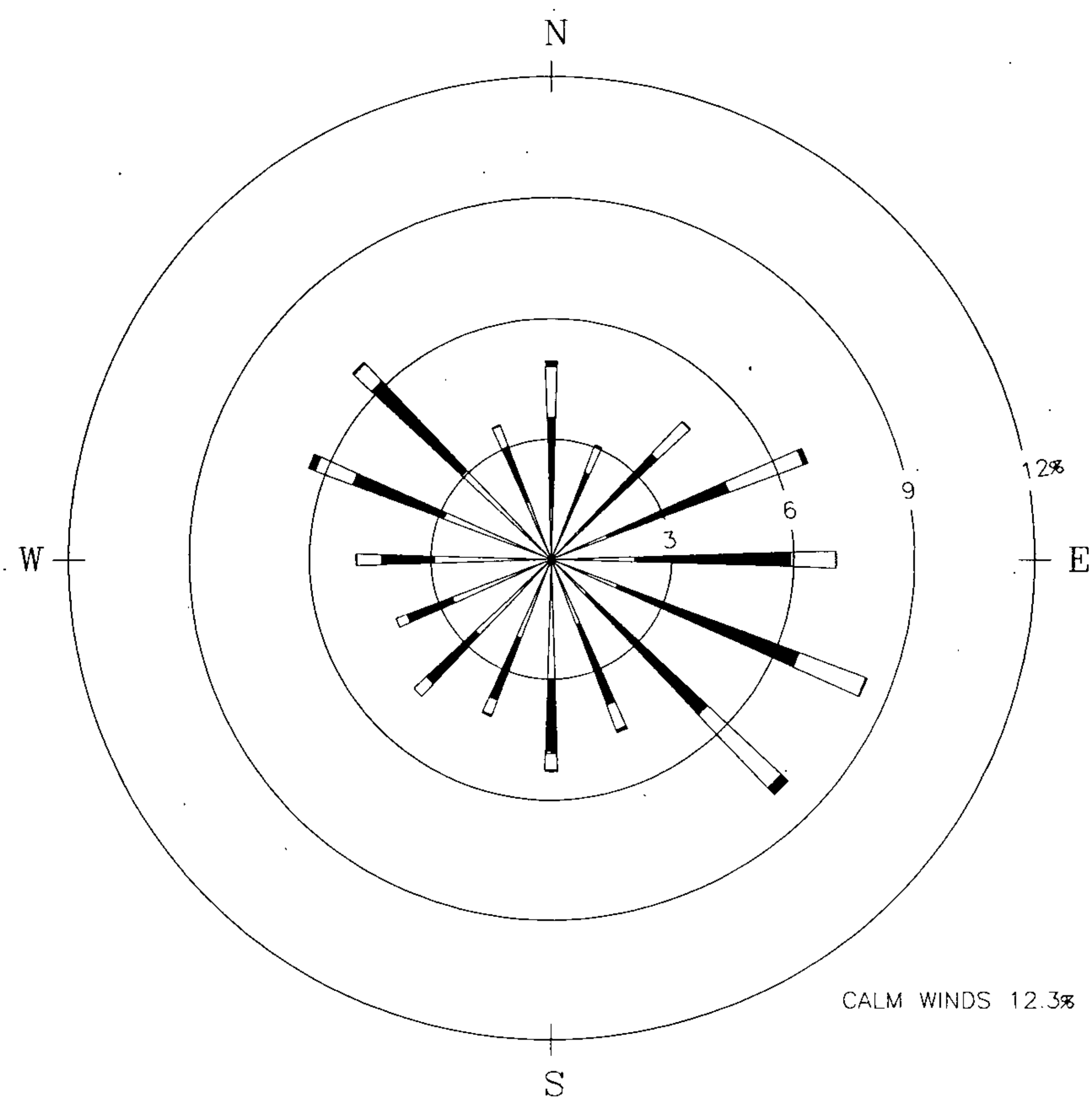
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

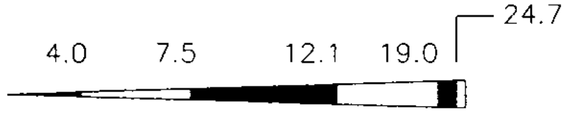
FIGURE D-3
WINDROSE

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





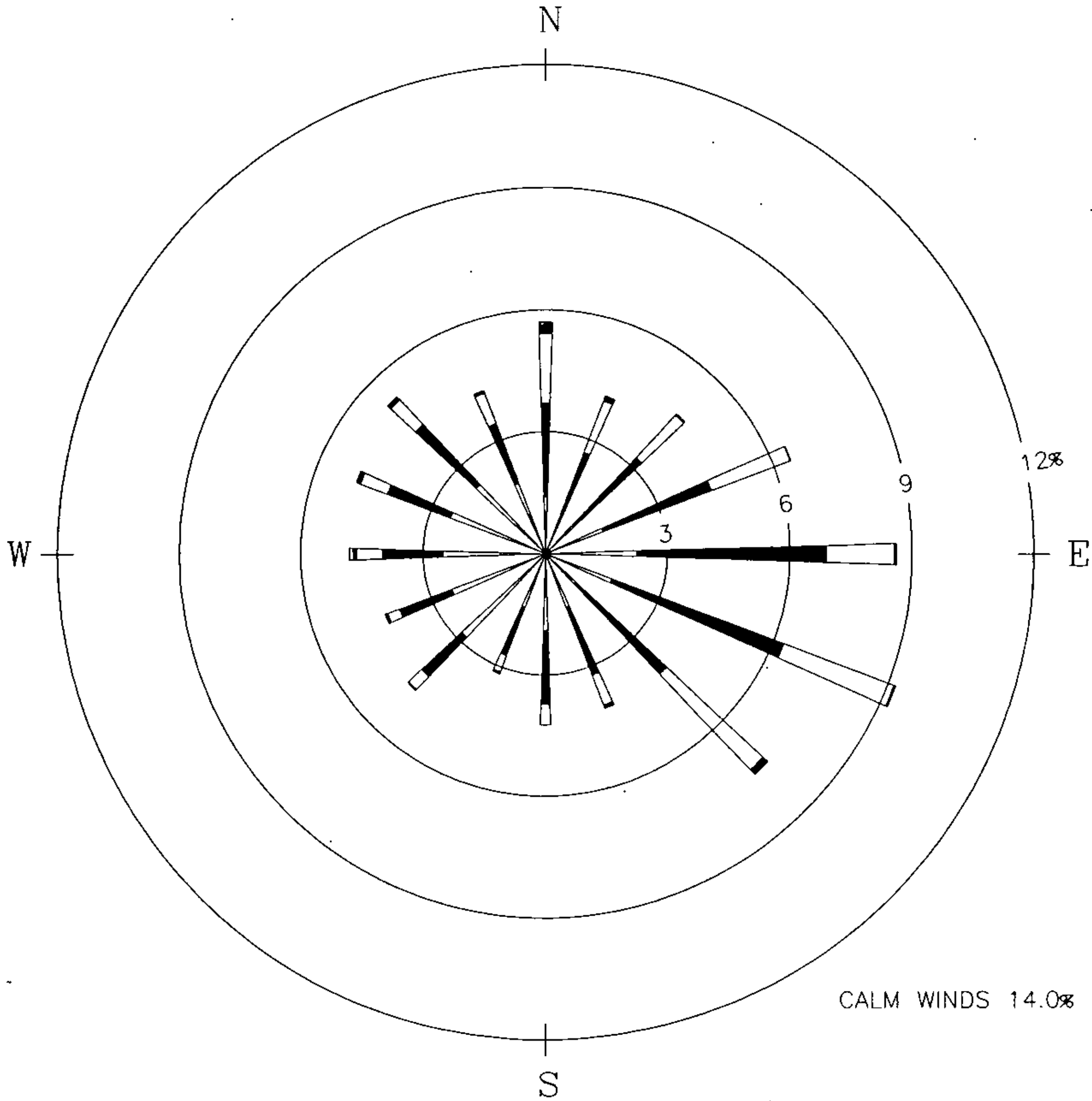
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

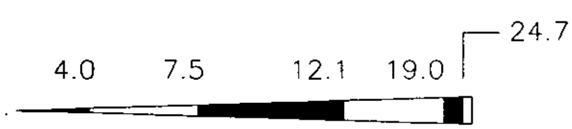
FIGURE D-4
WINDROSE

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





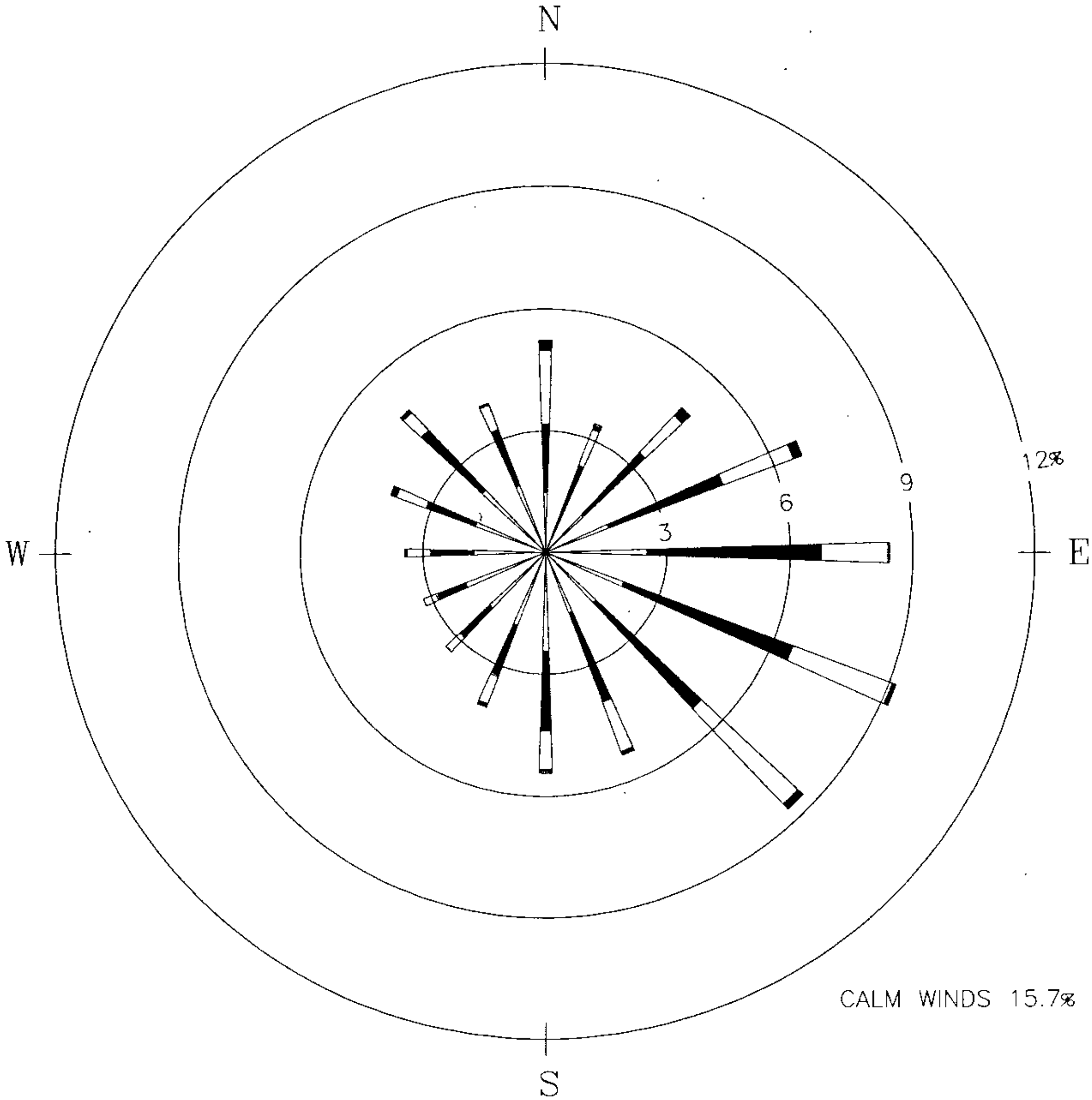
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

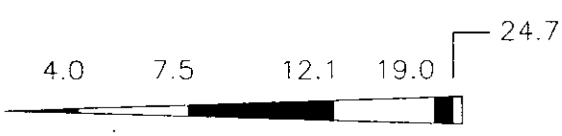
FIGURE D-5
WINDROSE

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





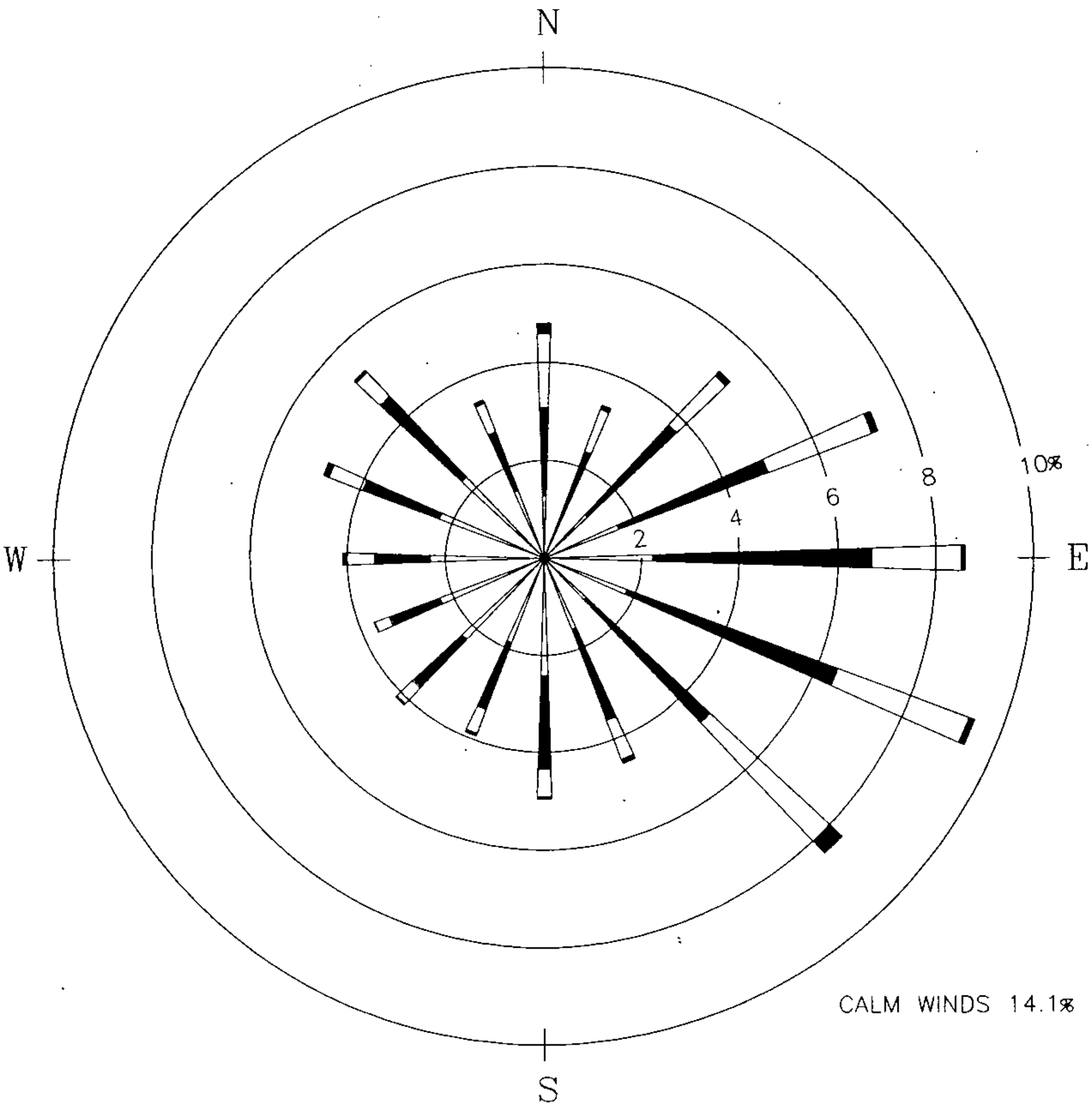
WIND SPEED CLASS BOUNDARIES
(MILES/HOUR)

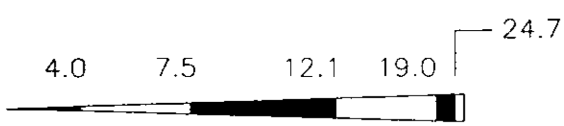
FIGURE D-6
WINDROSE

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

Type of Fuel	Operating Scenarios: No.	Ambient Temp. (deg F)	Evap Cooler	Load (%)	Maximum Predicted Single Source Impacts ($\mu g/m^3$) Pollutant: SO_2 3-Hour	SO_2 24-Hour	SO_2 Annual	NO_2 Annual	PM_{10} 24-Hour	PM_{10} Annual	CO 1-Hour	CO 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 PAR	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)	80	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	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	80	42.0	WET INJECTION	BACT-PSD
FLORIDA POWER GENERATION	DEBARY	FL	10/18/1991	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)	186	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	58	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	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	133	67.2		
KALAELOE PARTNERS, L.P		HI	03/09/1990	TURBINE, LSFO, 2	225	69.0	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	168	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 6,000 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, G	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	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 FU	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*	PPM*	CTRLDESC	BASIS
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE E/	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.	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 E/	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) (79MV	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 FRA	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	06/23/1988	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	05/01/1996	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 COMBUST	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	58	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	168	17.8	GOOD COMBUSTION PRACTICES	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE ST	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	184	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	28.2	CATALYTIC CONVERTER	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	04/09/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	28.3	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 V	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 FINANC	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 6	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 FINANCI	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[1]	lb/mmBtu[2]	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 TOWNSHIP	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	09/06/1989	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	56	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	0.0060	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), 83 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- I	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	166	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 COGENERATIOI	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	246	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	10/6/1997	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	4.3	NONE	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/1/1996	5/6/1998	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	267	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-CYCLI	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 AI	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. STEAMV	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	4/9/1996	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 SIEMES	260	6.0	DRY LOW NOX BURNER WITH SCR	BACT-PSD
AES PLACERITA, INC.		CA	7/2/1987	6/2/1988	TURBINE, GAS	86	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 GENEI	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 GENEI	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 8 PPM FOR NATI	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	61	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	6/26/1985	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) (7	81	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	156	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	56	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	56	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	2/28/1995	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 DLN2.6 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	228	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 STA	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	160	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	16.0	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	2/26/1986	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	7/28/1992	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	10/18/1990	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 V64.3 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	164	25.0	DRY LOW NOX COMBUSTOR	BACT-PSD
LORDSBURG L.P.	LORDSBURG	NM	6/18/1997	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	4/16/1999	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL A	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	38.0	WATER INJECTION	OTHER
FULTON COGENERATION ASSOCIATES	FULTON	NY	1/29/1990	5/18/1990	TURBINE, GE LM5000, GAS FIRED	63	38.0	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	8/8/1988	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	164	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	6/5/1989	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	63	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	60.0	STEAM INJECTION	BACT
ALASKA ELECTRICAL GENERATION & TRANSMISSION	BIG LAKE	AK	3/18/1987	6/10/1987	TURBINE, NAT GAS FIRED	80	75.0	H2O INJECTION	BACT-PSD
CONTINENTAL ENERGY ASSOC.	HAZELTON	PA	7/26/1988	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	9/6/1989	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	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 00	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. C	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	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 PARTNERS	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	11/1/1988	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	89	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 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) * 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.

[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

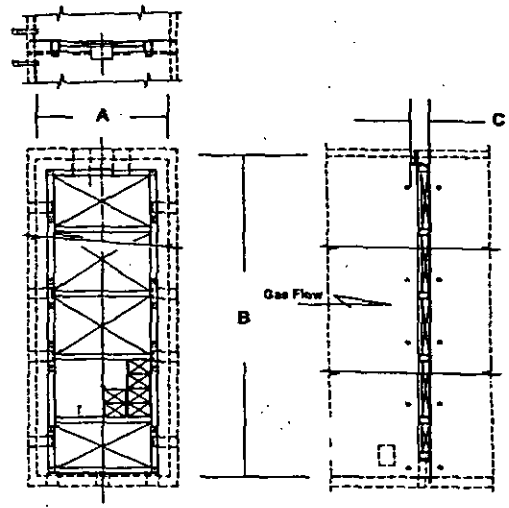
Drawings for Approval	3 – 4 weeks after notice to proceed with complete engineering specifications and Engelhard receipt of all engineering details.
Frame and Seals	16 weeks after release
Catalyst Modules	20 - 24 weeks after release

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 ±25% of the mean velocity at the catalyst face
Temperature (At catalyst face):	All Gas Temperatures must be within ±20°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**