CPV Gulfcoast Power Generating Facility
Application for Air Permit
Document ID: CPV-GC

Florida Department of Environmental Protection
Division of Air Resources Management

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Section 1

1.0 INTRODUCTION

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

CPV Gulfcoast, Ltd. is proposing to construct a combined-cycle power generation facility capable of generating a net electrical output of 250 megawatts. The CPV Gulfcoast, Ltd. power generation facility will be located in Manatee County. CPV Gulfcoast, Ltd. identified a tract of land approximately 160 acres in size located near Piney Point in Manatee County, Florida (Figure 1-1) for the development of a power plant facility. The project is bounded on the west side by U.S. Route 41, by Buckeye Road to the north, Bud Rhoden Road to the east, and Chapman Road to the south.

CPV Gulfcoast, Ltd. will install a single, efficient gas 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 the steam turbines to provide approximately 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 combustion turbine and HRSG will be built on a 10-acre portion of the Manatee County property. The new power generation facility includes a 150-foot stack. The steam turbine will be enclosed in a building, approximately 100 feet in height.

Section 2.0 provides a detailed description of the proposed facility. Section 3.0 describes the applicability of specific regulatory requirements to the CPV Gulfcoast project. Section 4.0 documents the air quality modeling study conducted to demonstrate compliance with ambient air quality standards and increments. Section 5.0 presents the air contaminant 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

2.0 PROJECT DESCRIPTION

CPV Gulfcoast, Ltd. proposes to construct a generation facility in Manatee County using state-of-the-art combined-cycle power generation technology and air pollution control systems. The major components of the Project include a new combustion turbine generator, a heat recovery steam generator (HRSG), and state-of-the-art air pollution controls. Natural gas will be used as the primary source of fuel. To enhance overall reliability, the system will also be capable of burning very low sulfur content distillate as backup fuel for up to an equivalent of 30 days at full load each year.

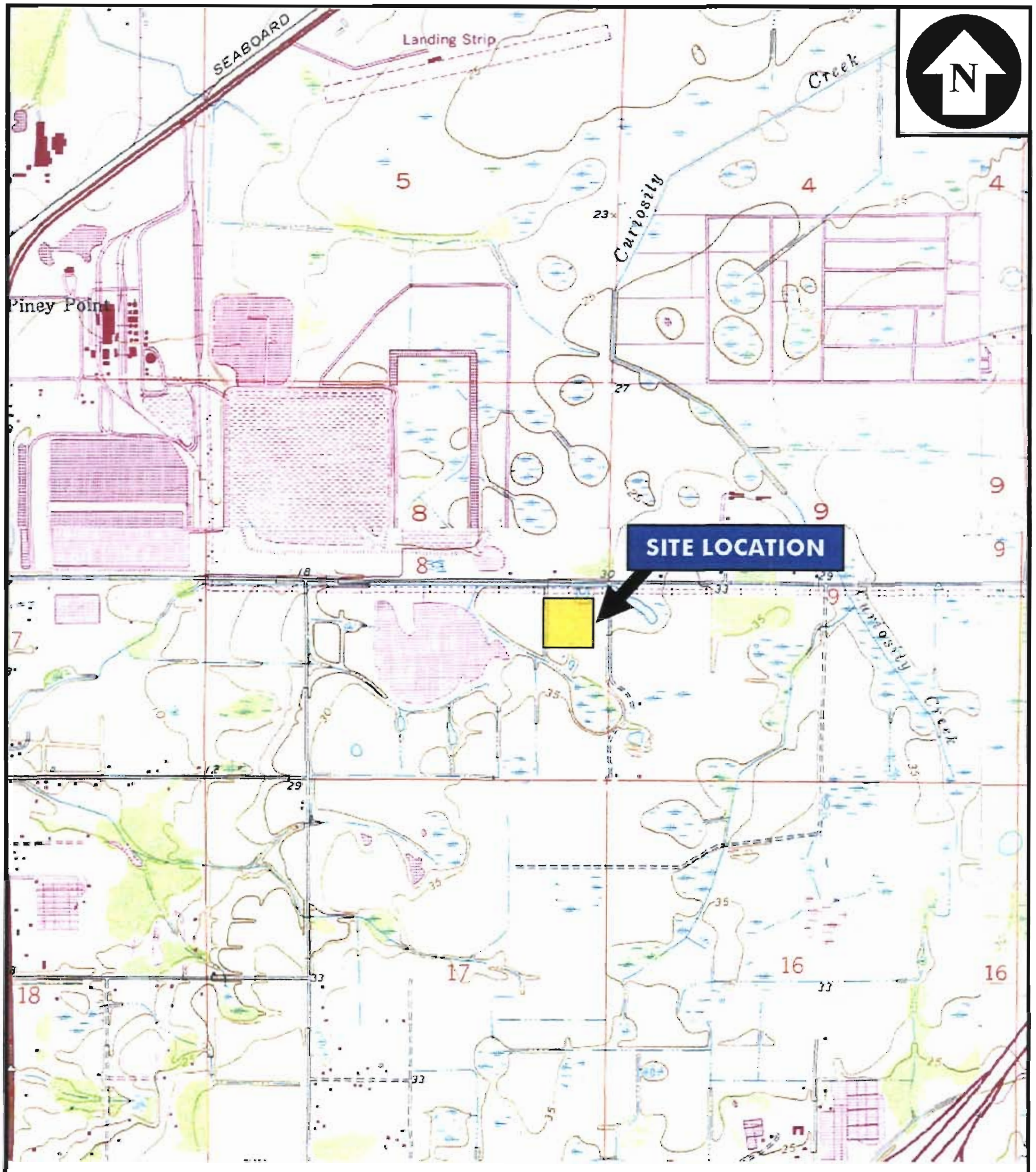
2.1 Site Description

The CPV Gulfcoast power generation facility will be located in Manatee County, Florida. CPV Gulfcoast, Ltd. identified a tract of land approximately 120 acres in size located near Piney Point for the development of a power plant facility. The project is bounded on the west side undeveloped land, by Buckeye Road to the north, Bud Rhoden Road to the east, and Chapman Road to the south. Figure 2-1 shows the site location.

2.2 Equipment Description

To maximize efficiency and energy conservation, the Project facilities will include both gas and steam cycles. In the gas cycle, the new combustion turbine will fire natural gas as its primary fuel to produce approximately 170 megawatts (MW). The steam cycle will consist of a new HRSG and steam turbine generator. This cycle 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 74.9 MW. The steam that exhausts the steam turbine generator is cooled and condensed for re-use in the steam cycle. The combined-cycle technology achieves an operational efficiency on a unit of energy output per unit of energy input basis greater than operational efficiency for older plants.

A description of each major Project component is provided below.



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987; PARRISH, FLA, 1973, PHOTOREVISED 1987; PALMETTO, FLA, 1964, PHOTOREVISED 1987; COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 2000 4000

scale in feet

QUADRANGLE LOCATION

L00-250/topo

TRC
Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

SITE LOCATION MAP

COMPETITIVE POWER VENTURES GULF COAST PROJECT PINEY POINT, FLORIDA

FIGURE 1	PROJ. NO. 28365

2.2.1 *Combustion Turbine Generator*

The Project will use an advanced natural gas and distillate fired combustion turbine generator. The combustion turbine generator to be supplied by General Electric will be equipped with their two-stage, lean pre-mix dry low-nitrogen oxide (NO_X) combustor.

The nominal 170 MW turbine generator is General Electric's 7241 FA. 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 resulting in a decrease in ambient air density reduce the mass flow rate available for power generation by the turbine. In the proposed unit, power augmentation would be employed to minimize the effect of decreasing output with increasing temperature.

During warmer ambient temperatures, the combustion turbine is power augmented to make additional 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 density of the air entering 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 superheater, an evaporator, and an economizer. Other HRSG components include a Selective Catalytic Reduction (SCR) NO_X control system (with associated ammonium hydroxide injection and control systems) and an exhaust stack.

2.2.3 *Emission Control Equipment*

The exhaust flow from the combustion turbine will pass through the SCR system before venting through one, 150-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 3.5 ppmvd @15% O_2 when firing natural gas and 10 ppmvd @15% O_2 when firing distillate.

2.2.4 *Cooling Tower*

Wet cooling towers are employed to cool and condense steam in electric generation facilities. The cooling tower reduces the temperature of cooling water by air-water contact. The facility will include a five-cell mechanical draft cooling tower.

Water 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. Counter-currently, air, induced through the tower by fans, passes upward through the fill section, where heat transfers from the water and a small fraction of the water evaporates, thus cooling the remaining water. The cooled water, which is collected in the basin, is then recirculated 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 remaining 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 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 blowdown losses is known as cooling tower makeup.

Air quality impacts would be expected with the mechanical draft cooling tower system due to the dissolved solids contained in the cooling tower drift, even if high efficiency drift eliminators were employed to limit the quantity of droplets in the plume were employed. The cooling tower will be designed to achieve a drift rate of 0.0005% of the circulating water flow rate, which represents the state of the art in drift elimination technology. Some of the solids would be less than 10 microns in size and would constitute PM-10 emissions. These cooling emissions would be in addition to 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 use is limited to the equivalent of the facility operating at 100% load for no more than 30 days. The distillate would 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 10-acre site. Site plans and facility arrangement drawings are contained in Appendix B.

Steam Turbine Building: This proposed building is designed to conform with all applicable zoning requirements. The building will house the steam turbine and associated mechanical and electrical equipment. The proposed building is approximately 100 feet wide by 160 feet long.

The highest portion of the building will be approximately 68 feet. This building will be a steel frame structure supported on a concrete foundation.

Storage Tanks: A tank will be constructed to store the distillate fuel. Two relatively small above ground storage tank will also be constructed: a de-mineralized water tank, and an ammonium hydroxide tank. A concrete containment dike will be built around the ammonium hydroxide tank.

2.4 Equipment Operation

The proposed design will be based on a General Electric STAG 107FA utilizing a single MS7001FA combustion turbine (CTG), a 3 pressure heat recovery steam generator (HRSG) and a steam turbine generator (STG) designed in conjunction with the HRSG steam conditions. The steam turbine generator output will be limited to less than 75 MW.

Control of STG output will be monitored and controlled to ensure the 75 MW output limit is not exceeded. A number of control options have been investigated and the most probable are described below.

When ambient temperature is at 59 °F or greater, excess steam generated in the HRSG will be extracted from the HRSG, bypassing the steam turbine, and injected into the CTG. This mode of operation is referred to as power augmentation. Since there is a limit on the quantity of steam that may be injected into the CTG, it may be necessary to further reduce steam flow to the STG to limit output or to reduce steam turbine output by other means

Bypass of a portion of heat exchange surface in the HRSG is an effective method of reducing steam production by reducing the heat recovered from the combustion turbine flue gas. The proposed design will make use of a low temperature economizer bypass to limit steam production by allowing more of the heat generated by the combustion turbine to be discharged to the atmosphere with the flue gas. This will limit STG output.

In many cases, application of both of these control modes will reduce steam output to the turbine to the required quantity. If additional reduction in STG output is required, raising 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 ambient temperature falls below 59 °F the manufacturer does not recommend injection of steam into the combustion turbine. If the low temperature economizer bypass combined with an increase cooling water temperature does not reduce STG output sufficiently, excess steam may bypass the steam turbine and be sent directly to the condenser.

Output of the STG will be controlled automatically utilizing the methods described above to ensure that the electrical power produced from steam does not exceed 74.9 MW.

2.5 Construction Schedule

The development schedule for the Project calls for obtaining all required pre-construction approvals by the first quarter of 2001. Upon financial closing, groundbreaking for the facility would be initiated by the Engineering Procurement Construction ("EPC") contractor. Construction of the Project would require approximately 22 months and is scheduled to be completed in the second quarter to third quarter of 2003. Start-up/testing activities would be ongoing during the later phases of construction. Commercial acceptance of the facility by CPV Gulfcoast, Ltd. would occur approximately six weeks after completion of the construction activities.

Section 3

3.0 APPLICABLE REGULATORY REQUIREMENTS

The CPV Gulfcoast Project (Project) proposed by CPV Gulfcoast, Ltd. must comply with air pollution control regulations administered by the Florida Department of Environmental Protection, Division of Air resources Management (DARM). Essential to understanding the regulatory requirements to which the Project must comply are the impacts of new power generation equipment on air pollutant emission rates.

The Project includes new combustion turbine, heat recovery steam generator (HRSG), and steam turbine that will produce approximately 250 megawatts (MW). This combination of equipment is considered a combined-cycle because it uses a gas cycle and a steam cycle to generate power.

Major pollutants of interest 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 (0.05 percent sulfur content) as the back-up fuel. The distillate fuel 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 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 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 Gulfcoast	
Pollutant	Potential Emissions (Tons/Year)
NO_X	125.7
SO_2	75.8
CO	222.2
PM/PM_{10}[1]	101.8
VOC	14.8

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 turbine (98.3 tons/year) and cooling tower drift (3.5 tons/year) emissions.

The U.S. Environmental Protection Agency (EPA) regulations establish air quality standards and air contaminant emission limits to 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 public health and welfare. The criteria pollutants are sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM_{10}), ozone (O_3), and lead (Pb). The FLDEP enforces the NAAQS as state air quality standards. Table 3-2 shows the NAAQS.

Primary standards protect human health with a 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 subsequent amendments. All areas of the nation have been classified as to their status with regard to attaining the standards. The site location is classified as "unclassified" or "attainment" for all criteria pollutants.

Table 3-2. Ambient Air Quality Limits 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	NA	1300[a]	512[a]	25
	24-hour	365[a]	NA	91[a]	5
	Annual	80[g]	NA	20[g]	1
Nitrogen Dioxides (NO_2)	Annual	100[g]	100[g]	25[g]	1
Carbon Monoxide (CO)	1-hour[a]	40,000	NA	NA	2000
	8-hour[a]	10,000	NA	NA	500
Particulate (PM_{10})	24-hour	150[d]	NA	30[a]	5
	Annual	50[g]	NA	17[g]	1
Ozone (O_3)	1-hour	235[b]	235[b]	NA	NA
	8-hour	157[c]	157[c]	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.

Implementation of the new PM_{10} compliance criteria, the $PM_{2.5}$ standard, and the 8-hour ozone standard has been delayed. The delay is due to a recent court decision and the need to develop additional ambient air quality data and compliance assessment procedures.

3.2 Non-attainment New Source Review

Because Manatee County is currently designated as "unclassified" 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 "unclassified" or "attainment" with respect to the NAAQS. The Manatee County is classified as such for all criteria pollutants.

As part of an 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 areas closest to the Project are the Chassahowitzka NWA. This Class I area is located approximately 109 km from the facility site, and therefore are beyond the distance for which an impact analysis is required under the PSD Rules.

A new major source in "unclassified" or "attainment" areas that will result in net emissions increases greater than the significant emissions increase levels presented in Table 3-3 are 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 addition of new power generation equipment is subject to PSD permitting requirements for these air pollutants.

Table 3-3. PSD Significant Emissions Increase Level And CPV Gulfcoast 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	125.7
SO_2	40	75.8
CO	100	222.2
PM	25	101.8
PM_{10}	15	101.8
VOC	40	14.8

3.4 New Source Performance Standards (NSPS)

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 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 new combustion turbine will generate no more than 9 ppm of NO_X prior to the addition of SCR controls and no more than 3.5 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 new combustion turbine will comply with the requirements of NSPS Subpart GG for NO_X.

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 which 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), HAP emissions do not exceed the regulatory thresholds. Accordingly, a MACT analysis will not be conducted.

3.6 Acid Rain Programs

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, the 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 system (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 become 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 through the market-trading program. The new power generation equipment incorporates the appropriate CEMS equipment in its design.

3.7 Operating Permit

The CPV Gulf Coast 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 Gulf Coast facility must comply and the methods used to demonstrate compliance.

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 above the applicable regulatory threshold. Because the SCR control technology proposed for the Project will utilize ammonia, a RMP may be required for the Project. If required, a RMP will be prepared before the presence of ammonia on-site above the applicable regulatory threshold.

3.9 Florida Air Permit Application

The purpose of the new source permitting process is to ensure that the new source 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 plan 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

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, models have become the primary analytical tools in most air quality assessments.

The following section describes the evaluation of the Project ambient air quality impacts. The air quality modeling study was conducted using data, assumptions, and procedures consistent with Florida DEP modeling guidelines and was based on discussions with Florida DEP 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 stack parameters for eleven combinations of ambient temperature and load conditions for natural gas and distillate oil firing to represent the range of operating conditions.

Table 4-1 contains the stack parameters for each of the eleven operating conditions for the proposed power generation equipment. Table 4-2 contains the estimated emission rates for all eleven of the modeled conditions for the power generation equipment based on vendor data currently available.

Table 4-1. Stack Exhaust Parameters CPV Gulfcoast Project		
Stack Height: 150 feet		
Stack Diameter: 18.5 feet		
	Temperature	**Velocity**
Case ID	**(°F)**	**(feet/second)**
Natural Gas Temperature (°F)/ Percent Load		
25/50	166	41
25/75	172	50
25/100	184	65
59/100FE	181	65
59/100	186	62
72/100	187	60
72/100FE	181	63
97/50	175	39
97/75	179	46
97/100	188	57
97/100FE	183	59
Low Sulfur Distillate Oil Temperature (°F)/ Percent Load		
25/50	255	47
25/75	258	59
25/100	285	79
59/100	284	74
72/50	255	46
72/75	265	56
72/100	284	72
97/50	259	44
97/75	270	54
97/100	284	67

Table 4-2. Power Generation Equipment Projected Criteria Pollutant Emissions CPV Gulfcoast Project

Ambient Temperature (^{0}F)	25	25	25	59	59	72	72	72	72	97	97	97	97
Load Condition (percent)	50	75	100	100	100FE	50	75	100	100FE	50	75	100	100FE
Natural Gas													
SO_2	7	8	10	10	10			9	9	6	7	9	9
NO_X	15.2	19.1	24.1	22.6	22.6			21.8	21.8	13.2	16.7	20.2	20.2
CO	20	25	31	29	29			28	28	18	21	26	26
PM	19	19	20	20	20			20	20	19	19	20	20
Distillate													
SO_2	63	80	99	94		58	74	92		54	69	84	
NO_X	49.5	63.8	80	75.7		46	58.8	73.6		42.4	54.5	67.6	
CO	65	58	70	66		73	52	63		83	51	58	
PM	46	49	53	52		45	48	51		44	47	50	

Note: All emissions in pounds per hour.

If the maximum predicted air quality impact of the new power generation equipment for a specific pollutant and averaging time is below the significance levels shown in Table 3-2, no additional modeling is required.

4.2 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 stack. Two structures, identified as the HRSG and the Steam Turbine Building have physical dimensions that could potentially affect plume dispersion. The steam turbine building has a maximum height of 68 feet above grade. The HRSG height is 75 feet above grade and is connected to the stack. Appendix B contains 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 contiguous cells is approximately 270 feet long, 48 feet wide, and 49 feet in height. The fan opening at the top of each cell is 42 feet in diameter. The cooling tower is to be located to the south and east of the Combustion Turbine and Steam Turbine Building (see Site Plan in Appendix B) with the long axis oriented east-west. As the cooling towers are sources of PM_{10}, the GEP analysis included these sources.

The Good Engineering Practice (GEP) stack height analysis was done following the procedures outlined in *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 new combustion turbine stack assuming a height of 150 feet. Each building's location and dimensions and the location of the proposed stack were input to calculate the maximum building downwash height and projected width for each 10-degree sector surrounding each stack. The ISCST3 model was used to predict air quality impacts. Input files for ISCST3 included the 36 pairs of effective building height and projected width values for each stack (including the cooling tower cells) generated by BPIP.

Appendix D-1 includes the output file from the GEP program and a graphic showing the location of the stacks and buildings.

4.3 Land Use Determination

The ISCST3 model options include using 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 radius circle centered on the project site (see Figure 4-1).

The project site is located in Piney Point, FL and is bordered by undeveloped land to the east, south and west. A mineral processing facility is located to the north (see Figure 4-1). The land use within three kilometers of the station is predominately rural. Based on the EPA recommended Auer Technique, the land use within the three-kilometer circle is rural.

4.4 Background Air Quality

The FDEP maintains a network of ambient air monitors to evaluate existing air quality throughout the state. The existing air quality in the area of project site is described using data from the FDEP monitoring network.

The most recent three years (1997 to 1999) of available data from nearby monitoring locations were analyzed to determine existing ambient levels for the criteria air contaminants. The highest annual average and highest second-high short-term concentrations were identified, as appropriate, for each air contaminant. Table 4-3 lists the monitoring stations, and the FDEP's classifications of their associated land uses, used to determine existing ambient levels in the vicinity of the project site.

The air contaminant measurements are summarized in Tables 4-4. The short-term levels are the second highest average values for each year. The values noted with asterisks are the highest second high and highest annual concentrations for all years and monitoring stations and represent the conservative worst-case background levels used for the modeling study.

Table 4-3. Air Quality Monitoring Stations

Monitor Address	Land Use	Location Type	Monitor ID
G. T. Bray Park, Bradenton (NO_2)	Residential	Urban/Center City	120814012
Port Manatee, Palmetto (SO_2)	Industrial	Rural	120813002
Holland House (PM_{10})	Industrial	Rural	120810008
220 Madison Avenue, Tampa	Commercial	Suburban	120570063-1

Table 4-4. Existing Air Quality

Pollutant	Station	Averaging Time	Concentration (ppm)		
			1997	1998	1999
NO_2	Bradenton	Annual	N/A	N/A	.007
SO_2	Palmetto	3-hour	N/A	.086	.056
		24-hour	N/A	.019	.017
		Annual	N/A	.004	.003
PM_{10}	Holland House	24-hour	40	38	42
		Annual	21.9	23.1	24.7
CO	Tampa	1-hour	4.5	6.7	8.5
		8-hour	2.6	3.7	4.7

4.5 Meteorological Data

The FDEP approved using five years of hourly surface Tampa Airport data (1987 to 1991). This recording site is located approximately twenty miles to the north of the project site. TRC downloaded this data from the EPA's SCRAM bulletin board. The meteorological data sets consist of hourly values of wind speed and direction, temperature, stability class, and mixing height.

Mixing height data were developed using upper air data recorded concurrently at Tampa Airport.

Windroses for the years 1987 through 1991 (individually and cumulatively) are contained in Appendix D-2. The predominant wind direction is from the east, east-northeast and northeast at approximately nine percent of the time for each of the three compass directions for the five years of data used in the modeling. Winds are from the north through the east approximately forty percent of the time. Calm winds occur on an average of about 6 percent each year.

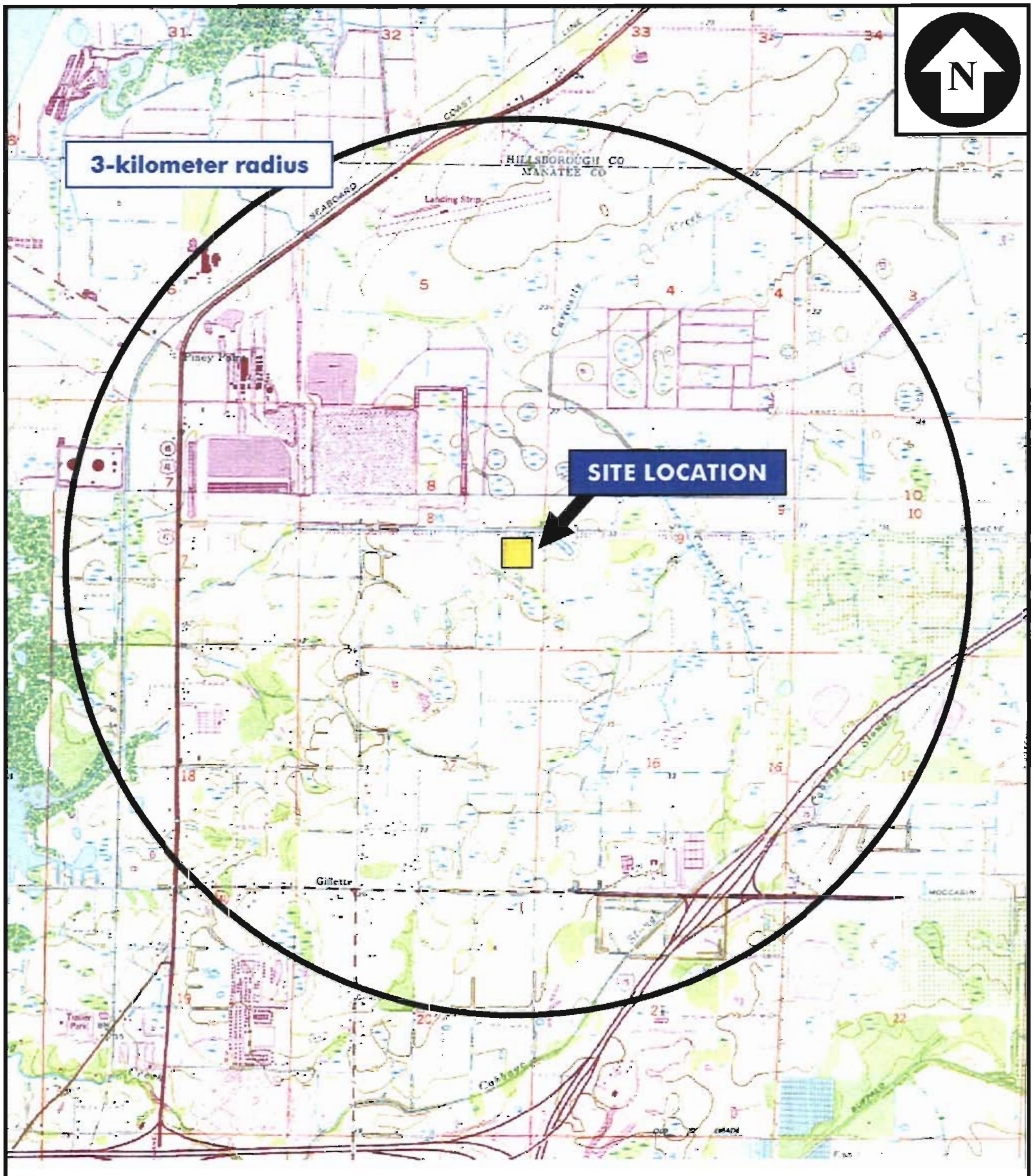
4.6 Receptors

A combination of receptor grid types was employed in the modeling analysis. Per recommendation of the FDEP, a rectangular grid was employed in the immediate vicinity of the plant. Receptors were also located at a greater density to the west, south and east of the perimeter to capture the maximum impact of the cooling tower. Proceeding away from the project site, a rectangular grid was centered on the project site out to a distance of approximately 8 kilometers. A total of 2944 rectangular grid receptors were developed.

A polar receptor grid was used to capture the maximum impacts from the combustion turbine stack emissions. Receptor rings were located at 9000, 10000, 12500, 15000, 20000, 30000 and 40000 meters at ten-degree intervals for a total of 252 polar receptors.

A total of 3,196 receptors contained in the three grids described above were used in the dispersion modeling analysis.

Per discussions with a FDEP representative, the receptor terrain values were set to zero along with the stack base elevations.



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987;
PARRISH, FLA, 1973, PHOTOREVISED 1987;
PALMETTO, FLA, 1964, PHOTOREVISED 1987;
COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 1 2

scale in kilometers

QUADRANGLE LOCATION

L00-250/3 kilo

TRC

Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

3-KILOMETER RADIUS MAP

COMPETITIVE POWER VENTURES
GULF COAST PROJECT
PINEY POINT, FLORIDA

FIGURE 2	PROJ. NO. 28365

4.7 Modeling Approach

TRC Environmental conducted the modeling study after consultation with FDEP, 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. ISCST3 is preferred by the 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 Tampa Airport meteorological data. If the maximum predicted impact was less then the significant level for a particular pollutant and averaging time, then no further assessment was required.

4.8 Predicted Impacts

Impacts predicted by the ISCST3 model are presented for each criteria pollutant and averaging time for the Project. The short term air quality impacts are documented for natural gas and backup low-sulfur distillate oil firing. The annual impacts are based on a weighted average of natural gas (11 months) and distillate (1 month) firing.

In assessing the impacts of the proposed new combustion turbine, the ISC3 model was run for all 24 operating cases using an emission rate of 1.0 grams per second. The predicted impacts were then scaled for each pollutant of concern in an electronic spreadsheet. Model output summaries for the proposed new turbine are contained in Appendix D-3. The scaled model results are presented in Appendix D-4.

The cooling tower is a source of PM_{10}. To address the combined impacts of this source and the proposed combustion turbine, separate model runs were conducted using estimated PM_{10} emission rates for the cooling tower and a worst-case PM_{10} scenario for the combustion turbine. For an ambient temperature of 97 F and at 50 percent load, the combustion turbine PM_{10} emission rate is 43 pounds per hour. For this operating scenario, modeled impacts reflect the low exhaust gas temperature and flow rate. Additional information is available in Section 4.8.4 below and in Appendix D-5.

4.8.1 Sulfur Dioxide (SO_2)

The maximum predicted 3-hour average impact for the five years of meteorological data modeled for the proposed combustion turbine alone was 10.4 $\mu g/m^3$ (distillate) and 2.2 $\mu g/m^3$ (natural gas). For the 24-hour average, the model predicted maximum impacts of 2.0 $\mu g/m^3$ (distillate) and 0.4 $\mu g/m^3$ (natural gas). These impacts are well below the 3-hour and 24-hour SO_2 Significant Impact Levels (SIL) of 25.0 and 5.0 $\mu g/m^3$, respectively.

The maximum annual average SO_2 impact is predicted to be 0.023 μg/m³. This maximum impact is well below the annual SIL of 1.0 μg/m³.

4.8.2 Nitrogen Dioxide (NO_2)

The modeled maximum annual impacts for a weighted average of the oil-fired and gas-fired scenarios were predicted to be 0.043 μg/m³, which is below the annual SIL of 1.0 μg/m³.

No additional modeling of this pollutant was performed.

4.8.3 Carbon Monoxide (CO)

The model predicted CO impacts for low-sulfur distillate oil firing were 22.8 μg/m³ and 7.2 μg/m³ for the 1-hour and 8-hour averaging periods, respectively. The predicted CO impacts for natural gas firing were 18.0 μg/m³ and 4.0 μg/m³ for the 1-hour and 8-hour averaging periods, respectively. With SILs for one-hour of 2,000 μg/m³ and for 8-hours of 500 μg/m³, the predicted CO impacts from the new power generation equipment are well below the SILs.

4.8.4 Particulate Matter (PM_{10})

The maximum predicted PM_{10} impacts for the combustion turbine for the 24-hour averaging period when firing low sulfur distillate oil firing was 1.6 μg/m³ (1.3 μg/m³ firing natural gas) and for the annual average was 0.053 μg/m³. The 24-hour and annual SILs for PM_{10} are 5.0 and 1.0 μg/m³, 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 description of the method used to develop the PM_{10} emission rate from the cooling tower is provided in Appendix D-5.

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.

Due to the location of the cooling tower on the project property, the maximum impacts are close to the property line. With the assumptions listed above, the maximum 24-hour combined impact for the cooling tower and combustion turbine is 3.6 $\mu g/m^3$ at a receptor located 35 meters to the east-southeast of the southeast corner of the property. At that location and time, the combustion turbine contributes 1.2 $\mu g/m^3$ to the combined impact with the balance due to the cooling tower. The maximum impact for each of the five years of modeling are located to the south or southeast of the cooling tower, suggesting that downwash is occurring due to the steam turbine building being upwind.

4.9 Class I Area Impacts

Proposed major sources within 200 km of a Class I area must perform an assessment of potential impacts in this area. The Class I area closest to CPV is the Chassahowitzka NWR area located approximately 120 km north of the proposed facility and within the distance for which an impact analysis is required.

In accordance with guidance from the FDEP, impacts at the Class I area were assessed using a distinct set of receptors placed along the boundary of the Class I area. The significance analysis consisted of modeling the "worst-case" operating scenario emissions of SO_2, NO_2, and PM-10 and determining the proposed project's impacts at the Chassahowitzka NWR.

Additional analyses to determine the impact of the proposed project on visibility, soils and vegetation, and regional haze at the Class I area were also conducted following the EPA's New Source Review Workshop Manual - Draft (EPA, 1990) and the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling

Long Range Transport Impacts (USEPA, 1998). The methodology for the Class I analyses is discussed below.

The CALPUFF (version 990228) model was used for the Class I analyses. CALPUFF is recommended by IWAQM for modeling the long-range transport impacts on Class I areas such as the Chassahowitzka NWR.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time-and space-varying meteorological conditions on pollutant transport, transformation, and removal. It also contains algorithms for near-source effects such as building downwash, transitional plume rise option, partial plume penetration, subgrid scale terrain interactions as well as longer range effects such as pollutant removal (wet scavenging and dry deposition), chemical transformation, overwater transport, and coastal interaction effects. The model can be used in a screening mode, using single station winds as used in the ISCST3 model, or a refined mode, using multiple meteorological stations and vertical wind profiles.

Following the guidance provided in the EPA's IWAQM Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts (EPA, 1998), the CALPUFF model was used in the screening mode to provide conservative results of the proposed project's impacts in the Class I area. Specifically, the model was used to demonstrate that the PSD Class I increments would not be threatened and the regional haze would not be significantly increased due to the proposed project.

In addition to the fenceline and polar receptors to be used for the refined air quality modeling, a separate set of receptors was used in the Class I impact analysis. In accordance with Mr. Chris Carlton of the FDEP, a set of 13 discrete receptors placed throughout the Chassahowitzka NWR was used to assess the impact at the Class I area.

4.9.1 Class I Area Impacts

Because CPV is located within 200 km of a Class I area (Chassahowitzka NWR), separate Class I significance, increment, and regional haze analyses were required to ensure the proposed project will not adversely affect the Class I area. These analyses were conducted following the latest guidance provided by the EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 1998), the FDEP, the National Park Service (NPS), and the Federal Land Manager (FLM) of the Chassahowitzka NWR.

4.9.2 Significance and Increment Analyses

The IWAQM Phase 2 Report (EPA, 1998) outlines the methodology for conducting a screening analysis to determine the impact on Class I areas from proposed sources. Results of the screening analysis were used to compare to the PSD Class I significance and increment levels and quantify the change in regional. Results of the screening analysis indicate that the proposed project's maximum impacts within the Class I area are well below the Class I significant impact concentrations and PSD Class I increment levels.

To determine the appropriate turbine operating load scenario to model in the Class I analyses, a screening analysis was conducted using the SCREEN3 model to determine each operating load's impact at the Class I area. The operating load, which yielded the maximum concentrations for SO_2, PM-10, and NO_2, was then used in the IWAQM screening analysis. The load analysis showed that operating Case 14 (turbine firing distillate oil at 100% load, 25°F) was the "worst-case" operating scenario for impacts at the Class I area for SO_2 and NO_2. Case 12 (turbine firing distillate oil at 50% load, 25°F) was the "worst-case" operating load for PM-10 impacts; however, Case 14 was used in the Class I analyses because it was the worst-case for two of the three main pollutants modeled in the Class I analyses. Results of the Class I load analysis are presented in Table 4-5. All SCREEN3 input and output files for the Class I load analysis are included electronically in Appendix D-6.

The IWAQM screening analysis consisted of modeling the "worst-case" operating scenario (Case 14) using the CALPUFF (version 990228) model with five years (1987-1991) of hourly surface data and twice daily mixing height data from Tampa Bay, Florida. Emissions of SO_2, PM-10, NO_X, and sulfuric acid (H_2SO_4) as primary sulfate, from the turbine were modeled. A discrete set of receptors provided by the FDEP were used to locate the maximum concentrations and depositions. A sea level terrain height was input for each receptor. This height is recommended by the FDEP for receptors located in the NWR.

The modeling domain input to the CALPUFF model consisted of a 12x12 cell grid centered on the proposed facility. Each grid cell was 25 km x 25 km with the southwest corner of cell covering the proposed facility at 348.5 km UTM East, 3057.0 km UTM North, zone 17. Therefore, the entire modeling domain was 300 km x 300 km (southwest corner of entire grid at 198.5 km UTM East, 2907.0 km UTM North, zone 17). The modeling domain extends more than 50 km beyond the set of receptors as recommended in IWAQM Phase 2 Report (EPA, 1998). Nine vertical layers were input to the CALPUFF model. These vertical layers had heights of 20, 80, 160, 300, 600, 1000, 1500, 2200, and 3000 meters.

To create the CALPUFF input file, the ISC2PUF conversion program, available with the CALPUFF suite of programs, was used to convert an ISC input file previously created for the Class II significance modeling to a CALPUFF input file. The MESOPUFF II chemistry option was selected to account for chemical transformation and wet and dry deposition was calculated. A land use category of irrigated agricultural was input along with a default surface roughness length of 0.25 m and a leaf area index of 3.0. The default geometric mean mass diameter of 0.11 μm (with a standard deviation of 0 μm) was also input for primary particulate emissions. The CALPUFF defaults (0.48 μm ± 2 μm) were used for the mean diameters and standard deviations for sulfate and nitrate.

Default background concentrations of ozone (80 ppb) and ammonia (10 ppb) were also input to the CALPUFF model because these pollutants act as catalysts for the chemical reactions creating sulfate and nitrate. The ammonia background concentration of 10 ppb was used as recommended in the IWAQM Phase 2 Report (EPA, 1998) for grasslands.

The CALPUFF input file was then run using the ISC meteorology option. The maximum modeled concentrations and deposition values are presented in Table 4-6. As shown in the table, the maximum concentrations of SO_2, PM-10, and NO_2 are less than their respective Class I significance levels, and, therefore, less than their Class I increment levels. The maximum concentrations of SO_4, NO_3, and nitric acid (HNO_3) presented in Table 4-6 were used in the regional haze analysis and the pollutant-specific deposition values were used in the AQRV analysis.

4.9.3 Regional Haze

Haze is a result of the suspension in the atmosphere of small aerosols, which individually are invisible to the naked eye, but collectively give the sky an opalescent appearance. Sources of aerosols are natural (e.g., sea spray, forest fires, dust storms) and anthropogenic (e.g., automobile and stack exhaust). Haze usually is associated with subsaturated air, whereas fog or mist indicates saturated conditions. To measure the amount of haze, light extinction, which is the attenuation of light (defined as the reduction in illuminance of a parallel beam of light as the light passes through a medium wherein absorption and scattering occur) is used. However, light extinction can also be caused by fog or mist and other atmospheric phenomenon (e.g., precipitation). Therefore, the change in light extinction should be based upon the change from the existing or background light extinction to the potential light extinction caused by a proposed source.

To determine the potential change in light extinction (the sum of light scattering and absorption) due to the proposed project at the Chassahowitzka NWR , the worst-case operating scenario determined in the load analysis was modeled. Emissions of SO_2, NO_x, PM-10, and sulfuric acid (H_2SO_4)(as primary sulfate) from the turbine were modeled with the CALPUFF model.

The maximum 24-hour sulfate, nitrate (NO_3 and HNO_3), and particulate concentrations presented in Table 4-6 from the CALPUFF screening analysis were used to determine the change in regional haze due to the proposed project. The sulfate and nitrate concentrations were converted to concentrations of ammonium sulfate (NH_4SO_4) and ammonium nitrate (NH_4NO_3) using conversion factors of 1.375 and 1.29, respectively, which are ratios of the respective molecular weights. Thus, the 24-hour NH_4SO_4 and NH_4NO_3 concentrations were calculated to be 1.90×10^{-2} $\mu g/m^3$ and 2.9×10^{-2} $\mu g/m^3$, respectively.

A relative humidity factor (6.0) from Appendix B of the IWAQM Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility (EPA, 1993) was determined based on a relative humidity of 90 percent as recommended in the IWAQM Phase 2 Report (EPA, 1998). The light extinction coefficients for sulfate and nitrate were then calculated using the equation:

$$b_{ext(i)} = 0.003 * conc * f(RH)$$

where:

$b_{ext(i)}$	=	the pollutant-specific extinction coefficient;
0.003	=	a nominal dry scattering efficiency;
conc	=	the pollutant-specific calculated concentration ($\mu g/m^3$); and
f(RH)	=	the relative humidity factor.

The IWAQM Phase 2 Report (EPA, 1998) provides light extinction calculation methods for four different particulate types: soil, coarse, organic, and elemental carbon (soot). The nominal dry scattering efficiencies for these four particulate types are 0.001, 0.0006, 0.004, and 0.01, respectively. Because the particulate emissions from the proposed project have not been categorized into these four particulate categories and the assumption that CALPUFF is not necessarily linear (i.e., the ratio of organic particulate emissions to total particulate emissions is not necessarily equal to the ratio of organic particulate impacts to the total particulate impacts), the light extinction coefficient for particulates was conservatively estimated using the maximum particulate nominal dry scattering efficiency (0.01) in the equation:

$$b_{ext(part)} = 0.01*conc$$

where:

$b_{ext(part)}$ = the particulate extinction coefficient; and

0.01 = the elemental carbon nominal dry scattering efficiency;

conc = the pollutant-specific calculated concentration ($\mu g/m^3$).

Using the above equations yields pollutant-specific light extinction coefficients of $8.91x10^{-5}$ km^{-1} for SO_4, $5.81x10^{-4}$ km^{-1} for nitrates (NO_3 and HNO_3), and $5.28x10^{-4}$ km^{-1} for particulates. The pollutant-specific light extinction coefficients were then summed to determine the total light extinction coefficient, $1.2x10^{-3}$ km^{-1}, due to the proposed project. Appendix D-7 contains all the calculations for the regional haze analysis.

According to the NPS, the background light extinction coefficient was calculated using the equation:

$$b_{ext(back)} = 3.912/BVR$$

where:

$b_{ext(back)}$ = the background light extinction coefficient; and

BVR = the background visual range (km).

The NPS recommends a BVR of 65 km for the Chassahowitzka NWR. The value represents the average visibility measured during the 20 percent of days with the greatest visual range at the NWR. Thus, $b_{ext(back)}$ equals 0.06 for the Chassahowitzka NWR.

The total light extinction coefficient and the background light coefficient were then used to calculate the percent change in light extinction due to the proposed source using the ratio of:

Δlight extinction = (total light extinction)/(background light extinction)

Calculating the change in light extinction using the above equation results in a change of 2.0%. This change in light extinction is less than recommended (5%) in the IWAQM Phase 2 Report (EPA, 1998); therefore, the proposed project will not adversely affect the regional haze at the Chassahowitzka NWR.

4.9.4 Air Quality Related Values (AQRVs)

There currently are no AQRVs for the Class I area; therefore, the deposition values have not been included in the Class I modeling analysis.

References

USEPA, 1998. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Report and Recommendations for Modeling Long Range Transport Impacts. U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

USEPA, 1993. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 1 Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility. U.S. Environmental Protection Agency. Research Triangle Park, North Carolina. April 1993.

Table 4-5. Class I Area Screening Results Maximum 1-Hour Modeled Concentrations				
Operating Scenario	χ/Q	NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	PM-10 ($\mu g/m^3$)
CASE01	0.15	0.29	0.13	0.36
CASE02	0.14	0.33	0.14	0.33
CASE03	0.12	0.36	0.15	0.30
CASE04	0.12	0.34	0.15	0.30
CASE05	0.12	0.34	0.15	0.30
CASE06	0.12	0.34	0.14	0.31
CASE07	0.12	0.33	0.14	0.31
CASE08	0.15	0.25	0.11	0.36
CASE09	0.14	0.29	0.12	0.33
CASE10	0.12	0.32	0.14	0.31
CASE11	0.12	0.32	0.14	0.31
CASE12	0.12	0.73	0.92	0.68
CASE13	0.10	0.83	1.04	0.64
CASE14	0.09	0.90	1.11	0.60
CASE15	0.12	0.68	0.86	0.67
CASE16	0.10	0.78	0.98	0.63
CASE17	0.09	0.85	1.06	0.59
CASE18	0.12	0.64	0.81	0.66
CASE19	0.11	0.73	0.92	0.63
CASE20	0.09	0.80	0.99	0.59

[a]Concentrations calculated using the SCREEN3 model at a distance of 100 km (actual distance to Chassahowitzka NWR is 120 km; however, SCREEN3 limited to receptors within 100 km of source).

Table 4-6. Maximum Modeled Class I Concentrations And Deposition Values					
Pollutant	**Averaging Period**	**Year of Maximum**	**Concentration ($\mu g/m^3$)**	**Class I Significance Level ($\mu g/m^3$)**	**Class I Increment Level ($\mu g/m^3$)**
Concentrations					
SO_2	3-Hour	1989	0.38	1.0	25
	24-Hour	1989	0.099	0.2	5
	Annual	1989	0.0040	0.1	2
PM-10	24-Hour	1989	0.053	0.3	8
	Annual	1989	0.0043	0.2	4
NO_2	Annual	1989	0.0028	0.1	2.5
SO_4	24-Hour	1989	0.0036	--	--
NO_3	24-Hour	1989	0.010	--	--
HNO_3	24-Hour	1989	0.015	--	--
-- Not Applicable					

Section 5

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 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, corrected to 15 percent O_2 content (ppmvd @ 15% O_2), 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 applicable regulations, including control technology requirements under the PSD and non-attainment rules, is provided in Section 3. 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 5.1, the existing 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) for a PSD area. A PSD area is defined as an attainment area. Based upon these criteria, the federal BACT requirements 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 for all criteria pollutants. Therefore, LAER requirements, including a control technology determination, are not applicable for any pollutant.

5.2 Approach Used in BACT Analysis

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, as necessary. 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 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 USEPA 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 search 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 *OAQPS Control Cost Manual*, (USEPA, EPA 450/3-90-006, January 1990) 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, which are 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) and installation. Indirect costs include costs for site and building preparation, 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 - 5% of PEC;
- Freight - 4% of PEC;
- Installation - 45% of PEC;
- Engineering Costs - 33% of TDC + $5,000; and
- Contingency - 20% of Direct and Indirect Costs.

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.

An 8% nominal interest rate has been selected for this evaluation. The investment life, n, has been assumed equal to a ten-year payback period. These values are consistent with values presented in the "*OAQPS Control Cost Manual*" and the latest update from William Vatavuk's companion text. Therefore, the TCI has been amortized over a ten-year period at an 8% interest rate.

The total annual operating cost is defined as the expenses associated with the annual operation of the control equipment and is the sum of 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

Two forms of energy impacts that may be associated with a control option can normally be quantified. Increases in energy consumption resulting from increased heat rate may be shown as incremental Btu's 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, NO_X, and VOC.

5.3 BACT Analysis for Carbon Monoxide

The new power generation equipment consists of a combustion turbine and a heat recovery steam generator (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.

5.3.1 Identification of Technically Feasible Control Options

The proposed General Electric Model 7FA turbines have inherently low CO emissions, due to the dry low-NO_x combustion technology employed. GE 7FA 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 are guaranteed to be no more than 9 ppmvd for this load range during gas fired operation and no more than 20 ppmvd 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 practical 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; only five facility permits in the BACT/LAER Clearinghouse indicate the use of an oxidation catalyst as a control.

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 units.

5.3.2 Economic Impact of Oxidation Catalyst

The initial capital cost for the catalyst is $1,005,200, based upon an estimate from a catalyst vendor that includes installation and contingency for the GE 7FA combustion turbines in simple cycle mode. 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), lost revenue due to reduced turbine output and increased fuel cost due to adverse effect on turbine heat rate, or efficiency. Equivalent annual cost for this technology (annualized capital plus annual O&M costs) is $522,842 per year. The uncontrolled CO emission levels of 9 ppmvd during natural gas firing and 20 ppmvd during oil firing can be reduced to 2 ppmvd and 4 ppmvd by an oxidation catalyst. Therefore, of the uncontrolled annual emissions of 124 tons of CO per year, an oxidation catalyst would control 99 tons of CO per year. The annual operating scenario used in the calculation (turbine operation at 100% load for 7884 hours per year firing gas 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 is $5,266 per ton, which is calculated as follows:

($536,619/yr)/(123 tons CO controlled/yr) = $4,350/ton CO

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, 1,517,670 kW-hr lost per year) 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. The increase in heat rate predicted to result from the catalyst, 9 Btu/kW-hr, corresponds to an additional 14,638 MMBtu fuel consumption per year.

5.3.4 Environmental Impacts of Technically Feasible CO Control

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's as well as CO, although the proposed VOC emissions are already quite low (maximum of 1.4 ppm) 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. 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.

5.3.5 BACT Proposal

The advanced dry low-NO_X turbine combustion technology is proposed as BACT for CO emissions from the combined cycle unit. The proposed limits are 9 ppmvd during natural gas firing for operating loads greater than 50% (15 ppmvd during periods of power augmentation at 100% load) and 20 ppmvd during distillate fuel oil firing at 100% load (See Appendix C for CO concentrations at other loads.).

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 and 0.05% sulfur distillate as back-up, which is considered BACT for SO_2 emissions. The proposed maximum SO_2 emission rate for natural gas firing is 10 lb/hr and for distillate firing is 99 lb/hour.

5.5 BACT Analysis for Particulate Matter

5.5.1 Combustion Turbine

Particulate mater (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 low sulfur (0.05%) distillate as the back-up fuel, the combination of clean fuels and good combustion is considered BACT for PM/PM-10 emissions. The proposed emission limits for PM/PM-10 are 20 lb/hr during natural gas firing, and 51 lb/hr during distillate firing.

5.5.2 Cooling Tower

PM/PM-10 emissions from 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 particulate 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% 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, concentrations of nitrogen and oxygen in the inlet air and residence time within the combustion zone. Fuel NO_X is formed by the oxidation of fuel-bound nitrogen. Fuel NO_X is 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); 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 General Electric 7FA turbine utilizes a dry low-NO_X combustion system, which produces expected uncontrolled NO_X emissions of 9 ppm during natural gas firing.

5.6.1 Identification of Technically Feasible Control Options

The "Top-Down" policy for 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 continuos emissions monitoring, the facility's emission limits have not been demonstrated to be achievable and are not considered LAER.

The most stringent permitted NO_X emission limit for combustion turbines, at the time of this permit application, is 3.5 ppm for the Brooklyn Navy Yard facility. This facility utilizes a dry low-NO_X GE turbine, which emits uncontrolled NO_X emissions of 9 ppm and utilizes SCR NO_X controls. The project had been in commercial operation for approximately three years, and was reported to be in compliance with emission limits based upon stack testing and CEM.

The new $SCONO_X$ technology has been installed on 32 MW natural gas-only plants using GE LM 2500 turbines. The facility is owned and operated by one of the parent companies of Goal Line Technologies, the $SCONO_X$ technology developer. To date, this technology has achieved a NO_X emission rate comparable to those considered LAER or Best Available Control Technology (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-2) 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 back-pressure 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. Since SCR effective temperatures are below turbine exit temperature and above stack temperature, the catalyst must be located within the HRSG.

The only proposed, proven available technology for the proposed level of NO_X control for the new power generation equipment is SCR.

5.6.2 Economic Impact of Oxidation Catalyst

In addition to having technical problems, $SCONO_X$ control technology if significantly more expense 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 $24,916/ton per year. The SCR annualized cost per ton, which is the proposed control technology for NO_X removal, totaled $2,835/ton per year.

5.6.3 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 new power generation equipment. Proposed BACT emission limits for the new power generation equipment are 3.5 ppm (24.1 lb/hr) NO_X during natural gas firing and 10 ppm (80.0 lb/hr) NO_X during distillate firing.

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 Gulfcoast, Ltd.	
2. Site Name: CPV Gulfcoast	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: Street Address or Other Locator: City: County: Manatee Zip Code:	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: Sean Finnerty, Director of Development
2. Application Contact Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton State: MA Zip Code: 02375
3. Application Contact Telephone Numbers: Telephone: (508) 238 - 0194 Fax: (508) 238 - 2844

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	9-11-00
2. Permit Number:	0810194-001-AC
3. PSD Number (if applicable):	PSD-FL-300
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, Executive Vice President
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton State: MA Zip Code: 02375
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (508) 238 - 0194 Fax: (508) 238 - 2844
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 Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Registration Number:	
2. Professional Engineer Mailing Address: Organization/Firm: Street Address: City: State: Zip Code:	
3. Professional Engineer Telephone Numbers: Telephone: ( ) - Fax: ( ) -	

4. Professional Engineer Statement:

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

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

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

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

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

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

______________________________ ______________________

Signature Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
--	General Electric 107FA 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 a combined cycle power generation facility consisting of one 170-MW General Electric 107FA combustion turbine and heat recovery steam generator designed to power a steam turbine with an operationally 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): 348.5	North (km): 3057.0	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):	Longitude (DD/MM/SS):		
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 Gulfcoast, Ltd. will install a single, efficient gas 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 and HRSG will be built on a 10-acre portion of the Manatee County property. The new power generation facility includes a 150-foot stack. The steam turbine will be enclosed in its own building, approximately 100 feet in height.			

Facility Contact

1. Name and Title of Facility Contact: Sean Finnerty, Development Director		
2. Facility Contact Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton	State: MA	Zip Code: 02375
3. Facility Contact Telephone Numbers: Telephone: (508) 238 - 0194	Fax: (508) 238 - 2844	

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?
8. 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	A				Sulfur Dioxide
NOX	A				Nitrogen Oxides
PM	A				Particulate Matter
PM10	A				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-GC [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Document ID: CPV-GC [ ] 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: ________ [X] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: CPV-GC [ ] 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.

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

General Electric 107FA combustion turbine

4. Emissions Unit Identification Number: [ ] No ID
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	September 2003	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

Construction of a combined cycle power generation facility consisting of one 170-MW General Electric 107FA 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
2. Control Device or Method Code(s): 65

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric Model Number: 107FA		
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:	1700 (natural gas)	1918 (distillate)	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:	hours/day		days/week
	weeks/year		8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum heat input based on lower heating values of fuels: • Natural gas - 21,500 Btu/lb • Distillate - 18,200 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 Da
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-GC Appendix B, Drawing SC004	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 single 150-foot stack.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 150 feet	7. Exit Diameter: 18.5 feet
8. Exit Temperature: See CPV-GC, Appendix C °F	9. Actual Volumetric Flow Rate: See CPV-GC, Appendix C	10. Water Vapor: See CPV-GC, Appendix C %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: 17 East (km): 348.5 North (km): 3057.0		
14. Emission Point Comment (limit to 200 characters): See CPV-GC, 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: 1.81	5. Maximum Annual Rate: 15,856	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.008	8. Maximum % Ash:	9. Million Btu per SCC Unit: 940
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): distillate		
2. Source Classification Code (SCC): 20100101	3. SCC Units: 1000 Gallons	
4. Maximum Hourly Rate: 14.562	5. Maximum Annual Rate: 10,485	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 131.7
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
SO2			**EL**
NOX	**65**		**EL**
PM			**EL**
PM10			**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, Burns and Roe	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-GC 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/tear	
10. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Emissions are for worst case operating load condition. See CPV-GC, 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: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 24.1 (natural gas), 80 (distillate) lb/hour 125.7 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric, Burns and Roe	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-GC Appendix C Values are maximum rates for all operating conditions Annual emissions: [(24.1 lb/hr) X (335 days/year) X (24 hr/day) + (80 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 125.7 tons/tear	
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:
4. Requested Allowable Emissions and Units: Natural Gas: 3.5 ppmvd @ 15% O_2 Distillate: 10 ppmvd @ 15% O_2	4. Equivalent Allowable Emissions: 24.1 (natural gas), 80 (distillate) lb/hour 125.7 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: 20 (natural gas), 53 (distillate) lb/hour 99.5 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric, Burns and Roe	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-GC Appendix C Values are maximum rates for all operating conditions Annual emissions: [(20 lb/hr) X (335 days/year) X (24 hr/day) + (53 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 99.5 tons/tear	
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: 20 lb/hour (natural gas), 53 lb/hour (distillate)	4. Equivalent Allowable Emissions: 20 (natural gas), 53 (distillate) lb/hour 99.5 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: PM10	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 20 (natural gas), 53 (distillate) lb/hour 99.5 tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: Reference: General Electric, Burns and Roe		7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-GC Appendix C Values are maximum rates for all operating conditions Annual emissions: [(20 lb/hr) X (335 days/year) X (24 hr/day) + (53 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton) = 99.5 tons/tear		
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: 20 lb/hour (natural gas), 51 lb/hour (distillate)	4. Equivalent Allowable Emissions: 20 (natural gas), 53 (distillate) lb/hour 99.5 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-GC Appendix C. lb/hour 222.2 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric, Burns and Roe	7. Emissions Method Code: 2

8. Calculation of Emissions (limit to 600 characters):
Short term emissions:
See CPV-GC Appendix C
Values are maximum rates at 100% operating load
Annual emissions:
[(49 lb/hr) X (335 days/year) X (24 hr/day) + (70 lb/hr) X (30 days/year) X (24 hr/day)] / (2000 lb/ton)
= 222.2 tons/tear

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: See CPV-GC Appendix C.	4. Equivalent Allowable Emissions: See CPV-GC Appendix C. lb/hour 222.2 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-GC 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 14.8 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: General Electric, Burns and Roe	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Short term emissions: See CPV-GC 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) = 14.8 tons/tear	
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 14.8 tons/year
5. 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 test 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): NOX, CO
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: Not yet determined. Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: CPV-GC [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: CPV-GC [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: CPV-GC [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: CPV-GC [ ] 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-GC [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: CPV-GC [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

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

[X] 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: [ ] No ID
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	September 2003	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

6. 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: General Electric Model Number:		
2. Generator Nameplate Rating:	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:	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	
7. Operating Capacity/Schedule Comment (limit to 200 characters): Maximum process rate (Item 3) is cooling tower water circulation rate.				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? Cooling Tower	2. Emission Point Type Code:

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code:	6. Stack Height: 58 feet	7. Exit Diameter: 42 feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

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.

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	
2. Maximum Hourly Rate: 4,500	3. 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/PM10	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/PM10	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): See CPV-GC Appendix D-5. [(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 [ ] Other
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)

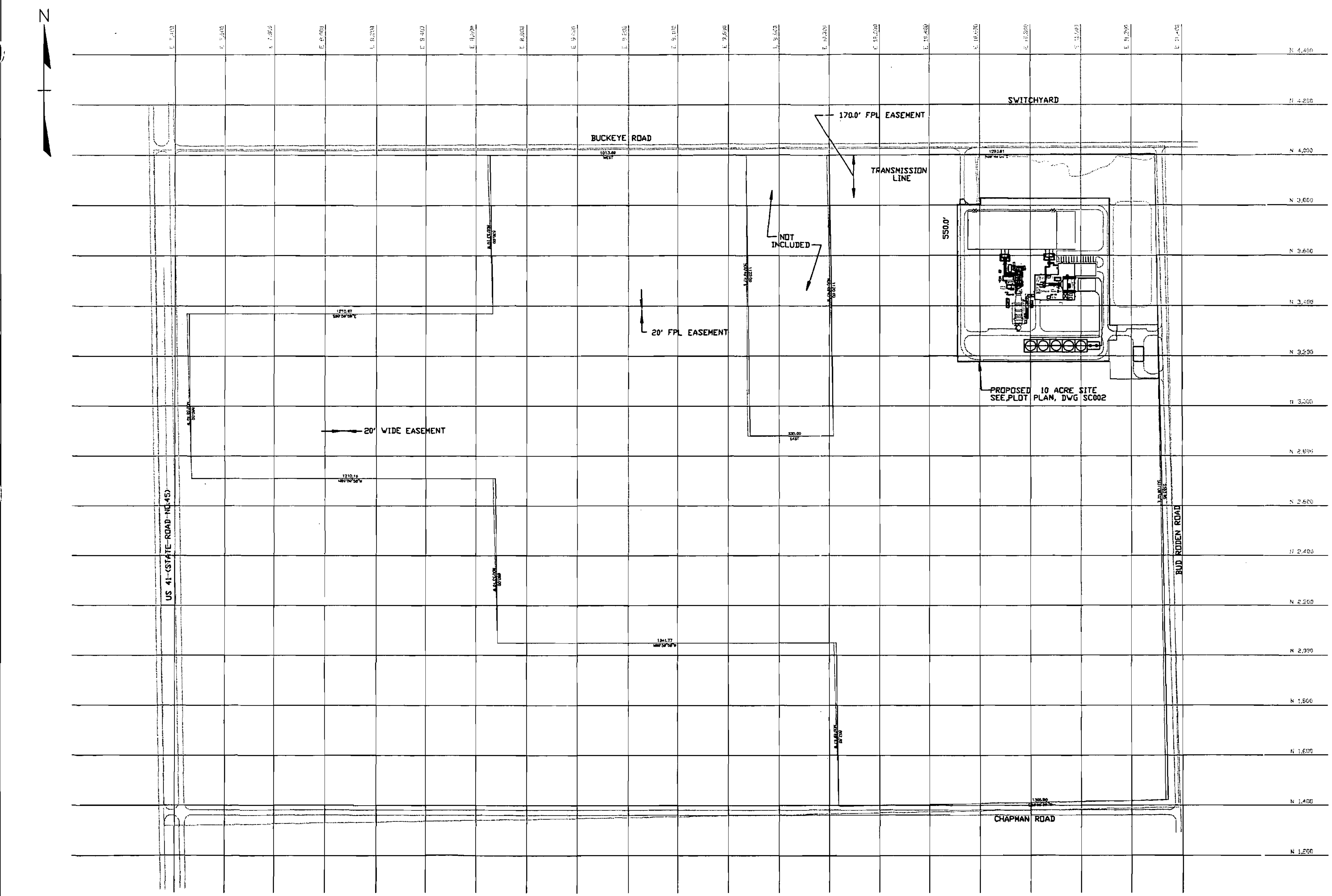
Supplemental Requirements

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:________[ ] 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:________[ ] 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 DRAWINGS

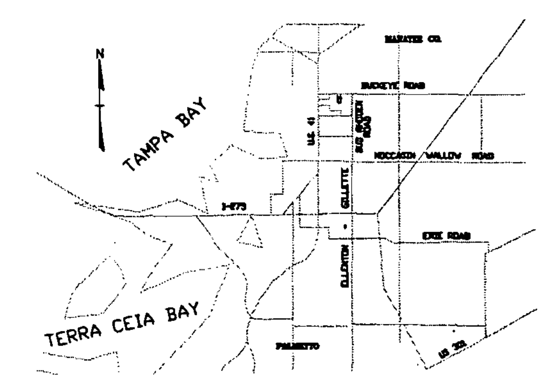


NOTES

1. PROPERTY LINES SHOWN ARE BASED ON SURVEY PREPARED BY LOE MILLS & ASSOCIATES,INC. 620 8TH AVENUE WEST, PALMETTO, FLORIDA 35561 JOB NO. A-9864 FOR FLORIDA CRUSHED STONE COMPANY, DATED 10/8/91.
2. LOT IS SECTION 7 & 8, TOWNSHIP 33 SOUTH, RANGE 18 EAST, COUNTY OF MANATEE, FLORIDA.

LEGEND

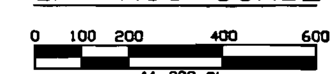
FPL = FLORIDA POWER AND LIGHT CO.



LOCATION PLAN

NTS

GRAPHIC SCALE



Rev No	Revision	Date	Dwn	Chkd	Approved Chief Engr	Rev No	Revision	Date	Dwn	Chkd	Approved Chief Engr	Rev No	Revision	Date	Dwn	Chkd	Approved Chief Engr

Drawing Control				
Purpose	Approved By	Date	Released By	Date
For Information				
For Comment				
For Bid				
For Construction	X			

Engineering Review		
Disc	Engr	Date
Mech		
Elec		
Civil		
Arch		
Nuc		
Dwn AMV	Chkd	SL

GULF COAST POWER PROJECT
FLORIDA

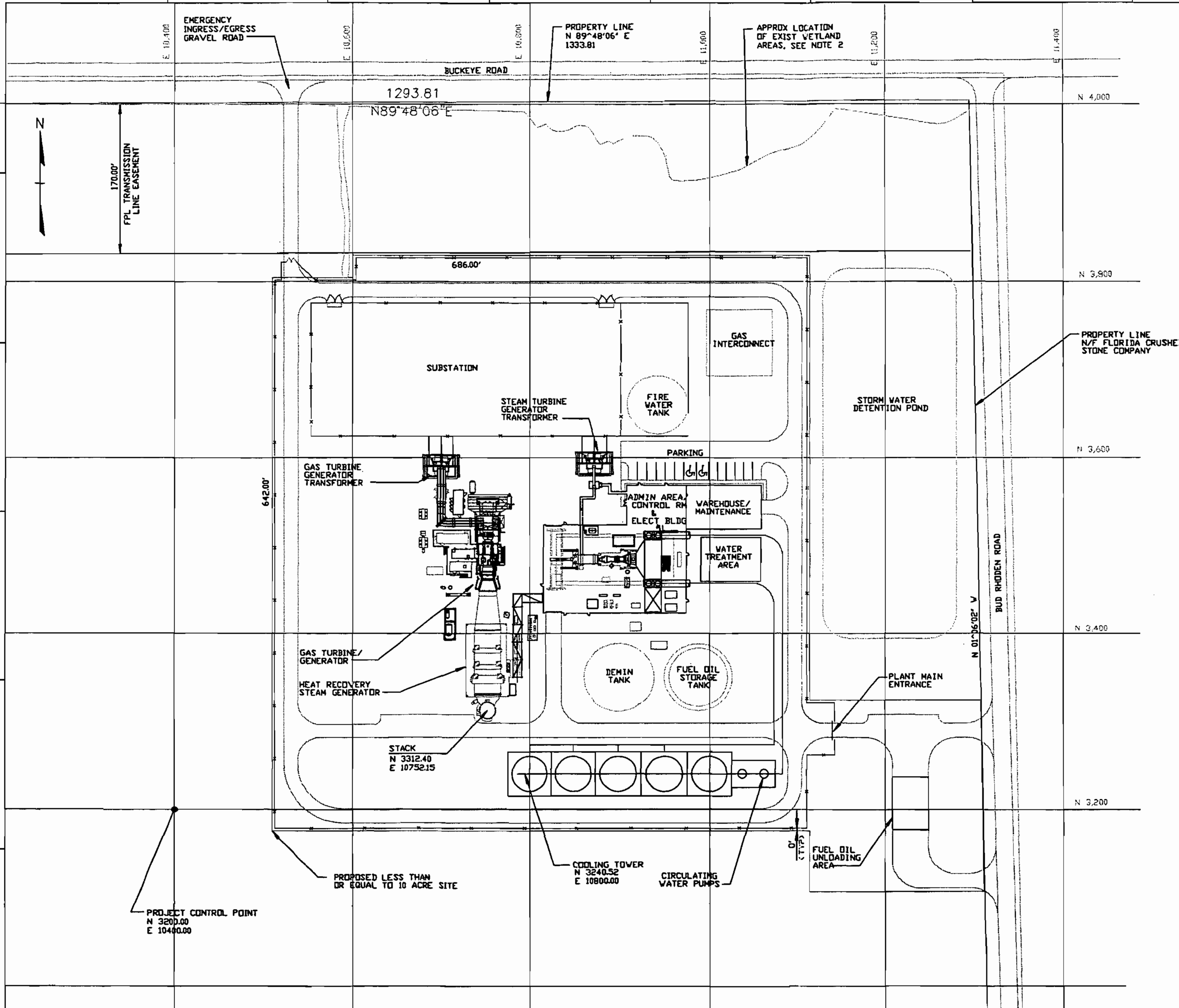
SITE PLAN

BURNS AND ROE ENTERPRISES, INC.
Engineers and Constructors - Oradell, NJ

Reviewed By	Approved for Construction	Date	Work Order	Drawing No	Sh	Rev
Manager-Design&Drafting	Chief Civil Engineer	Scale 1"=200.0'	2377	SC008		A

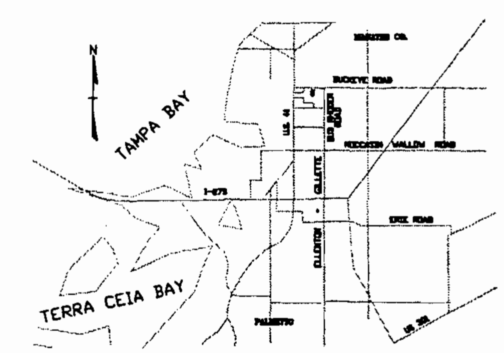
2377-001/SC008.DGN (200) STATUS: 8/24/2000

11	10	9	8	7	6	5	4	3	2	1



NOTES

1. SEE DRAWING SC008
2. FOR WETLAND MAPPING AND DESIGNATIONS SEE "MANATEE WETLAND LINES" DRAWING BY THE LOUIS BERGER GROUP INC. SHEET 1/1 DATED MAY 2000 (FILE ID=JA2242MANATEE.APR)



LOCATION PLAN

NTS

GRAPHIC SCALE

0 30 60 120 180

1" =60' -0"

Rev No	Revision	Date	Dwn	Chkd	Approved Chief Engr

Drawing Control				
Purpose	Approved By	Date	Released By	Date
For Information				
For Comment				
For Bid				
For Construction				

GULF COAST POWER PROJECT
FLORIDA

PLOT PLAN-SCHEME IV

BURNS AND ROE ENTERPRISES, INC.
Engineers and Constructors - Oradell, NJ

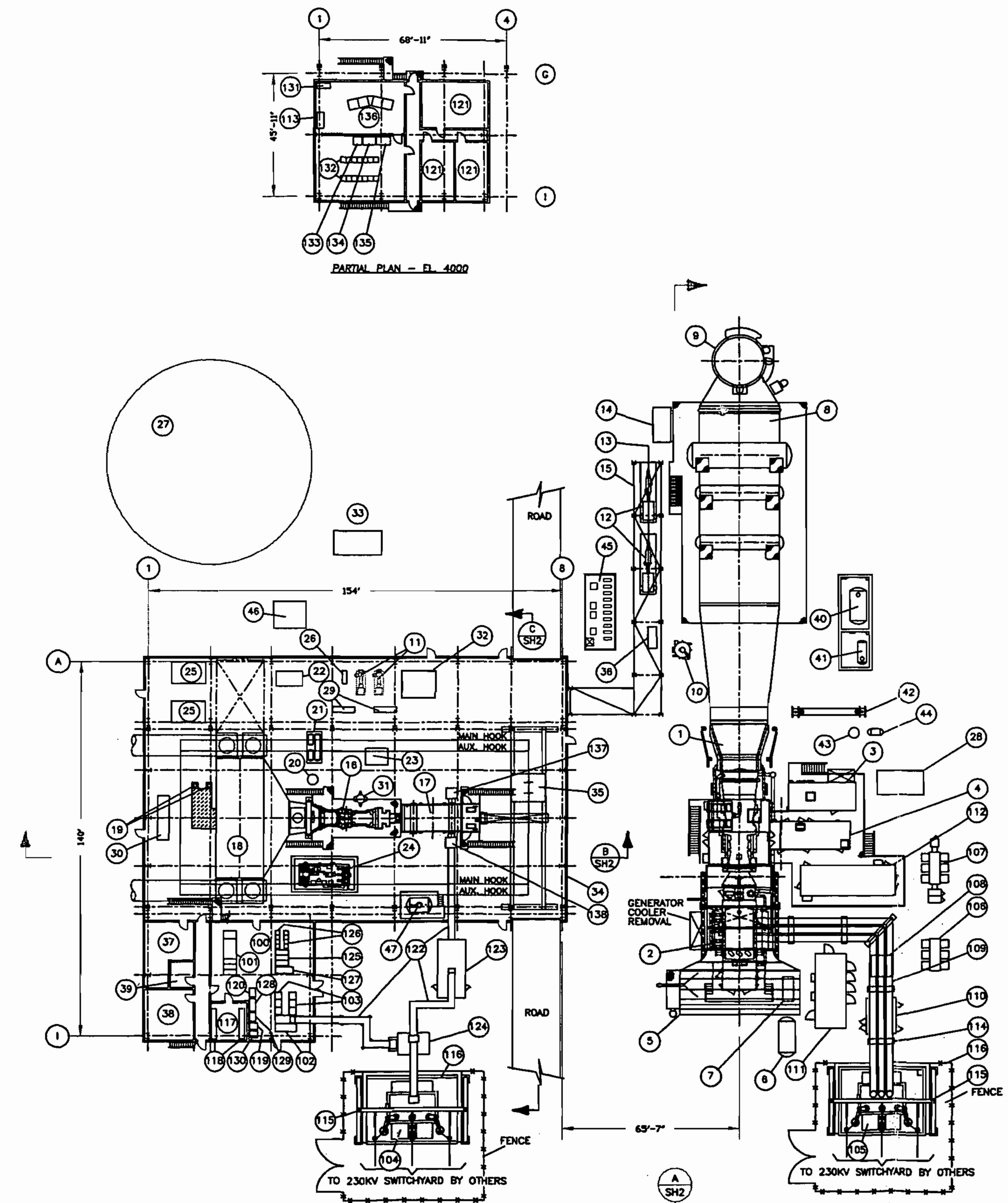
Engineering Review	Engr	Date
Mech		
Elec		
Civil		
Arch		
Nuc		

Dwn: AHV | Chkd: SL

Work Order 2377 | Drawing No SC009 | Rev A

2377-001/ STATUS: 8/24/2000 2377-001/SC009.DGN (60)

NAME: P:\prop_00\801c1321\bc\ 801c1321f_m005bc_sh1.dwg DATE: AUG 22, 2000 TIME: 9:44 AM



LEGEND:

1. GAS TURBINE
2. GT GENERATOR
3. LIQUID FUEL / ATOMIZING AIR MODULE
4. LUBE OIL / GAS VALVE MODULE
5. AIR INLET FILTER HOUSE
6. FIRE PROTECTION (CO2 SKID)
7. AIR PROCESS SKID
8. HEAT RECOVERY STEAM GENERATOR (HRSG)
9. STACK
10. BLOW DOWN TANK
11. AUXILIARY CIRCULATING WATER PUMPS
12. BOILER FEED PUMPS
13. BOILER FEED PUMP MONORAIL
14. CHEMICAL INJECTION SKID
15. PIPE RACK
16. STEAM TURBINE
17. STEAM TURBINE GENERATOR
18. CONDENSER
19. CONDENSATE PUMPS
20. CONDENSATE RECEIVER
21. GLAND SEAL CONDENSER
22. WATER BOX VACUUM PRIMING SKID
23. HYDRAULIC POWER UNIT
24. LUBE OIL STORAGE TANK
25. VACUUM PUMPS
26. NOx WATER INJECTION SKID
27. CONDENSATE STORAGE TANK
28. WATER WASH SKID
29. AUXILIARY COOLING WATER BOOSTER PUMPS
30. AUXILIARY COOLING WATER HEAT EXCHANGERS
31. MAIN STEAM STOP / CONTROL VALVES
32. CONDENSATE MAKE-UP PUMP
33. AIR COMPRESSOR SKID
34. STEAM TURBINE BUILDING
35. OVERHEAD CRANE
36. NITROGEN PURGE GAS BOTTLES
37. MEN'S LOCKER ROOM / TOILET
38. WOMEN'S LOCKER ROOM / TOILET
39. JANITORS CLOSET / STORAGE
40. WASH WATER DRAINS TANK (IN PIT)
41. GAS TURBINE DRAINS TANK (IN PIT)
42. FUEL GAS HEATER
43. FUEL GAS SCRUBBER
44. FUEL GAS SCRUBBER DRAINS TANK
45. CHEMICAL FEED AREA
46. OIL/WATER SEPARATOR
47. ACW EXPANSION TANK
48. CIRC WATER PIPING
100. SWITCH GEAR ROOM
101. 480V STATION SERVICE SECONDARY UNIT SUBSTATION
102. 4.16 KV STATION SERVICE SWITCH GEAR
103. 4.16 KV MOTOR CONTROLLERS (2-HIGH)
104. ST GENERATOR STEP-UP TRANSFORMER
105. GT GENERATOR STEP-UP TRANSFORMER
106. STATIC START ISOLATION TRANSFORMER
107. UNIT AUXILIARY SWITCH GEAR
108. DC LINK REACTOR
109. ISO-PHASE DUCT
110. BUS ACCESSORY COMPARTMENT
111. GT GENERATOR EXCITATION / LCI COMPARTMENT
112. PACKAGED ELECTRONIC CONTROL COMPARTMENT
113. ENGINEERING WORKSTATION
114. ISO-PHASE DUCT SUPPORT
115. TRANSFORMER DEAD-END TOWER
116. FIRE WALL
117. BATTERY ROOM
118. BATTERIES
119. BATTERY CHARGER
120. UPS INVERTER
121. OFFICE AREA
122. NON-SEGREGATED PHASE BUS DUCT
123. ST GENERATOR AUXILIARIES COMPARTMENT (GAC)
124. STARTUP / AUXILIARY TRANSFORMER
125. 480V ESSENTIAL SERVICE SWITCH GEAR
126. STATION SERVICE MCC'S
127. UPS DISTRIBUTION PANEL
128. DC DISTRIBUTION PANEL
129. AUTO TRANSFER SWITCH
130. BATTERY DISCONNECT SWITCH
131. PRINTERS
132. DCS I/O PANEL
133. ST MARK V (I)
134. GENERATOR CONTROL PANEL
135. TURBINE CONTROL PANEL
136. DCS OPERATOR CONSOLE
137. NEUTRAL ACCESSORY COMPARTMENT
138. LINE ACCESSORY COMPARTMENT

0 20 40 60 80 100
SCALE IN FEET

PRELIMINARY

DRAWN BY: S. FARR	CHECKED BY: N/A	SCALE: 1" : 20'	TITLE: STATION ARRANGEMENT
N/A	N/A	N. KUMAR	107FA MULTI-SHAFT
JOB NO.: 801C1321	N/A, N/A, DP, BG, FM		GULF COAST POWER PROJECT FLORIDA

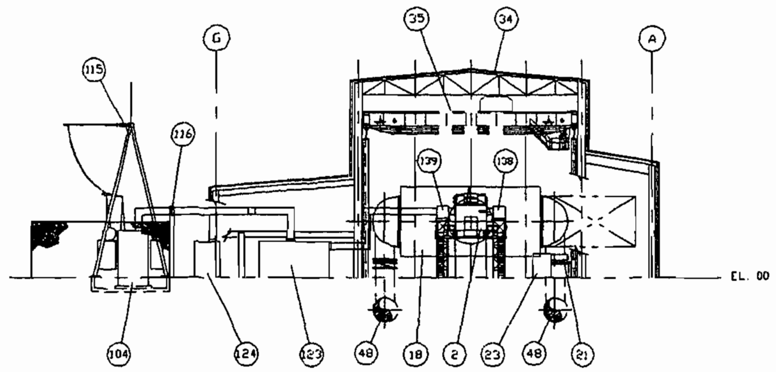
GENERAL ELECTRIC
POWER PLANT ENGINEERING
POWER PLANT SYSTEMS DEPARTMENT

801C1321F M005BC SH. 1 OF 2 REV A

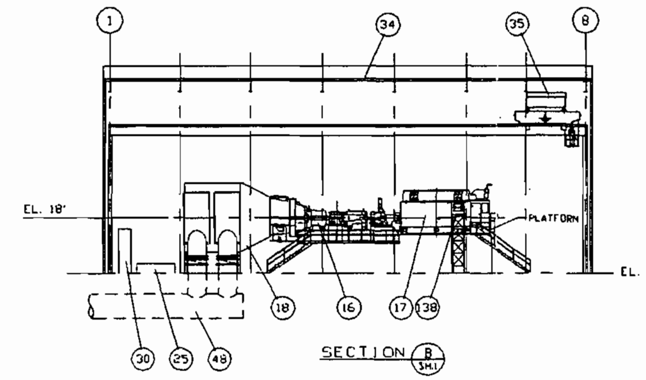
AUTOCAD 801c1321f _m005bc_sh1

NOTICE TO PURCHASER

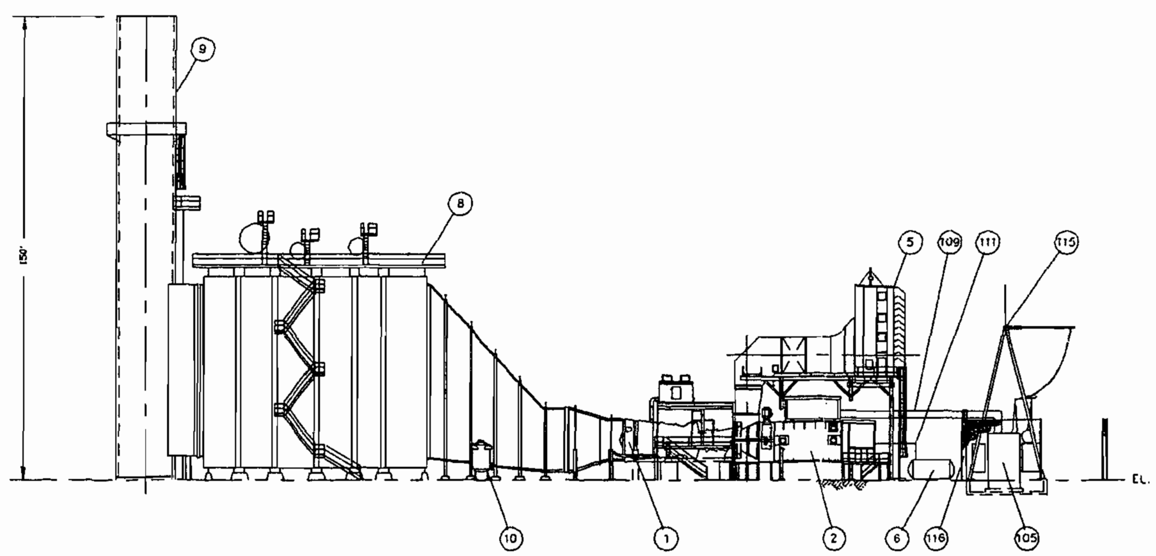
MADE FROM: 801c1321f_m005_sh1.dwg



SECTION C SH.1



SECTION B SH.1



SECTION A SH.1

0 10 20 30 40 50 60 70
SCALE IN FEET

PRELIMINARY

SEE LEGEND ON SH. 1

DRAWN BY: S. FARR	CHECKED BY: N/A	SCALE: 1" : 20'	TITLE: STATION ARRANGEMENT
N/A	N/A	PROJECT ENGINEER: N. KUMAR	PROJECT: S107FA MULTI-SHAFT
SYSTEMS: N/A	CONTROLS: N/A	CIVIL: N/A	GULF COAST POWER PROJECT FLORIDA
ELEC.: N/A	MECH.: PM	801C1321	

GENERAL ELECTRIC
POWER PLANT ENGINEERING
POWER PLANT SYSTEMS DEPARTMENT

801C1321F | M005BC | SH. 2 | CONT. ON SH. F | REV A

AUTOCAD
801c1321f
_m005bc_sh2

M005BC

APPENDIX C

AIR POLLUTANT EMISSIONS

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	25 F
Relative Humidity:	60%

100% Load   METHANE

NOx	3.5	ppmvd@15%O2	NOx	24.1	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	2	ppmvw	SO2	10	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	2	pph	Sulfur Mist	2	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	12	pph	Ammonia	12	pph
O2	12.77	%	O2	12.77	%
H2O	7.61	%	H2O	7.61	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	25 F
Relative Humidity:	60%

75% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	19.1	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	2	ppmvw	SO2	8	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	10	pph	Ammonia	10	pph
O2	12.63	%	O2	12.63	%
H2O	7.74	%	H2O	7.74	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	25 F
Relative Humidity:	60 %

50% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	15.2	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	2	ppmvw	SO2	7	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	8	pph	Ammonia	8	pph
O2	12.92	%	O2	12.92	%
H2O	7.47	%	H2O	7.47	%

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 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	7.1	ppmvw	UHC	16.0	pph
VOC	3.6	ppmvw	VOC	8.0	pph
SO2	12	ppmvw	SO2	99	pph
SO3	1	ppmvw	SO3	7	pph
Sulfur Mist	11	pph	Sulfur Mist	11	pph
Front Half + Sulfates Partic.	36	pph	Front Half + Sulfates Partic.	36	pph
PM10 Particulates	53	pph	PM10 Particulates	53	pph
Ammonia	10	pph	Ammonia	10	pph
O2	11.44	%	O2	11.44	%
H2O	10.34	%	H2O	10.34	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	25 F
Relative Humidity:	60%

75% Load Distillate

Parameter	Value	Unit	Parameter	Value	Unit
NOx	10.0	ppmvd@15%O2	NOx	63.8	pph
CO	22.0	ppmvd	CO	58.0	pph
UHC	7.1	ppmvw	UHC	12.0	pph
VOC	3.6	ppmvw	VOC	6.0	pph
SO2	12	ppmvw	SO2	80	pph
SO3	1	ppmvw	SO3	6	pph
Sulfur Mist	9	pph	Sulfur Mist	9	pph
Front Half + Sulfates Partic.	32	pph	Front Half + Sulfates Partic.	32	pph
PM10 Particulates	49	pph	PM10 Particulates	49	pph
Ammonia	8	pph	Ammonia	8	pph
O2	11.11	%	O2	11.11	%
H2O	10.45	%	H2O	10.45	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	25 F
Relative Humidity:	60%

50% Load Distillate

Parameter	Value	Unit	Parameter	Value	Unit
NOx	10.0	ppmvd@15%O2	NOx	49.5	pph
CO	29.0	ppmvd	CO	65.0	pph
UHC	7.0	ppmvw	UHC	10.0	pph
VOC	3.5	ppmvw	VOC	5.0	pph
SO2	12	ppmvw	SO2	63	pph
SO3	1	ppmvw	SO3	5	pph
Sulfur Mist	7	pph	Sulfur Mist	7	pph
Front Half + Sulfates Partic.	29	pph	Front Half + Sulfates Partic.	29	pph
PM10 Particulates	46	pph	PM10 Particulates	46	pph
Ammonia	6	pph	Ammonia	6	pph
O2	11.57	%	O2	11.57	%
H2O	9.59	%	H2O	9.59	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	22.6	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	2	ppmvw	SO2	10	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	12	pph	Ammonia	12	%
O2	12.55	%	O2	12.55	%
H2O	8.57	%	H2O	8.57	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel Distillate</u>, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	75.7	pph
CO	20.0	ppmvd	CO	66.0	pph
UHC	7.1	ppmvw	UHC	15.0	pph
VOC	3.6	ppmvw	VOC	7.5	pph
SO2	12	ppmvw	SO2	94	pph
SO3	1	ppmvw	SO3	7	pph
Sulfur Mist	10	pph	Sulfur Mist	10	pph
Front Half + Sulfates Partic.	35	pph	Front Half + Sulfates Partic.	35	pph
PM10 Particulates	52	pph	PM10 Particulates	52	pph
Ammonia	10	pph	Ammonia	10	pph
O2	11.21	%	O2	11.21	%
H2O	11.19	%	H2O	11.19	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load **METHANE**

NOx	3.5	ppmvd@15%O2	NOx	21.8	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	2	ppmvw	SO2	9	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	11	pph	Ammonia	11	pph
O2	12.46	%	O2	12.46	%
H2O	9.19	%	H2O	9.19	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

75% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	17.5	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	2	ppmvw	SO2	8	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	9	pph	Ammonia	9	pph
O2	12.50	%	O2	12.50	%
H2O	9.15	%	H2O	9.15	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

50% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	14.0	pph
CO	9.0	ppmvd	CO	19.0	pph
UHC	7.1	Ppmvw	UHC	9.0	pph
VOC	1.5	Ppmvw	VOC	1.8	pph
SO2	2	Ppmvw	SO2	6	pph
SO3	1	Ppmvw	SO3	1	pph
Sulfur Mist	1	Pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	Pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	Pph	PM10 Particulates	19	pph
Ammonia	7	Pph	Ammonia	7	pph
O2	12.91	%	O2	12.91	%
H2O	8.79	%	H2O	8.79	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel Distillate</u>, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 80 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load **Distillate**

Parameter	Value	Unit	Parameter	Value	Unit
NOx	10.0	ppmvd@15%O2	NOx	73.6	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	12	Ppmvw	SO2	92	pph
SO3	1	Ppmvw	SO3	6	pph
Sulfur Mist	10	Pph	Sulfur Mist	10	pph
Front Half + Sulfates Partic.	35	Pph	Front Half + Sulfates Partic.	35	pph
PM10 Particulates	51	Pph	PM10 Particulates	51	pph
Ammonia	10	Pph	Ammonia	10	pph
O2	11.08	%	O2	11.08	%
H2O	11.69	%	H2O	11.69	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel Distillate</u>, H/C ratio of 1.8
Fuel LHV 18,300 Btu/lb
Water injection for NOx control to 42 ppmvd @ 15% O2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 80 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

75% Load **Distillate**

NOx	10.0	ppmvd@15%O2	NOx	58.8	pph
CO	21.0	ppmvd	CO	52.0	pph
UHC	7.1	ppmvw	UHC	11.0	pph
VOC	3.6	ppmvw	VOC	5.5	pph
SO2	12	ppmvw	SO2	74	pph
SO3	1	ppmvw	SO3	5	pph
Sulfur Mist	8	pph	Sulfur Mist	8	pph
Front Half + Sulfates Partic.	31	pph	Front Half + Sulfates Partic.	31	pph
PM10 Particulates	48	pph	PM10 Particulates	48	pph
Ammonia	8	pph	Ammonia	8	pph
O2	11.12	%	O2	11.12	%
H2O	11.29	%	H2O	11.29	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG 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% O_2 at GT exhaust
Sulfur emission based on 0.05 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 80 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

50% Load Distillate

NOx	10.0	ppmvd@15%O_2	NOx	46.0	pph
CO	34.0	ppmvd	CO	73.0	pph
UHC	7.0	ppmvw	UHC	9.0	pph
VOC	3.5	ppmvw	VOC	4.5	pph
SO_2	11	ppmvw	SO_2	58	pph
SO_3	1	ppmvw	SO_3	4	pph
Sulfur Mist	7	pph	Sulfur Mist	7	pph
Front Half + Sulfates Partic.	28	pph	Front Half + Sulfates Partic.	28	pph
PM10 Particulates	45	pph	PM10 Particulates	45	pph
Ammonia	6	pph	Ammonia	6	pph
O_2	11.83	%	O_2	11.83	%
H_2O	10.19	%	H_2O	10.19	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ base load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	20.2	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	2	ppmvw	SO2	9	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	10	pph	Ammonia	10	pph
O2	12.10	%	O2	12.10	%
H2O	11.24	%	H2O	11.24	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 75% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

75% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	16.7	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	.2	ppmvw	SO2	.7	pph
SO3	.1	ppmvw	SO3	.1	pph
Sulfur Mist	.1	pph	Sulfur Mist	.1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	8	pph	Ammonia	8	pph
O2	12.19	%	O2	12.19	%
H2O	11.16	%	H2O	11.16	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 Btu/lb
Sulfur emission based on 0.0065 WT% Sulfur content in the fuel
Gas Turbine @ 50% load
Fuel temperature 365 F

Site elevation:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70 %

50% Load METHANE

Parameter	Value	Unit	Parameter	Value	Unit
NOx	3.5	ppmvd@15%O2	NOx	13.2	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	2	ppmvw	SO2	6	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	19	pph	PM10 Particulates	19	pph
Ammonia	7	pph	Ammonia	7	pph
O2	12.71	%	O2	12.71	%
H2O	10.69	%	H2O	10.69	%

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	67.6	pph
CO	20.0	ppmvd	CO	58.0	pph
UHC	7.1	ppmvw	UHC	13.0	pph
VOC	3.6	ppmvw	VOC	6.5	pph
SO2	11	ppmvw	SO2	84	pph
SO3	1	ppmvw	SO3	6	pph
Sulfur Mist	9	pph	Sulfur Mist	9	pph
Front Half + Sulfates Partic.	33	pph	Front Half + Sulfates Partic.	33	pph
PM10 Particulates	50	pph	PM10 Particulates	50	pph
Ammonia	9	pph	Ammonia	9	pph
O2	10.95	%	O2	10.95	%
H2O	12.91	%	H2O	12.91	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

75% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	54.5	pph
CO	21.0	ppmvd	CO	51.0	pph
UHC	7.0	ppmvw	UHC	11.0	pph
VOC	3.5	ppmvw	VOC	5.5	pph
SO2	12	ppmvw	SO2	69	pph
SO3	1	ppmvw	SO3	5	pph
Sulfur Mist	8	pph	Sulfur Mist	8	pph
Front Half + Sulfates Partic.	30	pph	Front Half + Sulfates Partic.	30	pph
PM10 Particulates	47	pph	PM10 Particulates	47	pph
Ammonia	7	pph	Ammonia	7	pph
O2	11.10	%	O2	11.10	%
H2O	12.41	%	H2O	12.41	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

50% Load Distillate

NOx	10.0	ppmvd@15%O2	NOx	42.4	pph
CO	40.9	ppmvd	CO	83.0	pph
UHC	7.0	ppmvw	UHC	10.0	pph
VOC	3.5	ppmvw	VOC	5.0	pph
SO2	11	ppmvw	SO2	54	pph
SO3	1	ppmvw	SO3	4	pph
Sulfur Mist	6	pph	Sulfur Mist	6	pph
Front Half + Sulfates Partic.	28	pph	Front Half + Sulfates Partic.	28	pph
PM10 Particulates	44	pph	PM10 Particulates	44	pph
Ammonia	5	pph	Ammonia	5	pph
O2	11.93	%	O2	11.93	%
H2O	11.22	%	H2O	11.22	%

GE does not recommend operation of the SCR during distillate fuel operation

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 21,515 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	97 F
Relative Humidity:	70%

100% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	21.6	pph
CO	15.0	ppmvd	CO	43.0	pph
UHC	7.1	ppmvw	UHC	14.0	pph
VOC	1.5	ppmvw	VOC	2.8	pph
SO2	2	ppmvw	SO2	9	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	11	pph	Ammonia	11	pph
O2	11.06	%	O2	11.06	%
H2O	16.11	%	H2O	16.11	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
<u>Fuel 100% Methane</u>
Fuel LHV 21,515 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	72 F
Relative Humidity:	73%

100% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	23.0	pph
CO	15.0	ppmvd	CO	47.0	pph
UHC	7.1	ppmvw	UHC	15.0	pph
VOC	1.5	ppmvw	VOC	3.0	pph
SO2	2	ppmvw	SO2	10	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	1	pph	Sulfur Mist	1	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	12	pph	Ammonia	12	pph
O2	11.44	%	O2	11.44	%
H2O	14.17	%	H2O	14.17	%

PRELIMINARY

HRSG EMISSIONS (after SCR for NOx reduction)

Assumptions:
Gas Turbine: **PG7241(FA)**
Fuel 100% Methane
Fuel LHV 21,515 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:	19ft
Site pressure:	14.69 psia
Ambient temperature:	59 F
Relative Humidity:	74%

100% Load METHANE

NOx	3.5	ppmvd@15%O2	NOx	23.6	pph
CO	15.0	ppmvd	CO	49.0	pph
UHC	7.1	ppmvw	UHC	15.0	pph
VOC	1.5	ppmvw	VOC	3.0	pph
SO2	2	ppmvw	SO2	10	pph
SO3	1	ppmvw	SO3	1	pph
Sulfur Mist	2	pph	Sulfur Mist	2	pph
Front Half + Sulfates Partic.	11	pph	Front Half + Sulfates Partic.	11	pph
PM10 Particulates	20	pph	PM10 Particulates	20	pph
Ammonia	12	pph	Ammonia	12	pph
O2	11.61	%	O2	11.61	%
H2O	13.52	%	H2O	13.52	%

Competative Power Ventures 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%
Natural Gas									
Operating Period	Hours	8040	8040	8040	8040	8040	8040	8040	8040
Emission Rate	lb/hr	24.1	49.0	3.0	10.0	1.0	20.0	2.0	12
Annual Emissions	tons/year	96.9	197.0	11.9	40.2	3.9	80.4	8.0	48.2
Distillate									
Operating Period	Hours	720	720	720	720	720	720	720	720
Emission Rate	lb/hr	80.0	70.0	8.0	99.0	7.0	53.0	11.0	10.0
Annual Emissions	tons/year	28.8	25.2	2.9	35.6	2.5	19.1	4.0	3.6
Total Annual Emissions	tons/year	125.7	222.2	14.8	75.8	6.4	99.5	12.0	51.8

Competative Power Ventures Maximum Actual Annual Emissions										
	Units	NO_X		CO	VOC	SO_2	SO_3	PM	H_2SO_4	NH_3
		Controlled	Uncontrolled							
Capacity Factor		100%	100%	100%	100%	100%	100%	100%	100%	100%
Natural Gas (with PA)										
Operating Period	Hours	2000	2000	2000	2000	2000	2000	2000	2000	2000
Emission Rate	lb/hr	22.5	57.9	47.0	3.0	10.0	1.0	20.0	1.0	12
Annual Emissions	tons/year	22.5	57.9	47.0	3.0	10.0	1.0	20.0	1.0	12.0
Natural Gas (without PA)										
Operating Period	Hours	6040	6040	6040	6040	6040	6040	6040	6040	6040
Emission Rate	lb/hr	22.5	57.9	28.0	2.8	9.0	1.0	20.0	1.0	11
Annual Emissions	tons/year	68.0	174.8	84.6	8.5	27.2	2.9	60.4	3.0	33.2
Distillate										
Operating Period	Hours	720	720	720	720	720	720	720	720	720
Emission Rate	lb/hr	73.6	311.5	63.0	7.0	92.0	6.0	51.0	10.0	10.0
Annual Emissions	tons/year	26.5	112.1	22.7	2.5	33.1	2.2	18.4	3.6	3.6
Total Annual Emissions	tons/year	116.9	344.9	154.2	14.0	70.3	6.1	98.8	7.6	48.8

Competitive Power Ventures - Gulfcoast 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
* per Marley specification		

APPENDIX D
AIR QUALITY MODELING

Appendix D-1

BEE-Line Software Version: 5.13

Input File - ct88.GPW
Input File - ct88.PIP
Output File - ct88.TAB
Output File - ct88.SUM
Output File - ct88.SO

BPIP (Dated: 95086)

DATE : 9/ 1/ 0
TIME : 15:24:21
O:\AIR_ENG\PROJECTS\pineypt\ct88.BST BEESTWin GEP Files 9/1/2000 3:24:20 PM

============================
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.

O:\AIR_ENG\PROJECTS\pineypt\ct88.BST BEESTWin GEP Files 9/1/2000 3:24:20 PM

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
25/50A	31.09	0.00	55.66	65.00
CELL1	17.83	0.00	54.08	65.00
CELL2	17.83	0.00	57.15	65.00
CELL3	17.83	0.00	57.15	65.00
CELL4	17.83	0.00	57.15	65.00
CELL5	17.83	0.00	57.15	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 : 9/ 1/ 0
TIME : 15:24:21

O:\AIR_ENG\PROJECTS\pineypt\ct88.BST BEESTWin GEP Files 9/1/2000 3:24:20 PM

BPIP output is in meters

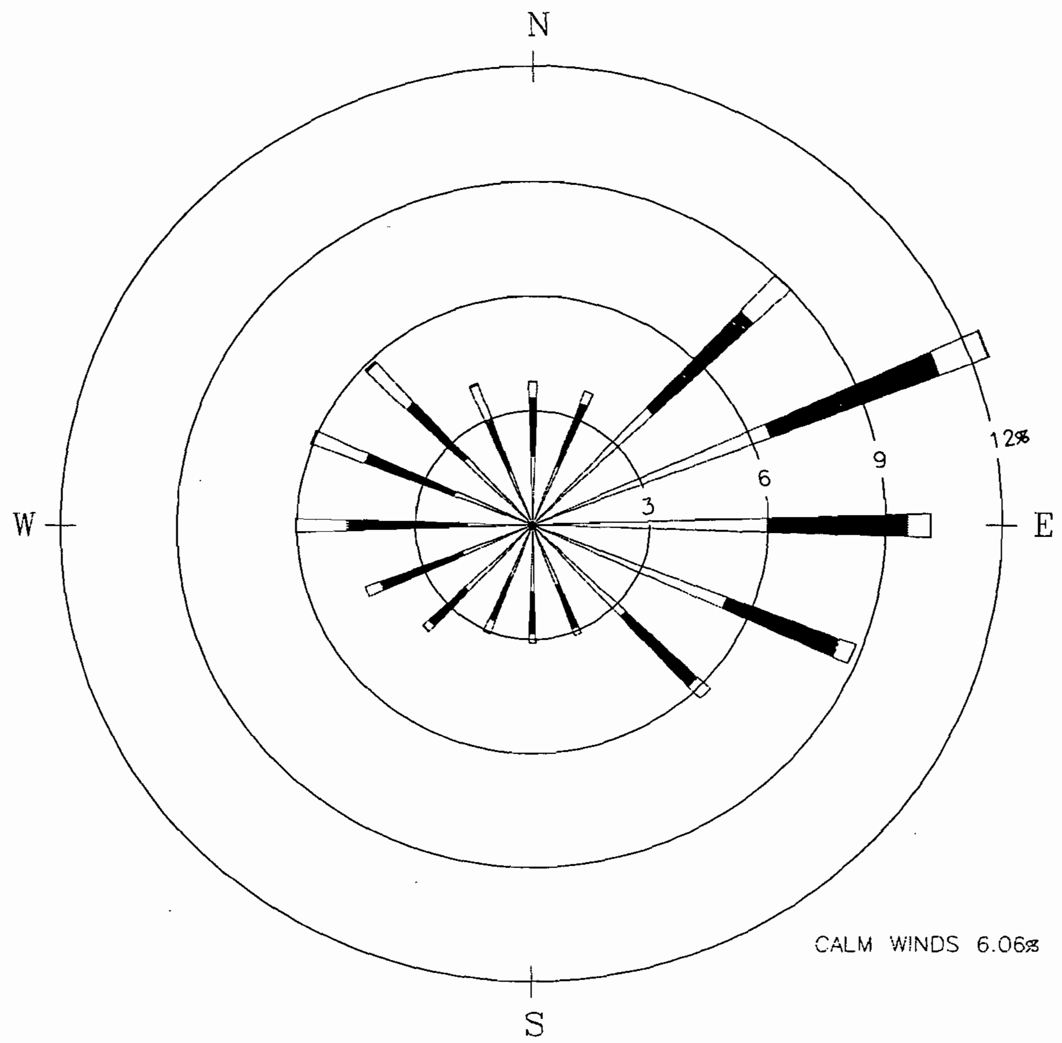
SO	BUILDHGT	25/50A	20.73	20.73	22.86	22.86	22.86	22.86
SO	BUILDHGT	25/50A	22.86	22.86	22.86	22.86	22.86	22.86
SO	BUILDHGT	25/50A	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDHGT	25/50A	20.73	20.73	22.86	22.86	22.86	22.86
SO	BUILDHGT	25/50A	22.86	22.86	22.86	22.86	22.86	22.86
SO	BUILDHGT	25/50A	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDWID	25/50A	50.32	53.39	19.88	21.87	21.87	21.87
SO	BUILDWID	25/50A	21.87	21.87	21.87	21.87	21.87	21.87
SO	BUILDWID	25/50A	21.87	21.87	19.88	85.71	78.95	69.80
SO	BUILDWID	25/50A	50.32	53.39	19.88	21.87	21.87	21.87
SO	BUILDWID	25/50A	21.87	21.87	21.87	21.87	21.87	21.87
SO	BUILDWID	25/50A	21.87	21.87	19.88	85.71	78.95	69.80

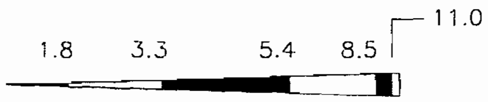
SO	BUILDHGT	CELL1	20.73	20.73	20.73	20.73	20.73	16.76
SO	BUILDHGT	CELL1	16.76	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL1	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDHGT	CELL1	20.73	20.73	20.73	20.73	20.73	16.76
SO	BUILDHGT	CELL1	16.76	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL1	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDWID	CELL1	67.79	63.72	57.71	54.62	52.74	20.82
SO	BUILDWID	CELL1	19.53	17.65	15.24	17.65	19.53	20.82
SO	BUILDWID	CELL1	20.82	20.82	19.88	85.71	78.95	45.72
SO	BUILDWID	CELL1	50.32	53.39	54.83	54.62	52.74	20.82
SO	BUILDWID	CELL1	19.53	17.65	15.24	17.65	19.53	20.82
SO	BUILDWID	CELL1	20.82	20.82	19.88	85.71	78.95	69.80

SO	BUILDHGT	CELL2	20.73	20.73	20.73	20.73	16.76	16.76
SO	BUILDHGT	CELL2	16.76	16.76	16.76	16.76	16.76	22.86
SO	BUILDHGT	CELL2	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDHGT	CELL2	20.73	20.73	20.73	20.73	16.76	16.76
SO	BUILDHGT	CELL2	16.76	16.76	16.76	16.76	16.76	22.86
SO	BUILDHGT	CELL2	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDWID	CELL2	67.79	63.72	57.71	54.62	21.47	20.82
SO	BUILDWID	CELL2	19.53	17.65	15.24	17.65	19.53	24.68

SO	BUILDWID	CELL2	23.79	22.17	19.88	53.39	50.32	45.72
SO	BUILDWID	CELL2	50.32	53.39	54.83	54.62	21.47	20.82
SO	BUILDWID	CELL2	19.53	17.65	15.24	17.65	19.53	24.68
SO	BUILDWID	CELL2	23.79	22.17	19.88	53.39	78.95	69.80
SO	BUILDHGT	CELL3	20.73	20.73	20.73	16.76	16.76	16.76
SO	BUILDHGT	CELL3	16.76	16.76	16.76	16.76	22.86	22.86
SO	BUILDHGT	CELL3	22.86	22.86	22.86	20.73	20.73	20.73
SO	BUILDHGT	CELL3	20.73	20.73	20.73	16.76	16.76	16.76
SO	BUILDHGT	CELL3	16.76	16.76	16.76	16.76	20.73	20.73
SO	BUILDHGT	CELL3	20.73	20.73	20.73	20.73	20.73	20.73
SO	BUILDWID	CELL3	67.79	63.72	54.83	21.47	21.47	20.82
SO	BUILDWID	CELL3	19.53	17.65	15.24	17.65	24.82	24.68
SO	BUILDWID	CELL3	23.79	22.17	19.88	53.39	50.32	45.72
SO	BUILDWID	CELL3	50.32	53.39	54.83	21.47	21.47	20.82
SO	BUILDWID	CELL3	19.53	17.65	15.24	17.65	79.15	85.84
SO	BUILDWID	CELL3	89.93	91.28	54.83	85.71	78.95	69.80
SO	BUILDHGT	CELL4	20.73	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL4	16.76	16.76	16.76	16.76	22.86	22.86
SO	BUILDHGT	CELL4	22.86	22.86	20.73	20.73	20.73	20.73
SO	BUILDHGT	CELL4	20.73	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL4	16.76	16.76	16.76	16.76	20.73	20.73
SO	BUILDHGT	CELL4	20.73	20.73	16.76	16.76	20.73	20.73
SO	BUILDWID	CELL4	67.79	19.53	20.82	21.47	21.47	20.82
SO	BUILDWID	CELL4	19.53	17.65	15.24	17.65	24.82	24.68
SO	BUILDWID	CELL4	23.79	22.17	54.83	53.39	50.32	45.72
SO	BUILDWID	CELL4	50.32	19.53	20.82	21.47	21.47	20.82
SO	BUILDWID	CELL4	19.53	17.65	15.24	17.65	79.15	85.84
SO	BUILDWID	CELL4	89.93	54.62	20.82	19.53	78.95	69.80
SO	BUILDHGT	CELL5	16.76	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL5	16.76	16.76	16.76	16.76	22.86	22.86
SO	BUILDHGT	CELL5	22.86	20.73	20.73	20.73	20.73	20.73
SO	BUILDHGT	CELL5	16.76	16.76	16.76	16.76	16.76	16.76
SO	BUILDHGT	CELL5	16.76	16.76	16.76	16.76	20.73	20.73
SO	BUILDHGT	CELL5	16.76	16.76	16.76	16.76	20.73	20.73
SO	BUILDWID	CELL5	17.65	19.53	20.82	21.47	21.47	20.82
SO	BUILDWID	CELL5	19.53	17.65	15.24	17.65	24.82	24.68
SO	BUILDWID	CELL5	23.79	54.62	54.83	53.39	50.32	45.72
SO	BUILDWID	CELL5	17.65	19.53	20.82	21.47	21.47	20.82
SO	BUILDWID	CELL5	19.53	17.65	15.24	17.65	79.15	85.84
SO	BUILDWID	CELL5	21.47	21.47	20.82	19.53	78.95	69.80

Appendix D-2





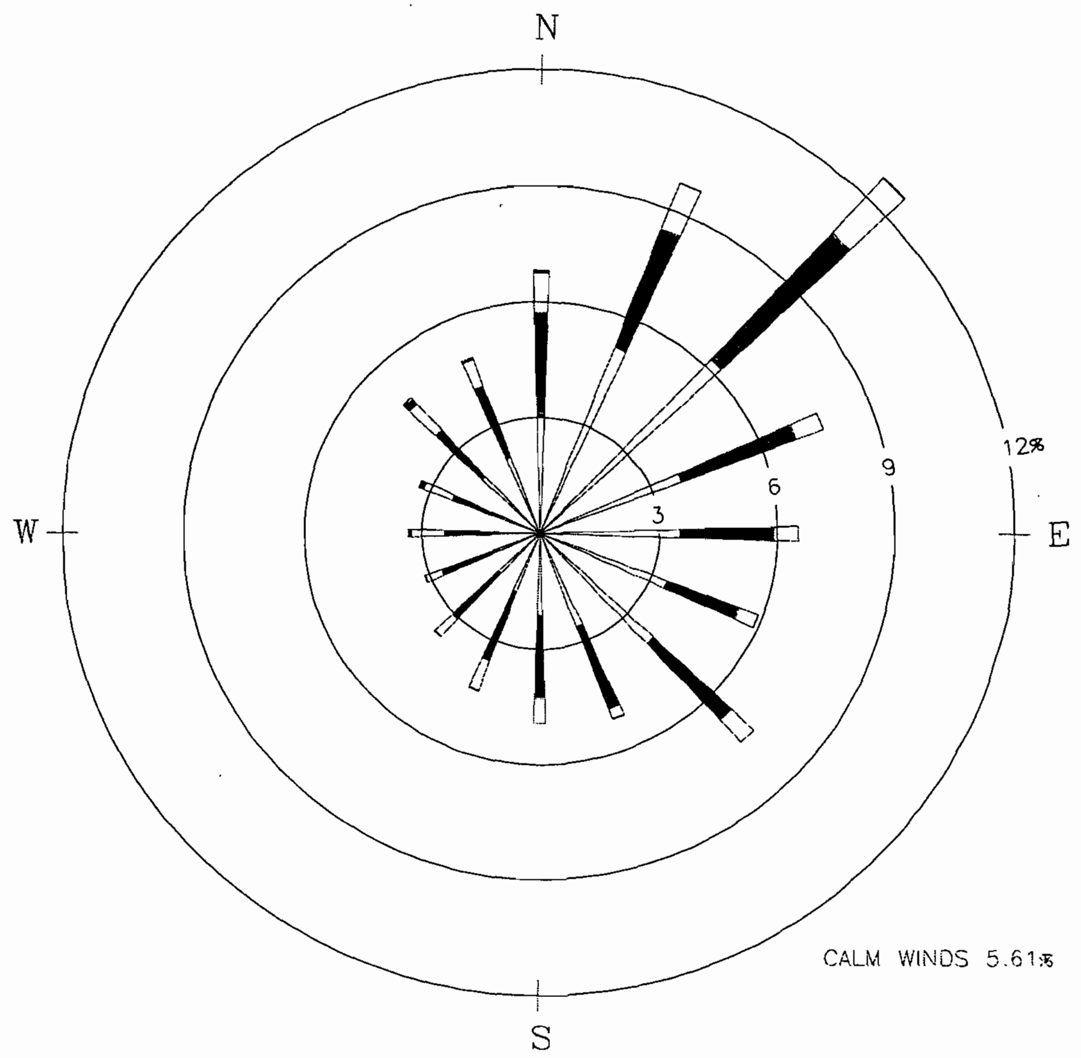
WIND SPEED CLASS BOUNDARIES
(METERS/SECOND)

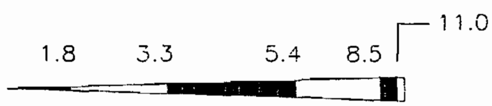
FIGURE 1
WINDROSE

STATION NO: 12842
PERIOD: 1987

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 3.8 PERCENT OF THE TIME.

BEE–LINE
SOFTWARE





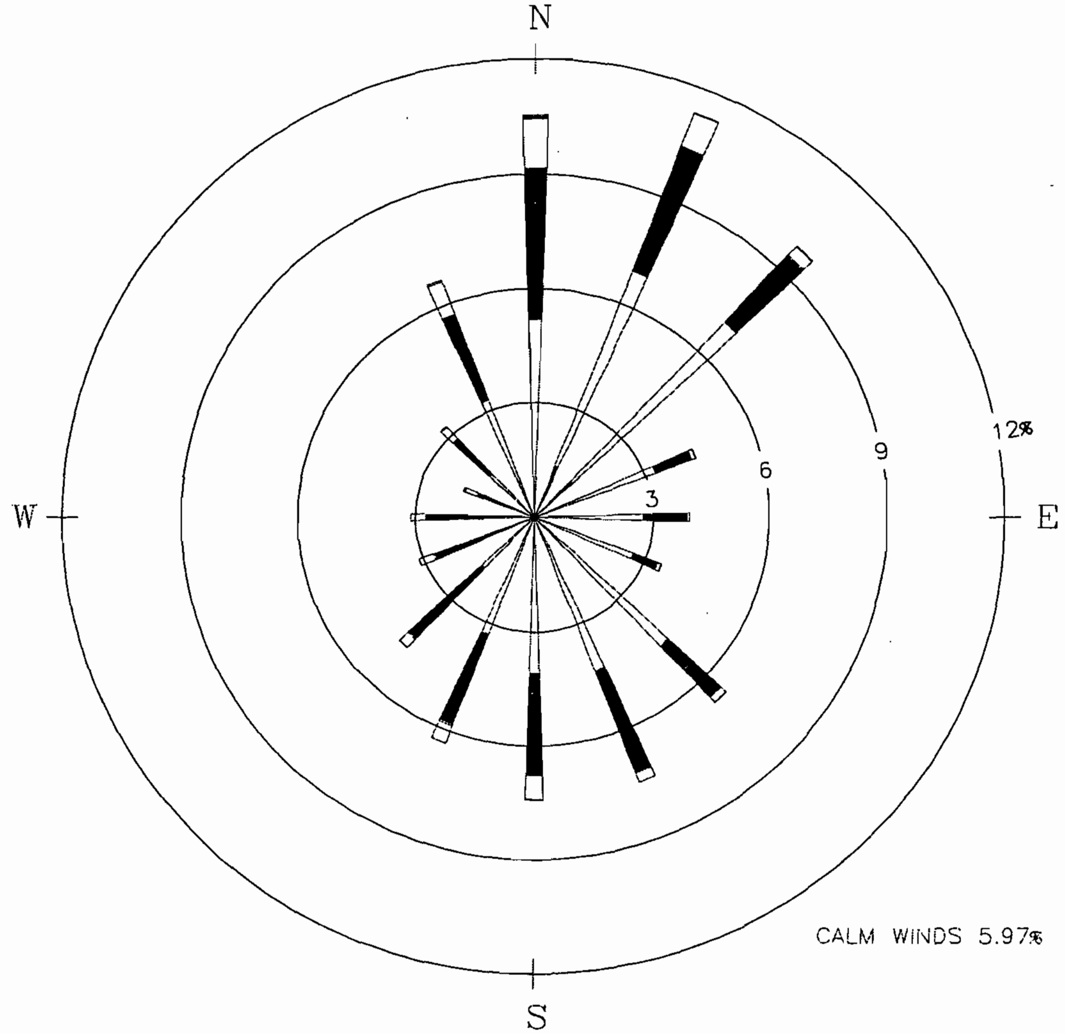
WIND SPEED CLASS BOUNDARIES
(METERS/SECOND)

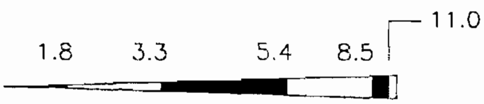
FIGURE 1
WINDROSE

STATION NO: 12842
PERIOD: 1988

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 6.8 PERCENT OF THE TIME.

BEE–LINE
SOFTWARE



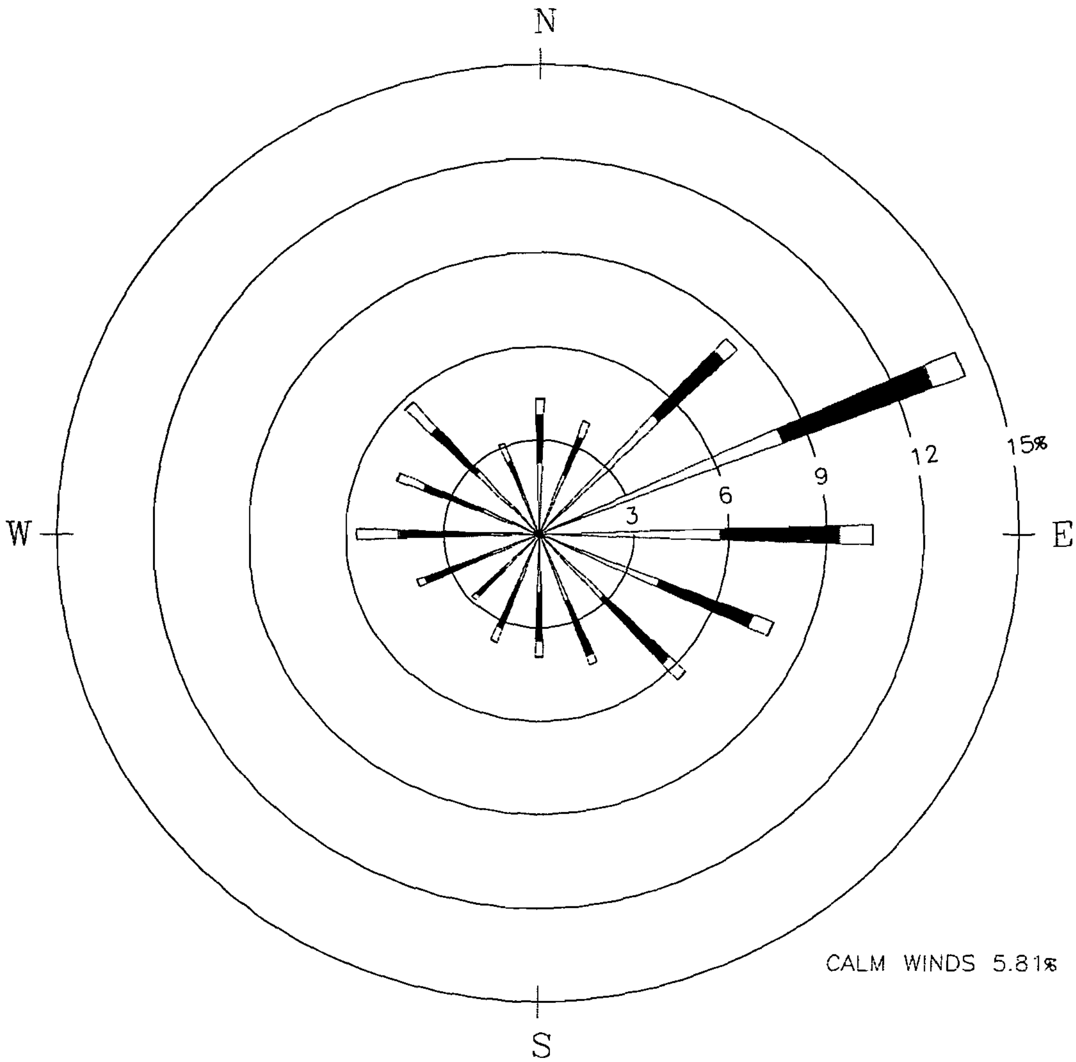


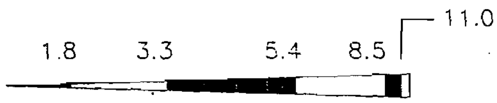
WIND SPEED CLASS BOUNDARIES
(METERS/SECOND)

FIGURE 1
WINDROSE
STATION NO: 12842
PERIOD: 1989

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 10.6 PERCENT OF THE TIME.

BEE-LINE SOFTWARE





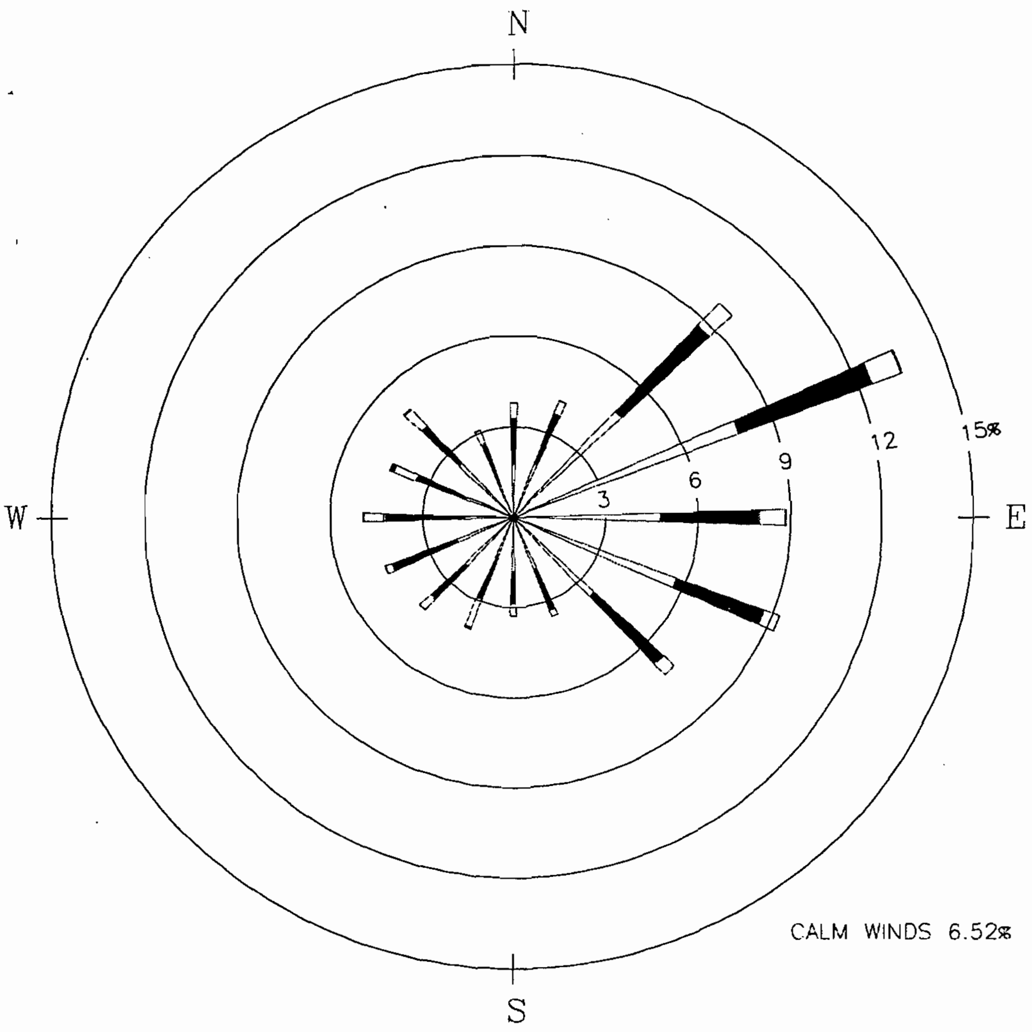
WIND SPEED CLASS BOUNDARIES
(METERS/SECOND)

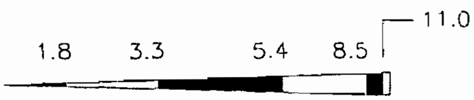
FIGURE 1
WINDROSE

STATION NO: 12842
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 4.3 PERCENT OF THE TIME.

BEE–LINE
SOFTWARE





WIND SPEED CLASS BOUNDARIES
(METERS/SECOND)

FIGURE 1
WINDROSE

STATION NO: 12842

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 3.8 PERCENT OF THE TIME.

BEE–LINE SOFTWARE

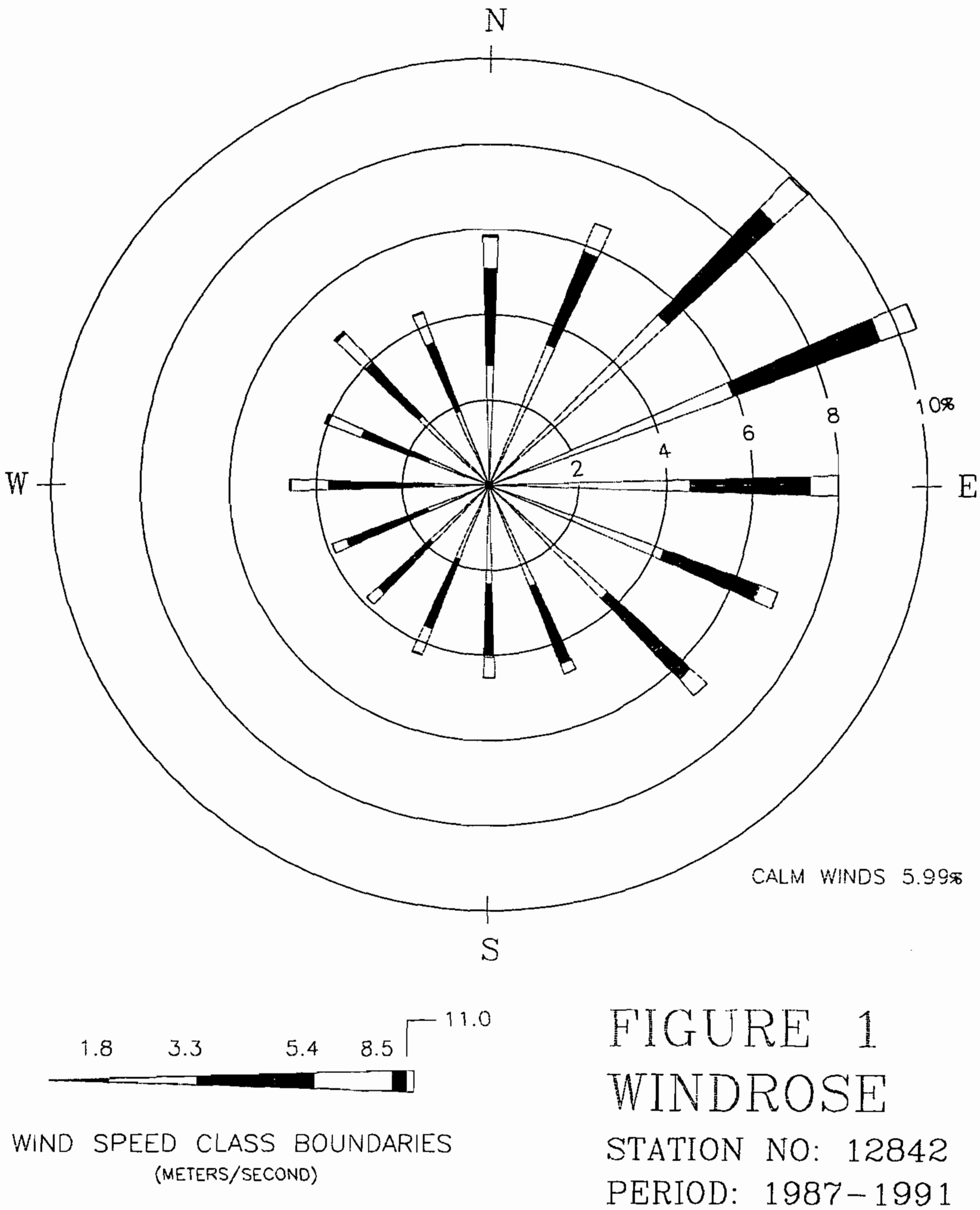


FIGURE 1
WINDROSE

STATION NO: 12842

PERIOD: 1987-1991

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 5.9 PERCENT OF THE TIME.

BEE-LINE SOFTWARE

Appendix D-3

*** ISCST3 - VERSION 99155 ***   *** gas 25 72 97F 9/8/00 1987 Tampa metdat   ***

BEE-Line ISCST3 "BEEST" Version 6.71

Input File - O:\AIR_ENG\PROJECTS\pineypt\g15087.DTA
Output File - O:\AIR_ENG\PROJECTS\pineypt\g15087.LST
Met File - O:\AIR_ENG\PROJECTS\pineypt\met\12842-87.OUT

Number of sources - 11
Number of source groups - 11
Number of receptors - 3196

*** POINT SOURCE DATA ***

SOURCE ID	NUMBER PART. CATS.	EMISSION RATE (GRAMS/SEC)	X (METERS)	Y (METERS)	BASE ELEV. (METERS)	STACK HEIGHT (METERS)	STACK TEMP. (DEG.K)	STACK EXIT VEL. (M/SEC)	STACK DIAMETER (METERS)	BUILDING EXISTS	EMISSION RATE SCALAR VARY BY
25/50	0	0.10000E+01	0.0	0.0	0.0	45.72	347.59	12.50	5.64	YES	
25/75	0	0.10000E+01	0.0	0.0	0.0	45.72	350.93	15.24	5.64	YES	
25F	0	0.10000E+01	0.0	0.0	0.0	45.72	357.59	19.81	5.64	YES	
59FE	0	0.10000E+01	0.0	0.0	0.0	45.72	355.93	19.81	5.64	YES	
59F	0	0.10000E+01	0.0	0.0	0.0	45.72	358.71	18.90	5.64	YES	
72F	0	0.10000E+01	0.0	0.0	0.0	45.72	359.26	18.29	5.64	YES	
72FE	0	0.10000E+01	0.0	0.0	0.0	45.72	355.93	19.20	5.64	YES	
97/50	0	0.10000E+01	0.0	0.0	0.0	45.72	352.59	11.89	5.64	YES	
97/75	0	0.10000E+01	0.0	0.0	0.0	45.72	354.82	14.02	5.64	YES	
97F	0	0.10000E+01	0.0	0.0	0.0	45.72	359.82	17.37	5.64	YES	
97FE	0	0.10000E+01	0.0	0.0	0.0	45.72	357.04	17.98	5.64	YES	

*** SOURCE IDs DEFINING SOURCE GROUPS ***

GROUP ID	SOURCE IDs
25/50	25/50 ,
25/75	25/75 ,
25F	25F ,
59FE	59FE ,

59F	59F	,
72F	72F	,
72FE	72FE	,
97/50	97/50	,
97/75	97/75	,
97F	97F	,
97FE	97FE	,

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR, YR, ZELEV, ZFLAG)				OF TYPE	NETWORK GRID-ID
25/50	1ST HIGHEST VALUE IS	0.02140 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.02115 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.02001 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01969 AT (	1320.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01857 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01844 AT (	1650.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01835 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01800 AT (	1980.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01799 AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01756 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
25/75	1ST HIGHEST VALUE IS	0.01684 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01640 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01634 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01555 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01491 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01463 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01455 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01450 AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA

	9TH HIGHEST VALUE IS	0.01448 AT (	1650.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01431 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
25F	1ST HIGHEST VALUE IS	0.01188 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01170 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01158 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01127 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01086 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01073 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01071 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01061 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01054 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01049 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
59FE	1ST HIGHEST VALUE IS	0.01217 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01195 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01191 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01148 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01110 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01094 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01089 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01088 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01084 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01078 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
59F	1ST HIGHEST VALUE IS	0.01223 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01200 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01198 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01153 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01116 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01099 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01094 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01093 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01091 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01084 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
72F	1ST HIGHEST VALUE IS	0.01252 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01230 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01225 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01175 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01140 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA

	6TH HIGHEST VALUE IS	0.01126 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01120 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01120 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01112 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01107 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
72FE	1ST HIGHEST VALUE IS	0.01252 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01231 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01226 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01175 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01140 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01127 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01121 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01121 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01112 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01108 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97/50	1ST HIGHEST VALUE IS	0.02065 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.02054 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01952 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01882 AT (	1320.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01818 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01787 AT (	1650.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01787 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01754 AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01747 AT (	1980.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01716 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
97/75	1ST HIGHEST VALUE IS	0.01723 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01676 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01675 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01586 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01517 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01487 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01487 AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01482 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01476 AT (	1650.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01465 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR, YR, ZELEV, ZFLAG)				OF TYPE	NETWORK GRID-ID
97F	1ST HIGHEST VALUE IS	0.01302 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01288 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01269 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01212 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01188 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01182 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01168 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01158 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01149 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01145 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
97FE	1ST HIGHEST VALUE IS	0.01310 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01296 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01275 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01217 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01198 AT (	1650.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01188 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01175 AT (	1980.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01163 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01155 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01149 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 1-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR, YR, ZELEV, ZFLAG)				OF TYPE	NETWORK GRID-ID
25/50	HIGH 1ST HIGH VALUE IS	2.67856	ON 87033114: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH 1ST HIGH VALUE IS	1.81547	ON 87033114: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
25F	HIGH 1ST HIGH VALUE IS	1.07978	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
59FE	HIGH 1ST HIGH VALUE IS	1.08383	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
59F	HIGH 1ST HIGH VALUE IS	1.08479	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
72F	HIGH 1ST HIGH VALUE IS	1.08909	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
72FE	HIGH 1ST HIGH VALUE IS	1.08920	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
97/50	HIGH 1ST HIGH VALUE IS	2.78041	ON 87033114: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH 1ST HIGH VALUE IS	2.05733	ON 87033114: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
97F	HIGH 1ST HIGH VALUE IS	1.09708	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA
97FE	HIGH 1ST HIGH VALUE IS	1.09825	ON 87090514: AT (	-660.00,	660.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 3-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	1.60643	ON 87033115: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.70226	ON 87091915: AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.53377	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
59FE	HIGH	1ST HIGH VALUE IS	0.54451	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.54507	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.55437	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
72FE	HIGH	1ST HIGH VALUE IS	0.55656	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	1.68190	ON 87033115: AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.88916	ON 87033112: AT (	250.00,	-143.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.57182	ON 87091915: AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA
97FE	HIGH	1ST HIGH VALUE IS	0.57657	ON 87091915: AT (	2310.00,	-330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 8-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	0.86893	ON 87033116: AT (	200.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.42059c	ON 87081916: AT (	1320.00,	330.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.32436	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
59FE	HIGH	1ST HIGH VALUE IS	0.32849	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.32980	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.33421	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
72FE	HIGH	1ST HIGH VALUE IS	0.33393	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	0.90652	ON 87033116: AT (	200.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.42482c	ON 87081916: AT (	1320.00,	330.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.34192	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
97FE	HIGH	1ST HIGH VALUE IS	0.34268	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 24-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)		RECEPTOR (XR, YR, ZELEV, ZFLAG)				OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	0.28964	ON 87033124:	AT (	200.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.16645	ON 87100424:	AT (	-2310.00,	-1320.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.11920c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
59FE	HIGH	1ST HIGH VALUE IS	0.12164c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.12272c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.12551c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
72FE	HIGH	1ST HIGH VALUE IS	0.12504c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	0.30217	ON 87033124:	AT (	200.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.17055	ON 87100424:	AT (	-2310.00,	-1320.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.13035c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97FE	HIGH	1ST HIGH VALUE IS	0.13058c	ON 87041024:	AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA

*** ISCST3 - VERSION 99155 ***   *** oil 25 72 97F 150 ft stax flat terrain 9/8/00 1987 Tampa metdat   ***

BEE-Line ISCST3 "BEEST" Version 6.71

Input File - O:\AIR_ENG\PROJECTS\pineypt\oil87150.DTA
Output File - O:\AIR_ENG\PROJECTS\pineypt\oil87150.LST
Met File - O:\AIR_ENG\PROJECTS\pineypt\met\12842-87.OUT

Number of sources - 10
Number of source groups - 10
Number of receptors - 3196

*** POINT SOURCE DATA ***

SOURCE ID	NUMBER PART. CATS.	EMISSION RATE (GRAMS/SEC)	X (METERS)	Y (METERS)	BASE ELEV. (METERS)	STACK HEIGHT (METERS)	STACK TEMP. (DEG.K)	STACK EXIT VEL. (M/SEC)	STACK DIAMETER (METERS)	BUILDING EXISTS	EMISSION RATE SCALAR VARY BY
25/50	0	0.10000E+01	0.0	0.0	0.0	45.72	397.04	14.33	5.64	YES	
25/75	0	0.10000E+01	0.0	0.0	0.0	45.72	398.71	17.98	5.64	YES	
25F	0	0.10000E+01	0.0	0.0	0.0	45.72	413.71	24.08	5.64	YES	
59F	0	0.10000E+01	0.0	0.0	0.0	45.72	413.15	22.56	5.64	YES	
72/50	0	0.10000E+01	0.0	0.0	0.0	45.72	397.04	14.02	5.64	YES	
72/75	0	0.10000E+01	0.0	0.0	0.0	45.72	402.59	17.07	5.64	YES	
72F	0	0.10000E+01	0.0	0.0	0.0	45.72	413.15	21.95	5.64	YES	
97/50	0	0.10000E+01	0.0	0.0	0.0	45.72	399.26	13.41	5.64	YES	
97/75	0	0.10000E+01	0.0	0.0	0.0	45.72	405.37	16.46	5.64	YES	
97F	0	0.10000E+01	0.0	0.0	0.0	45.72	413.15	20.42	5.64	YES	

*** SOURCE IDs DEFINING SOURCE GROUPS ***

GROUP ID	SOURCE IDs
25/50	25/50 ,
25/75	25/75 ,
25F	25F ,
59F	59F ,

72/50	72/50	,
72/75	72/75	,
72F	72F	,
97/50	97/50	,
97/75	97/75	,
97F	97F	,

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR, YR, ZELEV, ZFLAG)				OF TYPE	NETWORK GRID-ID
25/50	1ST HIGHEST VALUE IS	0.01081 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01078 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01048 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01037 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01003 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00992 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00991 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00968 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00968 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00966 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
25/75	1ST HIGHEST VALUE IS	0.00843 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00839 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00821 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00819 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00790 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00781 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00777 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00777 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00775 AT (	3300.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00763 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
25F	1ST HIGHEST VALUE IS	0.00555 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA

	2ND HIGHEST VALUE IS	0.00551 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00549 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00540 AT (	3960.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00530 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00526 AT (	4290.00,	0.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00523 AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00523 AT (	3300.00,	330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00520 AT (	3960.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00519 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
59F	1ST HIGHEST VALUE IS	0.00598 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00596 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00590 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00579 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00576 AT (	3960.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00566 AT (	3300.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00565 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00559 AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00558 AT (	3630.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00558 AT (	4290.00,	0.00,	0.00,	0.00)	DC	NA
72/50	1ST HIGHEST VALUE IS	0.01104 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01098 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01066 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01063 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01019 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01012 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01009 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00985 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00985 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00984 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
72/75	1ST HIGHEST VALUE IS	0.00866 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00860 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00846 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00837 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00806 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00804 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00799 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00795 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00791 AT (	3300.00,	-330.00,	0.00,	0.00)	DC	NA

	10TH HIGHEST VALUE IS	0.00788 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
72F	1ST HIGHEST VALUE IS	0.00625 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00625 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00616 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00608 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00601 AT (	3960.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00590 AT (	3300.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00590 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00582 AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00582 AT (	3630.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00581 AT (	4290.00,	0.00,	0.00,	0.00)	DC	NA
97/50	1ST HIGHEST VALUE IS	0.01134 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.01125 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.01096 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.01089 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.01039 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.01038 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.01033 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.01011 AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.01008 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.01005 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
97/75	1ST HIGHEST VALUE IS	0.00886 AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00879 AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00867 AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00855 AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00823 AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00823 AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00818 AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00808 AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00807 AT (	2310.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00806 AT (	1980.00,	0.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC		RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
97F	1ST HIGHEST VALUE IS	0.00673	AT (	2970.00,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.00670	AT (	3300.00,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.00660	AT (	2640.00,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.00657	AT (	3630.00,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.00638	AT (	3960.00,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.00633	AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.00630	AT (	3300.00,	330.00,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.00624	AT (	2310.00,	0.00,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.00623	AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.00622	AT (	3300.00,	-330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 1-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)		RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	1.48293	ON 87033114:	AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.72940	ON 87082111:	AT (	330.00,	1320.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.59668	ON 87072311:	AT (	330.00,	1320.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.60294	ON 87072311:	AT (	330.00,	990.00,	0.00,	0.00)	DC	NA
72/50	HIGH	1ST HIGH VALUE IS	1.54803	ON 87033114:	AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
72/75	HIGH	1ST HIGH VALUE IS	0.97919	ON 87033114:	AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.60714	ON 87072311:	AT (	330.00,	990.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	1.66806	ON 87033114:	AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	1.05073	ON 87033114:	AT (	150.00,	-143.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.69077	ON 87082111:	AT (	330.00,	1320.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 3-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)		RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	0.60864	ON 87033112:	AT (	250.00,	-143.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.38780	ON 87091915:	AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.26164	ON 87091915:	AT (	3300.00,	-330.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.29295	ON 87042412:	AT (	3960.00,	660.00,	0.00,	0.00)	DC	NA
72/50	HIGH	1ST HIGH VALUE IS	0.63712	ON 87033112:	AT (	250.00,	-143.00,	0.00,	0.00)	DC	NA

72/75	HIGH	1ST HIGH VALUE IS	0.39477	ON 87091915: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.29465	ON 87042412: AT (	3960.00,	660.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	0.68915	ON 87033112: AT (	250.00,	-143.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.40051	ON 87091915: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.31065	ON 87091915: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 8-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	0.31015	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.20785	ON 87051716: AT (	-2310.00,	1980.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.14254	ON 87081616: AT (	990.00,	3300.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.16398	ON 87042416: AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
72/50	HIGH	1ST HIGH VALUE IS	0.31373	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
72/75	HIGH	1ST HIGH VALUE IS	0.21256	ON 87051716: AT (	-2310.00,	1980.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.16657	ON 87042416: AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	0.31840	ON 87042416: AT (	2640.00,	330.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.28404	ON 87042416: AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.17370	ON 87042416: AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA

*** THE SUMMARY OF HIGHEST 24-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID			AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
25/50	HIGH	1ST HIGH VALUE IS	0.11272c	ON 87041024: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
25/75	HIGH	1ST HIGH VALUE IS	0.09112c	ON 87041024: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
25F	HIGH	1ST HIGH VALUE IS	0.06321c	ON 87041024: AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
59F	HIGH	1ST HIGH VALUE IS	0.06753c	ON 87041024: AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
72/50	HIGH	1ST HIGH VALUE IS	0.11470c	ON 87041024: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
72/75	HIGH	1ST HIGH VALUE IS	0.09331c	ON 87041024: AT (	2970.00,	-330.00,	0.00,	0.00)	DC	NA
72F	HIGH	1ST HIGH VALUE IS	0.06928c	ON 87041024: AT (	3630.00,	-330.00,	0.00,	0.00)	DC	NA
97/50	HIGH	1ST HIGH VALUE IS	0.11768c	ON 87041024: AT (	2640.00,	-330.00,	0.00,	0.00)	DC	NA
97/75	HIGH	1ST HIGH VALUE IS	0.09721	ON 87042424: AT (	2970.00,	330.00,	0.00,	0.00)	DC	NA
97F	HIGH	1ST HIGH VALUE IS	0.07419c	ON 87041024: AT (	3300.00,	-330.00,	0.00,	0.00)	DC	NA

*** ISCST3 - VERSION 99155 ***   *** cooling tower Marley data stak=150ft cart grid 9/8/00 1987 Tampa ***

BEE-Line ISCST3 "BEEST" Version 6.71

Input File - O:\AIR_ENG\PROJECTS\pineypt\ct87.DTA
Output File - O:\AIR_ENG\PROJECTS\pineypt\ct87.LST
Met File - O:\AIR_ENG\PROJECTS\pineypt\met\12842-87.OUT

Number of sources - 6
Number of source groups - 3
Number of receptors - 3520

*** POINT SOURCE DATA ***

SOURCE ID	NUMBER PART. CATS.	EMISSION RATE (GRAMS/SEC)	X (METERS)	Y (METERS)	BASE ELEV. (METERS)	STACK HEIGHT (METERS)	STACK TEMP. (DEG.K)	STACK EXIT VEL. (M/SEC)	STACK DIAMETER (METERS)	BUILDING EXISTS	EMISSION RATE SCALAR VARY BY
25/50A	0	0.56700E+01	0.0	0.0	0.0	45.72	397.04	14.20	5.64	YES	
CELL1	0	0.20000E-01	13.4	-21.2	0.0	17.83	310.93	11.57	8.50	YES	
CELL2	0	0.20000E-01	28.6	-21.2	0.0	17.83	310.93	11.57	8.50	YES	
CELL3	0	0.20000E-01	43.9	-21.2	0.0	17.83	310.93	11.57	8.50	YES	
CELL4	0	0.20000E-01	59.1	-21.2	0.0	17.83	310.93	11.57	8.50	YES	
CELL5	0	0.20000E-01	74.4	-21.2	0.0	17.83	310.93	11.57	8.50	YES	

*** SOURCE IDs DEFINING SOURCE GROUPS ***

GROUP ID	SOURCE IDs
ALL	25/50A , CELL1 , CELL2 , CELL3 , CELL4 , CELL5 ,
CELLS1_5	CELL1 , CELL2 , CELL3 , CELL4 , CELL5 ,
STAX	25/50A ,

*** THE SUMMARY OF MAXIMUM ANNUAL (1 YRS) RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
ALL	1ST HIGHEST VALUE IS	0.06607 AT (	2313.43,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.06604 AT (	2414.02,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.06587 AT (	2212.85,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.06581 AT (	2514.60,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.06540 AT (	2112.26,	0.00,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.06533 AT (	2313.43,	100.58,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.06528 AT (	2414.02,	100.58,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.06527 AT (	2414.02,	-100.58,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.06517 AT (	2313.43,	-100.58,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.06515 AT (	2212.85,	100.58,	0.00,	0.00)	DC	NA
CELLS1_5	1ST HIGHEST VALUE IS	0.04671 AT (	121.92,	-76.20,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.04591 AT (	105.16,	-76.20,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.04558 AT (	137.16,	-76.20,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.04268 AT (	137.16,	-60.96,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.03802 AT (	152.40,	-76.20,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.03693 AT (	137.16,	-91.44,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.03659 AT (	152.40,	-91.44,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.03587 AT (	121.92,	-91.44,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.03575 AT (	121.92,	-60.96,	0.00,	0.00)	DC	NA
	10TH HIGHEST VALUE IS	0.03418 AT (	105.16,	-91.44,	0.00,	0.00)	DC	NA
STAX	1ST HIGHEST VALUE IS	0.06195 AT (	2414.02,	0.00,	0.00,	0.00)	DC	NA
	2ND HIGHEST VALUE IS	0.06188 AT (	2514.60,	0.00,	0.00,	0.00)	DC	NA
	3RD HIGHEST VALUE IS	0.06181 AT (	2313.43,	0.00,	0.00,	0.00)	DC	NA
	4TH HIGHEST VALUE IS	0.06142 AT (	2212.85,	0.00,	0.00,	0.00)	DC	NA
	5TH HIGHEST VALUE IS	0.06136 AT (	2414.02,	100.58,	0.00,	0.00)	DC	NA
	6TH HIGHEST VALUE IS	0.06127 AT (	2514.60,	100.58,	0.00,	0.00)	DC	NA
	7TH HIGHEST VALUE IS	0.06124 AT (	2313.43,	100.58,	0.00,	0.00)	DC	NA
	8TH HIGHEST VALUE IS	0.06114 AT (	2514.60,	-100.58,	0.00,	0.00)	DC	NA
	9TH HIGHEST VALUE IS	0.06113 AT (	2743.20,	0.00,	0.00,	0.00)	GP	FARFIELD
	10TH HIGHEST VALUE IS	0.06113 AT (	2743.20,	0.00,	0.00,	0.00)	GP	FARFIELD

*** THE SUMMARY OF HIGHEST 24-HR RESULTS ***

** CONC OF OTHER IN MICROGRAMS/M**3 **

GROUP ID		AVERAGE CONC	DATE (YYMMDDHH)	RECEPTOR (XR,	YR,	ZELEV,	ZFLAG)	OF TYPE	NETWORK GRID-ID
ALL	HIGH 1ST HIGH VALUE IS	2.67234	ON 87033124: AT (	121.92,	-76.20,	0.00,	0.00)	DC	NA
	HIGH 2ND HIGH VALUE IS	1.58206	ON 87120424: AT (	137.16,	-76.20,	0.00,	0.00)	DC	NA
CELLS1_5	HIGH 1ST HIGH VALUE IS	2.26030	ON 87033124: AT (	121.92,	-76.20,	0.00,	0.00)	DC	NA
	HIGH 2ND HIGH VALUE IS	1.57666	ON 87120424: AT (	137.16,	-76.20,	0.00,	0.00)	DC	NA
STAX	HIGH 1ST HIGH VALUE IS	0.64297c	ON 87041024: AT (	2514.60,	-301.75,	0.00,	0.00)	DC	NA

HIGH 2ND HIGH VALUE IS 0.60504 ON 87042424: AT (2414.02, 301.75, 0.00, 0.00) DC NA

Appendix D-4

Gulfcoast - Single CT Firing Gas (150-foot stack)

1-hour	UNIT IMPACT (ug/m3)							CO	
Operating Scenario	**1987**	**1988**	**1989**	**1990**	**1991**	**MAX**		**Emissions(lb/hr)**	**Impact (ug/m^3)**
25/50	2.67856	3.13364	2.24116	3.15833	2.95004	3.16		20.0	7.96
25/75	1.81547	2.17883	1.53633	2.19053	2.07994	2.19		25.0	6.90
25F	1.07978	0.93656	0.86144	0.85568	1.35653	1.36		31.0	5.30
59FE*	1.08383	0.93938	0.90042	0.85777	1.37502	1.38		29.0	5.02
59F	1.08479	0.93964	0.90038	0.85806	1.44937	1.45		29.0	5.30
72F	1.08909	1.26011	0.90032	0.85995	1.51772	1.52		19.0	3.63
72FE*	1.0892	0.94257	0.90032	0.86146	1.44508	1.45		19.0	3.46
97/50	2.78041	5.09782	2.30172	3.26775	3.03449	5.10		28.0	17.99
97/75	2.05733	2.43932	1.71801	2.41534	2.29886	2.44		18.0	5.53
97F	1.09708	1.36869	0.90047	1.08846	1.63037	1.63		21.0	4.31
97FE*	1.09825	1.32409	0.90547	1.08846	1.5831	1.58		21.0	4.19
								Maximum	**17.99**
8-hour	**UNIT IMPACT (ug/m3)**							**CO**	
Operating Scenario	**1987**	**1988**	**1989**	**1990**	**1991**	**MAX**		**Emissions(lb/hr)**	**Impact (ug/m^3)**
25/50	0.86893	1.04087	0.61122	0.58916	1.10792	1.11		20.0	2.79
25/75	0.42059	0.43708	0.51354	0.48789	0.78026	0.78		25.0	2.46
25F	0.32436	0.30325	0.38176	0.35831	0.30406	0.38		31.0	1.49
59FE*	0.32849	0.30975	0.38993	0.36633	0.31229	0.39		29.0	1.42
59F	0.3298	0.31039	0.39063	0.36694	0.31356	0.39		29.0	1.43
72F	0.33421	0.31628	0.39793	0.37405	0.32135	0.40		19.0	0.95
72FE*	0.33393	0.31732	0.39933	0.37551	0.3222	0.40		19.0	0.96
97/50	0.90652	1.08422	0.63099	0.62981	1.13797	1.14		28.0	4.01
97/75	0.42482	0.78649	0.5187	0.49275	0.86719	0.87		18.0	1.97
97F	0.34192	0.32669	0.41077	0.38658	0.33508	0.41		21.0	1.09
97FE*	0.34268	0.32891	0.41358	0.38963	0.33757	0.41		21.0	1.09
								Maximum	**4.01**

Gulfcoast - Single CT Firing Natural Gas (150-foot stack)

Annual Average	UNIT IMPACT (ug/m3)						Emission Rate (lb/hr)			Gas-Fired Impact (ug/m3)			Combined Impact (ug/m3)		
	1987	1988	1989	1990	1991	MAX	NOX	PM10	SO2	NOX	PM10	SO2	NOX	PM10	SO2
25/50	0.0214	0.01483	0.0209	0.02054	0.01745	0.0214	15.2	19	7	0.04	0.05	0.02	0.043	0.053	0.023
25/75	0.01684	0.01169	0.01623	0.01622	0.01377	0.01684	19.1	19	8	0.04	0.04	0.02	0.043	0.043	0.021
25F	0.01188	0.00847	0.01131	0.01137	0.0097	0.01188	24.1	20	10	0.04	0.03	0.01	0.039	0.033	0.019
59FE*	0.01217	0.00864	0.0116	0.01165	0.00993	0.01217	22.6	20	10	0.03	0.03	0.02	0.037	0.034	0.020
59F	0.01223	0.00873	0.01166	0.01168	0.00998	0.01223	22.6	20	10	0.03	0.03	0.02	0.038	0.034	0.020
72F	0.01252	0.00897	0.01195	0.01196	0.01021	0.01252	21.8	20	9	0.03	0.03	0.01	0.037	0.034	0.019
72FE*	0.01252	0.00888	0.01197	0.012	0.01023	0.01252	21.8	20	9	0.03	0.03	0.01	0.037	0.034	0.019
97/50	0.02065	0.0145	0.02013	0.01977	0.01685	0.02065	13.2	19	6	0.03	0.05	0.02	0.037	0.051	0.020
97/75	0.01723	0.01198	0.01652	0.01644	0.01403	0.01723	16.7	19	7	0.04	0.04	0.02	0.039	0.043	0.019
97F	0.01302	0.00931	0.01248	0.01249	0.01068	0.01302	20.2	20	9	0.03	0.03	0.01	0.036	0.036	0.019
97FE*	0.0131	0.00933	0.01256	0.01259	0.01074	0.0131	20.2	20	9	0.03	0.03	0.01	0.036	0.036	0.019
									Maximum	0.041	0.051	0.019	**0.043**	**0.053**	**0.023**

3-Hour	UNIT IMPACT (ug/m3)						SO2	
Operating Scenario	1987	1988	1989	1990	1991	MAX	Emissions (lb/hr)	Impact (ug/m3)
25/50	1.60643	2.45398	1.06803	1.05411	1.79223	2.45398	7	2.16
25/75	0.70226	1.16554	0.75043	0.73018	1.27315	1.27315	8	1.28
25F	0.53377	0.52203	0.48715	0.51849	0.50386	0.53377	10	0.67
59FE*	0.54451	0.53935	0.49781	0.52917	0.51729	0.54451	10	0.69
59F	0.54507	0.53993	0.49852	0.53006	0.51752	0.54507	10	0.69
72F	0.55437	0.55491	0.50787	0.54314	0.52893	0.55491	9	0.63
72FE*	0.55656	0.55888	0.50989	0.5456	0.53222	0.55888	9	0.63
97/50	1.6819	2.55479	1.10374	1.18048	1.83672	2.55479	6	1.93
97/75	0.88916	1.85433	0.76315	0.80511	1.40867	1.85433	7	1.64
97F	0.57182	0.58177	0.53643	0.56645	0.54932	0.58177	9	0.66
97FE*	0.57657	0.58859	0.54256	0.57153	0.55471	0.58859	9	0.67
							Maximum	2.16

24-Hour	UNIT IMPACT (ug/m3)						Emissions (lb/hr)		Impact (ug/m3)	
Operating Scenario	1987	1988	1989	1990	1991	MAX	SO2	PM10	SO2	PM10
25/50	0.28964	0.48044	0.26693	0.23332	0.51222	0.51222	7	19	0.45	1.23
25/75	0.16645	0.15203	0.21104	0.18143	0.26009	0.26009	8	19	0.26	0.62
25F	0.1192	0.1076	0.1465	0.12993	0.13391	0.1465	10	20	0.18	0.37
59FE*	0.12164	0.11038	0.14996	0.1325	0.137	0.14996	10	20	0.19	0.38
59F	0.12272	0.11099	0.15016	0.13254	0.13721	0.15016	10	20	0.19	0.38
72F	0.12551	0.11376	0.15389	0.13471	0.13995	0.15389	9	20	0.17	0.39
72FE*	0.12504	0.11387	0.15439	0.13535	0.14055	0.15439	9	20	0.18	0.39
97/50	0.30217	0.50222	0.2583	0.22364	0.52829	0.52829	6	19	0.40	1.26
97/75	0.17055	0.27356	0.21425	0.18382	0.3309	0.3309	7	19	0.29	0.79
97F	0.13035	0.11865	0.16079	0.13902	0.14483	0.16079	9	20	0.18	0.41
97FE*	0.13058	0.11938	0.16213	0.14018	0.14596	0.16213	9	20	0.18	0.41
								Maximum	**0.45**	**1.26**

Gulfcoast - Single CT Firing Oil (150-foot stack)

1-hour	UNIT IMPACT (ug/m3)							CO	
Operating Scenario	1987	1988	1989	1990	1991	MAX		Emissions (lb/hr)	Impact (ug/m^3)
25/50	1.48293	2.01041	1.18874	1.73531	1.71884	2.01		65.0	16.47
25/75	0.7294	0.97782	0.75699	0.82519	1.22706	1.23		58.0	8.97
25F	0.59668	0.65964	0.62512	0.7999	0.69993	0.80		70.0	7.06
59F	0.60294	0.66617	0.63133	0.80445	0.70528	0.80		66.0	6.69
72/50	1.54803	2.07195	1.23901	1.80037	2.03176	2.07		73.0	19.06
72/75	0.97919	1.19012	0.75993	1.2103	1.30741	1.31		52.0	8.57
72F	0.60714	0.66887	0.63392	0.80623	0.80587	0.81		63.0	6.40
97/50	1.66806	2.18042	1.32903	1.91583	2.15837	2.18		83.0	22.80
97/75	1.05073	1.27023	0.76207	1.28242	1.36427	1.36		51.0	8.77
97F	0.69077	0.76569	0.68676	0.81086	0.92283	0.92		58.0	6.74
								Maximum	**22.80**

8-hour	UNIT IMPACT (ug/m3)							CO	
Operating Scenario	1987	1988	1989	1990	1991	MAX		Emissions (lb/hr)	Impact (ug/m^3)
25/50	0.31015	0.55886	0.34353	0.32058	0.62185	0.62		65.0	5.09
25/75	0.20785	0.23134	0.27299	0.25265	0.22602	0.27		58.0	2.00
25F	0.14254	0.17019	0.18154	0.16808	0.1571	0.18		70.0	1.60
59F	0.16398	0.17969	0.19521	0.17893	0.16794	0.20		66.0	1.62
72/50	0.31373	0.58496	0.34997	0.32682	0.64627	0.65		73.0	5.94
72/75	0.21256	0.23531	0.279	0.25848	0.33007	0.33		52.0	2.16
72F	0.16657	0.18354	0.20131	0.184	0.17228	0.20		63.0	1.60
97/50	0.3184	0.63345	0.35787	0.33447	0.69007	0.69		83.0	7.22
97/75	0.28404	0.23816	0.28338	0.26265	0.35036	0.35		51.0	2.25
97F	0.1737	0.19385	0.21762	0.19934	0.18373	0.22		58.0	1.59
								Maximum	**7.22**

Gulfcoast - Single CT Firing Oil (150-foot stack)

Annual Average	UNIT IMPACT (ug/m3)						Emission Rate (lb/hr)			Oil-Fired Impact (ug/m3)		
	1987	1988	1989	1990	1991	MAX	NOX	PM10	SO2	NOX	PM10	SO2
25/50	0.01081	0.00792	0.01031	0.01019	0.00874	0.01081	49.5	46.0	63.0	0.07	0.06	0.09
25/75	0.00843	0.00626	0.0082	0.00805	0.00704	0.00843	63.8	49.0	80.0	0.07	0.05	0.08
25F	0.00555	0.00431	0.00544	0.00537	0.00482	0.00555	80.0	53.0	99.0	0.06	0.04	0.07
59F	0.00598	0.00466	0.00588	0.00579	0.00524	0.00598	75.7	52.0	94.0	0.06	0.04	0.07
72/50	0.01104	0.00813	0.01056	0.0104	0.00894	0.01104	46.0	45.0	58.0	0.06	0.06	0.08
72/75	0.00866	0.0064	0.00837	0.00823	0.00719	0.00866	58.8	48.0	74.0	0.06	0.05	0.08
72F	0.00625	0.0048	0.00609	0.00595	0.00537	0.00625	73.6	51.0	92.0	0.06	0.04	0.07
97/50	0.01134	0.00835	0.01088	0.01067	0.00917	0.01134	42.4	44.0	54.0	0.06	0.06	0.08
97/75	0.00886	0.00651	0.00852	0.00835	0.0073	0.00886	54.5	47.0	69.0	0.06	0.05	0.08
97F	0.00673	0.00512	0.00654	0.00639	0.00577	0.00673	67.6	50.0	84.0	0.06	0.04	0.07
									Maximum	0.07	0.06	0.09

3-Hour	UNIT IMPACT (ug/m3)						SO2	
Operating Scenario	1987	1988	1989	1990	1991	MAX	Emissions (lb/hr)	Impact (ug/m3)
25/50	0.60864	1.31444	0.43603	0.57844	1.01809	1.31444	63.0	10.43
25/75	0.3878	0.36331	0.38202	0.37396	0.40902	0.40902	80.0	4.12
25F	0.26164	0.26429	0.33507	0.26822	0.30662	0.33507	99.0	4.18
59F	0.29295	0.2808	0.33794	0.33684	0.31031	0.33794	94.0	4.00
72/50	0.63712	1.37571	0.44444	0.60012	1.05721	1.37571	58.0	10.05
72/75	0.39477	0.39784	0.38363	0.40343	0.7057	0.7057	74.0	6.58
72F	0.29465	0.28734	0.33906	0.33827	0.31178	0.33906	92.0	3.93
97/50	0.68915	1.48933	0.62208	0.64188	1.12735	1.48933	54.0	10.13
97/75	0.40051	0.4246	0.38483	0.42747	0.74902	0.74902	69.0	6.51
97F	0.31065	0.30443	0.34348	0.34382	0.3168	0.34382	84.0	3.64
							Maximum	10.43

24-Hour	UNIT IMPACT (ug/m3)						Emissions (lb/hr)		Impact (ug/m3)	
Operating Scenario	1987	1988	1989	1990	1991	MAX	SO2	PM10	SO2	PM10
25/50	0.11272	0.19439	0.13952	0.1171	0.23687	0.23687	63.0	46.0	1.88	1.37
25/75	0.09112	0.07756	0.10612	0.09648	0.09461	0.10612	80.0	49.0	1.07	0.66
25F	0.06321	0.05976	0.07494	0.06786	0.06653	0.07494	99.0	53.0	0.93	0.50
59F	0.06753	0.06129	0.07801	0.07225	0.07073	0.07801	94.0	52.0	0.92	0.51
72/50	0.1147	0.20346	0.14141	0.11903	0.24632	0.24632	58.0	45.0	1.80	1.40
72/75	0.09331	0.07936	0.10832	0.09809	0.11002	0.11002	74.0	48.0	1.03	0.67
72F	0.06928	0.06196	0.07933	0.07402	0.07258	0.07933	92.0	51.0	0.92	0.51
97/50	0.11768	0.25695	0.14397	0.12136	0.29841	0.29841	54.0	44.0	2.03	1.65
97/75	0.09721	0.08064	0.1099	0.09924	0.11679	0.11679	69.0	47.0	1.02	0.69
97F	0.07419	0.06481	0.08483	0.07873	0.07747	0.08483	84.0	50.0	0.90	0.53
								Maximum	2.03	1.65

Appendix D-5

Date	CALPUFF 24-hr SO_4 concentration (ug/m^3)	CALPUFF 24-hr NO_3 concentration[a] (ug/m^3)	CALPUFF 24-hr PM_{10} concentration (ug/m^3)	24-hr $(NH_4)_2SO_4$ concentration (ug/m^3) {$[SO_4]$ * 1.375}	24-hr NH_4NO_3 concentration (ug/m^3) {$[NO_3]$ * 1.29}	Relative Humidity	RH factor (from IWAQM Figure B-1)
Overall Worst-Case	0.004	0.025	0.053	0.005	0.032	90.0	6.00

Sulfate Extinction Coefficient {0.003 * RH factor * $[(NH_4)_2SO_4]$}	Nitrate Extinction Coefficient {0.003 * RH factor * $[NH_4NO_3]$}	PM_{10} Extinction Coefficient {0.01 * $[PM_{10}]$}	Extinction Coefficient Sum (bexts)	Background Extinction (bext) {3.912 / BVR (65 km)}	% Change
8.91E-05	5.81E-04	5.28E-04	1.20E-03	6.02E-02	1.99%

[a]As per FLM, NO_3 concentration is equivalent to the sum of NO_3 and HNO_3 concentrations.

Appendix D-6

APPENDIX E

CONTROL TECHNOLOGY REVIEW

Appendix E-1

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - NOx

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
CITY OF ANAHEIM GAS TURBINE PROJECT		CA	09/15/1989	TURBINE, GAS, GE PGLM 5000	55	2.3	SCR, STEAM INJECTION, CO REACTOR	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	2.5	COMBUSTION CONTROL	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	ME	12/04/1998	TURBINE, COMBINED CYCLE	900	2.5	SELECTIVE CATALYTIC REDUCTION. EMISSION IS FRON	LAER
UNION OIL CO.	RODEO	CA	03/03/1986	TURBINE, GAS & DUCT BURNER	54	2.5	SCR, STEAM INJECTION	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/04/1998	TURBINE, COMBINED CYCLE, TWO	528	2.5	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BUR- NER	LAER
SEPCO	RIO LINDA	CA	10/05/1994	TURBINE, GAS COMBINED CYCLE GE MODEL 7	115	2.6	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX COMBU	BACT
SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	CA	08/19/1994	TURBINE, GAS, COMBINED CYCLE LM6000	53	3.0	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	CA	08/19/1994	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	157	3.0	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX COMBU	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	CA	08/19/1994	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2	157	3.0	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX CO MBUS	BACT
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	09/22/1997	TURBINE, COMBUSTION, ABB GT24	224	3.1	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON NO	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/06/1997	TURBINE, COMBUSTION, ABB GT11N2	166	3.5	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON NO	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	NY	06/06/1995	TURBINE, NATURAL GAS FIRED	240	3.5	SCR	LAER
CASCO RAY ENERGY CO	VEAZIE	ME	07/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	3.5	SELECTIVE CATALYTIC REDUCTION	BACT-PSD
GRANITE ROAD LIMITED		CA	05/06/1991	TURBINE, GAS, ELECTRIC GENERATION	58	3.5	SCR, STEAM INJECTION	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	02/02/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 50	317	3.5	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION WIT	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	77	3.5	SCR	BACT-PSD
RUMFORD POWER ASSOCIATES	RUMFORD	ME	05/01/1998	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	238	3.5	SCR AMMONIA INJECTION SYSTEM AND CATALYTIC REACTORTO F	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	02/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	3.5	SCR	LAER
ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	AL	03/16/1999	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCF	170	3.5	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT-PSD
ALABAMA POWER PLANT BARRY	BUCKS	AL	08/07/1998	TURBINES, COMBUSTION, NATURAL GAS	510	3.5	NATURAL GAS, CT-DLN COMBUSTORS, DUCTBURNER, LOW NOX	BACT-PSD
LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	03/01/1995	COMBUSTION TURBINE/GENERATOR	246	3.6	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
BADGER CREEK LIMITED		CA	10/30/1989	TURBINE, GAS COGENERATION	57	3.7	SCR, STEAM INJECTION	BACT-PSD
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	07/31/1996	COMBUSTION TURBINE WITH HEAT RECOVERY BOILE	153	4.0	DRY LNB WITH SCR WATER INJECTION IN PLACE WHEN FIRING OI	LAER
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	4.3	NONE	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	4.4	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTIO	BACT-PSD
HERMISTON GENERATING CO.	HERMISTON	OR	07/07/1994	TURBINES, NATURAL GAS (2)	212	4.5	SCR	BACT-PSD
LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	MN	11/10/1998	GENERATOR, COMBUSTION TURBINE & DUCT BURNE	1988	4.5	SELECTIVE CATALYTIC REDUCTION (SCR) WITH A NOX CEM AND A	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001	175	4.5	STEAM INJECTION FOLLOWED BY SCR	BACT
PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	OR	05/31/1994	TURBINES, NATURAL GAS (2)	215	4.5	SCR	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	NY	11/24/1992	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 M	267	4.5	SCR AND DRY LOW NOX	BACT-OTHER
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM S	HOBBS	NM	02/15/1997	COMBUSTION TURBINE, NATURAL GAS	100	4.5	DRY LOW NOX COMBUSTION	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE	MI	02/08/1999	TURBINE, COMBINED CYCLE, POWER PLANT	500	4.5	SCR	BACT
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE E	248	4.8	FUEL SPEC: FIRING #2 FUEL OIL	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140	5.0	DRY BURN LOW NOX BURNERS	BACT-PSD
CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING AUT	ELK GROVE	CA	07/23/1993	TURBINE, GAS, COMBINED CYCLE, GE LM6000	56	5.0	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION ALSO	BACT
CROCKETT COGENERATION - C&H SUGAR	CROCKETT	CA	10/05/1993	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(	240	5.0	DRY LOW-NOX COMBUSTERS AND A MITSUBISHI HEAVY INDUSTRI	BACT-OTHER
KALAMAZOO POWER LIMITED	COMSTOCK	MI	12/03/1991	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	5.0	DRY LOW NOX TURBINES	BACT-PSD
MOBILE ENERGY LLC	MOBILE	AL	01/05/1999	TURBINE, GAS, COMBINED CYCLE	168	5.1	SCR & DLN COMBUSTORS DURING GAS FIRING. STEAM/WAT	BACT-PSD
KERN FRONT LIMITED	BAKERSFIELD	CA	11/04/1986	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25	5.5	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT-OTHER
BRIDGEPORT ENERGY, LLC	BRIDGEPORT	CT	06/29/1998	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260	6.0	DRY LOW NOX BURNER WITH SCR	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	04/09/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	6.0	GOOD COMBUSTION CONTROLS	BACT-PSD
SUMAS ENERGY INC.	SUMAS	WA	06/25/1991	TURBINE, NATURAL GAS	88	6.0	SCR	BACT-PSD
AES PLACERITA, INC.		CA	07/02/1987	TURBINE, GAS	66	6.2	SCR, STEAM INJECTION	BACT-PSD
SIMPSON PAPER CO.		CA	06/22/1987	TURBINE, GAS	50	6.6	SCR, STEAM INJECTION	OTHER
MIDWAY - SUNSET PROJECT		CA	01/06/1987	TURBINE, GAS, 3	122	7.2	H2O INJECTION	BACT-PSD
SALINAS RIVER COGENERATION COMPANY		CA	11/19/1990	TURBINE,GAS, W/ HEAT RECOVERY STEAM GENERAT	43	7.8	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
SARGENT CANYON COGENERATION COMPANY		CA	11/19/1990	TURBINE, GAS W/ HEAT RECOVERY STEAM GENERAT	43	8.0	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
BASF CORPORATION	GEISMAR	LA	12/30/1997	TURBINE, COGEN UNIT 2, GE FRAME 6	42	8.0	STEAM INJECTION AND SCR TO LIMIT NOX TO 8 PPM FOR NATURA	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	ME	09/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	8.0		BACT-OTHER
RICHMOND POWER ENTERPRISE PARTNERSHIP	RICHMOND	VA	12/12/1989	TURBINE, GAS FIRED, 2	145	8.2	SCR, STEAM INJECTION	LAER
MOJAVE COGENERATION CO.		CA	01/12/1989	TURBINE, GAS	61	8.4	FUEL SPEC: OIL FIRING LIMITED TO 11 H/D	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	8.9	COMBUSTION CONTROL	BACT-PSD
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (NATURAL GAS) (2)	149	8.9	SCR, DRY LOW NOX BURNER	BACT-OTHER
NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	NJ	11/01/1990	TURBINE, NATURAL GAS FIRED	73	8.9	STEAM INJECTION AND SCR	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	GEISMAR	LA	02/13/1998	TURBINE GAS, GE, 7ME 7	121	9.0	DRY LOW NOX TO LIMIT NOX EMISSION TO 9PPMV	BACT-PSD
BAF ENERGY		CA	07/08/1987	TURBINE, GENERATOR	111	9.0	SCR, STEAM INJECTION	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	9.0	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	VA	03/03/1992	TURBINE, COMBUSTION	147	9.0	SCR, STEAM INJECTION	BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	9.0	DRY COMBUSTOR TO 25 PPM SCR TO 9 PPM USING NAT GAS	OTHER
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	CHARLOTTE NC (HEADQUARTERS)	FL	10/15/1999	TURBINE-GAS, COMBINED CYCLE	500	9.0	DLN GE DLN2.6 BURNERS	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	02/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	9.0	GOOD COMBUSTION CONTROL	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	LA	03/07/1997	TURBINE/HSRG, GAS COGENERATION	56	9.0	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTIO	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - NOx

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	LA	03/02/1995	TURBINE/HRSG, GAS COGENERATION	56	9.0	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL	LAER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW	81	9.0	DRY LOW NOX OR SCR	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	NY	11/05/1992	TURBINE, COMBUSTION (79 MW)	82	9.0	DRY LOW NOX OR SCR	BACT-OTHER
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	9.0	DRY LOW NOX BURNER WITH SCR	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	RI	04/13/1992	TURBINE, GAS AND DUCT BURNER	170	9.0	SCR	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	LAS VEGAS	NV	01/17/1991	COMBINED-CYCLE POWER GENERATION	85	9.0	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	NV	09/18/1992	COMBUSTION TURBINE ELECTRIC POWER GENERAT	600	9.0	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
OCEAN STATE POWER	BURRILLVILLE	RI	12/13/1988	TURBINE, GAS, GE FRAME 7, 4 EA	132	9.0	SCR, H2O INJECTION	BACT-PSD
OLEANDER POWER PROJECT	BALTIMORE (HEADQUARTERS)	FL	10/01/1999	TURBINE-GAS, COMBINED CYCLE	190	9.0	DLN 2.6 GE ADVANCED DRY LOW NOX BU	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	9.0	DRY LOW NOX	BACT-OTHER
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	9.0	SCR	BACT-OTHER
SUMAS ENERGY INC	SUMAS	WA	12/01/1990	TURBINE, GAS-FIRED	87	9.0	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
SUNLAW/INDUSTRIAL PARK 2		CA	06/28/1985	TURBINE, GAS W/#2 FUEL OIL BACKUP, 2 EA, GE FRA	52	9.0	SCR, STEAM INJECTION	OTHER
SANTA ROSA ENERGY LLC	NORTHBROOK	FL	12/04/1998	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	TURBINE, COMBUSTION COGENERATION	50	10.0	H2O INJECTION/SCR	BACT-PSD
TAMPA ELECTRIC COMPANY (TEC)	APOLLO BEACH	FL	10/15/1999	TURBINE, COMBUSTION, SIMPLE CYCLE	165	10.5	DLN GE DLN2.6	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	OLDMANS TOWNSHIP	NJ	02/23/1990	TURBINE, NATURAL GAS FIRED	125	11.8	STEAM INJECTION AND SCR	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, NATURAL GAS (2)	189	12.0	DRY LOW NOX COMBUSTOR	BACT-PSD
ALABAMA POWER COMPANY	MCINTOSH	AL	12/17/1997	COMBUSTION TURBINE W/ DUCT BURNER (COMBINE	100	15.0	DRY LOW NOX BURNERS	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	04/11/1995	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL	74	15.0	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUS	BACT-PSD
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
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, NATURAL GAS	109	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND	FL	06/01/1995	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 11	75	15.0	DRY LOW NOX BURNER	BACT-PSD
PEPCO - CHALK POINT PLANT	EAGLE HARBOR	MD	06/25/1990	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84	15.0	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	05/01/1996	COMBINED CYCLE TURBINES (2), NATURAL	471	15.0	DRY LOW NOX COMBUSTION SYSTEMS FOR TURBINES AND DUC	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN	FL	01/01/1996	COMBINED CYCLE COMBUSTION TURBINE	140	15.0	DRY LNB STAGED COMBUSTION	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	NM	11/04/1996	COMBUSTION TURBINE, NATURAL GAS	100	15.0	DRY LOW NOX COMBUSTION	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	15.0	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF NATURAL	BACT-PSD
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	15.0	DRY LOW NOX COMBUSTOR	BACT-PSD
WESTPLAINS ENERGY	PUEBLO	CO	06/14/1996	SIMPLE CYCLE TURBINE, NATURAL GAS	219	15.0	DRY LOW NOX COMBUSTION SYSTEM (DLN). COMMITMENT TOUP(	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY	DE	03/30/1998	TURBINES, COMBINED CYCLE, 2	103	16.0	NITROGEN INJECTION WHILE FIRING SYNGAS AND STEAM INJECT	LAER
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	05/02/1994	GAS TURBINES	75	20.5	INTERNAL COMBUSTION CONTROLS	BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	21.7	WATER INJECTION	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	MD	10/01/1989	TURBINE, NATURAL GAS FIRED ELECTRIC	90	22.0	WATER INJECTION	BACT-PSD
ANITEC COGEN PLANT	BINGHAMTON	NY	07/07/1993	GE LM5000 COMBINED CYCLE GAS TURBINE EP #000	56	25.0	NO CONTROLS	BACT-OTHER
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, GAS, 1 EACH	80	25.0	WET INJECTION	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	FL	07/10/1998	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALS	272	25.0	DRY LOW NOX BURNERS FOR SIMPLE CYCLE, SCR WHEN C	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN	CO	06/30/1998	SIMPLE CYCLE TURBINE, NATURAL GAS	1122	25.0	DRY LOW NOX COMBUSTION	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	192	25.0	H2O INJECTION & LOW NOX COMBUSTION, ANNUAL STACK TESTIN	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, GAS, 4 EACH	400	25.0	LOW NOX COMBUSTORS	BACT-PSD
GEORGIA GULF CORPORATION	PLAQUEMINE	LA	03/26/1996	GENERATOR, NATURAL GAS FIRED TURBINE	140	25.0	CONTROL NOX USING STEAM INJECTION	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	GA	05/13/1994	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	05/13/1994	TURBINE, COMBUSTION, NATURAL GAS	80	25.0	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, GAS FIRED (2 EACH)	227	25.0	MAXIMUM WATER INJECTION	BACT-PSD
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	TURBINE, GE FRAME 7, GAS FIRED	80	25.0	STEAM INJECTION	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	SIEMENS V64.3 GAS TURBINE (EP #00001)	81	25.0	WATER INJECTION	BACT
LORDSBURG L.P.	LORDSBURG	NM	06/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	25.0	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCH	BACT-PSD
MARCH POINT COGENERATION CO		WA	10/26/1990	TURBINE, GAS-FIRED	80	25.0	MASSIVE STEAM INJECTION	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 DRY LOW NOX C	BACT-PSD
PACIFIC THERMONETICS, INC.	CROCKETT	CA	12/10/1985	TURBINE, GAS, FRAME 7, 2 EA	127	25.0	QUIET COMBUSTOR. FUEL SPEC: NATURAL GAS FIRING L IMITED	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW NATURAL FAS FIRED	52	25.0	WATER INJECTION	BACT-OTHER
PEPCO - STATION A	DICKERSON	MD	05/31/1990	TURBINE, 124 MW NATURAL GAS FIRED	125	25.0	WATER INJECTION	BACT-PSD
PG & E, STATION T	SAN FRANCISCO	CA	08/25/1986	TURBINE, GAS, GE LM5000	50	25.0	STEAM INJECTION AT STEAM/FUEL RATIO = 1.7/1	BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/01/1993	GE LM-5000 GAS TURBINE	69	25.0	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	BACT
SYRACUSE UNIVERSITY	SYRACUSE	NY	09/01/1989	TURBINE, GAS FIRED	79	25.0	STEAM INJECTION	OTHER
UNION CARBIDE CORPORATION	HAHNVILLE	LA	09/22/1995	GENERATOR, GAS TURBINE	164	25.0	DRY LOW NOX COMBUSTOR	BACT-PSD
WI ELECTRIC POWER CO.	CONCORD STATION	WI	10/18/1990	TURBINES, COMBUSTION, SIMPLE CYCLE, 4	75	25.0	H2O INJECTION	BACT-PSD
DELMARVA POWER	WILMINGTON	DE	09/27/1990	TURBINE, COMBUSTION	100	27.1	LOW NOX BURNER	BACT-PSD
ONEIDA COGENERATION FACILITY	ONEIDA	NY	02/26/1990	TURBINE, GE FRAME 6	52	32.0	COMBUSTION CONTROL	OTHER
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	03/05/1985	TURBINE, GAS, 2	168	33.2		BACT-PSD
FULTON COGENERATION ASSOCIATES	FULTON	NY	01/29/1990	TURBINE, GE LM5000, GAS FIRED	63	36.0	H2O INJECTION	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - NOx

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	09/01/1989	TURBINE, GAS FIRED	79	36.0	WATER INJECTION	OTHER
MIDWAY-SUNSET COGENERATION CO.		CA	01/27/1988	TURBINE, GE FRAME 7, 3 EA	75	38.4	H2O INJECTION, QUIET COMBUSTOR**	BACT-PSD
O'BRIEN COGENERATION	HARTFORD	CT	08/08/1988	TURBINE, GAS FIRED	62	39.0	WATER INJECTION	BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	ENGINE, GAS TURBINE	92	42.0	STEAM INJECTION	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	SPRINGFIELD	MO	03/04/1991	GENERATION OF ELECTRICAL POWER	73	42.0	WATER INJECTION	BACT-PSD
CITY UTILITIES OF SPRINGFIELD	SPRINGFIELD	MO	03/06/1991	GENERATION OF ELECTRICAL POWER	94	42.0	WATER INJECTION	BACT-PSD
DELMARVA POWER	WILMINGTON	DE	08/23/1988	TURBINE, COMBUSTION, 2 EA	100	42.0	LOW NOX BURNER, WATER INJECTION	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	NY	05/02/1989	TURBINE, GR FRAME 6, 3 EA	52	42.0	STEAM INJECTION	BACT-PSD
FLORIDA POWER AND LIGHT	LAVOGROME	FL	03/14/1991	TURBINE, GAS, 4 EACH	240	42.0	COMBUSTION CONTROL	BACT-PSD
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, NAT GAS FIRED, 3 EA	129	42.0		BACT-PSD
INDECK-YERKES ENERGY SERVICES	TONAWANDA	NY	06/24/1992	GE FRAME 6 GAS TURBINE (EP #00001)	54	42.0	STEAM INJECTION	BACT
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	09/10/1992	GE FRAME 6 GAS TURBINE	62	42.0	WATER INJECTION	BACT
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	GE FRAME 6 GAS TURBINE	63	42.0	STEAM INJECTION	BACT
LEDERLE LABORATORIES	PEARL RIVER	NY		(2) GAS TURBINES (EP #S 00101&102)	14	42.0	STEAM INJECTION	BACT-PSD
LOCKPORT COGEN FACILITY	LOCKPORT	NY	07/14/1993	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	42.0	STEAM INJECTION	BACT
MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	08/05/1989	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	42.0	WATER INJECTION	BACT
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	03/06/1989	TURBINE, LM5000	54	42.0	H2O INJECTION	BACT-PSD
MIDLAND COGENERATION VENTURE	MIDLAND	MI	02/16/1988	TURBINE, 12 TOTAL	123	42.0	STEAM INJECTION	BACT-PSD
THE DEXTER CORP.	WINDSOR LOCKS	CT	09/29/1989	TURBINE, NAT GAS & #2 FUEL OIL FIRED	69	42.0	STEAM INJECTION	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	04/15/1988	TURBINE, GE,2 EA	234	42.0	STEAM INJECTION W/MAXIMIZATION (NSPS SUBPART GG)	LAER
VIRGINIA POWER		VA	09/07/1989	TURBINE, GAS	164	42.0	H2O INJECTION, RECORD KEEPING OF FUEL N2 CONTENT	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	131	44.8	H2O INJECTION	BACT-PSD
LONG ISLAND LIGHTING CO.		NY	11/01/1988	TURBINE, GE FRAME 7, 3 EA	75	55.0	WATER INJECTION	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	MEHOOPANY	PA	05/31/1995	TURBINE, NATURAL GAS	73	55.0	STEAM INJECTION	RACT
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	04/16/1993	GE FRAME 6 GAS TURBINE	53	60.0	STEAM INJECTION	BACT
ALASKA ELECTRICAL GENERATION & TRANSMISSION	BIG LAKE	AK	03/18/1987	TURBINE, NAT GAS FIRED	80	75.0	H2O INJECTION	BACT-PSD
CONTINENTAL ENERGY ASSOC.	HAZELTON	PA	07/26/1988	TURBINE, NAT GAS	98	75.0	STEAM INJECTION	BACT-PSD
SOUTHEAST PAPER CORP.	DUBLIN	GA	10/13/1987	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

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EA	248	1.0	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	GA	07/28/1992	TURBINE, GAS FIRED (2 EACH)	227	1.8	MAXIMUM WATER INJECTION	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	NJ	06/09/1993	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	77	1.8	OXIDATION CATALYST	OTHER
VIRGINIA POWER		VA	09/07/1989	TURBINE, GAS	164	2.1		BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	2.7	GOOD COMBUSTION PRACTICES	BACT-PSD
CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	FL	07/25/1991	TURBINE, GAS, 1 EACH	80	3.0	FUEL SPEC: NATURAL GAS	BACT-PSD
SARANAC ENERGY COMPANY	PLATTSBURGH	NY	07/31/1992	TURBINES, COMBUSTION (2) (NATURAL GAS)	140	3.0	OXIDATION CATALYST	BACT-OTHER
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	3.0	GOOD COMBUSTION PRACTICES	BACT-PSD
WYANDOTTE ENERGY	WYANDOTTE	MI	02/08/1999	TURBINE, COMBINED CYCLE, POWER PLANT	500	3.0	CATALYTIC OXIDIZER	LAER
BLUE MOUNTAIN POWER, LP	RICHLAND	PA	07/31/1996	COMBUSTION TURBINE WITH HEAT RECOVERY BOILE	153	3.1	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRING NO	OTHER
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	09/22/1997	TURBINE, COMBUSTION, ABB GT24	224	3.6	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, CG, 4 EACH	400	3.6	LOW NOX COMBUSTORS	BACT-PSD
AES PLACERITA, INC.		CA	03/10/1986	TURBINE & RECOVERY BOILER	65	3.7	OXIDATION CATALYST	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.I	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	236	4.3	COMBUSTION CONTROL	BACT-PSD
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	03/05/1985	TURBINE, GAS, 2	168	5.3		BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EA	248	5.3	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND	BACT-PSD
CROCKETT COGENERATION - C&H SUGAR	CROCKETT	CA	10/05/1993	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(F	240	5.9	ENGELHARD OXIDATION CATALYST	BACT-OTHER
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	CO	05/01/1996	COMBINED CYCLE TURBINES (2), NATURAL	471	5.9	GOOD COMBUSTION CONTROL PRACTICES. COMMITMENT	BACT-PSD
SUMAS ENERGY INC.	SUMAS	WA	06/25/1991	TURBINE, NATURAL GAS	88	6.0	CO CATALYST	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	04/07/1993	TURBINE, NATURAL GAS	109	6.1	DRY LOW NOX COMBUSTOR	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	8.5	COMBUSTION CONTROL	BACT-OTHER
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	8.8	COMBUSTOR DESIGN & OPERATION	OTHER
FULTON COGENERATION ASSOCIATES	FULTON	NY	01/29/1990	TURBINE, GE LM5000, GAS FIRED	63	8.9	COMBUSTION CONTROL	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	NY	12/31/1991	GE FRAME 6 GAS TURBINE	63	8.9	NO CONTROLS	BACT-OTHER
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERG	BUCKSPORT	ME	09/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	9.0	NONE	BACT-OTHER
FLORIDA POWER AND LIGHT	LAVOGROME REPOWER	FL	03/14/1991	TURBINE, GAS, 4 EACH	240	9.0	FUEL SPEC: NATURAL GAS AS FUEL	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	NY	09/10/1992	GE FRAME 6 GAS TURBINE	62	9.0	NO CONTROLS	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FA	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW	81	9.5	COMBUSTION CONTROLS	BACT-OTHER
KAMINE/BESICORP SYRACUSE LP	SOLVAY	NY	12/10/1994	SIEMENS V64.3 GAS TURBINE (EP #00001)	81	9.5	NO CONTROLS	BACT-OTHER
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #6 FRAME	62	9.6	COMBUSTION CONTROL	BACT-PSD
BRIDGEPORT ENERGY, LLC	BRIDGEPORT	CT	06/29/1998	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260	10.0	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL EMI	BACT-PSD
INDECK-YERKES ENERGY SERVICES	TONAWANDA	NY	06/24/1992	GE FRAME 6 GAS TURBINE (EP #00001)	54	10.0	NO CONTROLS	BACT-OTHER
LOCKPORT COGEN FACILITY	LOCKPORT	NY	07/14/1993	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	53	10.0	NO CONTROLS	BACT-OTHER
LONG ISLAND LIGHTING CO.		NY	11/01/1988	TURBINE, GE FRAME 7, 3 EA	75	10.0	COMBUSTION CONTROL	OTHER
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), NATURAL GAS	116	10.0	COMPLETE COMBUSTION	BACT-PSD
PILGRIM ENERGY CENTER	ISLIP	NY		(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&	175	10.0		BACT-OTHER
SUNLAW/INDUSTRIAL PARK 2		CA	06/28/1985	TURBINE, GAS W/#2 FUEL OIL BACKUP, 2 EA, GE FRAN	52	10.0	MFG GUARANTEE ON CO EMISSIONS	OTHER
SYCAMORE COGENERATION CO.	BAKERSFIELD	CA	03/06/1987	TURBINE, GAS FIRED, 4 EA	75	10.0	CO OXIDIZING CATALYST, COMBUSTION CONTROL	BACT-PSD
TRIGEN MITCHEL FIELD	HEMPSTEAD	NY	04/16/1993	GE FRAME 6 GAS TURBINE	53	10.0	NO CONTROLS	BACT-OTHER
WESTPLAINS ENERGY	PUEBLO	CO	06/14/1996	SIMPLE CYCLE TURBINE, NATURAL GAS	219	10.0	DRY LOW NOX COMBUSTION SYSTEM (DLN). COMMITMENT	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	VA	10/30/1992	TURBINE, COMBUSTION GAS	59	10.3	GOOD COMBUSTION	BACT-PSD
PORTSIDE ENERGY CORP.	PORTAGE	IN	05/13/1996	TURBINE, NATURAL GAS-FIRED	63	10.6	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 10 F	BACT-PSD
EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	NY	05/02/1989	TURBINE, GR FRAME 6, 3 EA	52	10.7	COMBUSTION CONTROL	BACT-PSD
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1986	TURBINE, NAT GAS FIRED, 3 EA	129	10.9	STEAM INJECTION	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO	PROVIDENCE	RI	04/13/1992	TURBINE, GAS AND DUCT BURNER	170	11.0	NONE	BACT-PSD
SEPCO	RIO LINDA	CA	10/05/1994	TURBINE, GAS COMBINED CYCLE GE MODEL 7	115	11.6	OXIDATION CATALYST	BACT
LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	NJ	04/01/1991	TURBINES (NATURAL GAS) (2)	149	11.6	TURBINE DESIGN	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC	CANTON	NY	08/05/1989	GE LM5000-N COMBINED CYCLE GAS TURBINE	401	11.6	NO CONTROLS	BACT-OTHER
MEGAN-RACINE ASSOCIATES, INC.	CANTON	NY	03/06/1989	TURBINE, LM5000	54	11.6	COMBUSTION CONTROL	OTHER
MIDLAND COGENERATION VENTURE	MIDLAND	MI	02/16/1988	TURBINE, 12 TOTAL	123	11.8	TURBINE DESIGN	BACT-PSD
DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	CHARLOTTE NC (HEADQ	FL	10/15/1999	TURBINE-GAS, COMBINED CYCLE	500	12.0	GOOD COMBUSTION	BACT-PSD
GRANITE ROAD LIMITED		CA	05/06/1991	TURBINE, GAS, ELECTRIC GENERATION	58	12.0	SCR, STEAM INJECTION	BACT-PSD
OLEANDER POWER PROJECT	BALTIMORE (HEADQUAR	FL	10/01/1999	TURBINE-GAS, COMBINED CYCLE	190	12.0	GOOD COMBUSTION	BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	02/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	12.0	GOOD COMBUSTION	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
KAMINE SYRACUSE COGENERATION CO.	SOLVAY	NY	09/01/1989	TURBINE, GAS FIRED	79	12.5	COMBUSTION CONTROL	OTHER
SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	NY	11/24/1992	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 M	267	13.0	COMBUSTION CONTROLS	BACT-OTHER
TIGER BAY LP	FT. MEADE	FL	05/17/1993	TURBINE, GAS	202	13.5	GOOD COMBUSTION PRACTICES	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE,GAS	152	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
DELMARVA POWER	WILMINGTON	DE	08/23/1988	TURBINE, COMBUSTION, 2 EA	100	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJE	ROBINS AIR FORCE BAS	GA	05/13/1994	TURBINE, COMBUSTION, NATURAL GAS	80	15.0	FUEL SPEC: LOW SULFUR FUEL (.3% AVG) FUEL 0.1	BACT-PSD
HERMISTON GENERATING CO.	HERMISTON	OR	07/07/1994	TURBINES, NATURAL GAS (2)	212	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
MEAD COATED BOARD, INC.	PHENIX CITY	AL	03/12/1997	COMBINED CYCLE TURBINE (25 MW)	71	15.0	PRIMARY FUEL IS NATURAL GAS WITH BACKUP FUEL AS	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	OR	05/31/1994	TURBINES, NATURAL GAS (2)	215	15.0	GOOD COMBUSTION PRACTICES	BACT-PSD
PSI ENERGY, INC. WABASH RIVER STATION	WEST TERRE HAUTE	IN	05/27/1993	COMBINED CYCLE SYNGAS TURBINE	222	15.0	OPERATION PRACTICES AND GOOD COMBUSTION, COMBI	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 COMBUSTI	BACT-PSD
SUMAS ENERGY INC	SUMAS	WA	12/01/1990	TURBINE, GAS-FIRED	67	15.0	CO CATALYST	BACT-PSD
TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	GA	12/18/1998	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160	15.0	USING 15% EXCESS AIR. CO EMISSION IS BECAUSE OF N	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/04/1998	TURBINE, COMBINED CYCLE, TWO	528	15.0	USING 15 % EXCESS AIR.	BACT-PSD
LORDSBURG L.P.	LORDSBURG	NM	06/18/1997	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100	15.0	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPER AI	BACT-PSD
UNION CARBIDE CORPORATION	HAHNVILLE	LA	09/22/1995	GENERATOR, GAS TURBINE	164	15.4	NO ADD-ON CONTROL GOOD COMBUSTI	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE P	BATON ROUGE	LA	03/07/1997	TURBINE/HSRG, GAS COGENERATION	56	15.8	COMBUSTION DESIGN AND CONSTRUCTION.	BACT-PSD
PROJECT ORANGE ASSOCIATES	SYRACUSE	NY	12/01/1993	GE LM-5000 GAS TURBINE	69	17.0	NO CONTROLS	BACT-OTHER
MOBILE ENERGY LLC	MOBILE	AL	01/05/1999	TURBINE, GAS, COMBINED CYCLE	168	17.8	GOOD COMBUSTION PRACTICES	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE ST	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	20.0	COMBUSTION CONTROL	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140	20.0	GOOD COMBUSTION PRACTICES	BACT-PSD
CASCO RAY ENERGY CO	VEAZIE	ME	07/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	20.0	15% EXCESS AIR	BACT-PSD
KALAMAZOO POWER LIMITED	COMSTOCK	MI	12/03/1991	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	226	20.0	DRY LOW NOX TURBINES	BACT-PSD
SEMINOLE HARDEE UNIT 3	FORT GREEN	FL	01/01/1996	COMBINED CYCLE COMBUSTION TURBINE	140	20.0	DRY LNB GOOD COMBUSTION PRA	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	CHESTERFIELD	VA	03/03/1992	TURBINE, COMBUSTION	147	23.5	FURNACE DESIGN	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	GEISMAR	LA	02/13/1998	TURBINE GAS, GE, 7ME 7	121	25.0	GOOD EQUIPMENT DESIGN, PROPER COMBUSTION TECHN	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	02/25/1994	TURBINE, NATURAL GAS (2)	189	25.0	GOOD COMBUSTION PRACTICES	BACT-PSD
JMC SELKIRK, INC.	SELKIRK	NY	11/21/1989	TURBINE, GE FRAME 7, GAS FIRED	80	25.0	COMBUSTION CONTROL	BACT-PSD
OCEAN STATE POWER	BURRILLVILLE	RI	12/13/1988	TURBINE, GAS, GE FRAME 7, 4 EA	132	25.0		BACT-PSD
PANDA-KATHLEEN, L.P.	LAKELAND	FL	06/01/1995	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 11	75	25.0	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE	BACT-PSD
ALABAMA POWER PLANT BARRY	BUCKS	AL	08/07/1998	TURBINES, COMBUSTION, NATURAL GAS	510	25.4	EFFICIENT COMBUSTION	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING P	LAS VEGAS	NV	09/18/1992	COMBUSTION TURBINE ELECTRIC POWER GENERAT	75	25.8	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	LAS VEGAS	NV	01/17/1991	COMBINED-CYCLE POWER GENERATION	85	26.2	CATALYTIC CONVERTER	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	MS	04/09/1996	COMBUSTION TURBINE, COMBINED CYCLE	162	26.3	GOOD COMBUSTION CONTROLS	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN	CO	06/30/1998	SIMPLE CYCLE TURBINE, NATURAL GAS	1122	30.0	DRY LOW NOX COMBUSTION	BACT-PSD
COMMONWEALTH ATLANTIC LTD PARTNERSHIP	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	192	30.0	COMBUSTION CONTROLS, ANNUAL STACK TESTING	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	FL	07/10/1998	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALS	272	31.2	DRY LOW NOX BURNERS FOR SIMPLE CYCLE, SCR	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	02/02/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501	317	31.2	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTI	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	33.0	COMBUSTION CONTROLS.	BACT-PSD
VIRGINIA POWER	CHESTERFIELD	VA	04/15/1988	TURBINE, GE,2 EA	234	33.2	EQUIPMENT DESIGN	LAER
ANITEC COGEN PLANT	BINGHAMTON	NY	07/07/1993	GE LM5000 COMBINED CYCLE GAS TURBINE EP #0000	56	36.0	BAFFLE CHAMBER	SEE NOTE #4
MARCH POINT COGENERATION CO		WA	10/26/1990	TURBINE, GAS-FIRED	80	37.0	GOOD COMBUSTION	BACT-PSD
CAROLINA COGENERATION CO., INC.	NEW BERN	NC	07/11/1986	TURBINE, GAS, PEAT FIRED	52	37.0	PROPER OPERATION	BACT-PSD
CARSON ENERGY GROUP & CENTERAL VALLEY FINAN	ELK GROVE	CA	07/23/1993	TURBINE, GAS SIMPLE CYCLE LM6000	56	39.5	OXIDATION CATALYST	BACT
INDECK ENERGY COMPANY	SILVER SPRINGS	NY	05/12/1993	GE FRAME 6 GAS TURBINE EP #00001	61	40.0	NO CONTROLS	BACT-OTHER
ONEIDA COGENERATION FACILITY	ONEIDA	NY	02/26/1990	TURBINE, GE FRAME 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 FINANC	ELK GROVE	CA	07/23/1993	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450	50.7	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTIO	BACT
FORMOSA PLASTICS CORPORATION	BATON ROUGE	LA	09/20/1990	TURBINE, GAS-FIRED, 2	73	53.1	COMBUSTION CONTROL	BACT-PSD

RACT/BACT/LAER Clearinghouse Search Results
Combustion Turbines (Natural Gas) - CO

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	PPM[2]	CTRLDESC	BASIS
SIMPSON PAPER CO.		CA	06/22/1987	TURBINE, GAS	50	61.0	COMBUSTION CONTROLS	OTHER
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	02/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	89	61.2	GOOD COMBUSTION CONTROL	BACT-PSD
MIDWAY-SUNSET COGENERATION CO.		CA	01/27/1986	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) - SO_2

FACILITY	CITY	STATE	PERMIT	PROCESS	MW[1]	lb/mmBtu[2]	CTRLDESC	BASIS
ECOELECTRICA, L.P.	PENUELAS	PR	10/01/1996	TURBINES, COMBINED-CYCLE COGENERATION	461	0.000014	MAINTAIN EACH TURBINE IN GOOD WORKING (	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345	0.00011	LOW SULFUR CONTENT & COMBUSTION CONT	BACT-PSD
PROCTOR AND GAMBLE PAPER PRODUCTS C	MEHOOPANY	PA	05/31/1995	TURBINE, NATURAL GAS	73	0.00014	STEAM INJECTION	RACT
PUERTO RICO ELECTRIC POWER AUTHORITY	ARECIBO	PR	07/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE E	248	0.00035	MAINTAIN EACH TURBINE IN GOOD WORKING (	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	04/11/1996	COMBUSTION TURBINE, 4 EACH	238	0.00052	COMBUSTION CONTROL	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TU	LOWESVILLE	NC	12/20/1991	TURBINE, COMBUSTION	164	0.00053	COMBUSTION CONTROL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #6 FRAME	62	0.00058	FUEL SPEC: LOW S FUEL	BACT-PSD
PANDA-ROSEMARY CORP.	ROANOKE RAPIDS	NC	09/06/1989	TURBINE, COMBUSTION, #7 FRAME	131	0.00059	FUEL SPEC: LOW S FUEL	BACT-PSD
FLORIDA POWER CORPORATION POLK COUN	BARTOW	FL	02/25/1994	TURBINE, NATURAL GAS (2)	189	0.00066	FUEL SPEC: LOW SULFUR IN NATURAL GAS	BACT-PSD
CAROLINA POWER AND LIGHT CO.	DARLINGTON	SC	09/23/1991	TURBINE, I.C.	80	0.00078	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
CHAMPION INTERNATIONAL CORP.	SHELDON	TX	03/05/1985	TURBINE, GAS, 2	168	0.00085		BACT-PSD
WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	TX	05/02/1994	GAS TURBINES	75	0.0011	INTERNAL COMBUSTION CONTROLS	BACT
SC ELECTRIC AND GAS COMPANY - HAGOOD	CHARLESTON	SC	12/11/1989	INTERNAL COMBUSTION TURBINE	110	0.0011	GOOD COMBUSTION PRACTICES	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	MA	09/22/1997	TURBINE, COMBUSTION, ABB GT24	224	0.0022	DRY LOW NOX COMBUSTION TECHNOLOGY W	BACT-PSD
DIGHTON POWER ASSOCIATE, LP	DIGHTON	MA	10/06/1997	TURBINE, COMBUSTION, ABB GT11N2	166	0.0023	DRY LOW NOX COMBUSTION TECHNOLOGY W	BACT-PSD
MILLENNIUM POWER PARTNER, LP	CHARLTON	MA	02/02/1998	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 50	317	0.0023	DRY LOW NOX COMBUSTION TECHNOLOGY IN	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	07/13/1998	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170	0.0060		BACT-PSD
TIVERTON POWER ASSOCIATES	TIVERTON	RI	02/13/1998	COMBUSTION TURBINE, NATURAL GAS	265	0.0060	FUEL SPEC: NATURAL GAS FIRED	BACT-PSD
WESTBROOK POWER LLC	WESTBROOK	ME	12/04/1998	TURBINE, COMBINED CYCLE, TWO	528	0.0060		BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEA	BUCKSPORT	ME	09/14/1998	TURBINE, COMBINED CYCLE, NATURAL GAS	175	0.0086		BACT-OTHER
MIDLAND COGENERATION VENTURE	MIDLAND	MI	02/16/1988	TURBINE, 12 TOTAL	123	0.016	FUEL SPEC: NAT GAS FUEL	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	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 PARTNERSH	CHESAPEAKE	VA	03/05/1991	TURBINE, NAT GAS & #2 OIL	192	0.057	FUEL SPEC: LOW SULFUR FUEL & NAT GAS	BACT-PSD
DOSWELL LIMITED PARTNERSHIP		VA	05/04/1990	TURBINE, COMBUSTION	158	0.059	FUEL SPEC: LOW SULFUR FUELS, NAT GAS	OTHER
DELMARVA POWER	WILMINGTON	DE	09/27/1990	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) - 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) - 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 C	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)	188	42.0	WATER INJECTION	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	42.0	WATER INJECTION	SEE NOTES
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	NY	09/01/1992	TURBINE, COMBUSTION GAS (150 MW)	143	42.0	WATER INJECTOR	BACT-OTHER
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	01/18/1994	GE FRAME 6 GAS TURBINE	61	42.0	STEAM INJECTION	BACT
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	05/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	168	49.5	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	NY	11/09/1992	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	81	55.0	DRY LOW NOX OR SCR	BACT-OTHER
PEPCO - CHALK POINT PLANT	EAGLE HARBOR	MD	06/25/1990	TURBINE, 84 MW OIL FIRED ELECTRIC	84	58.0	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
CAROLINA POWER AND LIGHT	HARTSVILLE	SC	08/31/1994	STATIONARY GAS TURBINE	190	62.0	FUEL SPEC: FUEL QUALITY	BACT-PSD
FLORIDA POWER AND LIGHT	NORTH PALM BEACH	FL	06/05/1991	TURBINE, OIL, 2 EACH	400	65.0	LOW NOX COMBUSTORS	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		TURBINE, 140 MW OIL FIRED ELECTRIC	140	65.0	WATER INJECTION	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	OK	12/17/1992	TURBINE, COMBUSTION	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) - 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	06/17/1992	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) - 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 (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	09/06/1969	TURBINE, COMBUSTION, #6 FRAME	64	0.033		
HOPEWELL COGENERATION LIMITED PARTNERSHIP		VA	07/01/1988	TURBINE, OIL FIRED, 3 EA	129	0.034		BACT-PSD
CAPITOL DISTRICT ENERGY CENTER	HARTFORD	CT	10/23/1989	ENGINE, GAS TURBINE	92	0.035		
EAST KENTUCKY POWER COOPERATIVE		KY	03/24/1993	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	187	0.036	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
KALAELOE PARTNERS, L.P.		HI	03/09/1990	TURBINE, LSFO, 2	225	0.044		BACT-PSD
KENTUCKY UTILITIES COMPANY	MERCER	KY	03/10/1992	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	188	0.045	COMBUSTION CONTROL	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	FL	12/14/1992	TURBINE, OIL	146	0.047	GOOD COMBUSTION PRACTICES	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	PEABODY	MA	11/30/1989	TURBINE, 38 MW OIL FIRED	52	0.050	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	0.059	PROPER COMBUSTION TECHNIQUE	BACT-OTHER
UNION ELECTRIC CO	WEST ALTON	MO	05/06/1979	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	78	0.064		BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	04/03/1996	COMBUSTION TURBINE (2), FUEL OIL	116	55.000	CLEAN FUEL	BACT-PSD

1) Some MW were converted from mmBtu/hr, KW, HP and BHP, assuming a heat rate of 8,000 Btu/KW-hr

2) Some lb/mmBtu values were calculated from lb/hr, lb/yr or ton/yr values

All turbines less than 50 MW and above 100 PPM were removed from this list

RACT/BACT/LAER Clearinghouse Search Results
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

Excerpt from::

ENVIRONMENTAL REVIEW OF THE CANAL STATION REDEVELOPMENT PROJECT

Tech Environmental, Inc.

June 20, 2000

The SCONOx system uses a catalyst bed to oxidize NO to NO_2 and absorb the NO_2 onto the surface of the catalyst during the "oxidation/absorption" cycle. The catalyst is divided into a number of sections, each of which is equipped with isolation dampers so that some sections can be regenerated while the plant is operating. A catalyst "regeneration" cycle is required periodically and involves passing hydrogen gas mixed with steam over the catalyst surface, producing nitrogen gas and water vapor. Since hydrogen and nitrogen are present in a high temperature environment, the formation of ammonia during the regeneration cycle is likely, since these conditions are similar to the Haber process of nitrogen fixation used to chemically create ammonia.[8] Neither Goal Line nor AAP have presented any test data to prove that SCONOx does not emit ammonia.

[8] Hiller and Herber, Principles of Chemistry, McGraw-Hill, 1960, p. 246.

Since small amounts of sulfur dioxide (SO_2) will blind (contaminate) the catalyst bed and cause it to stop working, SO_2 must be removed upstream of the SCONOx catalyst, and this is accomplished using the SCOSOx system. SCOSOx uses an oxidation/absorption cycle with a separate catalyst and a regeneration cycle with hydrogen gas just as the SCONOx system does.

The sulfur is not however permanently removed from the exhaust gas, but instead is most often re-emitted downstream of the SCONOx catalyst in the form of hydrogen sulfide (H_2S) and SO_2 according to Goal Line's technical literature.[9] The regeneration chemistry favors H_2S when operating temperatures are below 500° F, and it favors SO_2 when temperatures are highest. H_2S is an exceptionally poisonous gas and is hazardous at low concentrations. If a SCONOx/SCOSOx system were to be used on Unit 2, the 134 tons per year of potential SO_2 emissions from the combustion turbines could convert to 71 tons per year of H_2S if the regeneration cycle did not consistently operate at temperatures above 500° F. Even at high temperatures, some H_2S emissions may occur. Goal Line and AAP have presented no information on H_2S concentrations in the exhaust gas leaving a SCONOx/SCOSOx system.

A recent BACT analysis for a large (350 MW) combustion turbine project in the State[10] documented that SCONOx may impose an energy penalty twice that of SCR on a large power-generating unit, namely a 4 MW penalty for the SCONOx system (equipment electrical use, regeneration gas steam, and performance loss due to pressure drop). Coupled with the fact that the claimed zero-ammonia benefit of SCONOx remains undemonstrated and the likelihood that SCONOx creates another toxic air pollutant, hydrogen sulfide (H_2S), it has not been proven that SCONOx, on balance, offers environmental and energy benefits over SCR.

SCONOx is installed on only two turbine facilities at present: a single 30 MW gas turbine in Vernon, California owned and operated by a partner in the SCONOx technology and a 5 MW gas turbine at the Genetics Institute (G.I.). Only the Genetics Institute plant is providing independent information on how SCONOx is performing on a commercial turbine application.

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9 MacDoonald, R. and Debbage, L., "The SCONOx Catalytic Absorption System for Natural Gas Fired Power Plants," presented at Power-Gen International '97 Dallas, TX, December, 1997, page 8.

10 Cabot LNG Corporation, "Supplemental BACT Analysis on SCONOx for the Island End Cogeneration Plant," DEP Application MBR-97-COM-014, January 25, 2000.

And, given the overly optimistic information Goal Line has disseminated over the past year about the performance and commercial availability of SCONOx, we believe the Genetics Institute test data provide the best source of reliable information on how well SCONOx performs.

At the Northeast Energy and Commerce Association (NECA) meeting that was held on May 16-17, 2000 in Boxboro, the Manager for Environmental Engineering and Compliance at the Genetics Institute, Mr. Robert McGinnis, gave a presentation on how SCONOx is working at his facility. Although it has been nine months since SCONOx was installed and this is the simplest commercial application for SCONOx (a small combustion turbine), there are still unresolved problems with the SCONOx system, and it is not consistently meeting the NO_x emissions limits promised by Goal Line and written into the facility's permit. In addition, we note that no SCONOx system has ever been built or installed for large (100 MW) turbines.

During the NECA conference, G.I. gave conference attendees a tour of the plant. At the time, the turbine was burning natural gas and the SCONOx system was emitting 9 ppm of NO_x, or 360% of the 2.5 ppm permit limit. Mr. McGinnis has since determined that the turbine combustors were not properly tuned and the inlet concentration of NO_x to the SCONOx system was about 50% higher than it was designed for. This incident has, however, revealed that the SCONOx system does not consistently achieve the 90% NO_x removal rates demonstrated in practice by SCR systems. Mr. McGinnis notes that when the inlet concentration to SCONOx is 20 ppm of NO_x, the outlet concentration is about 2 ppm (90% removal). However, higher inlet concentrations cause a substantial degradation in SCONOx performance. When fired with distillate oil, the turbine emits about 50 ppm, and SCONOx, thus far, emits 20 ppm of NO_x, only a 60% removal rate. So far, the SCONOx system has been exceeding the ultimate 15 ppm NO_x limit for oil-firing in the DEP permit.

If the turbine was not running twice as clean as the manufacturer's guarantee (only 50 ppm of NO_x versus the guaranteed emissions of 96 ppm), NO_x emissions from the SCONOx system would be even higher. This same situation carries over to gas-fired operation. Mr. McGinnis notes that here again the turbine is generally cleaner than expected, emitting only 17 ppm of NO_x versus 25 ppm guaranteed and helping to lower the NO_x emitted by SCONOx.

In the past year, the SCONOx unit at G.I. has had a recurring problem with leaking dampers. Goal Line has redesigned the dampers three times. Goal Line has also been washing the catalyst blocks (there are 45 separate modules in the system for this single 5 MW turbine) every 2 to 2-1/2 months, which is more frequently than G.I. expected. Washing involves catalyst block removal, soaking in a potassium carbonate solution, and reinstallation of each block. Not only does catalyst washing involve substantial costs in terms of labor and wastewater disposal, during this maintenance period the turbine unit has to be shutdown. Availability of the turbine unit has been as low as 75% during some months according to G.I. The loss of electrical generation for unscheduled maintenance (e.g., to wash catalysts in order to stay within permit limits) greatly concerns G.I. and raises questions about the commercial reliability of SCONOx for much larger turbines in electric generating stations. Mr. McGinnis summed up the situation by stating that after nine months of experimentation, it is not clear if SCONOx will really work as promised over the long term.

One of the first steps of a BACT analysis, is to determine if a control technology option is "technically feasible." According to U.S. EPA guidance,[11] to be technically feasible a control technology must have been commercially demonstrated, i.e., installed and operated successfully on a source similar to the one under review. As discussed above, SCONOx has not been installed and operated on any large (100+ MW) turbine project similar to the Canal Redevelopment Project, and in the only independent commercial installation to date (a small 5 MW turbine), it has not yet been successful in consistently meeting permit limits. Thus, it is concluded that SCONOx is not technically feasible for the repowering of Unit 2 at Canal Station.

In summary, while SCONOx is a promising new technology being developed for commercial use, it is not the Best Available Control Technology for the repowering of Canal Unit 2 because:

[11] U.S. EPA, "New Source Review Workshop Manual," Research Triangle Park, NC, 1990.

(1) The only independent commercial application of SCONOx on a combustion turbine has not consistently met its ultimate permit emission limits,

(2) The only independent commercial application of SCONOx on a combustion turbine has not demonstrated a level of reliability, availability and performance equal to that of SCR,

(3) SCONOx has never been built for, installed and operated on a large (100+ MW) turbine unit,

(4) SCONOx is not technically feasible for the Project by EPA guidelines,

(5) It has not been proven that SCONOx, on balance, offers environmental and energy benefits over SCR.

Appendix E-3

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com

DATE: August 2, 2000		**NO. PAGES**	**3**
TO:	**TRC ENVIRONMENTAL** **ATTN: Dave Shotts**	**via e-mail**	
ATTN:	**ENGELHARD** **Nancy Ellison**		
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **GE 7FA Combined Cycle Project**
CO Catalyst - Engelhard Budgetary Proposal EPB00893

We provide Engelhard Budgetary Proposal EPB00893 for One (1) Engelhard **Camet®** CO Catalyst system for the above project. This is per e-mail request on August 1, 2000.

Catalyst selection and pricing are based on:

- Given Data for Siemens V84.2 combustion turbine;
- CO reductionfrom noted inlet levels to 2 ppmvd @ 15% O_2 (NG) and 4 ppmvd @ 15% O_2 (Oil);
- Three (3) year Performance Guarantee - expected life 5 – 7 years;
- Meet assumed HRSG inside liner dimensions of 67 ft H x 26 ft W;
- Scope: Normal to HRSG supplier - Catalyst modules with internal frame and tongue seals with interface engineering only.
- By others: Duct / catalyst housing (including any transitions), internal insulation, grooved internal liner sheets, and frame supports and bottom pedestals are provided by others, along with catalyst loading door, personnel manway and sample ports.

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

TRC
CO Oxidation Catalyst – GE 7FA Combined Cycle
Engelhard Budgetary Proposal EPB00893
August 2, 2000

ENGELHARD CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEM

Engelhard Corporation, ("Engelhard"), offers to supply the **CAMET®** metal substrate catalytic oxidation system ("CO System") based upon Buyer's technical data and site conditions provided.

DELIVERABLES: Equipment and services consisting of:

1. Catalyst modules;
2. Removable and replaceable sample catalysts;
3. Internal support frame and internal tongue seals;
4. Drawings showing installation details, loadings, and support requirements;
5. Installation and operating manuals;
6. Technical service for inspection of equipment installation performed by others - Five (5) days total and two (2) trips are provided.

BUDGET PRICE: Per Unit Delivery: FOB, plant gate, job site

CO System	**$ 560,000 – Per Turbine**
Replacement CO Catalyst Modules	**$ 480,000 – Per Turbine**

SPENT CATALYST
Engelhard agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is not a hazardous material. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Twelve (12) months from date of start up or eighteen (18) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.
Expected Life:	Five – Seven Years

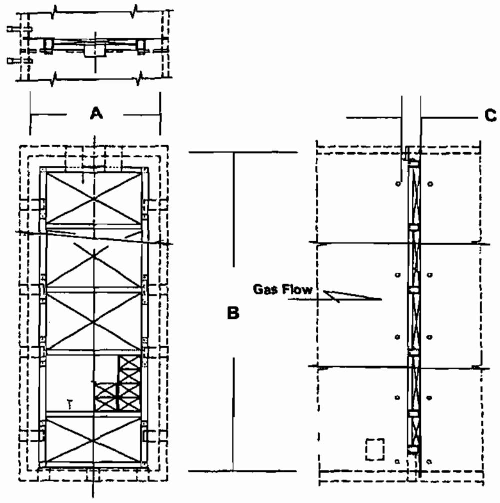
DOCUMENT / MATERIAL DELIVERY SCHEDULE

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

CO SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7FA Combustion Turbine
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Gas Velocities must be within $\pm$25% of the mean velocity at the catalyst face
Temperature (At catalyst face):	All Gas Temperatures must be within $\pm 20^{O}$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)

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.

Cost Quote Provided by Alstom-ABB

Sconox Base

Direct Costs			
a) Capital Cost	$	14,000,000	
b) Taxes (3%)	$	420,000	
c) Freight (4%)	$	-	
Purchased Equip Cost	$	14,420,000	
Installation	$	1,700,000	
Total Direct Costs	$	16,120,000	
Engineering Costs	$	200,000	
Contingency	$	250,000	
Total Capital Investment	$	16,570,000	
Direct Annual Costs			
Maintenance	$	331,400	
Steam & Natural Gas	$	406,400	
Pressure Drop	$	129,360	
Catalyst Replacement	$	190,000	
Total Annual Direct Costs	$	1,057,160	
Indirect Annual Costs			
Overhead	$	198,840	60% of maintenance
Property Tax	$	0	No property taxes
Insurance	$	165,700	1% of TCI
Administration	$	125,000	
Total Annual Investment	$	1,546,700	
Capital Recovery Factor		0.1424	10 yrs & 7% interest
Total Capital Required	$	16,570,000	
Total Annual Costs	$	1,546,700	
Total Annualized Costs	$	3,906,268	

Appendix E-4

Table E-1. CPV Gulf Coast
SCR to achieve 3.5 ppm NOx

COST COMPONENT	COST
DIRECT COSTS	
Purchased Equipment Costs	
SCR Catalyst System	950,000
Sales Tax (6% of equipment costs)	57,000
Freight (4% of equipment costs)	38,000
Subtotal-Purchased Equipment Costs (PEC)	1,045,000
TOTAL DIRECT COSTS (TDC)	1,045,000
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	52,250
CONTIGENCY (20% of Direct and Indirect Costs)	219,450
TOTAL CAPITAL INVESTMENT (TCI)	**1,316,700**
DIRECT ANNUAL COSTS	
Maintenance Materials and Labor (2% of TCI)	26,334
Ammonia Cost	27,763
Catalyst Pressure Derate	145,697
Catalyst Replacment (based on total SCR catalyst replacement cost every 3 years)	173,333
Catalyst Disposal (Amortized Over 5 Year Period)	8,333
TOTAL ANNUAL DIRECT COSTS	381,460
INDIRECT ANNUAL COSTS	
Overhead (60% of maintenance materials and labor)	15,800
Property Tax (1% of TCI)	13,167
Insurance (1% of TCI)	13,167
Administration (2% of TCI)	26,334
TOTAL INDIRECT ANNUAL COSTS	68,468
TOTAL ANNUAL INVESTMENT	**449,929**
*CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)*	
Equipment Life (years) = 10	
Interest Rate (%) = 8	
Capital Recovery Factor	0.1490
CAPITAL RECOVERY COSTS	
TOTAL CAPITAL REQUIREMENT	**1,316,700**
TOTAL ANNUAL CAPITAL REQUIREMENT	**196,227**
TOTAL ANNUALIZED COST **(Total annual O&M cost and annualized capital cost)**	**646,156**
BASELINE POTENTIAL NO_x EMISSIONS (TPY) FROM TURBINE	
(emissions based on 100% load at 72°F) **Uncontrolled**	**345**
Controlled	**117**
ANNUAL TONS OF NOx REMOVED	**228**
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS	
(\$ per ton of NO_x removed)	**2,835**

Table E-2. CPV Gulf Coast SCONOX to achieve 3.5 ppm NOx	
COST COMPONENT	COST
DIRECT COSTS	
Purchased Equipment Costs	
SCONOX System	16,000,000
Sales Tax (6% of equipment costs)	960,000
Freight (4% of equipment costs)	640,000
Subtotal-Purchased Equipment Costs (PEC)	17,600,000
Direct Installation Costs	
Construction	1,700,000
TOTAL DIRECT COSTS (TDC)	19,300,000
INDIRECT INSTALLATION COSTS	
Engineering Costs	200,000
CONTIGENCY (20% of Direct and Indirect Costs)	3,900,000
TOTAL CAPITAL INVESTMENT (TCI)	**23,400,000**
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)	234,000
Insurance (1% of TCI)	234,000
Administration (2% of TCI)	468,000
TOTAL INDIRECT ANNUAL COSTS	*1,134,840*
TOTAL ANNUAL INVESTMENT	**2,192,000**
*CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)*	
Equipment Life (years) = 10	
Interest Rate (%) = 8	
Capital Recovery Factor	0.1490
CAPITAL RECOVERY COSTS	
TOTAL CAPITAL REQUIREMENT	**23,400,000**
TOTAL ANNUAL CAPITAL REQUIREMENT	**3,487,290**
TOTAL ANNUALIZED COST (Total annual O&M cost and annualized capital cost)	**5,679,290**
BASELINE POTENTIAL NO_x EMISSIONS (TPY) FROM TURBINE	
(emissions based on 100% load at 72°F) **Uncontrolled**	**345**
Controlled	**117**
ANNUAL TONS OF NOx REMOVED	**228**
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS	
($ per ton of NO_x removed)	**24,916**

Table E-3. CPV Gulf Coast
CO Catalyst

COST COMPONENT:	COST
DIRECT COSTS	
Purchased Equipment Costs	
CO Catalyst (Engelhard Budgetary Quote)	$560,000
Sales Tax (6% of purchased equipment costs)	$33,600
Freight (4% of purchased equipment costs)	$22,400
Subtotal-Purchased Equipment Costs (PEC)	$616,000
Direct Installation Costs	
Installation/Foundation (35% of Catalyst Capital Cost)	$196,000
Subtotal-Direct Installation Costs	$196,000
TOTAL DIRECT COSTS (TDC)	$812,000
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	$30,800
Contingency (20% of TDC)	$162,400
TOTAL INDIRECT COSTS	$193,200
TOTAL CAPITAL INVESTMENT (TCI)	**$1,005,200**
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)	$20,104
Replacement Catalyst (3 Year Service Life)	$160,000
$ 480,000 * Capital Recovery Factor (0.3880 for n = 3 & i = 8%)	
3 Guaranteed catalyst life	
Pressure Drop Derate (Lost Revenue From Sale Of Power)	$101,178
0.7 Pressure drop across catalyst, inches H2O	
206,300 Full load CTG output (annual average), kW	
275 Output reduction for pressure drop, kW/inch H20	
193 kW derate	
1,686,300 kW-hr output lost per year	
6 cents per kW-hr	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)	$36,596
1.807E+09 Annual CTG output, kW-hr	
9 Btu//kW-hr	
16,265 mmBtu/yr natural gas	
2.25 $/mmBtu natural gas	
Catalyst Disposal	$16,667
$ 50,000 at the end of catalyst guaranteed life	
TOTAL DIRECT ANNUAL COSTS	$334,544
INDIRECT ANNUAL COSTS	
Overhead (60% of labor and maintenance materials)	$12,062
Property Tax (1% of TCI)	$10,052
Insurance (1% of TCI)	$10,052
Administration (2% of TCI)	$20,104
TOTAL INDIRECT ANNUAL COSTS	$52,270
TOTAL ANNUAL COSTS	**$386,815**
CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)	
10 Equipment Life (years)	
8 Interest Rate (%)	
Capital Recovery Factor	0.1490
CAPITAL RECOVERY COSTS	
TOTAL CAPITAL REQUIREMENT	**$1,005,200**
TOTAL ANNUALIZED CAPITAL REQUIREMENT	**$149,804**
TOTAL ANNUALIZED COST **(Total annual O&M cost and annualized capital cost)**	**$536,619**
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6040 hr/yr (no power augmentation)/ 15 ppm on gas for 2000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	**154**
TONS OF CO REMOVED PER YEAR Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	**123**
COST-EFFECTIVENESS **ENVIRONMENTAL BASIS** **($ per ton of CO removed)**	**$4,350**