FMPA/KEYS
STOCK ISLAND POWER PLANT

Air Construction Permit Application

Combustion Turbine Unit 4

October 2004

FMPA and KEYS **Black & Veatch**

BLACK & VEATCH

11401 Lamar Avenue
Overland Park, Kansas 66211 USA

Tel: (913) 458-2000

Black & Veatch Corporation

FMPA/KEYS
Stock Island Combustion Turbine Unit 4

B&V Project 136839
File No. 33.1000
October 19, 2004

Al Linero,
Professional Engineer Administrator
Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
2600 Blair Stone Road MS 5500
Tallahassee, FL 32399-2400
(850) 488-0114

REC
OCT 20 2004
BUREAU OF AIR REGULATION

Subject: Stock Island Power Plant Construction Permit Application

Dear Mr. Linero:

On behalf of the Florida Municipal Power Agency (FMPA) and Keys Energy Services (KEYS), enclosed please find an original and three (3) copies of an air construction permit application for the Stock Island Power Plant on Stock Island in Monroe County, Florida. The proposed construction includes the installation of a nominal 48 MW fuel oil fired combustion turbine, designated Combustion Turbine Unit 4, along with support facilities. Please see the application support document for a more detailed description of the requested construction. A check in the amount of $7,500 is enclosed for the application processing fee.

We look forward to working with your office and staff as this application proceeds through the review process. If you have any questions, please contact Edward Garcia of KEYS at (305) 295-1134 or Susan Schumann of FMPA at (407) 355-7767.

Sincerely,

Bob Holmes

Bob Holmes
Air Quality Scientist
BLACK & VEATCH

Enclosures

cc: Jim Hay, FMPA
Susan Schumann, FMPA
Daniel Cassel, KEYS
Edward Garcia, KEYS
Diane Tremor, RS&B
Angela Morrison, HGS
Stanley Armbruster/file, B&V

Prevention of Significant Deterioration Air Permit Application for Stock Island Power Plant Combustion Turbine Unit 4

Submitted by

Florida Municipal Power Agency
and
Keys Energy Services

Prepared by
Black & Veatch

October 2004
Project No. 136839

Contents

Contents (Continued)

Tables

Contents (Continued)

Figures

1.0 Introduction

The Florida Municipal Power Agency (FMPA) and Utility Board of the City of Key West d/b/a Keys Energy Services (hereinafter referred to as KEYS) are implementing the installation of a GE LM6000 PC SPRINT combustion turbine in simple cycle operation (Project) at the KEYS Stock Island Power Plant site near Key West, Florida. KEYS owns the Stock Island site and will operate the unit. The proposed Project will be comprised of one simple cycle combustion turbine (SCCT) rated at a nominal 48 megawatts (MW) at ISO conditions and 100 percent load, firing No. 2 fuel oil. New major support facilities for the Project will include an additional water storage tank and a fuel oil storage tank.

This report is a technical support document for the Prevention of Significant Deterioration Air Permit Application. The following sections contain a project characterization, best available control technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

2.0 Project Characterization

The following sections briefly characterize the Project, including a general description of the location, facility, and emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The Project is located on Stock Island in Monroe County near Key West, Florida. Figure 2-1 shows the general location of the Project. The nearest Federal Prevention of Significant Deterioration (PSD) Class I Area is the Everglades National Park (ENP), located approximately 90 km northeast of the Project site. The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

The Project will be composed of one nominal 48 MW GE LM6000 PC SPRINT simple cycle combustion turbine (SCCT) firing low sulfur No. 2 fuel oil. The energy of the combustion gases exiting the combustor will be transformed into rotating mechanical energy as it expands through the turbine sections of the SCCT. The rotating mechanical energy will be converted into electrical energy via a shaft on the SCCT connected to an electrical generator. The remaining combustion gases will be exhausted to the atmosphere through an exhaust stack. Due to the location of the Project in the Florida Keys, natural gas is not available as a fuel source.

2.3 Combustion Turbine Unit 4 Unique Project Aspects

The Florida Keys are a 220 mile long chain of islands that extend from the southeastern tip of Florida to the Dry Tortugas. The highest spot in the Keys is 18 feet above sea level and there is no point that is more than 4 miles from water. Only about 32 of the 822 islands that make up the Keys are inhabited. The more developed islands are connected by a narrow band of US Highway 1, which includes 19 miles of bridges.

The population of Monroe County was 79,589 in the year 2000, with approximately 30 percent, or 24,000 residents living in the City of Key West. In addition to resident populations, millions of tourists visit the Keys and provide the major source of employment for local residents. Retail services, commercial fishing, and government employment make up the other industries. Some of the unique aspects of the Stock Island facility and the proposed installation of Combustion Turbine Unit 4 are discussed on the following pages.

Map Source: Boca Chica Key USGS 7.5-Minute Quadrangle

Figure 2-1
Stock Island Combustion Turbine Unit 4
Proposed Project Location

2.3.1 Road Transportation Accessibility

The Stock Island Power Plant is located just off US Highway 1, approximately 100 miles by road from mainland Florida. US Highway 1, with 42 bridges covering 19 miles of the highway's length, is the only roadway that provides access to the Florida Keys. While US Highway 1 is a four-lane divided highway for a 10 mile stretch in the northernmost area of the Keys, it is a two-lane road from Tavernier to Key West, a 100 mile stretch. Therefore, any transport vehicle traveling to Stock Island will need to travel a 90 mile stretch of this two lane road, which provides the only access to Stock Island and Key West. Because this road is the only access to Stock Island, closure of this road due to an accident, weather, or for any other reason would result in a delay of shipment of materials to the facility. Road closure could become critical to sustaining reliable operation of Combustion Turbine Unit 4 if frequent maintenance and repairs of the combustion turbine or its control equipment are needed. Delays in providing maintenance or repair materials would cause hardship to the citizens of the Keys if adequate power cannot be provided due to unit downtime.

Recent history has shown that accidents and the resulting closure of US Highway 1 are not uncommon. As an example, based on information taken from web site www.nbc6.net, the seven mile bridge was closed for several hours on July 27, 2004 due to a fatality accident on the seven mile bridge. This same article indicated that another bridge in the Keys was closed for several hours on July 26, 2004 after a wreck left a semi-trailer hanging off the bridge by its wheels near Islamorada.

2.3.2 Accessibility of Electrical Power from the Mainland

The unique location of the Florida Keys and the limited means of electrical power supply to the Keys are always a concern and consideration regarding the reliability of the electricity generating units in the Key West area. The Utility Board of the City of Key West (KEYS) is connected to the mainland Florida transmission network through a 138 kV transmission line running adjacent to US Highway 1. The first 61 mile stretch of this transmission line, which is jointly owned by the Florida Keys Electric Cooperative Association, Inc. (FKEC) and KEYS, runs southwest along US Highway 1 from a tie-in with Florida Power & Light (FPL) at the Monroe-Dade County line to Tavernier Substation and then on to the Marathon Substation. The KEYS jointly owns with FKEC a second 138 kV transmission line, which runs 21 miles from a tie with the 138 kV FPL transmission line at the Monroe-Dade County line to the Tavernier Substation. The final section of the transmission line to Key West is solely owned by KEYS and is a 138 kV transmission line that extends from Marathon Substation to the Stock Island Substation, a distance of approximately 40 miles. The firm MW transfer allocation for KEYS over the transmission line is approximately 110 MW.

The generating units located at the Stock Island Power Plant and this 138 kV transmission line are the only sources of electrical power to the Key West area. Any electrical demand beyond what is allocated to KEYS via the transmission line must be provided by the generating units at Stock Island. If this 138 kV transmission line is out of service, all power demand for the Key West area must be supplied by the generating units at the Stock Island Power Plant. However, the units that make up this current local capacity have reliability issues and repairs for these units generally cannot be made by on-site personnel and require contractors from off-site to be called in, making the repair of one of these existing units a relatively time consuming process. Therefore, it is imperative that new generating units at the Stock Island Power Plant be as reliable as possible, even with BACT. Unlike a unit outage on the mainland, where the electrical demand can usually be met by buying power off the grid, if power is not available from the single transmission line coming from the mainland, then all power to the Key West area must be provided by the Stock Island Power Plant units and if these units are not available, power will not be available to the Key West area (i.e., Key West will be dark). In addition, when demand on KEYS exceeds the transfer capability of the transmission line, then that additional demand must also be met by generating units at Stock Island. Again, if the Stock Island generating units are not available due to planned or unplanned outages, including those to maintain emissions control equipment, then demand in Key West will not be met.

The need for reliable power generation at the Stock Island Power Plant is further heightened by the effect hurricanes have on the Key West area. A hurricane can result in the loss of power from the main transmission line from the mainland and the need for immediate and reliable power generation from the Stock Island Power Plant to avoid prolonged blackouts during a time when power availability may be essential for disaster recovery operations. As a recent example, during Hurricane Charley, a sailboat broke away from its moorings and started to drift. The mast of the drifting sailboat struck the transmission line carrying power to the Key West area from the mainland, which resulted in a blackout in the Key West area. A stronger hurricane making a direct hit in the Keys or on the Florida mainland could affect transmission of power to the Keys for an extended period of time. As an example, as a result of Hurricane Andrew, a category 5 hurricane, 3,300 miles of power lines were destroyed, 1.4 million residents lost electricity, and it took 34 days to restore power. A stronger hurricane, such as Hurricane Andrew, that makes a direct hit on the transmission line providing power to the Keys could knock out the transmission line from the mainland for days or weeks, in which case, all demand in the Key West area would have to be met by generation on Stock Island for an extended period of time. By ensuring that new Combustion Turbine Unit 4 is an extremely reliable unit, it will be able to meet the electricity demand to the Key West area in a time of disaster recovery, providing vital energy to aid in the recovery and operation of hospitals, sewage treatment plants, water plants, and other emergency operations.

Finally, the KEYS remote location at the end of a long transmission line can require that units at Stock Island be operated for voltage support. In these instances, it is imperative that the units be reliable. If generation at Stock Island is needed for voltage support and is not available due to planned or forced outages, voltage on KEYS system will collapse, causing a blackout in Key West.

2.3.3 Replacement Power Costs

The unique isolated nature of KEYS also has a significant impact on replacement power costs. While this BACT analysis utilizes the FMPA wholesale power rate as a replacement power cost, the actual cost of replacement power is likely to be much higher. The unavailability of Stock Island Combustion Turbine Unit 4, due to either the inability to meet emission limits or additional planned outages for emissions control equipment, has a much higher probability of keeping KEYS from meeting load demand than would be the case with a unit interconnected to the grid on the mainland. As a result, there is a much higher probability that the unavailability of Stock Island Combustion Turbine Unit 4 will result in unserved energy to KEYS customers. From the document *Electricity Market Module of the National Energy Modeling System: Model Documentation Report,* February 2001, the cost of unserved energy to consumers can vary widely. Estimates range from $2 to $25 per kilowatt-hour (kWh) and are affected by the type of warning before curtailment begins. The low end of this unserved energy cost is more than 30 times the energy cost used in the BACT analysis. In addition, unserved energy can have serious health, safety, and environmental impacts, which are not completely captured in the unserved energy cost. This is unique to KEYS due to its isolated nature. The effects of unserved energy may include the following:

- Power loss at hospitals.
- Loss of street lights.
- Loss of traffic lights.
- Loss of pump service at service stations.
- Loss of power at the Navy base.
- Closure of stores.

- Loss of refrigeration and associated food spoilage in homes and businesses.
- Loss of air conditioning.
- Loss of fire detection and security alarm systems.
- Loss of tourism.
- Loss of pumping for sewage lift stations.
- Loss of power to governmental agencies.

2.3.4 Availability of Fuels

The unique location of the Stock Island Power Plant also limits the availability of alternate fuels for electrical generation. The only readily available fuel source for combustion turbine operation is fuel oil, which is barge delivered. Trucking fuel oil on US Highway 1 would be a logistical nightmare, involving significant environmental risks due to accidents, and would cause undue hardship to the citizens of the Keys. For these reasons, KEYS receives fuel oil by truck only in emergency situations. The requirement to rely on barge delivery would also hold true for any other type of fuel that would have to be transported to the Stock Island Power Plant. A discussion of alternative fuels is included in the following subsections.

2.3.4.1 Natural Gas Pipeline. Unlike the majority of combustion turbine installations in the United States, there is not a source of natural gas in the Key West area. There is no natural gas pipeline to the Keys. To install a natural gas pipeline to the Keys as part of the Combustion Turbine Unit 4 project would be well beyond the scope and cost parameters for this project. As an example of natural gas pipeline costs, the BC Hydro website includes a discussion of the Georgia Strait Crossing Project, which is a proposal to construct a natural gas pipeline from Sumas, Washington, across the Strait of Georgia, and onto Vancouver Island. The pipeline would run approximately 85 miles, and the budget cost of the proposed pipeline is approximately $250 million. In addition, the time required to obtain approval for and actually construct such a pipeline would not meet the time schedule needed to meet the projected electrical demand for the Keys.

2.3.4.2 LNG Terminal. While the EcoElectrica project in Puerto Rico utilizes liquefied natural gas (LNG) supplied from a terminal adjacent to the combined cycle combustion turbine installation, requirements associated with the installation of an LNG terminal indicate that this approach would not be reasonable for the Stock Island site for several reasons, including siting constraints, infrastructure development costs, and environmental health and safety concerns.

2.3.4.2.1 Siting Constraints. The available land and adjacent marine bathymetry necessary to support LNG delivery, storage, and vaporization is not sufficient at the

Stock Island site. Installation of an LNG terminal requires a relatively large land area for the terminal itself. A shore-based terminal generally consists of a docking facility, LNG storage tanks, vaporization equipment, vapor conveyance and handling systems, which typically occupy 25 to 40 acres of land, nearly twice the size of the Stock Island site. Additionally, these sites are required under NFPA 59A to have minimum boundary set backs and safety exclusion zones to assure that public activities and structures outside the immediate LNG facility are not at risk in the event of an LNG fire or flammable vapor cloud release. The docking facility must be capable of handling LNG vessels, which currently range in capacity from 70,000 to 145,000 m^3, with dimensions of 1,000 feet in length and 150 feet in width. Ports and berthing areas must have minimum water depths of 40 to 45 feet to safely handle these LNG vessels. Currently, the Navy is dredging Key West Harbor to a maximum depth of 34 feet so destroyers and cruisers can fit through the City's channel. This new maximum depth is still significantly less than the depth required for an LNG vessel. Additionally, Safe Harbor Channel, adjacent to Stock Island Power Plant, has a depth of 16 to 23 feet.

2.3.4.2.2 Infrastructure Development Costs. The capital costs to develop and construct an LNG terminal facility to serve the plant are tremendous. A storage tank would need to be sized to the capacity of a single LNG vessel to make it feasible for receiving deliveries from LNG suppliers. Similarly, a berthing facility would need to be sized to serve a 145,000 m^3 vessel. Capital costs for a storage tank, berthing and unloading dock, and vaporization system alone would conservatively range from $100 to $200 million to construct.

Licensing of an LNG facility through the Federal Energy Regulatory Commission (FERC) currently takes a minimum of 16 months, with most developers spending $1 million or more for the necessary engineering design and environmental studies required for submittal of a resource report application and preparation of an environmental impact statement. Once approved, most LNG terminal facilities take 3 to 4 years to construct.

2.3.4.2.3 Environmental Health and Safety Concerns. Environmental concerns from the development and operation of an LNG facility would include potentially serious adverse impacts to marine, terrestrial, and air resources. Significant impacts to water quality, benthic communities, and aquatic species could result from cold water discharges from the regasification heat exchangers, suspension of sediment and ocean floor disturbance from dredging, potential strikes by vessels, and potential spills and discharges from both the terminal and LNG vessels. These concerns are only intensified by the project's proximity to environmentally sensitive areas of the Florida Keys National Marine Sanctuary and protected coral reefs. Terrestrial impacts would primarily result from the clearing of land needed to support the terminal. Air quality would be affected by emissions from flaring, ship unloading, and diesel generator operations, as well as fugitive dust during construction.

Perhaps the greatest concern is the potential risk posed to human health and safety from possible accidents. Clearly, this is the most contentious issue surrounding LNG terminal development today. While historically the LNG industry has a good safety record, accidents involving releases of LNG have and continue to occur, that result in serious injury and even death. LNG in its liquid form presents few dangers other than freezing surfaces it comes into contact with (as it is cryogenically stored and transported at -260° F). However, if released from a tank, vessel, or pipe, LNG will quickly vaporize as it absorbs heat from the environment (ambient air, land, or water). The resulting vapor is flammable when mixed in air at concentrations from 5 to 15 percent (volume basis). If the right concentration of LNG vapors come into contact with an ignition source, fires can occur either immediately above the released liquid LNG as it evaporates (pool fires), or as it exits a hole in the containment vessel (jet fires). Additionally, a flammable vapor cloud can be carried up to several miles downwind, which can become a flash fire if it comes into contact with an ignition source, or if it enters a confined space and is ignited can result in an explosion. Accordingly, LNG would present some level of risk to the health and safety of both Stock Island residents and plant workers.

Considering the preponderance of siting, schedule, licensing, environmental, and safety impacts associated with developing and operating an LNG terminal for the project, it is reasonable to conclude that this would not be a viable and cost-effective fuel alternative to the distillate fuel oil that is already available on-site.

2.3.4.3 Propane. The feasibility of utilizing propane as a fuel source for Stock Island Combustion Turbine Unit 4 from both a technical and site arrangement perspective was also considered.

From a technical standpoint, the LM6000 is capable of burning propane, with an estimated required flow rate of 21,000 pounds of propane per hour. According to GE, use of propane as a fuel has been considered on several projects, but has never actually been used. The propane has to be fired as a gas and not a liquid and requires a modification in the fuel nozzles. Vaporizers would be required to change the stored liquid into a gas for supply to the unit.

From a site arrangement standpoint, it was necessary to determine whether the Stock Island site is able to support the necessary onsite storage facilities required for 14 days of propane supply. Assuming a propane flow rate of 21,000 pounds per hour, the 14 day storage requirement is 7,056,000 pounds which, based on propane characteristics provided by the National Propane Gas Association, is equivalent to approximately 1,664,000 gallons of propane. It was further assumed that on-site storage would be provided by 90,000 gallon horizontal storage tanks, with a total of 19 such tanks required. The 90,000 gallon storage tanks are estimated to be 11 feet in diameter and 133 feet in length, with spacing requirements calculated consistent with *National Fire Protection Association* (NFPA) standards.

The NFPA standards governing installation of propane storage tanks with storage capacity between 70,001 and 90,000 gallons stipulate that the tanks must be spaced at a minimum distance of one fourth of the sum of the diameters of adjacent tanks, which for the 11 foot diameter storage tanks would be approximately 6 feet. Given the spacing requirements for the 19 required 90,000 gallon storage tanks, approximately 1.10 acres (47,705 square feet) would be required if the storage tanks are oriented parallel to one another in a single row, and approximately 1.17 acres (51,040 square feet) would be required if the storage tanks are oriented in two rows. The NFPA standards further require 100 feet of clearance between the storage tanks and the closest aboveground facility.

Analysis of the Stock Island site shows that, considering the square footage required for the 19 storage tanks as well as the additional 100 foot clearance requirement, there is not an available footprint on-site for propane storage. Therefore, utilizing propane as a fuel source is not feasible for the Stock Island site, from a land availability perspective.

Normal bulk propane deliveries are by transport truck or rail car. No rail line is available to Stock Island. Therefore, delivery of propane would need to be by transport truck. Typical transport truck capacity ranges from 7,000 to 12,000 gallons. With the estimated propane usage of 21,000 pounds per hour, which equates to approximately 5,000 gallons per hour, the fuel usage would be equivalent to approximately 10 to 17 transport trucks per day. The transport and offloading of this many propane trucks each day would result in unrealistic logistical problems. In addition, due to the hazardous nature of propane, it is likely that the transport, unloading, and storage of these quantities of propane would cause concerns among citizens in the Key West area.

Due to the storage and transport constraints associated with propane use at the Stock Island site, the use of propane is not considered a viable option.

2.3.5 Power Demand Increase

While the population growth in Key West was a relatively modest 2.6 percent over the period 1990 to 2000, tourism continues to have a major impact on the Keys and the energy demand for KEYS is expected to increase at a rate of approximately

2.5 percent per year for the next 10 years. From the period 1993 to 2002, the number of residential customers serviced by KEYS increased from 20,432 to 23,471, the number of small commercial customers increased from 2,253 to 2,847 and the number of large power consumers increased from 547 to 683.

Another source of increased power demands in the Key West area is expected to be due to increased operations at the Boca Chica Naval Air Station in Key West. In 2003, Navy officials announced that there would be a redeployment of military personnel to the Boca Chica Naval Air Station that will nearly double the Navy's presence on the island. The military is also spending an estimated $110 million on new barracks, runway expansions, a new flight control tower, and other projects. The Navy's decision to vacate Puerto Rico's Vieques Island facility also increased the importance of operations at the Key West Boca Chica Naval Station. An indication of this increase in operations is that for the first time in 40 years, the Navy is dredging the Key West Harbor to restore the harbor's depth to 34 feet so destroyers and cruisers can fit through the city's channel. KEYS has recently put in a larger transformer at the substation near the Key West Harbor and is looking at increasing the size of this substation.

This projected increase in electrical demand can only be met by adding additional generating capacity in the Keys. Current local capacity of approximately 86 MW is available at the Stock Island facility. Peak demand in 2003 was 140 MW. Projected peak demand in the years 2013 and 2023 are approximately 175 MW and 217 MW, respectively. It is important to note that these values represent projected demand and actual future demand could be much greater than these projected values. The proposed project is essential to meeting the future Key West energy needs.

The demand frequently exceeds, and will exceed at a greater frequency and amount in the future, the transmission line capacity of 110 MW. Combustion Turbine Unit 4 will be brought on-line to meet the demand above transmission line capacity. Therefore, the Combustion Turbine Unit 4 must have the flexibility of frequent start-ups (more than 200 per year), since it may have almost daily startups to meet daily peak demand.

2.3.6 Summary of Unique Aspects

The unique aspects of the Florida Keys and the Stock Island Power Plant, such as limited road access, the high cost impacts of loss of power, the unavailability of replacement power, a single limited capacity transmission line, limited access to fuel supplies, the need for frequent startups, and a growing energy demand, make it essential and of the utmost importance that the reliability of the Stock Island Unit 4 combustion turbine design be maximized. These unique aspects point to the importance of reliable power generation for the Stock Island Power Plant and the potentially detrimental social and environmental impacts of a BACT technology that reduces the reliability of Combustion Turbine Unit 4.

2.4 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- One SCCT firing No. 2 fuel oil (Combustion Turbine Unit 4).
- One approximately 1,000,000 gallon No. 2 distillate fuel oil storage tank.

2.4.1 Combustion Turbine Unit 4 Emissions

Performance data for Combustion Turbine Unit 4, based on vendor data from GE at design loads of 50, 75, and 100 percent, distillate fuel firing, and ambient air temperatures of 41° F, 59° F, 78° F, and 95° F are provided in Attachment 1.

Ambient temperature data were selected based on meteorological data from Key West, Florida. An ambient temperature of 41° F represents the winter seasonal site minimum temperature and corresponds to maximum heat input and power generation. An ambient temperature of 78° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 95° F represents the summer seasonal maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. An ambient temperature of 59° F represents ISO conditions.

The maximum pound per hour emission rates (rounded to the nearest pound) considering all ambient temperatures are presented in Table 2-1. The NO_x emission rate shown in Table 2-1 is based on using water injection to achieve 42 ppmv NO_x emissions.

2.4.2 No. 2 Distillate Fuel Oil Storage Tank

The fuel oil storage tank to be added to the site as part of the Project is estimated to have a capacity of 1,000,000 gallons. Volatile Organic Compound (VOC) emissions from the fuel oil storage tank were estimated using the EPA TANKS (Ver. 4.09) program. Results of the TANKS emission modeling are included in Attachment 2. The VOC emissions from the fuel oil storage tanks are approximately 0.63 tons per year (tpy) and are included in the total Project's PTE calculations. In accordance with Rule 62-210.300(3)(b)1., F.A.C., the fuel oil storage tank is exempt from the requirements to obtain an air construction permit and, as such, is included in the list of exempt emission units in Attachment F of the application forms.

Table 2-1 Project Maximum Emission Rates (lb/h)*	
Pollutant	Emission Rate (lb/h)
NO_x	76
SO_2	24
CO	17
PM/PM_{10}	25
VOC	5
SAM	7.2

*Maximum pound per hour emission rates (rounded to the nearest pound) for the SCCT considering site ambient temperatures and partial load operation.

2.5 Maximum Project Potential to Emit

The proposed operating scenario for Combustion Turbine Unit 4 includes a maximum of 13.567 million gallons per year of fuel oil use. This is intended to be an enforceable limit. This fuel oil firing rate is equivalent to 4,422 hours of full load operation at an ambient temperature of 78°F. At this fuel oil firing rate, NO_x emissions are equal to 154 tons per year. Combustion Turbine Unit 4 will operate between 50 and 100 percent of full load. Because the requested fuel oil use limit will effectively limit emissions from Combustion Turbine Unit 4, a limit on hours of operation is not needed. The Project's potential to emit for each pollutant is summarized in Table 2-2. The NO_x emission rate shown in Table 2-2 is based on using water injection to achieve 42 ppmv NO_x emissions. The emission rates given in Table 2-2 are based on using 13.567 million gallons of fuel oil per year in Combustion Turbine Unit 4. A limit on fuel oil use is requested rather than a limit on operating hours, as this will effectively limit emissions from Combustion Turbine Unit 4 to the levels shown in Table 2-2, while giving the facility operating flexibility. The applicable PSD significant emission levels for each pollutant are included for reference purposes in the table, and a spreadsheet used to calculate the potential to emit is included in Attachment 3.

Table 2-2
PSD Applicability

Pollutant	Project PTE (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required
NO_x	154.1[a]	40	**yes**
SO_2	47.8[a,b]	40	**yes**
CO	33.6[a]	100	no
PM/PM_{10}	109.5[a,c]	25/15	**yes**
VOC	10.2[a,d]	40	no
Sulfuric Acid Mist	14.6[a,e]	7	**yes**
Total Reduced Sulfur	negl.	10	no
Hydrogen Sulfide	negl.	10	no
Vinyl Chloride	negl.	1	no
Total Fluorides	negl.	3	no
Mercury	0.001[f]	0.1	no
Lead	0.013[f]	0.6	no

[a]Based on firing 13.567 million gallons of fuel oil per year, which is equivalent to 4,422 hours of operation at 100 percent load and an average ambient temperature of 78° F.
[b]Based on 0.05 percent sulfur distillate fuel oil and assuming 100 percent conversion to SO_2.
[c]Assumes front and back half PM/PM_{10} emissions. Conservatively assumes 8,760 hour of operation per year.
[d]VOC PTE is based on potential emissions from the Project's combustion source and emissions from the fuel oil storage tank.
[e]Conservatively assumes a 20 percent conversion of SO_2 to SO_3 and 100 percent conversion of SO_3 to H_2SO_4.
[f]Based on AP-42 emission factors, and firing 13.567 million gallons of fuel oil per year.
Note: PTE calculations are provided in a spreadsheet included in Attachment 3.

2.6 New Source Review Applicability

The federal Clean Air Act (CAA) New Source Review (NSR) provisions are implemented for new major stationary sources and major modifications under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 Code of Federal Regulations (CFR) 52.21, and the Nonattainment NSR program outlined in 40 CFR 51 and 52. The proposed facility is in an attainment area with respect to all pollutants. As such, the PSD program will apply to the Project, as administered by the state of Florida under 62-212.400, F.A.C., Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.

2.6.1 Prevention of Significant Deterioration

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the ambient air quality standards (AAQS), while providing a margin for future industrial and commercial growth. PSD regulations apply to major stationary sources and major modifications at major existing sources undergoing construction in areas designated as attainment or unclassifiable.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the facility is not one of the listed major source categories. The Stock Island Power Plant is not one of the 28 major source categories, and it therefore has a 250 tpy PSD major source threshold. Based on the conditions and limits in existing Stock Island Title V Air Operation Permit 0870003-005-AV, the facility has potential emissions of greater than 250 tpy for at least one regulated pollutant. Therefore, the existing facility is an existing major stationary source under PSD regulations. The estimated emissions of NO_x, SO_2, PM/PM_{10}, and sulfuric acid mist (SAM) resulting from the proposed Project exceed the PSD significant emissions levels of 40, 40, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO_2, PM/ PM_{10}, and SAM are subject to PSD review as a major modification to an existing major source. The PSD review includes a BACT analysis, air quality impact analysis (AQIA), and an assessment of the Project's total impact on general commercial, residential, and commercial growth, soils and vegetation, and visibility, as well as a Class I impact analysis. These analyses are included in Sections 3, 4, and 5.

2.7 CT MACT Applicability

On March 5, 2004, the EPA published final national emission standards for hazardous air pollutants (NESHAP) for stationary combustion turbines. This rule, found at 40 CFR Part 63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of hazardous air pollutants (HAPs). A major source of HAPs is a site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year. Potential HAP emissions at the facility were estimated using USEPA AP-42 emission factors and information on existing emission units that is included in the Stock Island Title V Air Operation Permit No. 0870003-005-AV. The following emission units were included in the HAP emissions analysis:

- Two diesel generators, 8.8 MW each (Medium Speed Diesels Units 1 and 2, EU ID Nos. 005 and 006).
- Three diesel peaking generators, 2 MW each (on Title V list of unregulated emission units and activities, formerly EU ID Nos. 002, 003, and 004).
- 23.5 MW simple cycle combustion turbine, (Combustion Turbine 1, EU ID No. 007).
- Two (2) 19.77 MW simple cycle combustion turbines (Combustion Turbines 2 and 3, EU ID Nos. 008 and 009).
- New 48 MW simple cycle combustion turbine (Combustion Turbine Unit 4).

The potential to emit for any combination of HAP at the Stock Island Power Plant, including potential emissions from the Project, is 2.9 tons per year. This potential to emit level is well below the HAP major source level, and as such, the site is not a major source of HAPs. Because the site is not a major source of HAPs, the CT MACT standard does not apply to Combustion Turbine Unit 4. Spreadsheets showing the HAP emission calculations for the Stock Island site are included in Attachment 3.

3.0 Best Available Control Technology

A best available control technology (BACT) analysis for the Project has been included as Attachment 4. The following is a summary of the BACT determination and associated emission rates for Combustion Turbine Unit 4 to be installed at the Stock Island facility for FMPA. The combustion turbine will fire only low sulfur fuel oil. Emissions for the BACT analysis are based on Combustion Turbine Unit 4 operation limited to 13.567 million gallons per year of fuel oil use, which is equivalent to the unit operating at 4,422 hours per year at full load and an average ambient temperature of 78 F.

3.1 Combustion Turbine Unit 4

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of water injection and good combustion controls to achieve 42 ppmvd at 15 percent O_2.
- Carbon monoxide (CO) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and use of low sulfur fuel oil with less than 0.05 percent sulfur by weight.
- Volatile Organic Compounds (VOC) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of good combustion controls and the use of low sulfur fuel oil with less than 0.05 percent sulfur.
- Sulfur acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls and the use of low sulfur fuel oil with less than 0.05 percent sulfur.

4.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the PSD air quality impact analysis for those pollutants which will have a PTE greater than the PSD significant emission rate (i.e., NO_x, SO_2, and PM/PM_{10}). The air dispersion modeling analysis was conducted in accordance with EPA's air dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of FMPA and KEYS in a memorandum from Black & Veatch dated June 4th, 2004 (Attachment 5).

4.1 Model Selection

The Industrial Source Complex Short-Term (ISCST3 Version 02035) air dispersion model was used to predict maximum ground level concentrations associated with the Project emissions. The ISCST3 model is an EPA approved, steady-state, straight-line Gaussian plume model, which may be used to assess pollutant concentrations from a wide variety of sources associated with an industrial source complex.

4.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the ISCST3 model default options and input databases.

4.2.1 Model Input Source Parameters

The ISCST3 model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads and ambient temperatures. This was accomplished by representing each proposed operating load range (i.e., 50, 75, and 100 percent loads) with a worst-case set of stack parameters and pollutant emission rates conservatively selected from performance data over a range of ambient temperatures (i.e., 41°, 59°, 78°, and 95°F) to produce worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping."

The worst-case representative stack parameters and emission rates for each load and ambient temperature considered in the analysis are presented in Table 4-1. A spreadsheet used in determining the load based representative emissions and stack parameters from the performance data is included in Attachment 1.

Table 4-1
Representative (Enveloped) Stack Parameters and Pollutant Emissions Used in ISCST3 Modeling Analysis[a]

Load [b]	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (K)	Pollutant Emission Rate (g/s)		
					NO_x	SO_2	PM/PM_{10}[c]
100	18.29	3.05	34.75	707.59	9.56	2.97	3.15
75	18.29	3.05	29.57	678.15	7.45	2.31	3.15
50	18.29	3.05	24.08	679.26	5.53	1.72	3.15

[a]Stack parameter and emission information obtained from an in-house computer application provided and approved by GE for estimating such data.
[b]Stack parameter and emission information provided by operating load has been enveloped over four ambient temperatures (i.e., 41°, 59°, 78°, 95°F) characteristic of the proposed Project location.
[c]PM/PM_{10} represents both front and back half emissions.

4.2.2 Land Use Dispersion Coefficient Determination

The EPA's land use method was used to determine whether rural or urban dispersion coefficients should be used in the ISCST3 air dispersion model. In this procedure, land circumscribed within a 3 km radius of the site was classified as rural or urban using the Auer land use classification method. Based on a visual inspection of the USGS 7.5 minute topographic map of the proposed Project's location, it was concluded that over 50 percent of the area surrounding the Project is classified as rural. Accordingly, the rural dispersion modeling option was used in the ISCST3 air dispersion modeling.

4.2.3 GEP Stack Height Determination

The Project's proposed buildings and structures were analyzed to determine their potential to influence the dispersion of stack emissions. Building and structure dimensions, as well as relative locations, were entered into EPA's Building Profile Input Program (BPIP) to produce an ISCST3 input file with the proper Huber-Snyder or Schulman-Scire direction specific building downwash parameters. The BPIP formula GEP height for the SCCT is 30.48 m (100 ft). The proposed Project stack height is 18.29 m (60 ft). As such, direction-specific downwash parameters from the BPIP program were included in the ISCST3 air dispersion modeling analysis.

4.2.4 Model Defaults

The following standard USEPA default regulatory modeling options were initialized in the ISCST3 air dispersion modeling:

- Final plume rise.
- Stack-tip downwash.
- Buoyancy induced dispersion.
- Default vertical wind profile exponents and vertical potential temperature gradient values.
- Calm processing option.
- Flat terrain option.

4.2.5 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends 10 km from the center of the proposed Project was used. The rectangular grid network consists of 100 m spacing from the proposed fenceline out to 1 km, 250 m spacing from 1 to 2.5 km, 500 m spacing from 2.5 to 5 km, and then 1,000 m spacing from 5 to 10 km.

Receptor spacing of 100 m intervals was used along the Project's fenceline, and a 100 m fine grid was used at the maximum impact receptors. The flat terrain option was used for all receptor points. Figure 4-1 illustrates the nested rectangular grid, fence line receptors, and the relative location of the emission source and downwash structures.

4.2.6 Meteorological Data

The ISCST3 air dispersion model requires hourly input of specific surface and upper-air meteorological data. These data include the wind flow vector, wind speed, ambient temperature, stability category, and the mixing height. Five years (1987-1991) of surface and upper air meteorological data from Key West and West Palm Beach, respectively, were used in the ISCST3 air dispersion modeling analysis. These meteorological data were obtained from the FDEP via email and were previously processed with PCRAMMET to combine the surface and mixing height data, interpolate hourly mixing heights from the twice-daily mixing heights, and calculate atmospheric stability class.

4.3 Model Results

As presented in Section 2.0, the Project's PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, and PM/PM_{10}. In accordance with the approved modeling protocol, ISCST3 air dispersion modeling was performed (as described in the preceding sections) using the enveloped emission rates for NO_x, SO_2, and PM/PM_{10} for each applicable averaging period. Table 4-2 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the pre-construction monitoring requirements. As Table 4-2 indicates, the Project's maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and AAQS analyses) are required.

Additionally, the maximum predicted concentrations are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements.

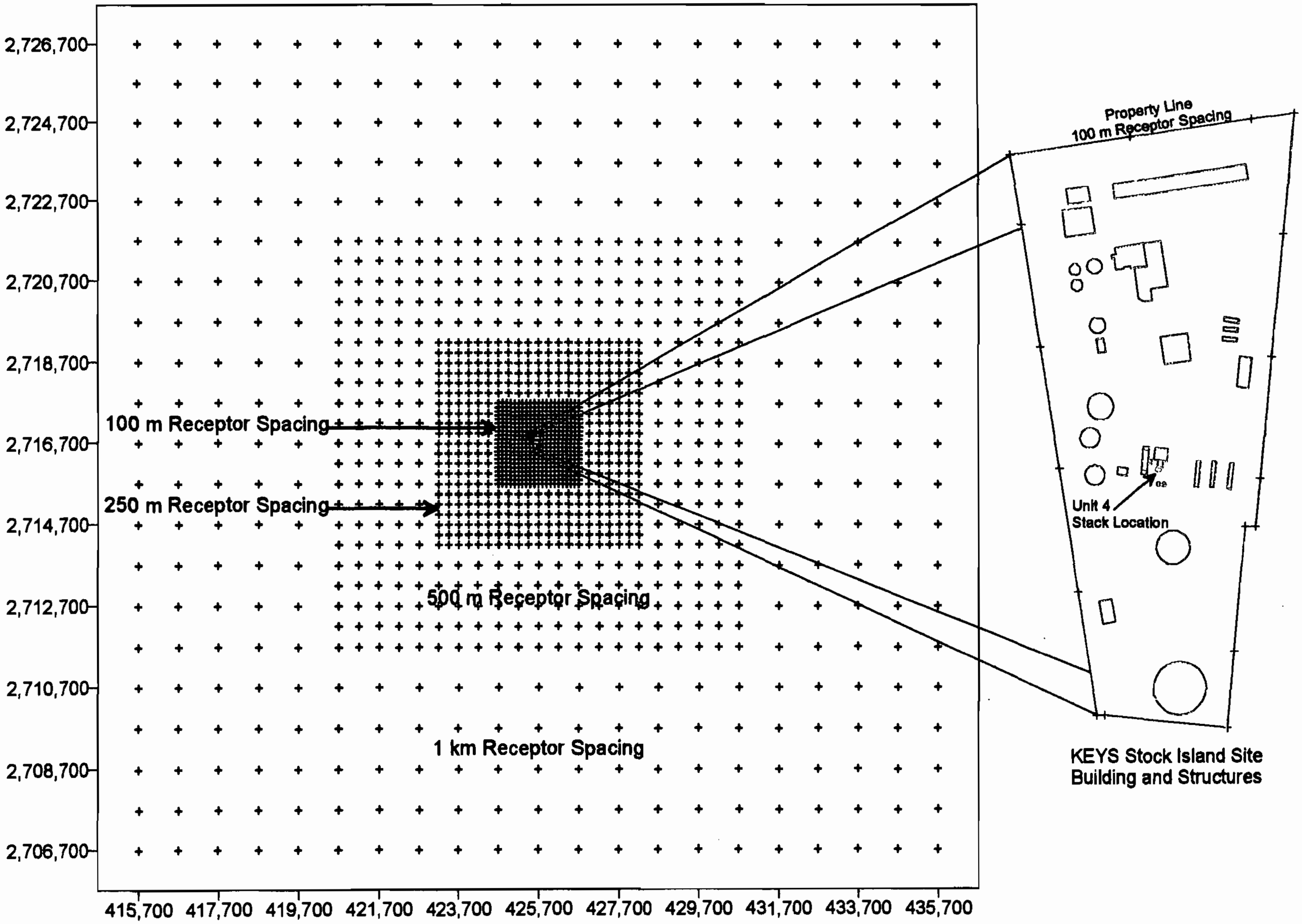

Figure 4-1
Receptor Location Plot

Table 4-2
ISCST3 Model-Predicted Class II Impacts

Load	Pollutant – Averaging Period	Model-Predicted Impact [a] ($\mu g/m^3$)	PSD Class II SIL [b] ($\mu g/m^3$)	Exceed SIL?	De Minimis Monitoring Level [c] ($\mu g/m^3$)	Pre-construction Monitoring Required?
100	NO_x – Annual	0.16	1	NO	14	NO
	PM/PM_{10} – Annual	0.05	1	NO	---	NO
	PM/PM_{10} – 24 hour	1.45	5	NO	10	NO
	SO_2 – Annual	0.05	1	NO	---	NO
	SO_2 – 24 hour	1.37	5	NO	13	NO
	SO_2 – 3 hour	4.27	25	NO	---	NO
75	NO_x – Annual	0.16	1	NO	14	NO
	PM/PM_{10} – Annual	0.07	1	NO	---	NO
	PM/PM_{10} – 24 hour	2.06	5	NO	10	NO
	SO_2 – Annual	0.05	1	NO	---	NO
	SO_2 – 24 hour	1.51	5	NO	13	NO
	SO_2 – 3 hour	5.53	25	NO	---	NO
50	NO_x – Annual	0.15	1	NO	14	NO
	PM/PM_{10} – Annual	0.09	1	NO	---	NO
	PM/PM_{10} – 24 hour	3.38	5	NO	10	NO
	SO_2 – Annual	0.05	1	NO	---	NO
	SO_2 – 24 hour	1.84	5	NO	13	NO
	SO_2 – 3 hour	5.14	25	NO	---	NO

[a]Impacts represent the highest first high model-predicted concentration from all five years of meteorological data modeled.
[b]Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.

5.0 Additional Impact Analyses

The following sections discuss the proposed Project's impacts upon commercial, residential, and industrial growth, as well as vegetation and soils, and the nearest Federal Class I area.

5.1 Commercial, Residential, and Industrial Growth

The proposed project is at the existing KEYS Stock Island electrical power generating station on Stock Island in the Florida Keys. Because the proposed project is being installed to meet the existing and current projected electrical demands of the surrounding area, it is anticipated that little growth will be associated with its operation. There will be an increase in the local labor force during the construction phase of the Project, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the project.

The electrical generating capacity created by the Project will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. According to the Key West Chamber of Commerce, the population of the Key West area, as well as Monroe County, has grown by an average of 2 percent per decade since the 1980 census. In line with the population growth, the net number of new, permanent jobs which will be created by the Project is estimated to be little to none. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the Project will be very small, compared to the overall existing population size of the surrounding area.

5.2 Vegetation and Soils

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the Project's impacts on soils and vegetation will be minimal.

The AAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation and soils. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations of NO_2, SO_2, and PM/PM_{10} below the secondary AAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutants which triggered an additional impact analysis include NO_x, SO_2, and PM/PM_{10}. The modeled impacts were compared to the secondary AAQS as the basis for assessing cumulative impacts. The modeling in Section 4.0 showed that the NO_x, SO_2, and PM/PM_{10} impacts are below the AAQS. The impacts are even less than the much lower significant impact level thresholds. Because the Project's emissions do not significantly impact the AAQS, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

5.3 Class I Area Impact Analysis

As part of the air impact evaluation for the proposed modification to the KEYS Stock Island site, analyses of the Project's effect on the Everglades National Park (ENP) were performed. The ENP is a PSD Class I area located in southern Florida, approximately 90 km northeast of the Project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this analysis are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) were evaluated and compared to the recommended thresholds. Figure 5-1 presents the location of the proposed Project site with respect to the ENP.

The methodology of the refined California Puff (CALPUFF) analysis followed those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report dated December 2000 where appropriate for model option selections, and an air dispersion modeling protocol submitted to FDEP on June 4, 2004 (Attachment 5). The following sections include discussions of the meteorological and geophysical databases used in the analysis, the preparation of those databases for introduction into the modeling system, the air modeling approach to assess impacts at ENP, and the model-predicted impacts from the Project onto the ENP.

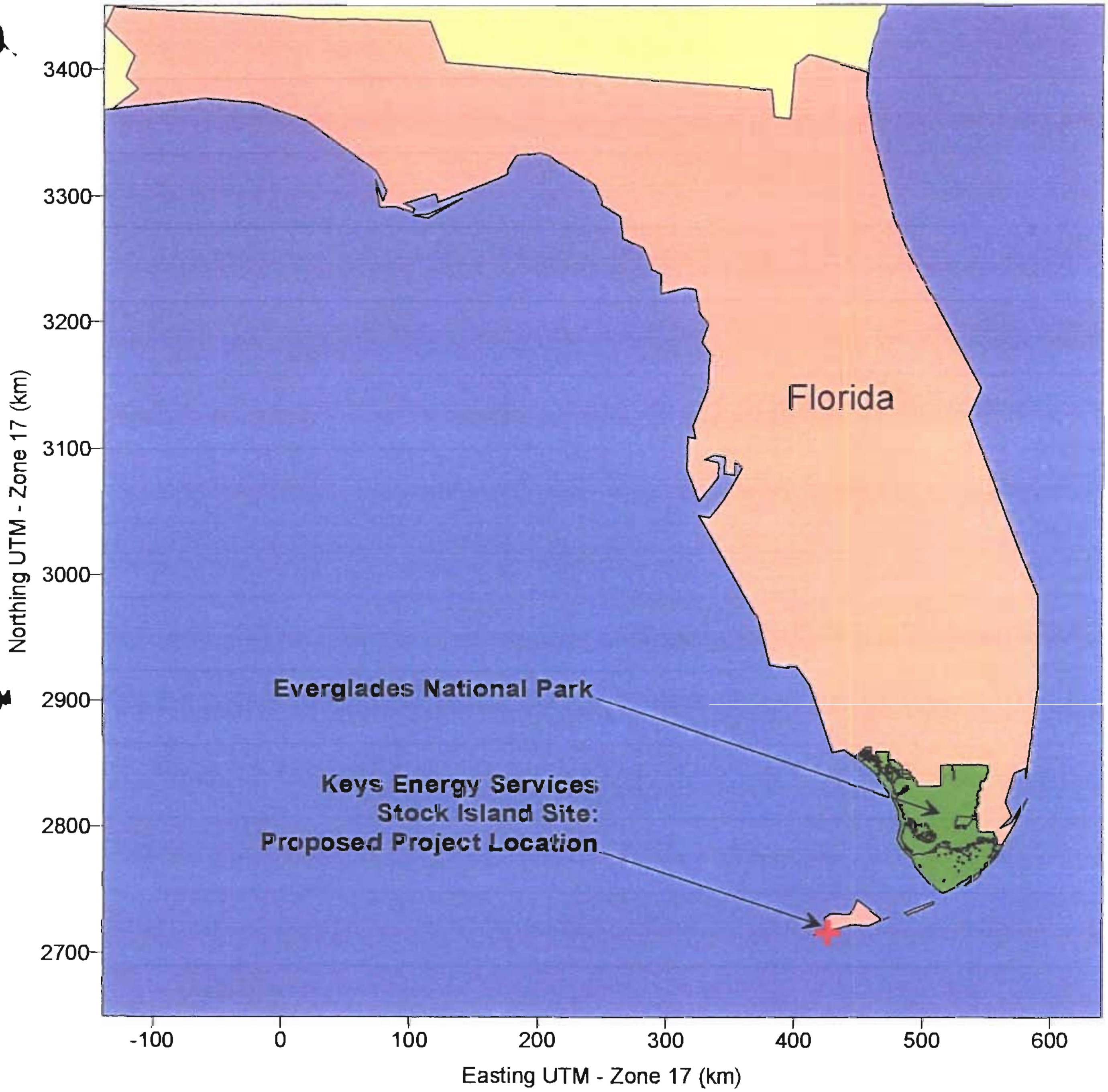

Figure 5-1
Proposed Project Location with Respect to Everglades National Park

5.3.1 Model Selection

The CALPUFF (Version 5.711, Level 030625) air modeling system was used to model the Project and assess the AQRVs at ENP. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and convert the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess pollutant specific impacts.

5.3.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.3.3 Building Wake Effects

The CALPUFF analysis included the site's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

5.3.4 Receptor Locations

The CALPUFF analysis used an array of discrete receptors for ENP, which were created and distributed by the National Park Service (NPS) for standardized use in Class I analyses. Terrain throughout the ENP is included in the same NPS-provided receptor file.

5.3.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.53, Level 030709) was used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data used and processed in the CALMET model.

Table 5-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST. Deposition: Highest predicted annual total sulfur and nitrogen values in deposition units. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 0.5 ppb; Monthly Ozone: 80 ppb

5.3.5.1 CALMET Settings. The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, were chosen to adequately characterize the area within the CALMET domain.

5.3.5.2 Modeling Domain. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed Project to the receptors at the ENP with at least a 50-km buffer zone in each direction. The modeling analysis was performed in the UTM coordinate system. A rectangular modeling domain extending 240 km in the east-west (x) direction and 250 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 376 km Easting and 2,667 km Northing (based on UTM Zone 17, North American Datum (NAD) 1983 coordinates). The grid resolution for the domain was 5 km. A grid spacing of 5 km yields 48 grid cells in the x-direction and 50 grid cells in the y-direction. Figure 5-2 illustrates the size and location of the modeling domain.

5.3.5.3 Mesoscale Model Data. Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are used to populate the modeling domain with meteorological data. The analysis used 1990 MM4, 1992 MM5, and 1996 MM5 mesoscale meteorological data sets to initialize the CALMET wind fields for each modeled year. The 3 years of MM data were obtained from a NPS database provided to Black & Veatch. The extraction program accompanying the data was used to obtain the appropriate MM data points to cover the modeling domain. The 1990 MM4 and 1992 MM5 data have a horizontal spacing, or resolution, of 80 km. The 1996 MM5 data has a resolution of 36 km. The meteorological observations contained with the MM data sets are assumed to be of sufficient density, both temporally and spatially, to make the need for discrete meteorological station observation unnecessary. Thus, CALMET was run with the No Observations mode developed in the latest version available from the model developer, EarthTech.

5.3.5.4 Geophysical Data Processing. Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the US Geological Survey (USGS). The DEM data were extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, were also obtained from the USGS. Land-use values for the domain grid were extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface

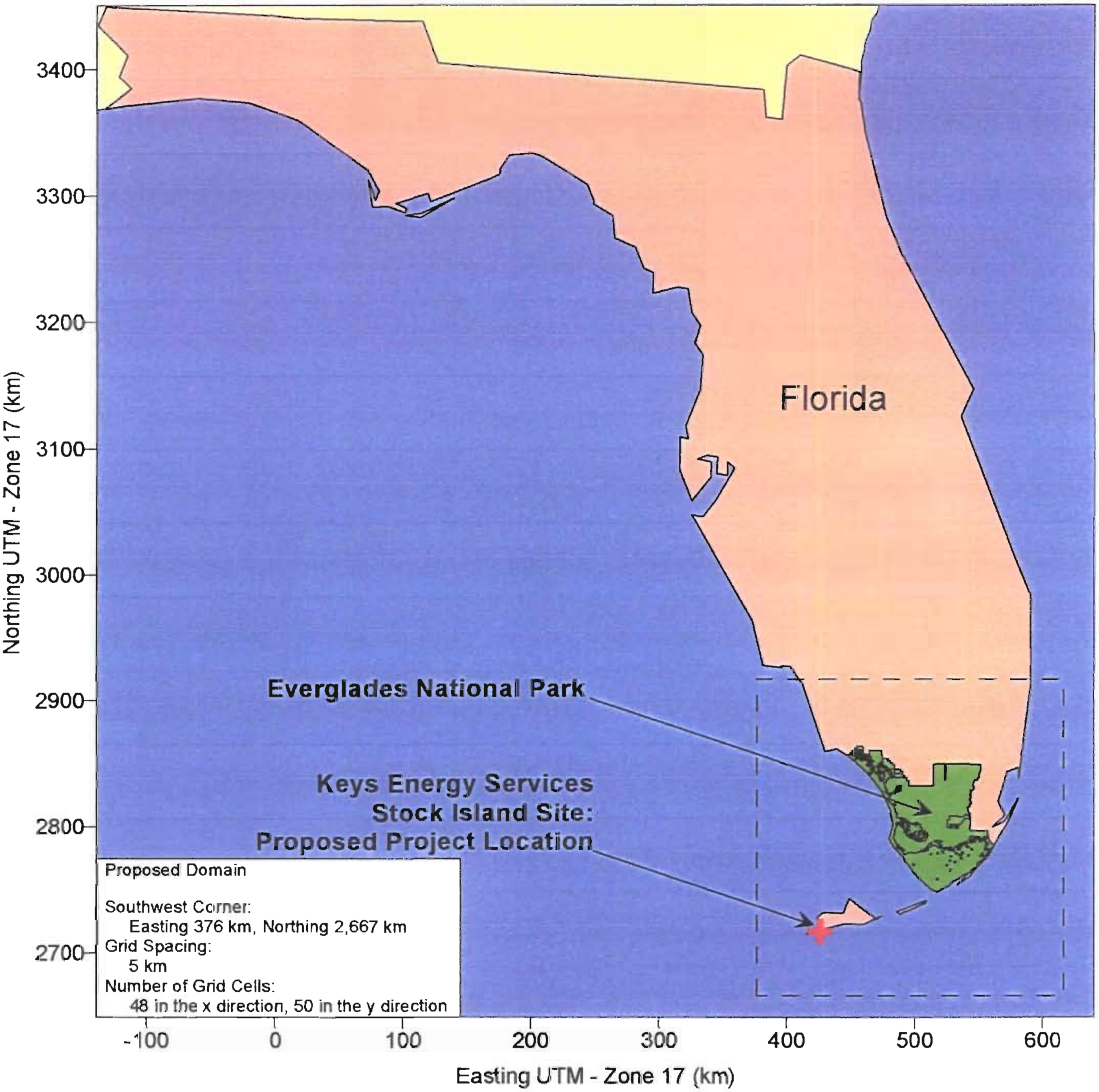

Figure 5-2
Modeling Domain

roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters were combined with the terrain information in a processor called MAKEGEO. This processor produced one GEO.DAT file for input to CALMET.

5.3.6 Project Emissions

The maximum pound per hour emission rates at 100 percent load and the average annual temperature were used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}. Table 4-1 contains the stack parameters and emission rates modeled in CALPUFF.

5.3.7 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the ENP, including regional haze, deposition, and Class I SILs.

5.3.7.1 Regional Haze Analysis. A regional haze analysis was performed for the ENP for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

Visibility

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the ENP lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where:

b_{exts} = the extinction coefficient calculated for the source, and

b_{extb} = the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta \text{ percent} = (b_{exts} / b_{extb}) \times 100$$

Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the ENP. The background visual range, or constituents thereof, for the ENP were be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day was computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each relative humidity, was obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) were then used to determine the average relative humidity factor for that day (24-hour period). All of this was accomplished with the selection of Method 2 in the CALPOST post-processor.

Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis closely followed the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98), where appropriate. Table 5-2 summarizes the IWAQM Phase II recommendations. The methodology in Table 5-2 was used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection was made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze was calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. Based on recent correspondence with staff of the NPS, the relative humidity will be capped at 95 percent. A supplementary analysis will be performed with the relative humidity capped at 98 percent for informational purposes only. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

$$(NH_4)_2SO_4\ (\mu g/m3) = SO_4\ (\mu g/m^3) \times \text{molecular weight } (NH_4)_2SO_4\ /\ \text{molecular weight } SO_4$$

$$(NH_4)_2SO_4\ (\mu g/m^3) = SO_4\ (\mu g/m^3) \times 132/96 = SO_4\ (\mu g/m^3) \times 1.375$$

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

$$NH_4NO_3\ (\mu g/m3) = NO_3\ (\mu g/m^3) \times \text{molecular weight } NH_4NO_3\ /\ \text{molecular weight } NO_3$$

$$NH_4NO_3\ (\mu g/m^3) = NO_3\ (\mu g/m^3) \times 80/62 = NO_3\ (\mu g/m^3) \times 1.29$$

3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

$$b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 1 \times PM_{10}$$

4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:

$$b_{extb} = 3.912\ /\ \text{Visual range (km)}$$

5. Compute the change in extinction coefficients:

   in terms of deciviews:

$$dv = 10 \ln (1 + b_{exts}/b_{extb})$$

   in terms of percent change of visibility:

$$\Delta \text{ percent} = (b_{exts}\ /\ b_{extb}) \times 100$$

Table 5-2
Outline of IWAQM Refined Modeling Analyses Recommendations*

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS provided the modeling receptors.
Dispersion	Use CALPUFF with default dispersion settings; Use MESOPUFF II chemistry with wet and dry deposition; Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species; calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.

**IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5. As illustrated in Table 5-3, the regional haze results are less than the 5 percent change in extinction threshold and, as such, no further analysis is necessary.

Table 5-3
Regional Haze Results[a]

Modeled Year	Change in Extinction[b] (%)	Recommended Threshold (%)
1990	0.27	5
1992	0.69	5
1996	0.61	5

[a]The results represent a relative humidity cap value of 95 percent. Additionally, the relative humidity was capped at 98 percent for informational purposes only. The results indicated no exceedances of the recommended 5 percent threshold over all 3 years modeled with the largest value being only 0.97 percent.
[b]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

5.3.7.2 Deposition Analyses. Deposition analyses were performed for ENP for both total sulfur and total nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses were performed as follows:

- Perform CALPUFF model runs using the specified options previously mentioned (including output of both dry and wet deposition).
- Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass, and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.

- Apply the appropriate scaling factors found in the IWAQM Phase II Report (Section 3.3, Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results were compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS). Table 5-4 presents the results of the deposition analysis for each of the 3 modeling years. As illustrated in the table, the deposition results are less than the 0.01 DAT and, as such, no further analysis is necessary.

Table 5-4
Deposition Results

Modeled Year	Total Nitrogen Deposition[a] (kg/ha/yr)	Total Sulfur Deposition[b] (kg/ha/yr)	Deposition Analysis Threshold[c]
1990	0.0004	0.0004	0.01
1992	0.0005	0.0005	0.01
1996	0.0007	0.0008	0.01

[a]Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
[b]Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
[c]For all areas east of the Mississippi River.

5.3.7.3 Class I Impact Analysis. Ground-level impacts (in µg/m3) at the ENP were calculated for NO_x, SO_2, and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Table 5-5 presents the results of the Class I analysis for each of the 3 modeling years. As illustrated in the table, there are no impacts above the Class I SILs and, as such, no further analysis is necessary.

Table 5-5
Class I Significant Impact Level (SIL) Modeling Results

Modeled Year	Pollutant and Averaging Period	Modeled Impact ($\mu g/m^3$)	Significant Impact Level* ($\mu g/m^3$)	Exceed SIL?
1990	NO_x – Annual	0.0004	0.10	NO
	PM_{10} – Annual	0.0003	0.16	NO
	PM_{10} – 24-hour	0.018	0.32	NO
	SO_2 – Annual	0.0003	0.08	NO
	SO_2 – 24-hour	0.016	0.20	NO
	SO_2 – 3-hour	0.053	1.0	NO
1992	NO_x – Annual	0.0003	0.10	NO
	PM_{10} – Annual	0.0004	0.16	NO
	PM_{10} – 24-hour	0.015	0.32	NO
	SO_2 – Annual	0.0003	0.08	NO
	SO_2 – 24-hour	0.013	0.20	NO
	SO_2 – 3-hour	0.064	1.0	NO
1996	NO_x – Annual	0.0005	0.10	NO
	PM_{10} – Annual	0.0004	0.16	NO
	PM_{10} – 24-hour	0.024	0.32	NO
	SO_2 – Annual	0.0004	0.08	NO
	SO_2 – 24-hour	0.017	0.20	NO
	SO_2 – 3-hour	0.050	1.0	NO

*Class I Significant Impact Levels are calculated as 4 percent of the PSD Class I Increment values.

Attachment 1
Turbine Data

4/21/2004
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
UHC, ppmvd	11.2	9.6	9.0	11.3	9.8	9.2	11.3	10.0	9.3	11.3	10.1	9.2
UHC, ppmvw	10.1	8.9	8.3	10.1	9.0	8.5	10.0	9.1	8.5	10.0	9.1	8.4
UHC, lb/h as CH4	6.3	4.9	3.6	6.1	4.8	3.6	5.8	4.5	3.4	5.4	4.2	3.2
UHC, lb/MBtu (LHV)	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145	0.0145
UHC, lb/MBtu (HHV)	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136	0.0136
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VOC, ppmvd (dry)	8.9	7.7	7.2	9.0	7.8	7.3	9.1	8.0	7.4	9.1	8.1	7.4
VOC, ppmvw (wet)	8.1	7.1	6.7	8.1	7.2	6.8	8.0	7.3	6.8	8.0	7.3	6.7
VOC, lb/h as CH4	5.0	3.9	2.9	4.9	3.8	2.9	4.6	3.6	2.7	4.3	3.4	2.6
VOC, lb/MBtu (LHV)	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116
VOC, lb/MBtu (HHV)	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109	0.0109
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
PM10, lb/MBtu (LHV)	0.0320	0.0410	0.0552	0.0329	0.0419	0.0564	0.0348	0.0445	0.0593	0.0375	0.0478	0.0631
PM10, lb/MBtu (HHV)	0.0300	0.0385	0.0518	0.0309	0.0394	0.0530	0.0327	0.0417	0.0557	0.0352	0.0449	0.0592
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
PM10, lb/MBtu (LHV)	0.0576	0.0740	0.0996	0.0593	0.0756	0.1017	0.0627	0.0802	0.1070	0.0677	0.0862	0.1138
PM10, lb/MBtu (HHV)	0.0541	0.0695	0.0935	0.0557	0.0710	0.0955	0.0589	0.0753	0.1004	0.0635	0.0809	0.1068
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Total Amount of SO2 converted to SO3, lb/h	4.71	3.67	2.73	4.58	3.59	2.67	4.33	3.38	2.54	4.01	3.15	2.39
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	7.21	5.62	4.18	7.01	5.49	4.09	6.62	5.18	3.89	6.14	4.82	3.65

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. Standard conditions are defined as 60 F, 14.696 psia, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas.
5. The CTG performance is from a General Electric estimation program.

4/21/2004
FMPA
Stock Island-Key West
Black & Veatch Project 136839.004
LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.91%	0.92%	0.93%	0.91%	0.92%	0.93%	0.89%	0.91%	0.92%	0.89%	0.90%	0.91%
CO2	4.31%	3.79%	3.54%	4.31%	3.83%	3.62%	4.27%	3.87%	3.60%	4.24%	3.88%	3.57%
H2O	9.30%	7.59%	6.79%	9.87%	7.90%	7.11%	11.33%	9.26%	8.45%	11.88%	9.85%	8.99%
N2	72.52%	73.64%	74.17%	72.08%	73.42%	73.95%	70.92%	72.37%	72.90%	70.47%	71.92%	72.46%
O2	12.96%	14.06%	14.57%	12.84%	13.92%	14.40%	12.59%	13.59%	14.14%	12.52%	13.44%	14.07%
SO2 (after SO2 oxidation)	0.000760%	0.000670%	0.000620%	0.000760%	0.000680%	0.000640%	0.000750%	0.000680%	0.000630%	0.000750%	0.000680%	0.000630%
SO3 (after SO2 oxidation)	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%	0.000190%	0.000170%	0.000160%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	814	761	763	822	789	796	837	824	820	856	853	840
Stack Diameter, ft (estimated)	10	10	10	10	10	10	10	10	10	10	10	10
Stack Flow, lb/h	1,099,310	979,077	779,592	1,065,780	944,785	746,759	1,011,305	879,155	709,664	942,618	812,986	671,175
Stack Flow, scfm	244,781	217,030	172,421	237,848	209,586	165,284	227,040	196,053	157,901	212,091	181,704	149,673
Stack Flow, acfm	600,044	509,450	405,390	586,716	503,731	399,519	566,335	484,125	388,898	536,825	458,798	374,406
Stack Exit Velocity, ft/s	127.0	108.0	86.0	125.0	107.0	85.0	120.0	103.0	83.0	114.0	97.0	79.0
Stack NOx Emissions												
NOx, ppmvd (dry, 15% O2)	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, ppmvd (dry)	47.0	40.5	37.6	47.3	41.2	38.5	47.6	42.1	38.9	47.6	42.6	38.8
NOx, ppmvw (wet)	42.6	37.4	35.0	42.6	37.9	35.8	42.2	38.2	35.6	41.9	38.4	35.3
NOx, lb/h as NO2	75.9	59.1	43.9	73.7	57.8	43.0	69.7	54.5	40.9	64.7	50.8	38.4
NOx, lb/MBtu (LHV) as NO2	0.1749	0.1750	0.1750	0.1750	0.1750	0.1751	0.1750	0.1749	0.1749	0.1750	0.1750	0.1749
NOx, lb/MBtu (HHV) as NO2	0.1643	0.1643	0.1643	0.1643	0.1643	0.1644	0.1643	0.1643	0.1643	0.1643	0.1643	0.1643
Stack CO Emissions												
CO, ppmvd (dry, 15% O2)	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
CO, ppmvd (dry)	16.8	14.5	13.4	16.9	14.7	13.8	17.0	15.1	13.9	17.0	15.2	13.9
CO, ppmvw (wet)	15.2	13.4	12.5	15.2	13.5	12.8	15.1	13.7	12.7	15.0	13.7	12.6
CO, lb/h	16.5	12.9	9.6	16.0	12.6	9.4	15.2	11.9	8.9	14.1	11.0	8.4
CO, lb/MBtu (LHV)	0.0380	0.0380	0.0381	0.0380	0.0380	0.0381	0.0380	0.0380	0.0380	0.0380	0.0380	0.0380
CO, lb/MBtu (HHV)	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357	0.0357
Stack SO2 Emissions, after SO2 Oxidation												
SO2, ppmvd (dry, 15% O2)	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49	7.49
SO2, ppmvd (dry)	8.38	7.22	6.70	8.43	7.34	6.86	8.49	7.51	6.93	8.48	7.60	6.92
SO2, ppmvw (wet)	7.60	6.68	6.25	7.60	6.76	6.38	7.53	6.82	6.35	7.47	6.85	6.29
SO2, lb/h	18.84	14.67	10.91	18.30	14.35	10.68	17.30	13.54	10.15	16.05	12.60	9.54
SO2, lb/MBtu (LHV)	0.0434	0.0434	0.0434	0.0434	0.0434	0.0435	0.0434	0.0434	0.0434	0.0434	0.0434	0.0434
SO2, lb/MBtu (HHV)	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408	0.0408

4/21/2004
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LM6000 Emissions Estimates, Revision 0

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV	LM6000 PC-SPT-VIGV
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	41	41	41	59	59	59	78	78	78	95	95	95
Ambient Conditions												
Ambient Temperature, F	41.0	41.0	41.0	59.0	59.0	59.0	78.0	78.0	78.0	95.0	95.0	95.0
Ambient Relative Humidity, %	100.0	100.0	100.0	60.0	60.0	60.0	81.8	81.8	81.8	60.2	60.2	60.2
Atmospheric Pressure, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
Combustion Turbine Performance												
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	41.0	41.0	41.0	59.0	59.0	59.0	78.0	78.0	78.0	95.0	95.0	95.0
CTG Compr. Inlet Relative Humidity, %	100.0	100.0	100.0	60.2	60.2	60.2	81.8	81.8	81.8	60.3	60.3	60.3
Inlet Loss, in. H2O	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust Loss, in. H2O	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Gross CTG Output, kW	49,848	37,388	24,923	47,966	35,975	23,986	44,705	33,532	22,353	40,695	30,524	20,348
Gross CTG Heat Rate, Btu/kWh (LHV)	8,702	9,036	10,076	8,786	9,187	10,245	8,912	9,298	10,456	9,080	9,506	10,800
Gross CTG Heat Rate, Btu/kWh (HHV)	9,268	9,623	10,730	9,357	9,784	10,911	9,492	9,902	11,136	9,670	10,124	11,502
CTG Heat Input, MBtu/h (LHV)	433.8	337.8	251.1	421.4	330.5	245.7	398.4	311.8	233.7	369.5	290.2	219.8
CTG Heat Input, MBtu/h (HHV)	462.0	359.8	267.4	448.8	352.0	261.7	424.3	332.1	248.9	393.5	309.0	234.0
CTG Water/Steam Injection Flow, lb/h	28,023	17,530	11,201	30,098	17,608	11,196	28,507	15,104	9,676	26,161	13,453	8,695
Injection Fluid/Fuel Ratio	1.2	1.0	0.8	1.3	1.0	0.8	1.3	0.9	0.8	1.3	0.9	0.7
CTG Exhaust Flow, lb/h	1,099,318	979,083	779,597	1,065,788	944,791	746,764	1,011,313	879,161	709,668	942,625	812,992	671,179
CTG Exhaust Temperature, F	814	761	763	822	789	796	837	824	820	856	853	840
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	23,570	18,360	13,650	22,900	17,960	13,360	21,650	16,940	12,700	20,080	15,770	11,940
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400	18,400
CTG Fuel HHV, Btu/lb	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596	19,596
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%	0.05000%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Attachment 2
Tanks Model Output

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification	
User Identification:	Stock Island CT No. 4 Fuel Oil Tank1 fixed
City:	Key West
State:	Florida
Company:	KEYS
Type of Tank:	Vertical Fixed Roof Tank
Description:	One million gallon No. 2 fuel oil tank
Tank Dimensions	
Shell Height (ft):	32.00
Diameter (ft):	75.00
Liquid Height (ft):	30.00
Avg. Liquid Height (ft):	30.00
Volume (gallons):	1,057,537.03
Turnovers:	25.45
Net Throughput (gal/yr):	26,914,317.38
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	35.00
Radius (ft) (Dome Roof):	75.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Key West, Florida (Avg Atmospheric Pressure = 14.73 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	79.99	76.37	83.62	77.82	0.0122	0.0109	0.0137	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Annual Emission Calculations	
Standing Losses (lb):	245.6788
Vapor Space Volume (cu ft):	108,597.6584
Vapor Density (lb/cu ft):	0.0003
Vapor Space Expansion Factor:	0.0230
Vented Vapor Saturation Factor:	0.9843
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	108,597.6584
Tank Diameter (ft):	75.0000
Vapor Space Outage (ft):	24.5815
Tank Shell Height (ft):	32.0000
Average Liquid Height (ft):	30.0000
Roof Outage (ft):	22.5815
Roof Outage (Dome Roof)	
Roof Outage (ft):	22.5815
Dome Radius (ft):	75.0000
Shell Radius (ft):	37.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0003
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0122
Daily Avg. Liquid Surface Temp. (deg. R):	539.6646
Daily Average Ambient Temp. (deg. F):	77.8042
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	537.4942
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,622.6774
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0230
Daily Vapor Temperature Range (deg. R):	14.4859
Daily Vapor Pressure Range (psia):	0.0027
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0122
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0109
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0137
Daily Avg. Liquid Surface Temp. (deg R):	539.6646
Daily Min. Liquid Surface Temp. (deg R):	536.0431
Daily Max. Liquid Surface Temp. (deg R):	543.2861
Daily Ambient Temp. Range (deg. R):	9.3917
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9843
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0122
Vapor Space Outage (ft):	24.5815

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Working Losses (lb):	1,019.0066
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0122
Annual Net Throughput (gal/yr.):	26,914,317.38 10
Annual Turnovers:	25.4500
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,057,537.028 7
Maximum Liquid Height (ft):	30.0000
Tank Diameter (ft):	75.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	1,264.8853

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Annual Emissions Report

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1,019.01	245.88	1,264.89

Attachment 3
Emission Calculation Spreadsheet

Stock Island Combustion Turbine No. 4
Potential to emit analysis
LM6000 data
Prepared by: Black & Veatch

CT performance data at average ambeint temperature (78°F) and 100% load
Potential to Emit based on 13.567 million gallons per year of fuel oil use (4,422 hours per year of operation).

Pollutant	Hourly Emission Rate (lb/hour)	Potential to Emit[c] (tpy)	PSD SEL (tpy)	PSD Major Modification (Yes/No)
NO_x	69.7	154.1	40	Yes
CO	15.2	33.6	100	No
PM (front half)	13.9	60.9	25	Yes
PM_{10} (front half)	13.9	60.9	15	Yes
PM (front and back half)	25.0	109.5	25	Yes
PM_{10} (front and back half)	25.0	109.5	15	Yes
SO_2[a]	21.6	47.8	40	Yes
VOC	4.6	10.2	40	No
H_2SO_4 mist[b]	6.6	14.6	7	Yes

[a] SO_2 emissions do not include effect of oxidation to SO_3.

[b] H_2SO_4 based on assumption that 20.0% by volume SO_2 is converted to SO_3 and 100% of SO_3 is converted to H_2SO_4.

[c] Based on equivalent 4,422 hours full load operation per year for all pollutants except PM and PM_{10}. PM and PM_{10} are based on 8,760 hours per year operation because estimated PM and PM_{10} emissions do not change with lower load operation.

STOCK ISLAND GENERATING STATION

HAZARDOUS AIR POLLUTANT (HAP) EMISSION ESTIMATES

Combustion Turbine No. 1

FUEL:		DISTILLATE OIL	
HEAT INPUT (MMBtu/hr):		312	
HOURS OF OPERATION:		2888.5	
NUMBER OF TURBINES		1	
DISTILLATE OIL FIRED TURBINE EMISSIONS			
Pollutant	**Emission factor[1] lb/MMBtu**	**Emissions lb/hr/turbine**	**Emissions tons/yr**
1,3 Butadiene	1.60E-05	4.99E-03	0.007
Benzene	5.50E-05	1.72E-02	0.025
Formaldehyde	2.80E-04	8.74E-02	0.126
Naphthalene	3.50E-05	1.09E-02	0.016
PAH	4.00E-05	1.25E-02	0.018
		Total HAP Emissions (tpy)	0.192
DISTILLATE OIL FIRED TURBINE METALLIC HAP EMISSIONS			
Pollutant	**Emission factor[2] lb/MMBtu**	**Emissions lb/hr/turbine**	**Emissions tons/yr**
Arsenic	1.10E-05	3.43E-03	0.005
Beryllium	3.10E-07	9.67E-05	0.000
Cadmium	4.80E-06	1.50E-03	0.002
Chromium	1.10E-05	3.43E-03	0.005
Lead	1.40E-05	4.37E-03	0.006
Manganese	7.90E-04	2.46E-01	0.356
Mercury	1.20E-06	3.74E-04	0.001
Nickel	4.60E-06	1.44E-03	0.002
Selenium	2.50E-05	7.80E-03	0.011
		Total Metallic HAP Emissions (tpy)	0.388

[1] Emission factors from AP-42 Section 3.1 Table 3.1-4.
[2] Emission factors from AP-42 Section 3.1 Table 3.1-5.

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.007
Benzene	0.025
Formaldehyde	0.126
Naphthalene	0.016
PAH	0.018
Arsenic	0.005
Beryllium	0.000
Cadmium	0.002
Chromium	0.005
Lead	0.006
Manganese	0.356
Mercury	0.001
Nickel	0.002
Selenium	0.011
Total HAPs	0.580

STOCK ISLAND GENERATING STATION

HAZARDOUS AIR POLLUTANT (HAP) EMISSION ESTIMATES

Combustion Turbines No. 2 and No. 3

FUEL:	DISTILLATE OIL
HEAT INPUT (MMBtu/hr):	305
HOURS OF OPERATION:	2000
NUMBER OF TURBINES	2

DISTILLATE OIL FIRED TURBINE EMISSIONS

Pollutant	Emission factor[1] lb/MMBtu	Emissions lb/hr/turbine	Total emissions for 2 turbines combined tons/yr
1,3 Butadiene	1.60E-05	4.88E-03	0.010
Benzene	5.50E-05	1.68E-02	0.034
Formaldehyde	2.80E-04	8.54E-02	0.171
Naphthalene	3.50E-05	1.07E-02	0.021
PAH	4.00E-05	1.22E-02	0.024
		Total HAP Emissions (tpy)	0.260

DISTILLATE OIL FIRED TURBINE METALLIC HAP EMISSIONS

Pollutant	Emission factor[2] lb/MMBtu	Emissions lb/hr/turbine	Total emissions for 2 turbines combined tons/yr
Arsenic	1.10E-05	3.36E-03	0.007
Beryllium	3.10E-07	9.46E-05	0.000
Cadmium	4.80E-06	1.46E-03	0.003
Chromium	1.10E-05	3.36E-03	0.007
Lead	1.40E-05	4.27E-03	0.009
Manganese	7.90E-04	2.41E-01	0.482
Mercury	1.20E-06	3.66E-04	0.001
Nickel	4.60E-06	1.40E-03	0.003
Selenium	2.50E-05	7.63E-03	0.015
		Total Metallic HAP Emissions (tpy)	0.526

[1] Emission factors from AP-42 Section 3.1 Table 3.1-4.
[2] Emission factors from AP-42 Section 3.1 Table 3.1-5.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
1,3 Butadiene	0.010
Benzene	0.034
Formaldehyde	0.171
Naphthalene	0.021
PAH	0.024
Arsenic	0.007
Beryllium	0.000
Cadmium	0.003
Chromium	0.007
Lead	0.009
Manganese	0.482
Mercury	0.001
Nickel	0.003
Selenium	0.015
Total HAPs	0.786

STOCK ISLAND GENERATING STATION

HAZARDOUS AIR POLLUTANT (HAP) EMISSION ESTIMATES

Combustion Turbine No. 4

FUEL:	DISTILLATE OIL		
HEAT INPUT (MMBtu/hr):	424.3		
HOURS OF OPERATION:	4422		
NUMBER OF TURBINES	1		
DISTILLATE OIL FIRED TURBINE EMISSIONS			
Pollutant	**Emission factor[1] lb/MMBtu**	**Emissions lb/hr/turbine**	**Emissions tons/yr**
1,3 Butadiene	1.60E-05	6.79E-03	0.015
Benzene	5.50E-05	2.33E-02	0.052
Formaldehyde	2.80E-04	1.19E-01	0.263
Naphthalene	3.50E-05	1.49E-02	0.033
PAH	4.00E-05	1.70E-02	0.038
		Total HAP Emissions (tpy)	0.400
DISTILLATE OIL FIRED TURBINE METALLIC HAP EMISSIONS			
Pollutant	**Emission factor[2] lb/MMBtu**	**Emissions lb/hr/turbine**	**Emissions tons/yr**
Arsenic	1.10E-05	4.67E-03	0.010
Beryllium	3.10E-07	1.32E-04	0.000
Cadmium	4.80E-06	2.04E-03	0.005
Chromium	1.10E-05	4.67E-03	0.010
Lead	1.40E-05	5.94E-03	0.013
Manganese	7.90E-04	3.35E-01	0.741
Mercury	1.20E-06	5.09E-04	0.001
Nickel	4.60E-06	1.95E-03	0.004
Selenium	2.50E-05	1.06E-02	0.023
		Total Metallic HAP Emissions (tpy)	0.809

(1) Emission factors from AP-42 Section 3.1 Table 3.1-4.
(2) Emission factors from AP-42 Section 3.1 Table 3.1-5.

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.015
Benzene	0.052
Formaldehyde	0.263
Naphthalene	0.033
PAH	0.038
Arsenic	0.010
Beryllium	0.000
Cadmium	0.005
Chromium	0.010
Lead	0.013
Manganese	0.741
Mercury	0.001
Nickel	0.004
Selenium	0.023
Total HAPs	1.208

STOCK ISLAND GENERATING STATION

HAZARDOUS AIR POLLUTANT (HAP) EMISSION ESTIMATES

Medium Speed Diesels Units 1 and 2

FUEL:	DISTILLATE OIL
HEAT INPUT (MMBtu/hr):	85.4
HOURS OF OPERATION (per unit):	1870
NUMBER OF ENGINES	2

DISTILLATE OIL FIRED ENGINE EMISSIONS

Pollutant	Emission factor[1] lb/MMBtu	Emissions lb/hr/engine	Total Emissions (both engines) tons/yr
Acetaldehyde	2.52E-05	2.15E-03	0.004
Acrolein	7.88E-06	6.73E-04	0.001
Benzene	7.76E-04	6.63E-02	0.124
Toluene	2.81E-04	2.40E-02	0.045
Xylenes	1.93E-04	1.65E-02	0.031
Formaldehyde	7.89E-05	6.74E-03	0.013
Naphthalene	1.30E-04	1.11E-02	0.021
PAH	2.12E-04	1.81E-02	0.034
		Total HAP Emissions (tpy)	0.267

DISTILLATE OIL FIRED ENGINE METALLIC HAP EMISSIONS

Pollutant	Emission factor lb/MMBtu	Emissions lb/hr/unit	Emissions tons/yr
Arsenic	No EF	#VALUE!	#VALUE!
Beryllium	No EF	#VALUE!	#VALUE!
Cadmium	No EF	#VALUE!	#VALUE!
Chromium	No EF	#VALUE!	#VALUE!
Lead	No EF	#VALUE!	#VALUE!
Manganese	No EF	#VALUE!	#VALUE!
Mercury	No EF	#VALUE!	#VALUE!
Nickel	No EF	#VALUE!	#VALUE!
Selenium	No EF	#VALUE!	#VALUE!
		Total Metallic HAP Emissions (tpy)	#VALUE!

[1] Emission factors from AP-42 Section 3.4 Table 3.4-3 and Table 3.4-4.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
Acetaldehyde	0.004
Acrolein	0.001
Benzene	0.124
Toluene	0.045
Xylenes	0.031
Formaldehyde	0.013
Naphthalene	0.021
PAH	0.034
Arsenic	
Beryllium	
Cadmium	
Chromium	
Lead	
Manganese	
Mercury	
Nickel	
Selenium	
Total HAPs	0.272

STOCK ISLAND GENERATING STATION

HAZARDOUS AIR POLLUTANT (HAP) EMISSION ESTIMATES

Three Diesel Peaking Generators (Insignificant Activities)

FUEL:	DISTILLATE OIL
HEAT INPUT (MMBtu/hr):[1]	21.35
HOURS OF OPERATION (per unit):	1670
NUMBER OF ENGINES	3

DISTILLATE OIL FIRED ENGINE EMISSIONS

Pollutant	Emission factor[2] lb/MMBtu	Emissions lb/hr/engine	Total Emissions (all 3 engines) tons/yr
Acetaldehyde	2.52E-05	5.38E-04	0.002
Acrolein	7.88E-06	1.68E-04	0.000
Benzene	7.76E-04	1.66E-02	0.046
Toluene	2.81E-04	6.00E-03	0.017
Xylenes	1.93E-04	4.12E-03	0.012
Formaldehyde	7.89E-05	1.68E-03	0.005
Naphthalene	1.30E-04	2.78E-03	0.008
PAH	2.12E-04	4.53E-03	0.013
		Total HAP Emissions (tpy)	0.100

DISTILLATE OIL FIRED ENGINE METALLIC HAP EMISSIONS

Pollutant	Emission factor lb/MMBtu	Emissions lb/hr/unit	Emissions tons/yr
Arsenic	No EF	#VALUE!	#VALUE!
Beryllium	No EF	#VALUE!	#VALUE!
Cadmium	No EF	#VALUE!	#VALUE!
Chromium	No EF	#VALUE!	#VALUE!
Lead	No EF	#VALUE!	#VALUE!
Manganese	No EF	#VALUE!	#VALUE!
Mercury	No EF	#VALUE!	#VALUE!
Nickel	No EF	#VALUE!	#VALUE!
Selenium	No EF	#VALUE!	#VALUE!
		Total Metallic HAP Emissions (tpy)	#VALUE!

[1] The Title V permit does not give heat rates or operating hours for these engines. The heat rates for these 2 MW engines were assumed to be proportional to the 8 MW medium speed diesels and operating hours were assumed to be equal to the medium speed diesels.

[2] Emission factors from AP-42 Section 3.4 Table 3.4-3 and Table 3.4-4.

Summary of HAP Emissions

Pollutant	Emissions (tons per year)
Acetaldehyde	0.002
Acrolein	0.000
Benzene	0.046
Toluene	0.017
Xylenes	0.012
Formaldehyde	0.005
Naphthalene	0.008
PAH	0.013
Arsenic	
Beryllium	
Cadmium	
Chromium	
Lead	
Manganese	
Mercury	
Nickel	
Selenium	
Total HAPs	0.102

STOCK ISLAND GENERATING STATION

Summary of HAP Emissions	
Pollutant	**Emissions (tons per year)**
1,3 Butadiene	0.032
Acetaldehyde	0.006
Acrolein	0.002
Benzene	0.280
Formaldehyde	0.577
Naphthalene	0.099
PAH	0.127
Toluene	0.062
Xylenes	0.042
Arsenic	0.022
Beryllium	0.001
Cadmium	0.010
Chromiuim	0.022
Lead	0.028
Manganese	1.579
Mercury	0.002
Nickel	0.009
Selenium	0.050
Total	2.948
Total HAPs	2.948

Attachment 4
Best Available Control Technology

Best Available Control Technology Analysis
for
Stock Island
Combustion Turbine Unit 4

Submitted by

Florida Municipal Power Agency

Prepared by
Black & Veatch

October 2004
Project No. 136839

Contents

Contents (Continued)

Tables

1.0 Executive Summary

The 1977 Clean Air Act Amendment (CAAA) established revised conditions for the approval of preconstruction permit applications under the Prevention of Significant Deterioration (PSD) program. One of these requirements is that the best available control technology (BACT) be installed on new major sources or modifications to existing major sources for all pollutants regulated under the Clean Air Act. Under the BACT process, the chosen technology cannot exceed the level of emission limits established by New Source Performance Standards (NSPS). The proposed Florida Municipal Power Agency (FMPA) Stock Island Combustion Turbine Unit 4 Project, which is considered a major modification to an existing major source, includes one simple cycle combustion turbine that is subject to the BACT process. This document presents the BACT analysis and results.

The following is a summary of the proposed BACT determinations and associated emission rates for one GE LM6000 PC combustion turbine with SPRINT technology operating in simple cycle mode (Combustion Turbine Unit 4) to be installed at the Stock Island facility in Key West, Florida. Combustion Turbine Unit 4 will fire only a low sulfur fuel oil. Emissions for the BACT analysis are based on Combustion Turbine Unit 4 firing a maximum of 13.567 million gallons of fuel oil per year, which is the equivalent of the unit operating at full load firing 4,422 hours per year, at an ambient temperature of 78°F. The unit will operate between 50 and 100 percent of full load, and frequent startups of this unit are expected (over 200 per year). FMPA is requesting a limit on fuel oil use rather than operating hours, because this will result in the greatest operating flexibility, while maintaining the validity of emission estimates and the emission reduction value used in the BACT economic analysis.

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of water injection and good combustion controls to achieve 42 ppmvd at 15 percent O_2.
- Carbon monoxide (CO) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below PSD major source modification thresholds.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and firing low sulfur fuel oil with less than 0.05 percent sulfur by weight.
- Volatile Organic Compounds (VOC) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below PSD major source modification thresholds.

- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of good combustion controls and firing low sulfur fuel oil with less than 0.05 percent sulfur by weight.
- Sulfuric acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls and firing low sulfur fuel oil with less than 0.05 percent sulfur by weight.

2.0 Project Description

The electric generating facility (hereinafter referred to as "Combustion Turbine Unit 4") to be installed by Florida Municipal Power Agency will consist of one (1) General Electric (GE) LM6000 PC simple cycle combustion turbine (SCCT) with SPRINT technology and will be located at KEYS Stock Island Power Plant on Stock Island in the Florida Keys. Combustion Turbine Unit 4 will fire only fuel oil. The GE LM6000 PC combustion turbine uses water injection to reduce NO_x emissions. The SPRINT technology is normally used in combination with the PC unit. The addition of SPRINT (SPRay INTercooling) technology basically consists of injection of water into the intermediate stage of the compressor to cool the air and reduce the compressor work, thereby increasing the power output of the combustion turbine.

The output ratings of Combustion Turbine Unit 4 will be nominally 48 MW at 100 percent load and ISO conditions. The proposed operating scenario for Combustion Turbine Unit 4, which was used in the BACT analysis, includes a maximum of 13.567 million gallons per year of fuel oil, which is the equivalent of operating up to 4,422 hours per year at full load. The unit will be subject to frequent startups (over 200 per year) and will operate between 50 and 100 percent of full load. FMPA is requesting a limit on fuel oil use rather than full load operating hours, because this will result in the required operating flexibility (operation at varying loads for a majority of the year), while maintaining the validity of emission estimates and the emission reduction value used in the BACT economic analysis.

2.1 Combustion Turbine Unit 4 Unique Project Aspects

The Florida Keys are a 220 mile long chain of islands that extend from the southeastern tip of Florida to the Dry Tortugas. The highest spot in the Keys is 18 feet above sea level and there is no point that is more than 4 miles from water. Only about 32 of the 822 islands that make up the Keys are inhabited. The more developed islands are connected by a narrow band of US Highway 1, which includes 19 miles of bridges.

The population of Monroe County was 79,589 in the year 2000, with approximately 30 percent, or 24,000 residents living in the City of Key West. In addition to resident populations, millions of tourists visit the Keys and provide the major source of employment for local residents. Retail services, commercial fishing, and government employment make up the other industries. Some of the unique aspects of the Stock Island facility and the proposed installation of Combustion Turbine Unit 4 are discussed on the following pages.

2.1.1 Road Transportation Accessibility

The Stock Island Power Plant is located just off US Highway 1, approximately 100 miles by road from mainland Florida. US Highway 1, with 42 bridges covering 19 miles of the highway's length, is the only roadway that provides access to the Florida Keys. While US Highway 1 is a four-lane divided highway for a 10 mile stretch in the northernmost area of the Keys, it is a two-lane road from Tavernier to Key West, a 100 mile stretch. Therefore, any transport vehicle traveling to Stock Island will need to travel a 90 mile stretch of this two lane road, which provides the only access to Stock Island and Key West. Because this road is the only access to Stock Island, closure of this road due to an accident, weather, or for any other reason would result in a delay of shipment of materials to the facility. Road closure could become critical to sustaining reliable operation of Combustion Turbine Unit 4 if frequent maintenance and repairs of the combustion turbine or its control equipment are needed. Delays in providing maintenance or repair materials would cause hardship to the citizens of the Keys if adequate power cannot be provided due to unit downtime.

Recent history has shown that accidents and the resulting closure of US Highway 1 are not uncommon. As an example, based on information taken from web site www.nbc6.net, the seven mile bridge was closed for several hours on July 27, 2004 due to a fatality accident on the seven mile bridge. This same article indicated that another bridge in the Keys was closed for several hours on July 26, 2004 after a wreck left a semi-trailer hanging off the bridge by its wheels near Islamorada.

2.1.2 Accessibility of Electrical Power from the Mainland

The unique location of the Florida Keys and the limited means of electrical power supply to the Keys are always a concern and consideration regarding the reliability of the electricity generating units in the Key West area. The Utility Board of the City of Key West (KEYS) is connected to the mainland Florida transmission network through a 138 kV transmission line running adjacent to US Highway 1. The first 61 mile stretch of this transmission line, which is jointly owned by the Florida Keys Electric Cooperative Association, Inc. (FKEC) and KEYS, runs southwest along US Highway 1 from a tie-in with Florida Power & Light (FPL) at the Monroe-Dade County line to Tavernier Substation and then on to the Marathon Substation. The KEYS jointly owns with FKEC a second 138 kV transmission line, which runs 21 miles from a tie with the 138 kV FPL transmission line at the Monroe-Dade County line to the Tavernier Substation. The final section of the transmission line to Key West is solely owned by KEYS and is a 138 kV transmission line that extends from Marathon Substation to the Stock Island Substation, a distance of approximately 40 miles. The firm MW transfer allocation for KEYS over the transmission line is approximately 110 MW.

The generating units located at the Stock Island Power Plant and this 138 kV transmission line are the only sources of electrical power to the Key West area. Any electrical demand beyond what is allocated to KEYS via the transmission line must be provided by the generating units at Stock Island. If this 138 kV transmission line is out of service, all power demand for the Key West area must be supplied by the generating units at the Stock Island Power Plant. However, the units that make up this current local capacity have reliability issues and repairs for these units generally cannot be made by on-site personnel and require contractors from off-site to be called in, making the repair of one of these existing units a relatively time consuming process. Therefore, it is imperative that new generating units at the Stock Island Power Plant be as reliable as possible, even with BACT. Unlike a unit outage on the mainland, where the electrical demand can usually be met by buying power off the grid, if power is not available from the single transmission line coming from the mainland, then all power to the Key West area must be provided by the Stock Island Power Plant units and if these units are not available, power will not be available to the Key West area (i.e., Key West will be dark). In addition, when demand on KEYS exceeds the transfer capability of the transmission line, then that additional demand must also be met by generating units at Stock Island. Again, if the Stock Island generating units are not available due to planned or unplanned outages, including those to maintain emissions control equipment, then demand in Key West will not be met.

The need for reliable power generation at the Stock Island Power Plant is further heightened by the effect hurricanes have on the Key West area. A hurricane can result in the loss of power from the main transmission line from the mainland and the need for immediate and reliable power generation from the Stock Island Power Plant to avoid prolonged blackouts during a time when power availability may be essential for disaster recovery operations. As a recent example, during Hurricane Charley, a sailboat broke away from its moorings and started to drift. The mast of the drifting sailboat struck the transmission line carrying power to the Key West area from the mainland, which resulted in a blackout in the Key West area. A stronger hurricane making a direct hit in the Keys or on the Florida mainland could affect transmission of power to the Keys for an extended period of time. As an example, as a result of Hurricane Andrew, a category 5 hurricane, 3,300 miles of power lines were destroyed, 1.4 million residents lost electricity, and it took 34 days to restore power. A stronger hurricane, such as Hurricane Andrew, that makes a direct hit on the transmission line providing power to the Keys could knock out the transmission line from the mainland for days or weeks, in which case, all demand in the Key West area would have to be met by generation on Stock Island for an extended period of time. By ensuring that new Combustion Turbine Unit 4 is an extremely reliable unit, it will be able to meet the electricity demand to the Key West area in a time of disaster recovery, providing vital energy to aid in the recovery and operation of hospitals, sewage treatment plants, water plants, and other emergency operations.

Finally, the KEYS remote location at the end of a long transmission line can require that units at Stock Island be operated for voltage support. In these instances, it is imperative that the units be reliable. If generation at Stock Island is needed for voltage support and is not available due to planned or forced outages, voltage on KEYS system will collapse, causing a blackout in Key West.

2.1.3 Replacement Power Costs

The unique isolated nature of KEYS also has a significant impact on replacement power costs. While this BACT analysis utilizes the FMPA wholesale power rate as a replacement power cost, the actual cost of replacement power is likely to be much higher. The unavailability of Stock Island Combustion Turbine Unit 4, due to either the inability to meet emission limits or additional planned outages for emissions control equipment, has a much higher probability of keeping KEYS from meeting load demand than would be the case with a unit interconnected to the grid on the mainland. As a result, there is a much higher probability that the unavailability of Stock Island Combustion Turbine Unit 4 will result in unserved energy to KEYS customers. From the document *Electricity Market Module of the National Energy Modeling System: Model Documentation Report,* February 2001, the cost of unserved energy to consumers can vary widely. Estimates range from $2 to $25 per kilowatt-hour (kWh) and are affected by the type of warning before curtailment begins. The low end of this unserved energy cost is more than 30 times the energy cost used in the BACT analysis. In addition, unserved energy can have serious health, safety, and environmental impacts, which are not completely captured in the unserved energy cost. This is unique to KEYS due to its isolated nature. The effects of unserved energy may include the following:

- Power loss at hospitals.
- Loss of street lights.
- Loss of traffic lights.
- Loss of pump service at service stations.
- Loss of power at the Navy base.
- Closure of stores.

- Loss of refrigeration and associated food spoilage in homes and businesses.
- Loss of air conditioning.
- Loss of fire detection and security alarm systems.
- Loss of tourism.
- Loss of pumping for sewage lift stations.
- Loss of power to governmental agencies.

2.1.4 Availability of Fuels

The unique location of the Stock Island Power Plant also limits the availability of alternate fuels for electrical generation. The only readily available fuel source for combustion turbine operation is fuel oil, which is barge delivered. Trucking fuel oil on US Highway 1 would be a logistical nightmare, involving significant environmental risks due to accidents, and would cause undue hardship to the citizens of the Keys. For these reasons, KEYS receives fuel oil by truck only in emergency situations. The requirement to rely on barge delivery would also hold true for any other type of fuel that would have to be transported to the Stock Island Power Plant. A discussion of alternative fuels is included in the following subsections.

2.1.4.1 Natural Gas Pipeline. Unlike the majority of combustion turbine installations in the United States, there is not a source of natural gas in the Key West area. There is no natural gas pipeline to the Keys. To install a natural gas pipeline to the Keys as part of the Combustion Turbine Unit 4 project would be well beyond the scope and cost parameters for this project. As an example of natural gas pipeline costs, the BC Hydro website includes a discussion of the Georgia Strait Crossing Project, which is a proposal to construct a natural gas pipeline from Sumas, Washington, across the Strait of Georgia, and onto Vancouver Island. The pipeline would run approximately 85 miles, and the budget cost of the proposed pipeline is approximately $250 million. In addition, the time required to obtain approval for and actually construct such a pipeline would not meet the time schedule needed to meet the projected electrical demand for the Keys.

2.1.4.2 LNG Terminal. While the EcoElectrica project in Puerto Rico utilizes liquefied natural gas (LNG) supplied from a terminal adjacent to the combined cycle combustion turbine installation, requirements associated with the installation of an LNG terminal indicate that this approach would not be reasonable for the Stock Island site for several reasons, including siting constraints, infrastructure development costs, and environmental health and safety concerns.

2.1.4.2.1 Siting Constraints. The available land and adjacent marine bathymetry necessary to support LNG delivery, storage, and vaporization is not sufficient at the

Stock Island site. Installation of an LNG terminal requires a relatively large land area for the terminal itself. A shore-based terminal generally consists of a docking facility, LNG storage tanks, vaporization equipment, vapor conveyance and handling systems, which typically occupy 25 to 40 acres of land, nearly twice the size of the Stock Island site. Additionally, these sites are required under NFPA 59A to have minimum boundary set backs and safety exclusion zones to assure that public activities and structures outside the immediate LNG facility are not at risk in the event of an LNG fire or flammable vapor cloud release. The docking facility must be capable of handling LNG vessels, which currently range in capacity from 70,000 to 145,000 m^3, with dimensions of 1,000 feet in length and 150 feet in width. Ports and berthing areas must have minimum water depths of 40 to 45 feet to safely handle these LNG vessels. Currently, the Navy is dredging Key West Harbor to a maximum depth of 34 feet so destroyers and cruisers can fit through the City's channel. This new maximum depth is still significantly less than the depth required for an LNG vessel. Additionally, Safe Harbor Channel, adjacent to Stock Island Power Plant, has a depth of 16 to 23 feet.

2.1.4.2.2 Infrastructure Development Costs. The capital costs to develop and construct an LNG terminal facility to serve the plant are tremendous. A storage tank would need to be sized to the capacity of a single LNG vessel to make it feasible for receiving deliveries from LNG suppliers. Similarly, a berthing facility would need to be sized to serve a 145,000 m^3 vessel. Capital costs for a storage tank, berthing and unloading dock, and vaporization system alone would conservatively range from $100 to $200 million to construct.

Licensing of an LNG facility through the Federal Energy Regulatory Commission (FERC) currently takes a minimum of 16 months, with most developers spending $1 million or more for the necessary engineering design and environmental studies required for submittal of a resource report application and preparation of an environmental impact statement. Once approved, most LNG terminal facilities take 3 to 4 years to construct.

2.1.4.2.3 Environmental Health and Safety Concerns. Environmental concerns from the development and operation of an LNG facility would include potentially serious adverse impacts to marine, terrestrial, and air resources. Significant impacts to water quality, benthic communities, and aquatic species could result from cold water discharges from the regasification heat exchangers, suspension of sediment and ocean floor disturbance from dredging, potential strikes by vessels, and potential spills and discharges from both the terminal and LNG vessels. These concerns are only intensified by the project's proximity to environmentally sensitive areas of the Florida Keys National Marine Sanctuary and protected coral reefs. Terrestrial impacts would primarily result from the clearing of land needed to support the terminal. Air quality would be affected by emissions from flaring, ship unloading, and diesel generator operations, as well as fugitive dust during construction.

Perhaps the greatest concern is the potential risk posed to human health and safety from possible accidents. Clearly, this is the most contentious issue surrounding LNG terminal development today. While historically the LNG industry has a good safety record, accidents involving releases of LNG have and continue to occur, that result in serious injury and even death. LNG in its liquid form presents few dangers other than freezing surfaces it comes into contact with (as it is cryogenically stored and transported at -260° F). However, if released from a tank, vessel, or pipe, LNG will quickly vaporize as it absorbs heat from the environment (ambient air, land, or water). The resulting vapor is flammable when mixed in air at concentrations from 5 to 15 percent (volume basis). If the right concentration of LNG vapors come into contact with an ignition source, fires can occur either immediately above the released liquid LNG as it evaporates (pool fires), or as it exits a hole in the containment vessel (jet fires). Additionally, a flammable vapor cloud can be carried up to several miles downwind, which can become a flash fire if it comes into contact with an ignition source, or if it enters a confined space and is ignited can result in an explosion. Accordingly, LNG would present some level of risk to the health and safety of both Stock Island residents and plant workers.

Considering the preponderance of siting, schedule, licensing, environmental, and safety impacts associated with developing and operating an LNG terminal for the project, it is reasonable to conclude that this would not be a viable and cost-effective fuel alternative to the distillate fuel oil that is already available on-site.

2.1.4.3 Propane. The feasibility of utilizing propane as a fuel source for Stock Island Combustion Turbine Unit 4 from both a technical and site arrangement perspective was also considered.

From a technical standpoint, the LM6000 is capable of burning propane, with an estimated required flow rate of 21,000 pounds of propane per hour. According to GE, use of propane as a fuel has been considered on several projects, but has never actually been used. The propane has to be fired as a gas and not a liquid and requires a modification in the fuel nozzles. Vaporizers would be required to change the stored liquid into a gas for supply to the unit.

From a site arrangement standpoint, it was necessary to determine whether the Stock Island site is able to support the necessary onsite storage facilities required for 14 days of propane supply. Assuming a propane flow rate of 21,000 pounds per hour, the 14 day storage requirement is 7,056,000 pounds which, based on propane characteristics provided by the National Propane Gas Association, is equivalent to approximately 1,664,000 gallons of propane. It was further assumed that on-site storage would be provided by 90,000 gallon horizontal storage tanks, with a total of 19 such tanks required. The 90,000 gallon storage tanks are estimated to be 11 feet in diameter and 133 feet in length, with spacing requirements calculated consistent with *National Fire Protection Association* (NFPA) standards.

The NFPA standards governing installation of propane storage tanks with storage capacity between 70,001 and 90,000 gallons stipulate that the tanks must be spaced at a minimum distance of one fourth of the sum of the diameters of adjacent tanks, which for the 11 foot diameter storage tanks would be approximately 6 feet. Given the spacing requirements for the 19 required 90,000 gallon storage tanks, approximately 1.10 acres (47,705 square feet) would be required if the storage tanks are oriented parallel to one another in a single row, and approximately 1.17 acres (51,040 square feet) would be required if the storage tanks are oriented in two rows. The NFPA standards further require 100 feet of clearance between the storage tanks and the closest aboveground facility.

Analysis of the Stock Island site shows that, considering the square footage required for the 19 storage tanks as well as the additional 100 foot clearance requirement, there is not an available footprint on-site for propane storage. Therefore, utilizing propane as a fuel source is not feasible for the Stock Island site, from a land availability perspective.

Normal bulk propane deliveries are by transport truck or rail car. No rail line is available to Stock Island. Therefore, delivery of propane would need to be by transport truck. Typical transport truck capacity ranges from 7,000 to 12,000 gallons. With the estimated propane usage of 21,000 pounds per hour, which equates to approximately 5,000 gallons per hour, the fuel usage would be equivalent to approximately 10 to 17 transport trucks per day. The transport and offloading of this many propane trucks each day would result in unrealistic logistical problems. In addition, due to the hazardous nature of propane, it is likely that the transport, unloading, and storage of these quantities of propane would cause concerns among citizens in the Key West area.

Due to the storage and transport constraints associated with propane use at the Stock Island site, the use of propane is not considered a viable option.

2.1.5 Power Demand Increase

While the population growth in Key West was a relatively modest 2.6 percent over the period 1990 to 2000, tourism continues to have a major impact on the Keys and the energy demand for KEYS is expected to increase at a rate of approximately

2.5 percent per year for the next 10 years. From the period 1993 to 2002, the number of residential customers serviced by KEYS increased from 20,432 to 23,471, the number of small commercial customers increased from 2,253 to 2,847 and the number of large power consumers increased from 547 to 683.

Another source of increased power demands in the Key West area is expected to be due to increased operations at the Boca Chica Naval Air Station in Key West. In 2003, Navy officials announced that there would be a redeployment of military personnel to the Boca Chica Naval Air Station that will nearly double the Navy's presence on the island. The military is also spending an estimated $110 million on new barracks, runway expansions, a new flight control tower, and other projects. The Navy's decision to vacate Puerto Rico's Vieques Island facility also increased the importance of operations at the Key West Boca Chica Naval Station. An indication of this increase in operations is that for the first time in 40 years, the Navy is dredging the Key West Harbor to restore the harbor's depth to 34 feet so destroyers and cruisers can fit through the city's channel. KEYS has recently put in a larger transformer at the substation near the Key West Harbor and is looking at increasing the size of this substation.

This projected increase in electrical demand can only be met by adding additional generating capacity in the Keys. Current local capacity of approximately 86 MW is available at the Stock Island facility. Peak demand in 2003 was 140 MW. Projected peak demand in the years 2013 and 2023 are approximately 175 MW and 217 MW, respectively. It is important to note that these values represent projected demand and actual future demand could be much greater than these projected values. The proposed project is essential to meeting the future Key West energy needs.

The demand frequently exceeds, and will exceed at a greater frequency and amount in the future, the transmission line capacity of 110 MW. Combustion Turbine Unit 4 will be brought on-line to meet the demand above transmission line capacity. Therefore, the Combustion Turbine Unit 4 must have the flexibility of frequent start-ups (more than 200 per year), since it may have almost daily startups to meet daily peak demand.

2.1.6 Summary of Unique Aspects

The unique aspects of the Florida Keys and the Stock Island Power Plant, such as limited road access, the high cost impacts of loss of power, the unavailability of replacement power, a single limited capacity transmission line, limited access to fuel supplies, the need for frequent startups, and a growing energy demand, make it essential and of the utmost importance that the reliability of the Stock Island Unit 4 combustion turbine design be maximized. These unique aspects point to the importance of reliable power generation for the Stock Island Power Plant and the potentially detrimental social and environmental impacts of a BACT technology that reduces the reliability of Combustion Turbine Unit 4.

3.0 Basis of Combustion Turbine BACT Analysis

This section describes the basis for the Combustion Turbine Unit 4 BACT analysis. Information is provided on the BACT methodology and approach used as well as the parameters and factors used in developing the analysis. The BACT analysis for Combustion Turbine Unit 4 is based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions on which this BACT analysis is based.

3.1 Regulatory and Methodology Basis

As defined in the air permit application, operation of the Project will result in a significant increase in the potential to emit emissions of NO_x, PM/PM_{10}, SO_2, and H_2SO_4 (sulfuric acid mist) in excess of the major modification PSD threshold levels set for these pollutants. As required by PSD, a BACT analysis is required for those pollutants with potential emission increases greater than the applicable major modification threshold. Project potential CO and VOC emissions are less than the PSD major modification threshold levels for these pollutants. As a result, CO and VOC emissions were not evaluated as part of the BACT process.

BACT is defined in Rule 62-210.200(37), F.A.C. as:

""Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes, and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."

However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS), which for NO_x is estimated to be 106 ppmv (at the Combustion Turbine Unit 4 heat rate of 10.20 kJ/watt-hr and a fuel-bound nitrogen F value of zero).

To bring consistency to the BACT process, the United States Environmental Protection Agency (USEPA) has authorized the development of a guidance document (March 15, 1990) on the use of the "top-down" approach to BACT determinations. The first step in a top-down BACT analysis is to determine, for the pollutant in question, the control technology alternatives that are technically feasible for the source category in question. Technologies required under the Lowest Achievable Emission Rate (LAER) for the source category must be considered when determining the control technology for the pollutant in question. LAER determinations, although not applicable to Combustion Turbine Unit 4, represent the top control alternatives under the BACT analysis process. A LAER determination would be required if Combustion Turbine Unit 4 was located in a nonattainment area.

Federal and state ambient air quality standards, emission limitations, and other applicable regulations must be met by the technology chosen as BACT. The following criteria are given in Rule 62-212.400(6)(a), F.A.C.:

"(6) Best Available Control Technology (BACT).

(a) BACT Determination. Following receipt of a complete application for a permit to construct an air emissions unit or facility which requires a determination of Best Available Control Technology (BACT), the Department shall make a determination of Best Available Control Technology during the permitting process. In making the BACT determination, the Department shall give consideration to:

1. Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

2. All scientific, engineering, and technical material and other information available to the Department.

3. The emission limiting standards or BACT determinations of any other state.

4. The social and economic impact of the application of such technology."

As previously noted, BACT cannot be less stringent than an applicable NSPS standard. The Federal NSPS for combustion turbines with a heat input greater than 10 mmBtu/h (40 CFR 60 Subpart GG) establishes applicable NO_x and SO_2 emission limits or standards. No NSPS emission limits have been established for PM/PM_{10} and H_2SO_4. The following standards have been established by NSPS for Subpart GG units:

- NO_x allowable limit = 106 ppmvd at 15 percent O_2 (based on a heat rate of 10.20 kJ/watt-hr and accepting a fuel-bound nitrogen F-value of zero).
- SO_2 standard consisting of a fuel sulfur limit of 0.8 percent sulfur by weight.

3.2 Operations/Emissions Basis

As mentioned previously, the proposed operating scenario for Combustion Turbine Unit 4 is a maximum low sulfur fuel oil usage of 13.567 million gallons per year (equivalent to 4,422 hours per year at full load operation). Table 3-1 shows the baseline emission rates for low sulfur fuel oil operation for Combustion Turbine Unit 4 at 100 percent base load at an average annual site temperature of 78°F. The emissions shown in Table 3-1 are controlled with water injection. The lb/mmBtu values are based on the higher heating value (HHV) of the expected fuel oil to be fired. This unit is expected to cycle with frequent startups (over 200 per year) and will be operated at 50 to 100 percent of full load for up to 8,760 hours per year.

Table 3-1
Baseline Emission Rates for Combustion Turbine Unit 4

Emission Parameter	Combustion Turbine Unit 4[a,b]
NO_x, ppmvd at 15% O_2	42
NO_x, lb/h	69.7
NO_x, lb/mmBtu (HHV)	0.1643
PM/PM_{10} (front and back), lb/h	25.0
PM/PM_{10} (front and back), lb/mmBtu (HHV)	0.0589
SO_2, lb/h	21.63
SO_2, lb/mmBtu (HHV)	0.051
H_2SO_4, lb/h	6.62
H_2SO_4, lb/mmBtu	0.0156

[a]Emissions are based on firing low sulfur fuel oil at 100 percent of baseload at an ambient temperature of 78° F.
[b]NO_x emissions with water injection and without any post-combustion control equipment.

3.3 Economic Basis

The economic analyses used to determine the capital and annualized costs of the control technologies were based on USEPA methodologies shown in the USEPA "Best Available Control Technology Draft Guidance Document" (October 1990), ""Top Down" Best Available Control Technology Guidance Document" (March 1990), The

Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (February 1996, Fifth Edition), internal owner cost factors, and vendor budgetary cost quotes.

Table 3-2 lists the economic criteria used in the analysis of BACT alternatives. The capital recovery factor was calculated based on the real interest rate and economic life of the equipment or the assumed catalyst life.

Table 3-2
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	20
Real Interest Rate, percent	7.0
Economic Life, years	15
Capital Recovery Factor, (15 years)	0.1098
Labor Cost, $/man-hour	35
Fuel Oil Cost, $/mmBtu	5.24
Aqueous Ammonia Cost, $/ton (2004)	750
Energy Cost, $/kWhr (2004)	0.05925
Sales Tax, percent	7.25
SCR Catalyst Life, years	1

4.0 Combustion Turbine NO_x BACT Analysis

The objective of this analysis is to determine the BACT for NO_x emissions from the simple cycle combustion turbine, considering the unique aspects of Combustion Turbine Unit 4. These unique aspects are the following:

- Fuel oil fired only.
- Daily start-ups (over 200 per year).
- Extended hours of operation on oil.
- Need for high reliability because of limited transmission connection.
- Seaside island location.

Unless otherwise noted, the NO_x emission rates described in this section are corrected to 15 percent oxygen.

4.1 NO_x BACT/LAER and Technology Review

A summary of the pertinent BACT/LAER and other NO_x control technology decisions for simple cycle combustion turbines burning only fuel oil is attached in Appendix A. A review of BACT/LAER and other NO_x control technology decisions for simple cycle combustion turbines firing fuel oil as a primary or backup fuel has identified water injection as the primary form of NO_x control while firing oil. This review further indicates that selective catalytic reduction (SCR) is being used on only two simple cycle projects where oil is permitted, and in both of these situations, oil has been fired only in minimal amounts (750 hours over 2 years for one project and 200 hours per year for the other project) and represents very limited operational experience. Discussion of the relevant history of SCR on fuel oil units is included in Subsection 4.2.6.

4.2 Alternative NO_x Emission Reduction Systems

During combustion, NO_x is formed from two sources. NO_x emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxide control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process.

A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Water/Steam Injection.
  - Dry Low-NO_x (DLN) Burners.
  - Xonon.
- Post-Combustion Type:
  - Selective Non-Catalytic Reduction (SNCR).
  - $SCONO_x$.
  - Selective Catalytic Reduction (SCR).

The rationale behind whether the above technologies are evaluated as NO_x control for BACT is included in the following subsections.

4.2.1 Water or Steam Injection

NO_x emissions from Combustion Turbine Unit 4 can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. Since the combustion turbine NSPS was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. A limit exists, however, on the amount of water that can be injected into the system before reliability of the combustion turbine is seriously degraded and operational life is affected. This type of control can also be counterproductive with regard to carbon monoxide (CO) and volatile organic compound (VOC) emissions that are formed as a result of incomplete combustion.

The development of dry low-NO_x burners has replaced the use of wet controls, except for certain cases such as oil firing. Since Unit 4 will fire only low sulfur fuel oil, water injection will be considered for control of NO_x formation in this BACT analysis.

4.2.2 Dry Low-NO_x Burners

NO_x can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low-NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN burners because, when firing fuel, injecting water into the combustion chamber is not necessary to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state of the art for NO_x controls in combustion turbines. This method is exclusively utilized when firing natural gas. This application will, therefore, not be reviewed further as a BACT alternative for the fuel oil fired Combustion Turbine Unit 4.

4.2.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700°F at full power generation, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine. This emerging technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers.

Although this technology has been applied to small turbines, such as a Kawasaki M1A-13X (1.5 MW) combustion turbine, it has not been applied to utility size combustion turbines or combustion turbines firing fuel oil, such as proposed for the Combustion Turbine Unit 4. It is expected that application of this technology to utility size combustion turbines will require a period of "scale up" and testing before it can be determined that this technology can demonstrate in practice a given NO_x emission limit. Because this technology has not been applied to utility size combustion turbines firing fuel oil, it is not considered to be technically feasible for Combustion Turbine Unit 4. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

4.2.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,500° to 1,900°F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia emissions (ammonia slip). Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the combustion turbine proposed for this project (approximately 837°F) is less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this project and it will be eliminated from further evaluation in this BACT analysis.

4.2.5 SCONOx

A second, relatively new post-combustion technology from Goal Line Environmental Technologies in conjunction with ABB Alstom Power is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. The South Coast Management District in California recently determined LAER for NO_x to be 2.0 ppmvd at 15 percent O_2 using this technology for gas fired combustion turbines.

The $SCONO_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700°F. ABB Alstom/Goal Line guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The $SCONO_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated or "washed" every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the $SCOSO_x$ catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module in a potassium carbonate reagent tank, which is the active ingredient of the catalyst. The $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is uncertain how often this will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately 10 months on a small LM-2500 combined cycle combustion turbine unit before the $SCONO_x$ system was taken out of service because of poor regeneration gas distribution.

The USEPA has stated its concerns (November 19, 1999 letter from USEPA Region I) with the technical uncertainties of the $SCONO_x$ system and was apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. The combustion turbine proposed for this project is approximately 48 MW, which is within the operating range (32 MW) of the $SCONO_x$ system currently operating at the Federal Cold Storage Cogeneration facility in California. However, Combustion Turbine Unit 4 will fire low sulfur fuel oil for which $SCONO_x$ has no applications.

As discussed above, the $SCONO_x$ technology may have future promise. The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 40 MW. This $SCONO_x$ method of post-combustion control is not considered technically feasible and, therefore, is not included in this BACT analysis to control NO_x emissions.

4.2.6 Selective Catalytic Reduction

Another post-combustion method is selective catalytic reduction (SCR). The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades, ammonia slip will increase. As the ammonia slip approaches the permitted ammonia emissions level, catalyst replacement will be required to maintain compliance with the permit.

4.2.6.1 SCR Operational Issues While Firing Fuel Oil. The ability to promote the chemical reaction converting NO_x and NH_3 to nitrogen and water of a catalyst degrades over time in all applications. The reduced activity, reduced effectiveness, and degradation of the SCR catalyst while firing oil in a simple cycle unit is greatly increased in comparison to standard combined cycle natural gas applications. In addition, frequent start-ups reduce activity, reduce effectiveness, and increase degradation of the catalyst. A marine environment may also accelerate reduced effectiveness and increased degradation. Ultimately, such degradation and reduced effectiveness lead to the requirement to replace catalyst in the reactor vessel at more frequent intervals than a similar application firing natural gas or without frequent start-ups.

The primary causes of SCR catalyst degradation include fouling and sooting, mechanical failures, thermal degradation, and poisoning, as more fully described below.

4.2.6.1.1 Fouling and sooting. Fouling occurs when solids build up on the catalyst surface, blocking the small pores of the active sites. Due to the constituents of distillate fuel oil, the unit produces a sooty residue on the SCR catalyst during times of incomplete combustion. While this occurs during normal operations, it is more pronounced during frequent start-ups, which are expected with the Stock Island Combustion Turbine Unit 4. A sooty residue has much the same affects as fouling. The majority of SCR applications utilizing fuel oil are based upon the unit primarily firing natural gas and being limited in operating hours while firing fuel oil. These applications, due to a limited number of hours on fuel oil firing, would have few startup scenarios on oil, thereby minimizing the impacts of the secondary fuel oil firing on the SCR catalyst. Combustion Turbine Unit 4 can be expected to have startups in excess of 200 times within a calendar year and would, therefore, experience problems because of sooty residue.

Another form of fouling is ammonium bisulfate formation. This is a sticky substance, which can form when ammonia is injected in the presence of SO_3 at low flue gas temperatures as a result of maldistribution of the tempering air. Most of the ammonium bisulfate deposits would be removed from the catalyst surface when flue gas temperature is increased above approximately 660° F upon correction of the distribution problem, so permanent fouling of the catalyst by ammonium bisulfate should be minimal. The ammonia bisulfate is removed through evaporation, which can take several hours.

4.2.6.1.2 Mechanical failures. Mechanical failures are cracks or debonding of the catalyst from the substrate material, leaving small voids or channels of reduced catalyst in the SCR grid. Mechanical failures can occur from thermal stresses associated with frequent starts (which are expected for the Stock Island Combustion Turbine Unit 4), as well as dynamic forces on the modules. This could result in catalyst deficient channels, which allows the exhaust gas to bypass the active catalyst sites.

4.2.6.1.3 Thermal degradation. The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadium/titanium catalysts have been used on the majority of SCR system installations. The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600° to 750°F. At temperatures above 800°F, permanent damage to the vanadium/titanium catalyst can occur. Either a zeolite catalyst (high temperature) or dilution tempering air is required to minimize the impact to the SCR vanadium/titanium catalyst. The flue gas temperature at the outlet of Combustion Turbine Unit 4 will typically range from 700° to 860°F, which will require the application of dilution air tempering with utilization of the vanadium/titanium catalyst.

4.2.6.1.4 Poisoning. A number of alkali metals and trace elements, which are expected in the Combustion Turbine Unit 4 fuel oil and which are more prevalent in oil than in gas, will poison the catalyst, significantly reducing reactivity and resulting in a much shorter life span. Known catalyst poisons are as follows:

- Arsenic
- Calcium
- Potassium
- Sodium
- Lead
- Cadmium
- Beryllium
- Chromium
- Copper
- Mercury
- Manganese
- Nickel
- Thorium
- Uranium

These poisoning effects do not occur suddenly; they are a continual process over the entire life of the catalyst. For example, AP-42 identifies arsenic as being 50 times greater in fuel oil than in natural gas. Arsenic, the major poison when in the form of gaseous arsenic oxide, can be deposited on catalyst surfaces, clogging small pores of the catalyst. This limits the transport of the ammonia-NO_x mixture to the activity sites. This effect can be somewhat minimized by enlarging the pores of the catalyst to limit the blocking of active sites. However, arsenic, as well as the other poisons listed, can chemically attack (neutralize) the active sites on the catalyst surface and reduce catalyst effectiveness over time.

Another form of poisoning is caused by sodium. This has occurred in two installations. The first occurrence was at a plant with a coastal environment. It was believed that the source of the sodium originated from sea air or an aqueous ammonia supply. The second occurrence was attributed to sodium in a low quality aqueous ammonia supply. This will be greatly exacerbated at the Stock Island site due to the geographical location of the facility and a great amount of salt in the air.

While some of these operational issues can be minimized through design features, because of the daily cycling, extensive oil use, and a severe marine environment, the

Stock Island Combustion Turbine Unit 4 can be expected to need frequent catalyst replacement. The daily cycling while firing fuel oil is a significant contributor to the degradation categories of sooting, poisoning, mechanical failures, and thermal degradation. Ultimately, the need to replace catalyst will be a function of the SCR system's ability to meet the requisite NO_x and ammonia slip permit requirements.

4.2.6.2 Relevant Operating History. As indicated in Appendix A, the application of SCR on simple cycle combustion turbines firing oil is very limited. The following is a discussion of the test programs and units which have actually operated using SCR while firing fuel oil.

4.2.6.2.1 EPRI Fuel Oil Pilot Test. The Electric Power Research Institute (EPRI) has performed an analysis of SCR operation on fuel oil in both a combined cycle and simple cycle configuration, and confirmed these expected problems. The analysis report was performed in 1997 (TR-108169). A test pilot program was initiated on a slip stream SCR system at the Maalea Generating Station owned by Maui Electric Co. The LM2500 unit fired low sulfur fuel oil with less than 0.04 percent sulfur by weight. The results of the pilot plant indicated that the SCR system experienced long term operating problems for both the combined and simple cycle arrangement. For both configurations in the pilot test plant, the SCR system experienced greater than expected catalyst deactivation rates and excessive oxidation of SO_2 to SO_3. At that time, EPRI recommended that simple cycle SCR oil fired applications were not a feasible technology.

4.2.6.2.2 Shoreham Electric Generating Station – Long Island, New York. The Shoreham Electric Generating Station on Long Island, New York includes two simple cycle combustion turbines permitted to fire fuel oil only with the use of water injection and SCR for control of NO_x emissions. This facility is located in an ozone non-attainment area and would have been subject to LAER for NO_x control if New Source Review were required. The permit limits annual NO_x emissions to 22.5 tons per year, and the permit states that it does not permit the operation of a major electric generating facility. Thus, it is presumed that the applicant decided to install SCR controls as a means to avoid New Source Review. Because the facility was not subject to PSD review, a BACT analysis was not required as part of the permit application for the facility. The effective date of this facility's "Air state facility permit for a new facility (preconstruction permit)" is January 10, 2002.

Based on owner provided information, additional catalyst in excess of design was added to address concerns about reliability. Based on information contained on the USEPA Airmarkets Web site, total operation of these units through the first quarter of 2004 was less than 750 operating hours, which equates to approximately 1 month of operation. This data, along with the permit limit on annual NO_x emissions, points to the limited use of these units. A copy of the Shoreham Electric Generation Station Permit is included in Appendix B.

4.2.6.2.3 Puget Sound Energy Fredonia – Mount Vernon, Washington. The Puget Sound Energy (PSE) Fredonia facility combustion turbines are two Pratt & Whitney FT8 (Twin Pack) units, which began operation in 2001. These units were permitted in 2003 (after the fact) to fire natural gas or distillate fuel and have a NO_x limit of 5 ppmvd, corrected to 15 percent O_2, for both fuels. Based on a conversation with an Environmental Manager at PSE, each of the units has approximately 2,000 to 3,000 hours of run time with a couple hundred hours of oil firing run time. Therefore, while these units are permitted to fire either natural gas or distillate oil, they have a limited number of hours of distillate oil firing to date.

4.2.6.2.4 PREPA – Cambalache Power Plant. The Puerto Rico Power Authority (PREPA) Cambalache Power Plant, located in Puerto Rico was originally installed with SCR catalyst in 1997, but due to repeated operation failures, the USEPA approved the removal of the SCR system in 2000 and indicated that SCR was not BACT for these units. This failure occurred more than 20 years after the first installation of SCR on oil fired utility boilers. Notwithstanding the advances in technology, the application of SCR on this unit failed after just 2 months of oil firing. Numerous attempts to correct the problems were unsuccessful. The units currently control NO_x with steam injection down to 42 ppmvd. A further discussion and a copy of the compliance order are attached as Appendix C.

4.2.6.2.5 Vendor Experience. FMPA has found no SCR packager or catalyst manufacturer that has had equipment operating in a situation like the proposed Stock Island project, a simple cycle combustion turbine firing on fuel oil only in a marine environment with daily starts and extended hours.

4.2.6.2.6 Summary of Operational Experience. As indicated above, no simple cycle combustion turbines have successfully operated while using SCR and firing fuel oil for more than 750 hours. No known simple cycle combustion turbine utilizing SCR and firing fuel oil has operated anywhere close to the 8,760 hours per year proposed for Stock Island Combustion Turbine Unit 4, leading to a lack of needed operational experience on which to project catalyst life. Nor has any such unit successfully operated in a severe tropical marine environment such as the Stock Island Power Plant.

4.2.6.3 Recent Permitting Actions.

4.2.6.3.1 PREPA San Juan Repowering Project. From the USEPA BACT/RACT/LAER Clearinghouse, the PREPA San Juan Repowering Project PSD permit was issued in March 2000. This project included the addition of two 232 MW combined cycle combustion turbines. The combustion turbines were to be fired with fuel oil only. The draft PSD permit for the repowering project included BACT as being the use of an SCR system to control NO_x emissions. However, after further review, the USEPA determined that BACT for this project was steam injection for NO_x control. This determination was outlined in an USEPA press release dated March 24, 2000 (copy included in Appendix D). This press release included the following statements regarding the use of an SCR system with an oil fired only combustion turbine:

> "In its draft permit, proposed in March 1999, EPA included Selective Catalytic Reduction (SCR), which uses an ammonia injection system to reduce nitrogen oxide emissions, and steam injection. However, new data indicate that, on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA has removed the SCR requirement and will instead require PREPA to install special burners, called "low NO_x burners," on the four old boilers at its facility. PREPA would still use steam injection on its turbines."
>
> "After carefully considering the feasibility of using SCR on an oil-fired plant and reviewing public comments, the choice to remove SCR was clear," said Jeanne M. Fox, EPA Regional Administrator. "We want to ensure that PREPA uses the most reliable pollution controls. Steam injection systems and low NO_x burners are both tried and true nitrogen oxide controls."

4.2.6.3.2 Virgin Islands Water and Power Authority (VIWAPA) Unit 22. The VIWAPA received a PSD construction permit from USEPA Region 2 in January 2001 for the installation of Unit 22. The PSD construction permit allowed for the installation of Unit 22, a 24 MW United Technologies FT8-1 Power Pac gas turbine at the VIWAPA St. Thomas facility. Unit 22 will operate in simple cycle mode without any secondary heat recovery. The only permitted fuel for Unit 22 is No. 2 fuel oil with a maximum sulfur content of 0.2 percent sulfur by weight. The VIWAPA St. Thomas facility was an existing PSD major stationary source. Unit 22 was PSD affected for NO_x, SO_2, CO, PM_{10}, and VOCs, and was, therefore, required to employ BACT to control emissions of these pollutants. For NO_x emissions, BACT was determined to be the use of water injection. The PSD permit includes a NO_x emissions limit of 42 ppmvd, corrected to 15 percent oxygen. A copy of the VIWAPA Unit 22 Permit is included in Appendix E.

4.2.6.3.3 Virgin Islands Water and Power Authority (VIWAPA) Unit 23. On March 5, 2004, the USEPA announced approval of an exemption of the Clean Air Act for the Territory of the United States Virgin Islands. This exemption allowed for the construction, but not operation, of Unit 23 at the VIWAPA St. Thomas facility. This exemption was sought by the US Virgin Islands Governor, on behalf of VIWAPA, so that

VIWAPA could proceed as quickly as possible with the construction of Unit 23, a 36 MW simple cycle combustion turbine. It was stated that the petitioner did not seek any exemption from obtaining a PSD permit and meeting all emission control and air quality related obligations under the CAA prior to beginning operation of the new turbine. It was also stated that the exemption will not affect any emission or any air quality requirements and that the new turbine will be held to the same emission limitations as a similar source built in another area which is attaining the NAAQS.

USEPA Region 2 issued a PSD permit for VIWAPA Unit 23 on September 8, 2004. The PSD permit lists Unit 23 as a 36 MW General Electric Frame 6 combustion turbine. The type of fuel is limited to No. 2 fuel oil or distillate fuel oil with a sulfur content of no more than 0.15 percent sulfur by weight and a nitrogen content of no more than 1,000 ppm nitrogen by weight. BACT for NO_x is the use of water injection to control NO_x emissions. The permit includes various NO_x limits, including a NO_x limit of 135 lb/hr, a NO_x limit of 84 ppmvd, corrected to 15 percent oxygen, and a NO_x limit based on a monthly average of 42 ppm with an adjustment based on the nitrogen content of the fuel oil. Based on a discussion with USEPA Region 2, the USEPA decided early on in the permitting process that SCR would not be required and identified to the applicant that they did not have to address SCR as part of their permit application. Thus, the permittee did not evaluate SCR as part of the BACT analysis. A copy of the VIWAPA Unit 23 permit and PSD Waiver is included in Appendix F.

4.2.6.3.4 Commonwealth Chesapeake Power Station – New Church, Virginia. The Commonwealth Chesapeake Power Station functions as a peaker plant with seven LM6000 simple cycle combustion turbines firing fuel oil only. This facility was permitted by the Virginia Department of Environmental Quality. The facility was issued a PSD permit in October 2000. CT 1 through 3 were installed in 2000 and CT 4 through 7 were installed in 2001. BACT for NO_x for these units was determined to be the use of water injection. The following summary is taken from a document discussing the BACT decision for the Commonwealth Chesapeake Power Station:

> "NO_x average cost for HT (high temperature) SCR control was reasonable at \$1,452 per ton; however, the incremental cost at \$12,354 per ton was judged too costly for BACT. Besides the large incremental cost, HTSCR system for oil fired simple cycle turbines is still in the design stage. The one permitted turbine facility that tried HTSCR system for oil fired turbines in Puerto Rico failed. USEPA, Region II removed the SCR system in the revised permit issued in 2000 – leaving control to water injection. Tentative technology, high cost, and ammonia emissions do not make HTSCR a BACT selection for the CCC peaker plant project. BACT selected as the use of water injection for NO_x control."

Permitting information for the Commonwealth Chesapeake Power Station is located in Appendix G.

4.2.6.3.5 City of Tallahassee Arvah B. Hopkins Station – Tallahassee, Florida. The Florida Department of Environmental Protection (FDEP) published an intent to issue an air construction permit on September 9, 2004, for the installation of two LM6000 simple cycle combustion turbines at the City of Tallahassee Arvah B. Hopkins Station. The draft permit for these units allows for the use of natural gas and fuel oil in the combustion turbines, with annual hours of operation limited to 5,840 hours of operation per year for each turbine, of which 4,000 hours may be with fuel oil. The draft permit requires the use of SCR for NO_x control with a NO_x emissions limit of 5 ppmvd corrected to 15 percent O_2 and an ammonia slip limit of 10 ppmvd at 15 percent O_2. As indicated in the permit application BACT economic analysis for this construction permit, the catalyst guarantee is for 1,500 hours per year of fuel oil firing. It appears that this limited fuel oil firing catalyst guarantee is reflected in the BACT economic analysis, where a catalyst life of less than 1 year is used. Naturally, since this installation is still in the permitting phase and construction has not begun, there is no SCR operational information associated with these units.

4.2.6.3.6 Permitting Summary. Out of the 95 projects identified in Appendix A, only 4 include the use of SCR. In each of these cases, SCR was voluntarily proposed by the permittee. As indicated in Appendix A, water injection continues to be the predominant method of controlling NOx emissions while firing fuel oil in a combustion turbine. For example, as recently as September 2004, EPA determined water injection was BACT for a simple cycle combustion turbine firing fuel oil.

4.2.6.4 SCR Summary. The industry, and the USEPA itself in previous rulings as noted above, has indicated reservations and concerns regarding the capability for SCR systems to provide reliable NO_x control on a unit such as Combustion Turbine Unit 4 (i.e., fuel oil only operation with a large number of operating hours each year and with frequent start-ups and shut downs in a marine environment). The only oil fired combustion turbine units that are operating with SCR have very limited operated hours.

Although some SCR vendors appear willing to offer guarantees for a three-year catalyst life on oil fired simple cycle combustion turbines while meeting SCR system emission requirement, available data regarding the degradation of catalyst in an oil fired operating project with similar vendor guarantees cannot be ignored. Based on the aforementioned concerns about catalyst degradation, the lack of long-term demonstration of use of an SCR for a simple cycle combustion turbine firing oil and the failed SCR experience at the Cambalache Plant, a one-year catalyst life is assumed for the BACT economic analysis. This is consistent with the recently submitted BACT economic analysis for the proposed installation of simple cycle combustion turbines at the City of Tallahassee's Arvah B. Hopkins Generating Station.

4.3 Energy, Environmental, and Economic Impacts Evaluation

The following evaluation considers energy, environmental, and economic impacts for the NO_x BACT scenarios evaluated. Table 4-1 outlines the expected NO_x emissions rates from the evaluated emissions control alternatives for NO_x of water injection and SCR. SCR is considered the most stringent NO_x emissions control alternative as it achieves the lowest outlet emission rate. Based on the City of Tallahassee Arvah B. Hopkins Generating Station draft permit, the BACT analysis will be based on 5 ppmvd NO_x emissions corrected to 15 percent O_2 and an ammonia slip of 10 ppmvd at 15 percent O_2. Water injection is the next most stringent NO_x emissions control alternative and is considered the base NO_x emissions control installation for Combustion Turbine Unit 4. No other alternatives were considered. Therefore, if SCR is not found viable via energy, environmental, or economic impacts, by default water injection will be determined as BACT for Combustion Turbine Unit 4. Therefore, this section focuses on the evaluation of SCR for Combustion Turbine Unit 4 relative to it being able to achieve the associated emission rates on a reliable basis with reasonable impacts.

4.3.1 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of the Project compared to use of water injection alone. An SCR system requires an ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. The following is a breakout of the parasitic power requirements associated with an SCR system:

- Dilution air energy use--52 kW.
- Ammonia vaporization--76 kW.

In addition, an SCR system catalyst would increase the backpressure on the combustion turbine. The SCR system would add about 11.0 inches water gauge (in. w.g.) backpressure to the unit for the NO_x reduction to 5 ppmvd. This would reduce the output of the unit by approximately 0.97 percent for the Combustion Turbine Unit 4 stack outlet emission of 5 ppmvd.

Table 4-1
Estimated NO_x Emissions from Alternate Control Technologies for Combustion Turbine Unit 4

	Control Technology Alternatives	
	Water Injection	SCR (5.0 ppmvd)
NO_x Emissions		
ppmvd (at 15 percent O_2)	42.0	5.0
lb/h	69.7	8.3
lb/mmBtu	0.1643	0.0196
Tons per year (tpy)[a]	154.1	18.3
Percent reduction	N/A	88
NO_x BACT (Annual)[a] (tpy)	154.1	18.3
NO_x Emission Reduction (tpy)	N/A	135.8

[a]Total emissions are based on 13.567 million gallons per year firing low sulfur fuel oil (equivalent to 4,422 hours at 100 percent of base load) at an ambient temperature of 78° F.

In addition, due to the potential rapid deactivation of the SCR catalyst, yearly catalyst replacements are factored into the energy impact, including downtime needed during catalyst replacement. As described previously, Combustion Turbine Unit 4 is a unique installation of which unit reliability and availability are required as outlined in Section 2.0 of this BACT analysis. Increased power consumption and lost power generation are included in the annualized cost estimate.

4.3.2 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. Because of this, recycling of SCR catalysts for vanadium has become common.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes and is also regulated by USEPA's Chemical Accident Prevention Provisions.

This BACT analysis is based on the use of aqueous ammonia that can be stored and used more safely than anhydrous ammonia. According to the Committee on Toxicology of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

The Combustion Turbine Unit 4's location on a small island is a unique circumstance compared to other SCR installations. The island location significantly reduces evacuation possibility and increases the possibility of exposure to the public in case of accidental release. The aqueous ammonia would have to be trucked to the plant site on the only access road to the island. The human response thresholds would apply to the aqueous ammonia if an accidental release occurred during transportation. It is expected that Unit 4 would require one 19 percent aqueous ammonia truck shipment every 2 weeks. Due to the access to Combustion Turbine Unit 4 being the main road into Key West, any accident involving the aqueous ammonia supply truck would result in closure of the main roadway for many hours. Typically, if the public is leaving an area because of an ammonia spill, citizens would want to escape from the point of the spill. However, Stock Island is between Key West and the only road out of Key West. Key West is at the tip of US Highway 1, any ammonia spill at Stock Island may cause a concern that the citizens of Key West would not be able to evacuate the area and could be trapped by the ammonia release with no where to go. While aqueous ammonia inherently is not fatal like anhydrous ammonia, a public relations issue could exist concerning limited evacuation routes.

Some ammonia slip from the Combustion Turbine Unit 4 stack is unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Ammonia slip emissions from an SCR system is a design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictate associated catalyst replacement. Consistent with NESCAUM's recommendation, FDEP recently proposed an ammonia slip of 10 ppmvd for a similar simple cycle unit utilizing SCR. A design value of 10 ppmvd is appropriate for the low sulfur fuel oil to be used with Combustion Turbine Unit 4. Although with fresh catalyst, ammonia slip emissions will be lower; ammonia slip will increase as the catalyst deactivates until the system approaches the design value and catalyst replacement will be required. As noted in Subsection 4.2.6.2.4, the catalyst at the PREPA Cambalache Plant showed degradation within 1 to 2 months after start-up or chemical cleaning of the catalyst. The facility was able to maintain a 10 ppmvd ammonia slip level for only 1 to 2 months after chemical cleaning of the catalyst.

SCR catalysts can become contaminated over a period of time due to trace elements in the flue gas and be classified as hazardous waste. Therefore, spent catalyst needs to be handled and disposed of following hazardous waste procedures.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. Once the flue gas cools below approximately 600°F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than PM_{10}. As the catalyst gradually deactivates because of oil usage and the expected problems discussed in Subsection 4.2.6.1, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip for a given level of performance. Increased ammonia slip in turn results in additional ammonia salt formation which could result in increased opacity and particulate emissions from Combustion Turbine Unit 4.

We can find other evidence of SO_2 to SO_3 conversion problems if we look outside the combustion turbine source category. As an example, although not included in the same Combustion Turbine Unit 4 source category, the Mirant Canal oil fired boiler experienced higher than design SO_3 outlet emissions. The primary cause of the increased SO_3 was the fuel oil. Fuel oil inherently contains high amounts of vanadium. Vanadium is one of the primary active catalyst ingredients that promotes the conversion of NO_x to nitrogen in water in the presence of ammonia. As the vanadium from the fuel oil built up in the catalyst (the catalyst acts similar to a sponge in the presence of vanadium), the SO_3 values increased significantly. The end result was that the entire catalyst system was replaced ahead of schedule. Due to limited continuous operation of combustion turbine units on oil, the possible occurrence of a situation similar to the Canal operating problem is unknown.

4.3.3 Economic Impacts for SCR (5.0 ppmvd) System

The use of an SCR has significant economic impacts to the Project. The application of SCR on Combustion Turbine Unit 4 must incorporate special design and operational/maintenance criteria, such as yearly catalyst replacements and increased associated plant outage costs. Such special criteria are not normally considered for natural gas only applications, or for applications with limited planned operation on fuel oil. These criteria have been addressed in this economic analysis evaluation of the BACT. The BACT costs presented in this analysis are based on operating the combustion turbine on 13.567 million gallons of low sulfur fuel oil (equivalent to 100 percent of base load for 4,422 hours per year).

4.3.3.1 Capital Costs for SCR (5.0 ppmvd). Table 4-2 presents the capital costs for installing an SCR system on Combustion Turbine Unit 4 to achieve a NO_x outlet emission level of 5.0 ppmvd. The cost of the SCR system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing; dilution air fans; controls and instrumentation; sales taxes; and freight. The balance of plant (BOP) equipment cost for the SCR system was estimated to be 30 percent based on the OAQPS *Control Cost Manual* estimates. The BOP cost for the SCR system consists of 8 percent for foundation and supports, 14 percent for handling and erection, 4 percent for electrical installation, 2 percent for piping, 1 percent for insulation, and 1 percent for painting. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates.

Quotations for the SCR were based on vanadium/titanium type catalyst. The direct installation costs included the BOP items, as previously discussed, and were calculated as percentages of the total purchased equipment costs. The total capital investment (TCI) was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR systems are percentages of the total direct cost (DC) and are site specific. There are many potential items and uncertainties that are not captured by the cost items included in the estimate, such as possible changes between cost quotes and contract values, changes in operating conditions, process contingency, increased equipment cost, scope changes, labor/wage increases, and schedule acceleration. In addition, the Electric Power Research Institute

Table 4-2
NO_x Emission Control Alternative Capital Cost for Combustion Turbine Unit 4

	SCR (5 ppmvd)	Water Injection	Remarks
Direct Capital Cost			Cost based on emissions in Table 4-1.
SCR System	1,894,000	N/A	Estimated from Deltak Corporation.
Catalyst Reactor Housing	Included	N/A	
Control/Instrumentation	135,000	N/A	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	Included	N/A	
Purchased Equipment Costs (PEC)	**2,029,000**	**N/A**	
Sales Tax	147,000		7.25% of Purchased Equipment Costs.
Freight	203,000	N/A	10% of Purchased Equipment Costs.
Total Purchased Equipment Costs (TPEC)	**2,379,000**	**N/A**	
Direct Installation Costs			
Balance of Plant	713,000	N/A	See text for background information on this item.
Total Direct Cost (DC)	**3,092,000**	**Base**	
Indirect Capital Costs			
Contingency	618,000	N/A	20% of DC
Engineering and Supervision	309,000	N/A	10% of DC
Construction & Field Expense	155,000	N/A	5% of DC
Construction Fee	309,000	N/A	10% of DC
Start-up Assistance	62,000	N/A	2% of DC
Performance Test	31,000	N/A	1% of DC
Total Indirect Capital Costs (IC)	**1,484,000**	**Base**	
Installed Costs (DC + IC)	**4,576,000**		
Less SCR Catalyst Cost	-369,000		Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**$4,207,000**	**Base**	TCI = DC + IC

published the document titled, "NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook" in November 1991, which includes the following text (page 5-5) pertaining to NO_x control costs:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3 percent of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50 percent of the sum of direct and indirect costs. A contingency factor of 20 percent of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors. Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

For Combustion Turbine Unit 4, the contingency was estimated at 20 percent.

Total capital costs for the SCR control system are calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital cost for a 5 ppmvd (8.3 lb/h at average operating conditions and 100 percent load) NO_x outlet emission SCR system for the Project is estimated to be $4,207,000.

4.3.3.2 Operating Costs for SCR. Table 4-3 presents the annualized operating costs and emission rates using an SCR system with fuel oil firing to achieve NO_x outlet emissions of 5 ppmvd for Combustion Turbine Unit 4. Annualized operating costs for the SCR include catalyst replacement, energy impacts, operating personnel, maintenance, reagent, and heat rate penalty. Throughout the life of the unit, catalyst elements for the SCR catalyst would require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions would increase. As discussed in Subsection 4.3.2, an ammonia slip design value of 10 ppmvd is considered appropriate for this type of SCR application. If a permit limit of 10 ppmvd ammonia emissions was associated with a unit operating with an SCR, to avoid permit violations, the catalyst would have to be replaced when ammonia slip approaches 10 ppmvd. Currently, SCR catalyst manufacturers are willing to guarantee a catalyst life of 3 years or equivalent operating hours for natural gas fired applications, but have provided no examples of proven applications of long term operation of an SCR on a simple cycle combustion turbine firing fuel oil. The only units identified that fire fuel oil only with an SCR system and have significant run time were at the

Table 4-3
NO_x Emission Control Annualized Cost for Combustion Turbine Unit 4

	SCR (5 ppmvd)	Water Injection	Remarks
Direct Annual Cost			Cost based on emissions in Table 4-1.
Catalyst Replacement	478,000	N/A	See text for background information.
Operation and Maintenance	67,000	N/A	See text for background information.
Reagent Feed	63,000	N/A	Assumes 1.4 stoichiometric ratio.
Power Consumption	34,000	N/A	Includes injection blower and vaporization of ammonia for SCR.
Lost Power Generation			
Backpressure	117,000	N/A	Includes backpressure on CT.
Catalyst Replacement	241,000	N/A	Based on FMPA energy cost and 7 day catalyst replacement.
Annual Distribution Check	55,000	N/A	Required for SCR.
Total Direct Annual Cost	**1,055,000**	**N/A**	
Indirect Annual Costs			
Overhead	40,000	N/A	60% of O&M Cost.
Administrative Charges	92,000	N/A	2% of Installed Costs.
Property Taxes	126,000	N/A	See text for background information.
Insurance	46,000	N/A	1% of Installed Costs.
Capital Recovery	462,000	N/A	CR = CRF*TCI
Total Indirect Annual Costs	**766,000**	**N/A**	
Total Annualized Cost	**1,821,000**	**N/A**	
Annual Emissions, tpy	18.3	154.1	Emissions from Tables 4-1.
Emissions Reduction, tpy	135.8	N/A	Emissions calculated.
Total Cost Effectiveness, $/ton	**13,410**	**N/A**	Total Annualized Cost/Emissions Reduction.

Cambalache Power Plant located in Puerto Rico. Due to sooting and repeated failure of the SCR system to maintain catalyst performance, the USEPA required the removal of SCR from that plant. Based on that case study, this economic analysis has assumed a 1 year catalyst life due to potential for sooting and contamination of the catalyst. This is consistent with the recently submitted BACT economic analysis for the proposed installation of simple cycle combustion turbines at the City of Tallahassee's Arvah B. Hopkins Generating Station. The SCR catalyst replacement cost was calculated by multiplying the cost of the catalyst replacement modules by 15 percent for installation cost, 7.25 percent for sales taxes, and 5 percent for freight, and a capital recovery factor based on the real interest rate over the 1 year life of the catalyst.

Ammonia consumption rates were based on a stoichiometric ratio of 1.4 for reacting NO. The higher stoichiometric ratio allows for a higher molar ratio of ammonia required to react with NO_2. The heat rate penalty cost item reflects the cost due to the SCR catalyst backpressure losses. The additional backpressure would derate the combustion turbine resulting in lost electric sales revenue. In addition, electric sales revenue of 1 week would be lost due to the replacement of catalyst once a year. The costs associated with these impacts are included in the annualized cost estimate.

The use of an SCR system would increase the energy requirements of the Project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. It would also require dilution air fans to operate when the turbine outlet temperature is higher than 800°F. Increased NO_x reduction rates require increased ammonia consumption resulting in increased power consumption of the Project. The maintenance costs would consist of routine system maintenance for the SCR system. The SCR system replacement materials are assumed to be 2 percent of the original cost for equipment. Labor for the SCR system was calculated by multiplying the labor rate by the number of estimated working hours per year. For the SCR system, this was estimated to be 2 hours per day for one operating year. The indirect annual costs include capital recovery, overhead, administrative charges, property taxes, and insurance. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). The overhead annual cost is estimated to be 60 percent of the O&M costs. According to the OAQPS Cost Manual there are two types of overhead, payroll and plant. Payroll overhead expenses include workmen's compensation, social security, vacations, group insurance, and other fringe benefits. Plant overhead is not tied into O&M of the control system, but is related to plant protection, control labs, employee amenities, plant lighting, parking areas, and landscaping. The OAQPS Cost Manual allows one to combine these overhead costs into one sum. The administrative cost covers sales, research and development, accounting, and other home office expenses. The insurance cost was based on 1 percent of the total capital investment for each system. The property taxes for the SCR system were estimated to be 2.75 percent of the total capital investment per OAQPS cost methods.

4.3.3.3 Total Annualized Costs for SCR (5 ppmvd). Total annualized costs for the SCR control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Table 4-3 shows the total annualized cost for an SCR system is estimated to be $1,821,000. This annualized cost for the Combustion Turbine Unit 4 SCR system results in a cost effectiveness of approximately $13,410 per ton of NO_x removed. The SCR cost effectiveness analysis was also performed using a 3 year catalyst life. Under the 3 year catalyst life scenario, the cost effectiveness of SCR is approximately $10,050 per ton of NOx removed, which is still not considered cost effective.

While it is clearly evident that $13,410 per ton of NO_x removed is not cost effective, when one considers anticipated actual operation during the first few years of operation, the costs are even more exorbitant. Consider, for example, that during the initial 5 years of operation of Combustion Turbine Unit 4, the actual fuel usage is expected to be approximately 6.1 million gallons, which is equivalent to approximately 2,000 hours per year full load operation. Performing the economic analysis based on a fuel use rate of only 6.1 million gallons per year during this initial 5 year period would give an approximate SCR cost effectiveness of $25,550 per ton of NO_x removed. In the subsequent four years, the actual fuel usage is expected to be approximately 9.2 million gallons per year, which is equivalent to approximately 3,000 hours per year full load operation. The cost effectiveness of SCR with 3,000 hours per year of operation is approximately $18,180 per ton of NOx removed. The end of life cost effectiveness is expected to be approximately equal to the cost effectiveness shown in Table 4-3.

4.4 Conclusions

To summarize the information discussed in this section, there are concerns regarding energy, environmental, and economic impacts of the potential NO_x emission control by SCR for Combustion Turbine Unit 4. The social, environmental, and economic impacts associated with installation of SCR on Combustion Turbine Unit 4 are listed in Table 4-4. Because of these concerns, SCR is not proposed as BACT for this unit.

Table 4-4
Summary of Social, Environmental and
Economic Impacts of NOx BACT Technologies

Impacts	Control Option Impact Potential	
	SCR	Baseline
Blackouts (Unserved Energy and Social Consequences)	More	Less
Transportation of Ammonia Along Two-Lane Road with Numerous Bridges	Yes	No
Storage and Transportation of Ammonia in Area with Minimal Egress Options	Yes	No
Storage and Transportation of Ammonia in Areas in Close Proximity to Heavily Traveled Waterway	Yes	No
Ammonia Slip	Yes	No
Handling of Toxic Substances (Spent Catalyst)	Yes	No
Increased Particulate Emissions and Opacity (Ammonium Sulfates and Ammonium Bisulfates)	Yes	No
Excessive Cost of Operation	Yes	No

SCR catalysts have proven emissions reduction capabilities and low maintenance requirements at a variety of different natural gas combustion turbine facilities throughout the United States. However, several factors raise serious questions regarding the year round operational reliability of SCR on fuel oil fired applications (especially with frequent startups) and SCR's subsequent impact on KEYS ability to meet energy demands. These technical factors are:

- Oil firing inherently degrades catalyst at a faster rate in comparison to natural gas and thus could result in catalyst changes more frequently than yearly as estimated in this BACT analysis. This is a significant consideration and negative factor for an installation such as the Combustion Turbine Unit 4 when power supply cannot be interrupted.
- The sooting phenomenon has been seen on other units that fire fuel oil, such as the PREPA Cambalache Power Plant. After 4 years of attempting to make the SCR system work, the SCR system was removed from service as agreed upon by the USEPA due to operational problems and its inability to meet permit limits.

- The USEPA, as indicated in press releases, has determined that SCR is unreliable on units exclusively firing fuel oil. Recent permitting actions in the Virgin Islands and at the Commonwealth Chesapeake Power Station where SCR was not evaluated or was found not to be economically viable support the USEPA press releases.
- There is no proven long term SCR experience in the firing of fuel oil in simple cycle combustion turbines. The longest base operating experience of any turbines (Shoreham Long Island) exclusively firing fuel oil is barely in excess of 750 operating hours.
- Addition of an SCR would lead to increased opacity, particulate, and PM_{10} emissions through the form of ammonium bisulfate from increased SO_2 to SO_3 conversion.

The capital cost for an SCR system for Combustion Turbine Unit 4 would be about $4,207,000 for the project to control to 5 ppmvd. Installation of an SCR system would add approximately $1,821,000 to the annualized operating cost of the unit. The resultant cost effectiveness is approximately $13,410 per ton of pollutant removed and approximately $25,550 per ton over the first 5 years of operation.

Based upon the previously stated technical reasons related to an application of SCR on a fuel oil only fired simple cycle combustion turbine and the prohibitive cost of $13,410 per ton removed, the utilization of an SCR cannot be considered BACT for Combustion Turbine Unit 4. Water injection is a proven technical solution that offers no additional particulate in the form of ammonium bisulfate and minimal adverse reliability impacts to Combustion Turbine Unit 4. Therefore, based on technical, economic, environmental, and energy impacts, the proposed BACT for the control of NO_x emissions from Combustion Turbine Unit 4 is good combustion practices and water injection to achieve an emission level of 42.0 ppmvd at 15 percent O_2 (69.7 lb/h at 100 percent load and a 78°F ambient temperature).

5.0 Combustion Turbine PM/PM_{10} BACT Analysis

The objective of this analysis was to determine BACT for PM/PM_{10} emissions from Combustion Turbine Unit 4.

PM/PM_{10} emissions from the combustion turbine are a result of incomplete combustion and trace particulate parameters in the fuel. The emissions of particulate matter from Combustion Turbine Unit 4 will be controlled by ensuring as complete combustion of the fuel as possible and by minimizing SO_2 to SO_3 oxidation. The NSPS for combustion turbines does not establish a particulate emission limit.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines of the Combustion Turbine Unit 4 size range. Inherently, Combustion Turbine Unit 4 particulate emissions are consistent with the previous determinations as referenced by the State of Florida, such as the FPL Fort Myers, FPL Martin and Manatee projects. The use of combustion controls and low sulfur fuel oil is considered BACT for particulate matter and is proposed for this project.

6.0 Combustion Turbine SO_2 BACT Analysis

The objective of this analysis was to determine BACT for SO_2 emissions from the Combustion Turbine Unit 4. The SO_2 emissions are based on operating the combustion turbine using a maximum low sulfur fuel oil usage of 13.567 million gallons (equivalent of 100 percent of base load for 4,422 hours) per year.

Emissions of SO_2 can be controlled by limiting the sulfur content in the fuel or by a post-combustion flue gas desulfurization (FGD) system. The fuel oil to be fired for Combustion Turbine Unit 4 will be a low sulfur fuel oil with less than 0.05 percent sulfur by weight. The selection of low sulfur fuel oil provides inherently low SO_2 emissions.

Another lower sulfur fuel oil to consider is what is referred to as ultra-low-sulfur diesel (ULSD), which has a sulfur content of 0.0015 percent by weight. In December 2000, the USEPA issued a final rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. The new rule requires refiners and importers to produce highway diesel meeting a 15 ppm maximum sulfur content requirement starting June 1, 2006. Under a phase-in, up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010. The highway diesel meeting the 15 ppm (0.0015 percent sulfur) limit is commonly referred to as ULSD. The use of ULSD could be considered as an option in reducing SO_2 emissions from proposed Combustion Turbine Unit 4 at Stock Island.

Based on discussions with the fuel supplier for the Stock Island facility, they would not guarantee the availability of ULSD in the early part of 2006, the scheduled start-up date of Combustion Turbine Unit 4. However, when ULSD becomes available later in 2006, it is possible that deliveries of ULSD could be made to the Stock Island facility. The fuel supplier did not have an estimate of the cost differential of supplying the ULSD as compared to the cost of supplying the low sulfur (0.05 percent sulfur) fuel oil that is currently used at the Stock Island facility. The fuel supplier also indicated that until ULSD is available as required by the USEPA rulemaking, they do not have enough information to know what types of fuel blends would be available to supply a fuel oil with sulfur levels between 0.0015 percent and 0.05 percent sulfur, or the cost of such blends. It is apparent that any such fuel blends would be considered a “special order” fuel.

A comprehensive analysis of the supply and cost considerations associated with ULSD is included in a report titled “The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply”, dated May 2001, prepared by the Energy Information Administration, which is part of the U.S. Department of Energy. This report was prepared on behalf of the Committee on Science, U.S. House of Representatives. The report outlines some of the concerns regarding the availability of ULSD as this rule comes into effect. The following information was taken directly from the executive summary of this report.

> "The scenarios indicate the possibility of a tight diesel market when the ULSD Rule is implemented. Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the Annual Energy Outlook 2001. Only more aggressive investment scenarios or lower demand scenarios show adequate supply to meet estimated demand. Furthermore, this analysis compares supply and demand at a very aggregate level. Maintaining a balance of supply and demand across regions and throughout the distribution system could be even more difficult."

> "Some refiners may be able to produce ULSD at a cost differential of about 2.5 cents per gallon; however, at the volumes needed to meet demand, costs are estimated at 5.4 to 6.8 cents per gallon, and they could be higher if supply falls short of demand and consumers bid up the price."

Note that these are marginal costs on the industry supply curve, based on average refinery costs for producing ULSD. These costs do not include additional costs for distribution, estimated at 1.1 cents per gallon in the mid-term analysis.

> "In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011. The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD."

Note that the Regulation case is the case where major assumptions are consistent with those used by the USEPA in its Regulatory Impact Analysis (RIA) of the Rule.

The 6.5 to 7.2 cents per gallon marginal cost estimate is also stated in a two page summary of the report titled "Energy Plug: The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply." In this summary, it is indicated that these costs are based on modeling runs using USEPA assumptions, and it is clarified that these are projected increased prices compared with the projected price of 500-ppm diesel fuel. It also states that under a variety of industry assumptions, the premiums range from 8.4 to 10.7 cents per gallon.

Using this cost information and assuming that all sulfur in the fuel is converted to SO_2, one can easily determine the cost effectiveness of using ULSD to reduce SO_2 emissions. The following details this calculation when using the lowest ULSD cost estimate of 6.5 cents per gallon:

Assuming a diesel density of 7.05 lb/gallon (AP-42, Appendix A for distillate oil), the reduction in sulfur is equal to

(7.05 lb/gallon)(500 – 15 ppm S/1,000,000)(ton/2,000 lb) = 1.71 E-6 ton S/gal

Because the molecular weight of SO_2 is twice that of sulfur (64/32), this equates to removing 3.42E-6 ton SO_2/gal.

At a marginal cost of 6.5 cents per gallon, the cost of SO_2 removal is:

\$0.065/gal ÷ 3.42E-6 ton SO_2/gal = \$19,006 per ton SO_2 removed

A similar calculation at a marginal cost of 10.7 cents per gallon, the high end of the range when using industry assumptions, gives a cost of $31,287 per ton SO_2 removed. This analysis demonstrates that the use of ULSD is not a cost-effective method to reduce SO_2 emissions, and BACT for SO_2 remains the use of low sulfur (0.05 percent sulfur) fuel oil.

To date, no supplemental SO_2 emission controls, such as FGD systems have been imposed on low sulfur fuel oil combustion turbines by regulatory agencies. Such a system would be both technically and economically prohibitive.

Therefore, BACT for Combustion Turbine Unit 4 is the use of low sulfur fuel oil with less than 0.05 percent sulfur.

7.0 Combustion Turbine H_2SO_4 BACT Analysis

The objective of this analysis was to determine BACT for sulfuric acid mist (H_2SO_4) emissions from Combustion Turbine Unit 4. The H_2SO_4 emissions are based on operating the combustion turbine at a maximum low sulfur fuel oil usage of 13.567 million gallons per year (equivalent to 4,422 hours per year at full load operation).

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The fuel oil to be fired for Combustion Turbine Unit 4 will be a low sulfur fuel oil with less than 0.05 percent sulfur by weight. The selection of low sulfur fuel oil provides inherently low SO_2 emissions, thus controlling the formation of sulfuric acid mist. In addition, no supplemental SO_3 emission controls, such as FGD systems or H_2SO_4 abatement systems, have been imposed on low sulfur fuel oil combustion turbines by regulatory agencies.

Therefore, BACT for Combustion Turbine Unit 4 is the use of low sulfur fuel oil with less than 0.05 percent sulfur and good combustion controls.

8.0 Conclusions

The following is a summary of the proposed BACT determinations and associated emission rates for Combustion Turbine Unit 4 to be installed at the Stock Island facility for FMPA. The combustion turbine will fire only low sulfur fuel oil. Emissions for the BACT analysis are based on Combustion Turbine Unit 4 operating with a maximum low sulfur fuel oil usage of 13.567 million gallons per year (equivalent to 4,422 hours per year at full load operation) at an ambient temperature of 78°F.

8.1 Combustion Turbine Unit 4:

- Nitrogen oxides (NO_x) emissions--BACT was determined to be the use of water injection and good combustion controls to achieve 42 ppmvd at 15 percent O_2.
- Carbon monoxide (CO) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and the use of low sulfur fuel oil with less than 0.05 percent sulfur by weight.
- Volatile Organic Compounds (VOC) emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of good combustion controls and the use of low sulfur fuel oil with less than 0.05 percent sulfur.
- Sulfur acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls and the use of low sulfur fuel oil with less than 0.05 percent sulfur.

Appendix A
NO_x Control Technology Review for Simple Cycle Turbines Capable of Firing Fuel Oil

Appendix A

State	Facility	# of New MW	Final Permit Issued	# of CTs	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method
Region 1										
Region 2										
NJ	PSEG Fossil LLC - Linden	170	02/10/2000	2	GE 7EA	NG; FO	SC	8,760	12 ppm NG; 42 ppm FO	DLN
VI	VIWAPA-St Thomas	24	01/03/2001	1	UT FT8-1 Power Pac	FO	SC	8,760	42 ppm	WI
Region 3										
DE	NRG Energy	100	10/20/2000	2	LM 6000	NG/FO	SC		73 lb/hr on oil	LNB
VA	Virginia Power - Remington, VA	550	09/01/1999	3	GE 7FA	NG/FO	SC		9ppm/42 ppm fo	LNB/WI
VA	Commonwealth Chesapeake	350	10/05/2000	4	LM6000	Fuel Oil	SC		42 ppm	WI
VA	COMMONWEALTH CHESAPEAKE	350	10/05/2000	7	LM6000	FO	CTSC		42 ppm	WI
VA	Dominion Energy - Caroline County, VA	550	07/02/2000	5	GE 7FA	NG/FO	SC		9ppm/42 ppm	LNB/WI
VA	FAUQUIER COUNTY	550	09/01/1999	3	GE 7FA	NG/FO	CTSC		9 ppm/42	LNB/WI
VA	LADYSMITH	800	07/02/2000	5	GE 7FA	NG/FO	CTSC		9ppm/42 p	LNB/WI
PA	ALLEGHENY WESTMORELAND(1)	500	02/01/2001	0	LM6000	NG/FO	CTSC		3.5	DLC+SCR
PA	Armstrong	660	12/07/2000	4	GE 7FA	NG/FO	SC	8900 unit hours NG/ 770 unit hours on FO	9 ppm ng/42 ppm fo	LNB
WV	Pleasants	335	Issued	2	GE 7FA	NG/FO	CTSC	3708	9ppm	wi/LNB
Region 4										
AL	Calhoun Power Company	680	1-01	4	GE 7FA (170 MW)	NG; FO	SC	4,000; 1,000 FO	0.033/0.044/0.055 lbmmbtu NG; 0.163 lb/mmbtu (327 lb/hr) FO	DLN; WI
AL	Tenaska Alabama III Partners	510	1-01	3	GE 7FA (170 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI
FL	Polk Power (TECO)	330	10-99	2	GE 7 FA (165 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI
FL	Oleander Power	950	11-99	5	GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Hardee Power Partners (TECO)	75	10-99	1	GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Reliant Energy Osceola	510	12-99	3	GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI
FL	Florida Power Corp., Intercession City	261	12-99	3	GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Jacksonville Electric Authority - Brandy Branch	510	10-99	3	GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI
FL	IPS Avon Park Corp. - Vandola Power Project	680	12-99	4	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	IPS Avon Park - Shady Hills	510	1-00	3	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Granite Power Partners	540	8-00	3	GE/SW (180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15 ppm NG; 42 ppm FO (GE only)	DLN
FL	IPS Avon Park Corp. - DeSoto Power Project	510	6-00	3	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Florida Power & Light - Martin Power Plant	340	7-00	2	GE 7FA (170 MW)	NG; FO	SC	3,390; 500 FO	9/12/15 ppm NG; 42 ppm FO	DLN; WI
FL	Peace River Station	510	12-00	3	GE 7FA (170 MW)	NG; FO	SC	3,390; 720 FO	9/10 ppm NG; 42 ppm FO	DLN; WI
FL	Florida Power & Light - Fort Myers	340	12-00	2	GE 7FA (170 MW)	NG; FO	SC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI
FL	Duke Energy - Ft. Pierce	640	06/18/2001	8	GE 7EA (80 MW)	NG; FO	SC	2,500; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI
FL	Pompano Beach Energy Center, LLC	510	draft permit	3	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI
FL	Midway Development Center	510	2-01	3	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG (9 ppm on startup); 42 ppm FO	DLN; WI
FL	Deerfield Beach Energy Center	510	draft permit	3	GE 7FA (170 MW)	NG; FO	SC	3,500; 1000 FO	9 ppm NG; 42 ppm FO	DLN; WI
GA	Tenaska Georgia Partners, L.P.	960	12-98	6	GE 7FA (160 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI
GA	West Georgia Generating; Thomaston	680	6-99	4	GE 7FA (170 MW)	NG; FO	SC	4,760; 1,687 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI

Appendix A

State	Facility	# of New MW	Final Permit Issued	# of CTs	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method
GA	Georgia Power, Jackson County	1,216	8-99	16	GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI
GA	Duke Energy Sandersville, LLC	640	11/09/2001	8	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	10 ppm NG; 42 ppm FO	DLN; WI
GA	Oglethorpe Power Corp. - Talbot	648	08/09/2001	6	SW V84.2 (108 MW)	NG; FO	SC	8,760; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI
GA	MEA of Georgia - W. R. Clayton	500	draft permit	3	GE 7FA (170 MW)	NG; FO	SC	8,760; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI
KY	Duke Energy - Marshall Co.	640	draft permit	8	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI
KY	East Kentucky Power Cooperative, Inc.	240	07/27/2001	3	GE 7EA (80 MW)	NG; FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI
MS	Duke Energy Southaven	640	8-00	8	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI
MS	Duke Energy Enterprise	160	05/10/2001	2	GE 7EA (80 MW)	NG; FO	SC	3,000; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI
MS	TVA - Kemper CT Plant	440	07/30/2001	4	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI
NC	Carolina Power & Light, Rowan Co.	850	11/99	5	GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	9 ppm NG at startup/10.5 ppm long-term; 42 ppm FO	DLN; WI
NC	Rockingham Power (Dynegy)	780	6/99	5	SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG until 4/01, 20 ppm until 4/02, 15 ppm after; 42 ppm FO	DLN; WI
NC	Duke Energy - Buck Steam Station	640	11/20/2001	8	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI
NC	Entergy Power - Rowan Generating Facility	930	01/25/2002	6	GE 7FA (155 MW)	NG; FO	SC	4,400; 1,000 FO	10.5 ppm (9 ppm initially) NG; 42 ppm FO	DLN; WI
SC	Broad River Energy (SkyGen)	513	12-99	3	GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI
SC	Duke Power - Mill Creek (f/k/a/ RIPP)	654	11/08/2001	8	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI
SC	Greenville Generating	930	draft prmit	6	GE 7FA (155 MW)	NG, FO	SC	3,400; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI
SC	Broad River Energy Center (f/k/a Cherokee Falls)	340	05/22/2003	2	GE 7FA (170 MW)	NG, FO	SC	3,000	9 ppm (12 ppm w/PA); 42 ppm FO	DLN
TN	TVA, Johnsonville Fossil Plant	340	7-99	4	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI
TN	TVA, Gallatin Fossil Plant	340	7-99	4	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI
TN	TVA, Lagoon Creek Plant	1,760	4-00	16	GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI
Region 5										
IL	Calumet Energy LLC - Chicago	305	05/18/2000	2	152.5 MW each	NG; FO	SC	?		DLN
IL	Soyland Power Alsey	45	07/07/2000	1	25 MW	NG; FO	SC	460		WI
IL	Union Electric, Gibson City Power	170	06/16/1999	2	135 MW each	NG; FO	SC	1,500	25 ppm NG; 42 ppm FO	DLN
IL	Union Electric, Kinmundy Power	170	06/28/1999	2	135 MW ech	NG; FO	SC	1,500	9 ppm NG; 42 ppm FO	DLN
IL	Duke Energy - Lee Generating	664	03/31/2000	8	83 MW each	NG; FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN
IL	Skygen Services - Zion Energy Center	800	Final review	5	160 MW each	NG; FO	SC	?	?	DLN
IL	Soyland Power Alsey	100	03/24/1999	4	30 MW (2), 22.5 MW (2)	NG; FO	SC	?	?	2 with WI. other 2 ?
IN	Duke Energy Knox, LLC	640	05/29/2001	8	GE 7EA 8 @ 80MW each	NG; FO	SC	8,760	>=60% load 9.0 ppmvd NG; 42 ppmvd FO	DLN; WI
IN	Duke Energy Vermillion, LLC	640	07/01/1999	8	GE 7EA 8 @ 80MW each	NG; FO	SC	8,760	15 ppmvd NG; 42 ppmvd FO	DLN; WI
IN	SIGECO - A.B. Brown (Southern Indiana Gas and Electric Company) permit# 12029	109 (max)	11/29/2001	1	GE 7EA @ 80-109 MW	NG/2 distillate oil	SC	8,760	NG < 9ppmvd NG; #2oil <=42ppmvd	DLN, SI
IN	PSI-Wabash Peaking Station	169	01/19/1999	3	LM 6000 (43 MW)	NG; FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI
IN	Duke Energy Vermillion Generating Station	640	06/01/2000	8	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI

Appendix A

State	Facility	# of New MW	Final Permit Issued	# of CTs	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method
IN	PSI Cinergy Corporation	169	07/15/1999	3	GE LM6000 (43 MW)	NG; FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI
IN	Indianapolis Power and Light	191	08/17/1999	1	GE 7121EA (95.7 MW)	NG; FO	SC	peaking	25 ppm NG; 42 ppm FO	WI
MN	Lakefield Junction	552	draft permit	6	GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI
OH	Duke Energy Madison LLC	640	07/01/1999	8	GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN
WI	RockGen Energy	525	01/01/1999	3	GE 7FA (175 MW each)	NG; FO	SC	3,800 Total, 800/CT FO	12/15 ppm NG; 42 ppm FO	DLN
WI	Southern Energy	?	02/25/1999	2	GE 7FA (180 MW each)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN, WI
WI	Wisconsin Public Service	360	07/01/1999	1	GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN
WI	Wisconsin Electric	85	draft permit	1	GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug.	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	DLN
Region 6										
NM	Lordsburg Limited/100 MW Repowering,	100	06/18/1997	1	WH 501D5A 100MW total	NG; FO	SC	1,440	15 ppm >75% output, 42 ppm <75% output. 42 ppm/60 ppm FO	DLN, WI
Region 7										
KS	Western Resources	380	06/11/1999	3	2 - GE-7EA (100 MW each); 1 GE-7FA (180 MW)	NG; FO	SC		15 ppm NG; 42 ppm FO	DLN; WI
KS	Great Plains Power, Paola	320	05/28/2002	4	4 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN
KS	Great Plains Power, Gardner	640	05/28/2002	8	8 - GE-7EA (80 each)	NG; FO	SC	4,000 NG; 500 FO	9 ppm NG; 42 ppm FO	DLN
KS	Board of Public Utilities of Kansas City Kansas, Nearman Creek Station	80	Currently Under Review	1	1 - GE-7EA	NG; FO	SC	8,760	proposed in application: 9 ppm NG; 42 ppm FO	DLN
MO	Duke Energy - Audrain	640	05/09/2000	8	GE 7EA (80 MW, each)	NG; FO	SC	2,500; 500 FO	12 ppm/9 ppm (NG); 42 ppm (FO)	DLN; WI
MO	Associated Electric Cooperative - Centralia	360	02/13/2001	3	Siemens V84.2 (120 MW, each)	NG; FO	SC	8,760	15 ppm NG/42 ppm FO	DLN
NE	Omaha Public Power - Sarpy Units 1, 2, 3, and 4	100	07/29/1999	4	Pratt & Whitney FT-8 (25 MW, each)	NG; FO	SC	2,000 each	25 ppm NG; 42 ppm FO	WI
NE	Lincoln Electric System Rokeby Unit 3	90	11/22/1999	1		NG; FO	SC	3,504	25 ppm NG; 42 ppm FO	DLN; WI/SI
NE	City of Grand Island, Burdick Station	80	01/08/2002	2	2 GE PG6581(B), 40 MW each	NG; FO	SC	5,000	15ppm NG/65 ppm FO	

Appendix A

State	Facility	# of New MW	Final Permit Issued	# of CTs	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method
Region 8										
CO	TriState Generation & Transmission/Limon Station (164 MW)	164	1/01	2	GEF7EA, or equiv	NG, FO (1000 hr, each turbine, limit on FO)	SC	8,760	9 ppm (42 ppm on FO)	DLN (plus WI on FO)
Region 9										
HI	Maui Electric	40	01/06/1998	2	40 MW *total*	FO	SC		42 ppm	WI
Region 10										
ID, Permit 039-00025	Mountain View Power, LLC	80	09/09/2002	2	GE LM6000	NG;FO	SC	8760	25 ppmdv @ 15% O2 - gas, 42 ppmdv @ 15% O2 - oil	WI
WA, PSD-X80-02	Whitehorn (Puget Sound Energy)	187	12/19/1979	2	GE 7E	NG;FO	SC	8760	NSPS GG	WI
WA, PSD-X80-17	Frederickson (Puget Sound Energy)		09/25/1980	2	GE 7E	NG;FO	SC	8760	NSPS GG	WI
WA, PSD-X82-09	Fredonia (Puget Sound Energy)	228	08/23/1982	2	SW W501D	NG;FO	SC	8760	NSPS GG	WI
WA, SCAPCA	Northeast Combustion Turbine (Avista - formerly Washington Water Power)	66	Initial NOC - 1/20/1978, NOC #1065 - 4/24/01, NOC #1092 - pending	2	2 - Pratt & Whitney FT4C-3F (Twin-Jet Power Pac)	NG;FO	SC	Initial NOC & SCAPCA Order #95-12 - 500, NOC #1065 - none, NOC #1092 - ng (4000), FO (120)	NOC #1092 NG- 75.44 lb/MMft3, FO - 21.3 lb/1000 gal, SCAPCA Order #95-12 (VEL) - 95 ton/yr	DLN
WA, PSD-01-04 & minor NSR	Puget Sound Energy - Fredonia	110	07/16/2003	2	2 - Pratt & Whitney FT8 (Twin Pack)	NG; FO	SC	8760	5.0 ppmdv @ 15% O2	SCR
Facilities identified through additional searches										
NY	PPL Shoreham Electric Generating Facility	79.9	01/11/2002	2	GE LM6000	FO	SC		9 ppmvd @ 15% O2	WI and SCR
PR	PREPA - Combalache Power Plant	248	PSD permit 7/31/1995 Compliance order 10/24/2001	3	ABB GT 11N	FO	SC	8760	10 ppmvd @ 15% O2 per PSD permit 42 ppmvd @ 15% O2 per PSD permit modification application and compliance order	SCR, Steam Injection
VI	VIWAPA, St Thomas Unit 23	39	09/08/2004	1	GE Frame 6	FO	SC	8760	42 ppmvd @ 15% O2, with an allowance for fuel nitrogen content	WI
FL	City of Tallahassee - Arvah B. Hopkins Generating Station	100	Draft	2	GE LM6000	NG; FO	SC	5840; 4000 FO	5 ppm	WI and SCR
Totals =	**95**	**40,203**		**370**						

SC = Simple Cycle
CC = Combined Cycle
DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction

(1) Contact was made with personnel at the Pennsylvania Department of Environmental Protection (PDEP). A contact person regarding RACT/BACT/LAER determinations in Pennsylvania was contacted. This person indicated that he could not find an Allegheny Westmoreland facility in their database. He thought that the reference may be to the Allegheny Harrison City facility, as this was the only combustion turbine facility in Westmoreland County. A permitting engineer with PDEP Region 5 was contacted. She indicated that she was involved in permitting a number of combustion turbine projects in her region and had not heard of an Allegheny Westmoreland facility. She indicated that the Allegheny Harrison City facility did include simple cycle combustion turbines, but SCR was not required for those units. In summary, contact with PDEP personnel would indicate that there is not an Allegheny Westmoreland facility and if the reference is to the Allegheny Harrison City facility, SCR was not required for that facility.

Appendix B
Shoreham Electric Generating Station Air Permit

New York State Department of Environmental Conservation
Facility DEC ID: 1472204133

PERMIT
Under the Environmental Conservation Law (ECL)

IDENTIFICATION INFORMATION

Permit Type: Air State Facility
Permit ID: 1-4722-04133/00001
Effective Date: 01/10/2002 Expiration Date: No expiration date

Permit Type: Title IV (Phase II Acid Rain)
Permit ID: 1-4722-04133/00002
Effective Date: 01/10/2002 Expiration Date: 01/11/2007

Permit Issued To: PPL SHOREHAM ENERGY LLC
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030

Contact: JAMES POTTER
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030
(800) 765-6103

Facility: SHOREHAM ELECTRIC GENERATING FACILITY
NORTH COUNTRY ROAD
SHOREHAM, NY 11786

Contact: JAMES POTTER
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030
(800) 765-6103

Description:
NATURE OF BUSINESS AT THE FACILITY:

Electric power generation.

4911 (primary SIC) - Electrical and Other Services Combined

TYPE OF EQUIPMENT AND OPERATION AT THE FACILITY:

This facility consists of two General Electric LM6000 SPRINT gas turbines. The gas turbines shall fire only distillate oil and operate as simple cycle units, using a water injection system and a selective catalytic reduction system (SCR) for control of NOx emissions. This permit does not permit the operation of a major electric generating facility.

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New York State Department of Environmental Conservation
Facility DEC ID: 1472204133

AIR PERMIT APPLICABILITY:

Air state facility permit for a new facility (preconstruction permit).

CAPPING NON-APPLICABLE RULES:

The facility shall accept permit limitations which shall keep the new emission unit below the applicability threshold for 6 NYCRR 231-2 and 40 CFR 52.21.

CONSENT ORDERS OR COMPLIANCE PLANS:

None.

By acceptance of this permit, the permittee agrees that the permit is contingent upon strict compliance with the ECL, all applicable regulations, the General Conditions specified and any Special Conditions included as part of this permit.

Permit Administrator: WILLIAM R. ADRIANCE
625 BROADWAY
ALBANY, NY 12233

Authorized Signature: William R Adriance Date: 02/11/02

New York State Department of Environmental Conservation
Facility DEC ID: 1472204133

Notification of Other Permittee Obligations

Item A: Permittee Accepts Legal Responsibility and Agrees to Indemnification

The permittee expressly agrees to indemnify and hold harmless the Department of Environmental Conservation of the State of New York, its representatives, employees, agents, and assigns for all claims, suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

Item B: Permittee's Contractors to Comply with Permit

The permittee is responsible for informing its independent contractors, employees, agents and assigns of their responsibility to comply with this permit, including all special conditions while acting as the permittee's agent with respect to the permitted activities, and such persons shall be subject to the same sanctions for violations of the Environmental Conservation Law as those prescribed for the permittee.

Item C: Permittee Responsible for Obtaining Other Required Permits

The permittee is responsible for obtaining any other permits, approvals, lands, easements and rights-of-way that may be required to carry out the activities that are authorized by this permit.

Item D: No Right to Trespass or Interfere with Riparian Rights

This permit does not convey to the permittee any right to trespass upon the lands or interfere with the riparian rights of others in order to perform the permitted work nor does it authorize the impairment of any rights, title, or interest in real or personal property held or vested in a person not a party to the permit.

New York State Department of Environmental Conservation
Facility DEC ID: 1472204133

PAGE LOCATION OF CONDITIONS

DEC GENERAL CONDITIONS

**** General Provisions ****

Condition 1: **Facility Inspection by the Department**
Applicable State Requirement: ECL 19-0305.

Item 1.1:
The permitted site or facility, including relevant records, is subject to inspection at reasonable hours and intervals by an authorized representative of the Department of Environmental Conservation (the Department) to determine whether the permittee is complying with this permit and the ECL. Such representative may order the work suspended pursuant to ECL 71-0301 and SAPA 401(3).

Item 1.2:
The permittee shall provide a person to accompany the Department's representative during an inspection to the permit area when requested by the Department.

Item 1.3:
A copy of this permit, including all referenced maps, drawings and special conditions, must be available for inspection by the Department at all times at the project site or facility. Failure to produce a copy of the permit upon request by a Department representative is a violation of this permit.

Condition 2: **Relationship of this Permit to Other Department Orders and Determinations**
Applicable State Requirement: ECL 3-0301.2(m)

Item 2.1:
Unless expressly provided for by the Department, issuance of this permit does not modify, supersede or rescind any order or determination previously issued by the Department or any of the terms, conditions or requirements contained in such order or determination.

Condition 3: **Applications for Permit Renewals and Modifications**
Applicable State Requirement: 6NYCRR 621.13(a)

Item 3.1:
The permittee must submit a separate written application to the Department for renewal, modification or transfer of this permit. Such application must include any forms or supplemental information the Department requires. Any renewal, modification or transfer granted by the Department must be in writing.

Item 3.2:
The permittee must submit a renewal application at least 180 days before expiration of permits for Title V Facility Permits, or at least 30 days before expiration of permits for State Facility Permits.

Condition 4: **Permit Modifications, Suspensions, and Revocations by the Department**
Applicable State Requirement: 6NYCRR 621.14

Item 4.1:
The Department reserves the right to modify, suspend, or revoke this permit. The grounds for

modification, suspension or revocation include:

a) the scope of the permitted activity is exceeded or a violation of any condition of the permit or provisions of the ECL and pertinent regulations is found;

b) the permit was obtained by misrepresentation or failure to disclose relevant facts;

c) new material information is discovered; or

d) environmental conditions, relevant technology, or applicable law or regulation have materially changed since the permit was issued.

****** Facility Level ******

Condition 5: Submission of Applications for Permit Modification or Renewal-REGION 1 HEADQUARTERS
Applicable State Requirement: 6NYCRR 621.5(a)

Item 5.1:
Submission of applications for permit modification or renewal are to be submitted to:

NYSDEC Regional Permit Administrator
Region 1 Headquarters
Division of Environmental Permits
SUNY Campus, Loop Road, Building 40
Stony Brook, NY 11790-2356
(631) 444-0365

New York State Department of Environmental Conservation
Facility DEC ID: 1472204133

DEC SPECIAL CONDITIONS

Condition 6: Permit modifications, suspensions, and revocations by the Department.
Applicable State Requirement: 6NYCRR 621.14

Item 6.1:
Failure to operate the approved facility in accordance with the application's commitments to monitor electrical output and to operate at a net output of no more than 79.9 megawatts is grounds for modification, suspension, or revocation of this permit. Operation above 79.9 megawatts is a violation of this permit.

The Permittee shall maintain records, at the facility, for a minimum of five years. All reports shall be submitted to both the Regional Air office and to the Public Service Commission.

Monitored Parameter:
Code: 41
Name: Electrical Output
Upper Limit: 79.9 megawatts
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Require
ments: MONTHLY (CALENDAR YEAR)

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New York State Department of Environmental Conservation
Permit ID: 1-4722-04133/00001 **Facility DEC ID: 1472204133**

Permit Under the Environmental Conservation Law (ECL)

ARTICLE 19: AIR POLLUTION CONTROL - AIR STATE FACILITY PERMIT

IDENTIFICATION INFORMATION

Permit Issued To: PPL SHOREHAM ENERGY LLC
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030

Contact: JAMES POTTER
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030
(800) 765-6103

Facility: SHOREHAM ELECTRIC GENERATING FACILITY
NORTH COUNTRY ROAD
SHOREHAM, NY 11786

Contact: JAMES POTTER
11350 RANDOM HILLS ROAD
SUITE 400
FAIRFAX, VA 22030
(800) 765-6103

Authorized Activity By Standard Industrial Classification Code:
4911 - ELECTRIC SERVICES

Permit Effective Date: 01/11/2002 Permit Expiration Date: No expiration date.

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New York State Department of Environmental Conservation
Permit ID: 1-4722-04133/00001 Facility DEC ID: 1472204133

PAGE LOCATION OF CONDITIONS

New York State Department of Environmental Conservation
Permit ID: 1-4722-04133/00001 Facility DEC ID: 1472204133

FEDERALLY ENFORCEABLE CONDITIONS
**** Facility Level ****

Condition 1: Sealing
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 200.5

Item 1.1:
(a) The commissioner may seal an air contamination source to prevent its operation if compliance with 6 NYCRR Chapter III is not met within the time provided by an order of the commissioner issued in the case of the violation. Sealing means labelling or tagging a source to notify any person that operation of the source is prohibited, and also includes physical means of preventing the operation of an air contamination source without resulting in destruction of any equipment associated with such source, and includes, but is not limited to, bolting, chaining or wiring shut control panels, apertures or conduits associated with such source.

(b) No person shall operate any air contamination source sealed by the commissioner in accordance with this section unless a modification has been made which enables such source to comply with all requirements applicable to such modification.

(c) Unless authorized by the commissioner, no person shall remove or alter any seal affixed to any contamination source in accordance with this section

Condition 2: Acceptable ambient air quality
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 200.6

Item 2.1:
Notwithstanding the provisions of 6 NYCRR Chapter III, Subchapter A, no person shall allow or permit any air contamination source to emit air contaminants in quantities which alone or in combination with emissions from other air contamination sources would contravene any applicable ambient air quality standard and/or cause air pollution. In such cases where contravention occurs or may occur, the commissioner shall specify the degree and/or method of emission control required.

Condition 3: Maintenance of equipment
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 200.7

Item 3.1:
Any person who owns or operates an air contamination source which is equipped with an emission control device shall operate such device and keep it in a satisfactory state of maintenance and repair in accordance with ordinary and necessary practices, standards and procedures, inclusive of manufacturer's specifications, required to operate such device effectively.

Condition 4: Unpermitted Emission Sources
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-1.2

Item 4.1:
If an existing emission source was subject to the permitting requirements of 6NYCRR Part 201 at the time of construction or modification, and the owner and/or operator failed to apply for a permit for such emission source then the following provisions apply:

(a) The owner and/or operator must apply for a permit for such emission source or register the facility in accordance with the provisions of Part 201.

(b) The emission source or facility is subject to all regulations that were applicable to it at the time of construction or modification and any subsequent requirements applicable to existing sources or facilities.

Condition 5: Emergency Defense
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-1.5

Item 5.1:
An emergency constitutes an affirmative defense to an action brought for noncompliance with emissions limitations or permit conditions for all facilities in New York State.

(a) The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

(1) An emergency occurred and that the facility owner and/or operator can identify the cause(s) of the emergency;

(2) The equipment at the permitted facility causing the emergency was at the time being properly operated;

(3) During the period of the emergency the facility owner and/or operator took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

(4) The facility owner and/or operator notified the Department within two working days after the event occurred. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(b) In any enforcement proceeding, the facility owner and/or operator seeking to establish the occurrence of an emergency has the burden of proof.

(c) This provision is in addition to any emergency or upset provision contained in any applicable requirement.

Condition 6: **Recycling and Salvage**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-1.7

Item 6.1:
Where practical, any person who owns or operates an air contamination source shall recycle or salvage air contaminants collected in an air cleaning device according to the requirements of 6 NYCRR.

Condition 7: **Prohibition of Reintroduction of Collected Contaminants to the Air**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-1.8

Item 7.1:
No person shall unnecessarily remove, handle, or cause to be handled, collected air contaminants from an air cleaning device for recycling, salvage or disposal in a manner that would reintroduce them to the outdoor atmosphere.

Condition 8: **Public Access to Recordkeeping**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-1.10(a)

Item 8.1:
Where emission source owners and/or operators keep records pursuant to compliance with the operational flexibility requirements of 6 NYCRR Subpart 201-5.4(b)(1), and/or the emission capping requirements of 6 NYCRR Subparts 201-7.2(d), 201-7.2(f), 201-7.3(g), 201-7.3(h)(5), 201-7.3(i) and 201-7.3(j), the Department will make such records available to the public upon request in accordance with 6 NYCRR Part 616 - Public Access to Records. Emission source owners and/or operators must submit the records required to comply with the request within sixty working days of written notification by the Department of receipt of the request.

Condition 9: **Proof of Eligibility**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-3.2(a)

Item 9.1:
The owner and/or operator of an emission source or unit that is eligible to be exempt, may be required to certify that it operates within the specific criteria described in 6 NYCRR Subpart 201-3. The owner or operator of any such emission source must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility which contains emission sources or units subject to 6 NYCRR Subpart 201-3, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations, or

law.

Condition 10: Proof of Eligibility
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-3.3(a)

Item 10.1:
The owner and/or operator of an emission source or unit that is listed as being trivial in 6 NYCRR Part 201 may be required to certify that it operates within the specific criteria described in 6 NYCRR Subpart 201-3. The owner or operator of any such emission source must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility which contains emission sources or units subject to 6 NYCRR Subpart 201-3, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations, or law.

Condition 11: Non Applicable requirements
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 201-6.5(g)

Item 11.1:
This section contains a summary of those requirements that have been specifically identified as being not applicable to this facility and/or emission units, emission points, processes and/or emission sources within this facility. The summary also includes a justification for classifying any such requirements as non-applicable.

6NYCRR 227-2.
Reason: The facility shall cap its emissions of oxides of nitrogen below the applicability threshold of this regulation.

40CFR 52-A.21
Reason: The facility shall cap its emissions of criteria contaminants below the applicability threshold of this regulation.

Condition 12: Required emissions tests
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 202-1.1

Item 12.1:
An acceptable report of measured emissions shall be submitted, as may be required by the commissioner, to ascertain compliance or noncompliance with any air pollution code, rule, or regulation. Failure to submit a report acceptable to the commissioner within the time stated shall be sufficient reason for the commissioner to suspend or deny an operating permit. Notification and acceptable procedures are specified in 6NYCRR Part 202-1.

Condition 13: Permit requirements (facilities commencing operation on or after 01/00)
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-1.6

Item 13.1: The NOx authorized account representative of each NOx budget unit shall submit to the Department a complete NOx Budget permit application (as defined under Section 204-3.3) by May 1, 2002 or 12 months before the date on which the NOx Budget unit commences operation.

Condition 14: Submissions to the Department.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-2.1

Item 14.1: Each submission under the NOx Budget Trading Program shall be submitted, signed and certified by the NOx authorized account representative for each NOx Budget source on behalf of which the submission is made. Each submission shall include a certification statement (as stated in paragraph 204-2.1(e)(1)) by the NOx authorized account representative.

Condition 15: Contents of reports and compliance certifications.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-4.1

Item 15.1: The NOx authorized account representative shall include in the compliance certification report the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NOx Budget emissions limitation for the control period covered by the report:

(1) Identification of each NOx Budget unit; and

(2) In the compliance certification report the NOx authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NOx Budget units at the source in compliance with the NOx Budget Trading Program, whether each NOx Budget unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the NOx Budget Trading Program applicable to the unit, including:

(i) Whether the unit was operated in compliance with the NOx Budget emissions limitation;
(ii) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute NOx emissions to the unit, in accordance with Subpart 204-8;
(iii) Whether all the NOx emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with Subpart 204-8. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly

report resubmissions has been made;
(iv) Whether the facts that form the basis for certification under Subpart 204-8 of each monitor at the unit or a group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under Subpart 204-8, if any, has changed; and
(v) If a change is required to be reported under item (iv) above, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

Condition 16: Discretionary report contents.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-4.1

Item 16.1: At the NOx authorized account representative's option the following may be included in the compliance certification report:

(1) The serial numbers of the NOx allowances that are to be deducted from each unit's compliance account under Section 204-6.5 for the control period; and
(2) For units sharing a common stack and having NOx emissions that are not monitored separately or apportioned in accordance with Subpart 204-8, the percentage of NOx allowances that is to be deducted from each unit's compliance account under Subdivision 204-6.5(e).

Condition 17: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-4.1

Item 17.1:
The Compliance Certification activity will be performed for the Facility.

Item 17.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
For each control period in which one or more NOx Budget units at a source are subject to the NOx Budget emissions limitation, the NOx authorized account representative of the source shall submit to the Department and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

Reporting Requirements: AS REQUIRED - SEE MONITORING DESCRIPTION

Condition 18: Submission of NOx allowance transfers.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-7.1

Item 18.1: The NOx authorized account representatives seeking recordation of a NOx allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the NOx allowance transfer shall include the following elements in a format specified by the Administrator:

(a) The numbers identifying both the transferor and transferee accounts;
(b) A specification by serial number of each NOx allowance to be transferred; and
(c) The printed name and signature of the NOx authorized account representative of the transferor account and the date signed.

Condition 19: General provisions.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.1

Item 19.1: The owners and operators, and to the extent applicable, the NOx authorized account representative of a NOx Budget unit, shall comply with the monitoring and reporting requirements as provided in this Subpart and in Subpart H of 40 CFR Part 75. For purposes of complying with such requirements, the definitions in Section 204-1.2 and in 40 CFR 72.2 shall apply, and the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in 40 CFR Part 75 shall be replaced by the terms "NOx Budget unit," "NOx authorized account representative," and "continuous emission monitoring system" (or "CEMS"), respectively, as defined in Section 204-1.2.

Condition 20: Prohibitions.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.1

Item 20.1: No owner or operator of a NOx Budget unit or a non-NOx Budget unit monitored under 40 CFR 75.72(b)(2)(ii) shall:

(1) use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with Section 204-8.6;
(2) operate the unit so as to discharge, or allow to be discharged, NOx emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this Subpart and 40 CFR Part 75 except as provided for in 40 CFR 75.74;
(3) disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Subpart and 40 CFR Part 75 except as provided for in 40 CFR 75.74; and
(4) permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this Subpart, except under any one of the following circumstances:

(i) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this Subpart and 40 CFR Part 75, by the Department for use at that unit that provides emission data for the same pollutant or parameter as the discontinued monitoring system; or
(ii) The NOx authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with Paragraph 204-8.2(b)(2).

Condition 21: Requirements for installation, certification, and data accounting.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.1

Item 21.1: The owner or operator of each NOx Budget unit must meet the following requirements. These provisions also apply to a unit for which an application for a NOx Budget opt-in permit is submitted and not denied or withdrawn, as provided in Subpart 204-9:

(1) Install all monitoring systems required under this Subpart for monitoring NOx mass. This includes all systems required to monitor NOx emission rate, NOx concentration, heat input, and air or fuel flow, in accordance with 40 CFR 75.71 and 75.72.
(2) Install all monitoring systems for monitoring heat input, if required under Section 204-8.7 for developing NOx allowance allocations.
(3) Successfully complete all certification tests required under Section 204-8.2 and meet all other provisions of this Subpart and 40 CFR Part 75 applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.
(4) Record and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

Condition 22: Requirements for recertification of monitoring systems.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.2

Item 22.1: Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the Department determines significantly affects the ability of the system to accurately measure or record NOx mass emissions or heat input or to meet the requirements of 40 CFR 75.21 or Appendix B to 40 CFR Part 75, the owner or operator shall recertify the monitoring system according to 40 CFR 75.20(b). Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the Department determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to 40 CFR 75.20(b). Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

Condition 23: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.2

Item 23.1:
The Compliance Certification activity will be performed for the Facility.

Item 23.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
The owner or operator of a NOx Budget unit under paragraphs (b)(2) or (b)(3) of this section must determine, record and report NOx mass, heat input (if required for purposes of allocations) and any other values required to determine NOx Mass (e.g. NOx emission rate and heat input or NOx concentration and stack flow) using the provisions of 40 CFR 75.70(g), from the date and hour that the unit starts operating until all required certification tests are successfully completed.

Reporting Requirements: AS REQUIRED - SEE MONITORING DESCRIPTION

Condition 24: Out of control periods.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.3

Item 24.1: Whenever any monitoring system fails to meet the quality assurance requirements of Appendix B of 40 CFR Part 75, data shall be substituted using the applicable procedures in Subpart D, Appendix D, or Appendix E of 40 CFR Part 75.

Condition 25: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.4

Item 25.1:
The Compliance Certification activity will be performed for the Facility.

Item 25.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
The Authorized Account Representative for a NOx Budget unit shall submit written notice to the Department and the USEPA Administrator in accordance with the requirements of this subpart as follows.

All monitoring plans or monitoring plan modifications: compliance certifications, recertifications and quarterly QA/QC reports; and, petitions for alternative monitoring, shall be submitted to the USEPA

Administrator (or his/her representatives) as well as two copies to the Department (one copy to the Regional Air Pollution Control Engineer (RAPCES) in the regional office and one one copy to the Bureau of Compliance Monitoring and Enforcement (BCME) in the DEC central office. All Authorized Account Representative changes shall be sent to the NYSDEC central office.

All quarterly emission data shall be electronically filed with the USEPA Clean Air Markets Division with a copy (disc or hard copy) to the NYSDEC offices.

The address for the USEPA Administrator is as follows:

USEPA Clean Air Markets Division
401 M Street SW (6204J)
Washington D.C. 20460

CEM Coordinator
USEPA-Region 2
2890 Woodbridge Avenue
Edison, N.J. 08837

The address for the BCME is as follows:

NYSDEC
Bureau of Compliance Monitoring and Enforcement
625 Broadway, 2nd Floor
Albany N.Y. 12233-3258

ACR changes should be sent to the attention of:

NYSDEC
Stationary Source Planning Section
Bureau of Air Quality Planning
625 Broadway, 2nd Floor
Albany NY 12233-3251

The address for the RAPCE is as follows:

NYS SUNY
Building 40
Stony Brook, NY 11790-2356

Reporting Requirements: AS REQUIRED - SEE MONITORING DESCRIPTION

Condition 26: **Compliance Certification**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 204-8.7

Item 26.1:
The Compliance Certification activity will be performed for the Facility.

Item 26.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
The owner or operator of a unit that elects to monitor and report NOx Mass emissions using a NOx concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in 40 CFR Part 75.

Monitoring Frequency: HOURLY
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 4/30/02.
Subsequent reports are due every 3 calendar month(s).

Condition 27: Visible emissions limited.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 211.3

Item 27.1:
Except as permitted by a specific part of this Subchapter and for open fires for which a restricted burning permit has been issued, no person shall cause or allow any air contamination source to emit any material having an opacity equal to or greater than 20 percent (six minute average) except for one continuous six-minute period per hour of not more than 57 percent opacity.

Condition 28: Open Fires Prohibited at Industrial and Commercial Sites
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 215.

Item 28.1:
No person shall burn, cause, suffer, allow or permit the burning in an open fire of garbage, rubbish for salvage, or rubbish generated by industrial or commercial activities.

Condition 29: Facility Permissible Emissions
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 231-2.

Item 29.1:

The sum of emissions from the emission units specified in this permit shall not exceed the following Potential To Emit (PTE) rate for each regulated contaminant:

CAS No: 0NY210-00-0 PTE: 45,000 pounds per year
Name: OXIDES OF NITROGEN

Condition 31: EPA Region 2 address.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.4, NSPS Subpart A

Item 31.1:
All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the following address:

Director, Division of Enforcement and Compliance Assistance
USEPA Region 2
290 Broadway, 21st Floor
New York, NY 10007-1886

Copies of all correspondence to the administrator pursuant to this part shall also be submitted to the NYSDEC Regional Office issuing this permit (see address at the beginning of this permit) and to the following address:

NYSDEC
Bureau of Enforcement and Compliance Assurance
625 Broadway
Albany, NY 12233-3258

Condition 32: Date of construction notification - If a COM is not used.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(a), NSPS Subpart A

Item 32.1:
Any owner or operator subject to this part shall furnish the Administrator with the following information:

1) a notification of the date construction or reconstruction commenced, post marked no later than 30 days after such date;

3) a notification of the actual date of initial start up, post marked within 15 days after such date;

4) a notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless the change is specifically

exempted under this part. The notice shall be post marked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capability of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional information regarding the change;

5) a notification of the date upon which the demonstration of continuous monitoring system performance commences, post marked not less than 30 days prior to such date;

6) a notification of the anticipated date for conducting the opacity observations, post marked not less than 30 days prior to such date.

Condition 33: Date of construction notification.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(a), NSPS Subpart A

Item 33.1:
Any owner or operator subject to this part shall furnish the Administrator with the following information:

1) a notification of the date construction or reconstruction commenced, postmarked no later than 30 days after such date;

3) a notification of the actual date of initial start up, postmarked within 15 days after such date;

4) a notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless the change is specifically exempted under 40 CFR 60. The notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capability of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional information regarding the change;

5) a notification of the date upon which the demonstration of continuous monitoring system performance commences, postmarked not less than 30 days prior to such date;

6) a notification of the anticipated date for conducting the opacity observations, postmarked not less than 30 days prior to such date; and

7) a notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during the performance test, postmarked not less than 30 days prior to the performance test.

Condition 34: Recordkeeping requirements.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(b), NSPS Subpart A

Item 34.1:
Affected owners or operators shall maintain records of occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

Condition 35: **Excess emissions report.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(c), NSPS Subpart A

Item 35.1:
Affected owners or operators shall submit an excess emissions report and/or a summary report form (as defined in 40 CFR 60.7(d)) semi-annually (or more frequently as required by the applicable Subpart or the Administrator), to the Administrator. These reports shall be post marked no later than 30 days after each calendar quarter (or as appropriate), and shall contain the following information:

1) the magnitude of excess emissions computed, any conversion factors used, the date and time of each occurrence, and the process operating time during the reporting period;

2) specific identification of each period of excess emissions that occur during startup, shutdown, or malfunction, where the nature, cause, and corrective action are provided for a malfunction;

3) the date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

4) when no excess emissions have occurred or when the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be provided in the report.

Condition 36: **Excess emissions report.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(d), NSPS Subpart A

Item 36.1:
A summary report form, for each pollutant monitored, shall be sent to the Administrator in the form prescribed in Figure 1 of 40 CFR Part 60.7(d).

Condition 37: **Facility files for subject sources.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.7(f), NSPS Subpart A

Item 37.1:
The following files shall be maintained at the facility for all affected sources: all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations;all continuous monitoring device

calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part, recorded in permanent form suitable for inspections. The file shall be maintained for at least two years following the date of such measurements, reports, and records.

Condition 38: **Performance testing timeline.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.8(a), NSPS Subpart A

Item 38.1:
Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of the facility, the owner or operator of the facility shall conduct performance testing and provide the results of such tests, in a written report, to the Administrator.

Condition 39: **Performance test methods.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.8(b), NSPS Subpart A

Item 39.1:
Performance testing shall be conducted in accordance with the methods and procedures prescribed in 40 CFR 60 or by alternative methods and procedures approved by the Administrator.

Condition 40: **Required performance test information.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.8(c), NSPS Subpart A

Item 40.1:
Performance tests shall be conducted under such conditions specified by the Administrator, based upon representative performance data supplied by the owner or operator of the facility.

Condition 41: **Prior notice.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.8(d), NSPS Subpart A

Item 41.1:
The owner or operator shall provide the Administrator with prior notice of any performance test at least 30 days in advance of testing.

Condition 42: **Performance testing facilities.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.8(e), NSPS Subpart A

Item 42.1:

The following performance testing facilities shall be provided during all tests:

1) sampling ports adequate for tests methods applicable to such facility;

2) a safe sampling platform;

3) a safe access to the sampling platform; and

4) utilities for sampling and testing equipment.

Condition 43: Availability of information.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.9, NSPS Subpart A

Item 43.1:
The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by 40 CFR Part 2.

Condition 44: Opacity standard compliance testing.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.11, NSPS Subpart A

Item 44.1:
The following conditions shall be used to determine compliance with the opacity standards:

1) observations shall be conducted in accordance with Reference Method 9, in Appendix A of 40 CFR Part 60(or an equivalent method approved by the Administrator including continuous opacity monitors);

2) the opacity standards apply at all times except during periods of start up, shutdown, and malfunction; and

3) all other applicable conditions cited in section 60.11 of this part.

Condition 45: Circumvention.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.12, NSPS Subpart A

Item 45.1:
No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

Condition 30: Monitoring requirements.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.13, NSPS Subpart A

Item 30.1:
All continuous monitoring systems and devices shall be installed, calibrated, maintained, and operated in accordance with the requirements of section 60.13.

Condition 46: Modifications.
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.14, NSPS Subpart A

Item 46.1:
Within 180 days of the completion of any physical or operational change (as defined in section 60.14), compliance with the applicable standards must be achieved.

Condition 47: Reconstruction
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.15, NSPS Subpart A

Item 47.1:
The following shall be submitted to the Administrator prior to reconstruction (as defined in section 60.15):

1) a notice of intent to reconstruct 60 days prior to the action,

2) name and address of the owner or operator;

3) the location of the existing facility;

4) a brief description of the existing facility and the components to be replaced;

5) a description of the existing air pollution control equipment and the proposed air pollution control equipment;

6) an estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility;

7) the estimated life of the facility after the replacements; and

8) a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

Condition 48: Facility Subject to Title IV Acid Rain Regulations and Permitting

Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 72.

Item 48.1: This facility is subject to the Title IV Acid Rain Regulations found in 40 CFR Parts 72, 73, 75, 76, 77 and 78. The Acid Rain Permit is an attachment to this permit.

****** Emission Unit Level ******

Condition 49: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 231-2.

Item 49.1:
The Compliance Certification activity will be performed for:

Emission Unit: U-00001

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

Item 49.2:
Compliance Certification shall include the following monitoring:

Capping: Yes
Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
The owner or operator of the facility shall install, calibrate, maintain, and operate a continuous emissions monitor for oxides of nitrogen. The limits for emissions of oxides of nitrogen shall be based upon the higher heating value of the fuel and shall apply at all loads of operation and during startup and shutdown. All required records shall be kept at the facility for a minimum of five years.

Manufacturer Name/Model Number: NOx CEM
Upper Permit Limit: 22.5 tons per year
Reference Test Method: 40 CFR Appendix B&F
Monitoring Frequency: CONTINUOUS
Averaging Method: ANNUAL MAXIMUM ROLLED DAILY
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 4/30/02.
Subsequent reports are due every 3 calendar month(s).

Condition 50: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.334(a), NSPS Subpart GG

Item 50.1:
The Compliance Certification activity will be performed for:

Emission Unit: U-00001

Item 50.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: RECORD KEEPING/MAINTENANCE PROCEDURES
Monitoring Description:
The owner or operator of any stationary gas turbine subject to the provisions of 40CFR60 Subpart GG that is using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record fuel consumption and the ratio of water to fuel fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

Monitoring Frequency: CONTINUOUS
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 7/30/02.
Subsequent reports are due every 6 calendar month(s).

Condition 51: **Custom fuel monitoring for nitrogen and sulfur content.**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 40CFR 60.334(b), NSPS Subpart GG

Item 51.1:
This Condition applies to Emission Unit: U-00001

Item 51.2:
The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. Owners, operators, or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the requirements of this Section.

Condition 52: **Compliance Certification**
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable Federal Requirement: 6NYCRR 227-1.3(a)

Item 52.1:

The Compliance Certification activity will be performed for:

Emission Unit: U-00001 Emission Point: 00001

Item 52.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: MONITORING OF PROCESS OR CONTROL DEVICE PARAMETERS AS SURROGATE
Monitoring Description:
No owner or operator of a combustion installation shall emit greater than 20 percent opacity except for one six minute period per hour, not to exceed 27 percent, based upon the six minute average in reference test method 9 in Appendix A of 40 CFR 60.

Parameter Monitored: OPACITY
Upper Permit Limit: 20 percent
Reference Test Method: Method 9
Monitoring Frequency: ANNUALLY
Averaging Method: 6-MINUTE AVERAGE (METHOD 9)
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 7/30/02.
Subsequent reports are due every 6 calendar month(s).

STATE ONLY ENFORCEABLE CONDITIONS
****** Facility Level ******

Condition 53: Unavoidable noncompliance and violations
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-1.4

Item 53.1:
At the discretion of the commissioner a violation of any applicable emission standard for necessary scheduled equipment maintenance, start-up/shutdown conditions and malfunctions or upsets may be excused if such violations are unavoidable. The following actions and recordkeeping and reporting requirements must be adhered to in such circumstances.

(a) The facility owner and/or operator shall compile and maintain records of all equipment maintenance or start-up/shutdown activities when they can be expected to result in an exceedance of any applicable emission standard, and shall submit a report of such activities to the commissioner's representative when requested to do so in writing or when so required by a condition of a permit issued for the corresponding air contamination source except where conditions elsewhere in this permit which contain more stringent reporting and notification provisions for an applicable requirement, in which case they supercede those stated here. Such reports shall describe why the violation was unavoidable and shall include the time, frequency and duration of the maintenance and/or start-up/shutdown activities and the identification of air contaminants, and the estimated emission rates. If a facility owner and/or operator is subject to continuous stack monitoring and quarterly reporting requirements, he need not submit reports for equipment maintenance or start-up/shutdown for the facility to the commissioner's representative.

(b) In the event that emissions of air contaminants in excess of any emission standard in 6 NYCRR Chapter III Subchapter A occur due to a malfunction, the facility owner and/or operator shall report such malfunction by telephone to the commissioner's representative as soon as possible during normal working hours, but in any event not later than two working days after becoming aware that the malfunction occurred. Within 30 days thereafter, when requested in writing by the commissioner's representative, the facility owner and/or operator shall submit a written report to the commissioner's representative describing the malfunction, the corrective action taken, identification of air contaminants, and an estimate of the emission rates. These reporting requirements are superceded by conditions elsewhere in this permit which contain reporting and notification provisions for applicable requirements more stringent than those above.

(c) The Department may also require the owner and/or operator to include in reports described under (a) and (b) above an estimate of the maximum ground level concentration of each air contaminant emitted and the effect of such emissions depending on the deviation of the malfunction and the air contaminants emitted.

(d) In the event of maintenance, start-up/shutdown or malfunction conditions which result in emissions exceeding any applicable emission standard, the facility owner and/or operator shall take appropriate action to prevent emissions which will result in contravention of any applicable ambient air quality standard. Reasonably available control technology, as determined by the commissioner, shall be applied during any maintenance, start-up/shutdown or malfunction condition subject to this paragraph.

(e) In order to have a violation of a federal regulation (such as a new source performance standard or national emissions standard for hazardous air pollutants) excused, the specific federal regulation must provide for an affirmative defense during start-up, shutdowns, malfunctions or upsets.

Condition 54: General Provisions
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 54.1:
This section contains terms and conditions that are not federally enforceable and are not required under the Act or under any of its applicable requirements. Terms and conditions so designated are not subject to the requirements of Section 201-6.4 of Part 201.

Item 54.2:
Any person who owns and/or operates stationary sources shall operate and maintain all emission units and any required emission control devices in compliance with all applicable Parts of this Chapter and existing laws, and shall operate the facility in accordance with all criteria, emission limits, terms, conditions, and standards in this permit. Failure of such person to properly operate and maintain the effectiveness of such emission units and emission control devices may be sufficient reason for the Department to revoke or deny a permit.

Item 54.3:
The owner or operator of the permitted facility must maintain all required records on-site for a period of five years and make them available to representatives of the Department upon request. Department representatives must be granted access to any facility regulated by this Subpart, during normal operating hours, for the purpose of determining compliance with this and any other state and federal air pollution control requirements, regulations or law.

Condition 55: Permit Exclusion Provisions
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 55.1:
The issuance of this permit by the Department and the receipt thereof by the Applicant does not and shall not be construed as barring, diminishing, adjudicating or in any way affecting any currently pending or future legal, administrative or equitable rights or claims, actions, suits, causes of action or demands whatsoever that the Department may have against the Applicant including, but not limited to, any enforcement action authorized pursuant to the provisions of applicable federal law, the Environmental Conservation Law of the State of New York (ECL) and Chapter III of the Official Compilation of the Codes, Rules and Regulations of the State of New York (NYCRR).

The issuance of this permit by the Department and the receipt thereof by the Applicant does not supercede, revoke or rescind an order or modification thereof on consent or determination by the Commissioner issued heretofore by the Department or any of the terms, conditions or requirements contained in such order or modification thereof unless specifically intended by this permit.

The issuance of this permit by the Department and the receipt thereof by the Applicant does not and shall not be construed as barring, diminishing, adjudicating or in any way affecting the right of the Department to bring any future action, or pursue any pending action, either administrative or judicial, to required remediation, contribution for costs incurred or funds expended, for any violations, past, present or future, known or unknown, of applicable federal law, the ECL, or the rules and regulations promulgated thereunder, or conditions contained in any other licenses or permits issued to the Applicant and not addressed in this permit.

The issuance of this permit by the Department and the receipt thereof by the Applicant does not and shall not be construed as barring, diminishing, adjudicating or in any way affecting the right of the Department to pursue any claims for natural resource damages against the Applicant.

Condition 56: Emission Unit Definition
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 56.1:
The facility is authorized to perform regulated processes under this permit for:
Emission Unit: U-00001
Emission Unit Description:
EMISSION UNIT U00001 REPRESENTS TWO (2) IDENTICAL GENERAL ELECTRIC LM6000 COMBUSTION TURBINES. THE TURBINES WILL FIRE DISTILLATE FUEL OIL. THE TURBINES WILL BE EQUIPPED WITH SELECTIVE CATALYTIC REDUCTION (SCR) AND WATER INJECTION TO CONTROL NOX EMISSIONS. EACH TURBINE UNIT WILL VENT TO AN INDIVIDUAL 110 FOOT STACK.

Building(s): 1
2

Condition 57: Contaminant List
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.3(b)

Item 57.1:
Emissions of the following contaminants are subject to contaminant specific requirements in this permit(emission limits, control requirements or compliance monitoring conditions).

CAS No: 007664-41-7
Name: AMMONIA

CAS No: 0NY210-00-0
Name: OXIDES OF NITROGEN

Condition 58: Air pollution prohibited
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 211.2

Item 58.1:
No person shall cause or allow emissions of air contaminants to the outdoor atmosphere of such quantity, characteristic or duration which are injurious to human, plant or animal life or to property, or which unreasonably interfere with the comfortable enjoyment of life or property. Notwithstanding the existence of specific air quality standards or emission limits, this prohibition applies, but is not limited to, any particulate, fume, gas, mist, odor, smoke, vapor, pollen, toxic or deleterious emission, either alone or in combination with others.

****** Emission Unit Level ******

Condition 59: Emission Point Definition By Emission Unit
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 59.1:
The following emission points are included in this permit for the cited Emission Unit:

Emission Unit: U-00001

Emission Point: 00001
Height (ft.): 110 Diameter (in.): 126

Condition 60: Process Definition By Emission Unit
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 60.1:
This permit authorizes the following regulated processes for the cited Emission Unit:

Emission Unit: U-00001
Process: OIL Source Classification Code: 2-01-001-01
Process Description:
EMISSION UNIT U00001 REPRESENTS TWO (2) IDENTICAL GE LM6000 COMBUSTION TURBINES FIRING DISTILLATE OIL. WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR) WILL BE EMPLOYED FOR CONTROL OF NOX EMISSIONS.

Emission Source/Control: WI001 - Combustion
Design Capacity: 421 million Btu per hour

Emission Source/Control: WI002 - Combustion
Design Capacity: 421 million Btu per hour

Emission Source/Control: SCR01 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

Emission Source/Control: SCR02 - Control
Control Type: SELECTIVE CATALYTIC REDUCTION (SCR)

Condition 61: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 61.1:
The Compliance Certification activity will be performed for:

Emission Unit: U-00001

Item 61.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: WORK PRACTICE INVOLVING SPECIFIC OPERATIONS
Monitoring Description:
The owner or operator of this facility shall analyze each delivery of distillate oil to determine sulfur content of the fuel. These measurements shall be recorded and kept at the facility for a minimum of five years.

Work Practice Type: PARAMETER OF PROCESS MATERIAL
Process Material: DISTILLATES - NUMBER 1 AND NUMBER 2 OIL
Parameter Monitored: SULFUR CONTENT
Upper Permit Limit: 0.05 percent by weight
Monitoring Frequency: PER DELIVERY
Averaging Method: MAXIMUM - NOT TO BE EXCEEDED AT ANY TIME (INSTANTANEOUS/DISCRETE OR GRAB)
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 4/30/02.
Subsequent reports are due every 3 calendar month(s).

Condition 62: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 62.1:
The Compliance Certification activity will be performed for:

Emission Unit: U-00001

Regulated Contaminant(s):
CAS No: 0NY210-00-0 OXIDES OF NITROGEN

Item 62.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)
Monitoring Description:
The owner or operator of the facility shall install, calibrate, maintain, and operate continuous emissions monitors for oxides of nitrogen and either oxygen or carbon dioxide. All required records shall be kept at the facility for a minimum of five years.

Manufacturer Name/Model Number: NOx CEM
Upper Permit Limit: 9 parts per million by volume (dry, corrected to 15% O2)
Reference Test Method: 40 CFR Appendix B&F
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: QUARTERLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 4/30/02.
Subsequent reports are due every 3 calendar month(s).

Condition 63: Compliance Certification
Effective between the dates of 01/11/2002 and Permit Expiration Date

Applicable State Requirement: 6NYCRR 201-5.

Item 63.1:
The Compliance Certification activity will be performed for:

Emission Unit: U-00001

Regulated Contaminant(s):
CAS No: 007664-41-7 AMMONIA

Item 63.2:
Compliance Certification shall include the following monitoring:

Monitoring Type: CONTINUOUS EMISSION MONITORING (CEM)

Monitoring Description:

The owner or operator of the facility shall install, calibrate, maintain, and operate continuous emissions monitors for ammonia. All required records shall be kept at the facility for a minimum of five years.

Manufacturer Name/Model Number: Ammonia CEM
Upper Permit Limit: 10 parts per million by volume (dry, corrected to 15% O2)
Reference Test Method: Method 027
Monitoring Frequency: CONTINUOUS
Averaging Method: 1-HOUR AVERAGE
Reporting Requirements: SEMI-ANNUALLY (CALENDAR)
Reports due 30 days after the reporting period.
The initial report is due 7/30/02.
Subsequent reports are due every 6 calendar month(s).

Appendix C
Cambalache Permitting Documents

Appendix C
Cambalache Permitting Documents

Summary - PREPA Cambalache Power Plant

An SCR system was permitted as BACT to reduce NO_x emissions from fuel oil only simple cycle combustion turbines at the Puerto Rico Electric Power Authority (PREPA) Cambalache Plant in Arecibo, Puerto Rico. PREPA received a PSD permit in July, 1995 that allowed for installation of a 248 megawatt (MW) combustion turbine simple cycle electric generating station in Cambalache, in the Municipality of Arecibo. The permit allowed for construction of three ABB GT11N combustion turbines to be operated in simple cycle mode firing only low sulfur fuel oil (0.15 percent sulfur), each with a power output of 83 MW. The facility was classified as a major source for PSD because it had the potential to emit more than 250 tons per year of at least one PSD regulated pollutant. The project was subject to PSD standards for NO_x, SO_2, sulfuric acid mist, CO, PM, PM_{10}, and VOC. The PSD permit required the use of steam injection and an SCR system for NO_x control. The units were permitted with a NO_x limit of 10 parts per million by volume on a dry basis (ppmvd), corrected to 15 percent oxygen. The PSD permit also included an ammonia emissions limit of 10 ppmvd corrected to 15 percent oxygen.

Construction was completed and operation commenced at the Cambalache Plant in July of 1997. PREPA operated the Cambalache Plant from its startup in July of 1997 until September of 2001 using steam injection and the SCR to control NO_x emissions. During this period, the SCR system, operated in accordance with the manufacturers' recommendations, was not able to consistently meet design specifications or permit limits due to resultant sooting of the catalyst. The station eliminated the sooting phenomenon by adding a fuel oil additive. The additive, however, contained several catalyst poisons that rapidly deactivated the catalyst. Over time, in order to meet the NO_x emission limits, increased ammonia use was required and ammonia emissions greater than 100 ppm were seen. According to USEPA Region 2 personnel, these high ammonia emission levels resulted in a visible ammonia plume. Based on a review of plots of operating data for all three units at the Cambalache Plant between the periods January 1998 to November 1999, the facility operated with an ammonia slip less than the permit limit of 10 ppmv for a total of only approximately 7.5 percent of the time. During this same period, the units operated with an ammonia slip greater than 40 ppmv approximately 70 percent of the time and an ammonia slip greater than 100 ppmv approximately 15 percent of the time.

The combustion turbines were commissioned in July of 1997 and SCR problems were identified in August of 1997. Various fixes were used to try to attain proper operation of the SCR system. A catalyst cleaning procedure that included air blowing was developed by Engelhard, the SCR vendor, in October of 1997, and Units 1 and 2 were cleaned in December 1997. Units 1 and 2 were again cleaned using air blowing in February 1998. Units 1 and 2 were again cleaned using air blowing in March 1998. New SCR decoking procedures were submitted by Engelhard in January 1998, and Unit 1 was cleaned using SCR decoking in April 1998. An SCR acid wash procedure was proposed by Engelhard in June 1998. This acid washing procedure was used to clean the catalyst in Unit 3 in August 1998, in Unit 2 in November 1998, and in Unit 1 in December 1998. Graphs included in the application to amend the Cambalache PSD permit show that the acid washing procedure was effective in getting the ammonia slip level below the permitted 10 ppm level, but generally within 1 to 2 months after the SCR acid washing procedure, the ammonia slip was back above 10 ppm and the ammonia slip continued to rise over time. In summary, all of the fixes used to try to get the SCR system to work properly and meet design specifications and permit limits failed.

PREPA proposed, in an August 2000 PSD permit amendment application, to comply with the BACT requirement by ceasing ammonia injection, removing the SCR system, and limiting NO_x emissions to 42 ppmvd at 15 percent O_2 between 60 and 100 percent load using steam injection. Based on verbal approval from Attorney Joseph Siegel of USEPA Region 2, PREPA removed the SCR system on all three combustion turbines in September 2001. USEPA Region 2 issued Compliance Order CAA-02-2002-1002 on October 24, 2001. This compliance order required removal of the SCR system, performance testing for PM, PM_{10}, NO_x, and sulfuric acid mist; and submittal of a revised BACT analysis. PREPA submitted a revised BACT analysis in July 2003, and an application to amend the PSD permit in September 2003. This application proposes BACT for NO_x to be steam injection with a NO_x emission limit of 42 ppmvd.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION II

OCT 24 2001

In the Matter of:	:	**COMPLIANCE ORDER**
Puerto Rico Electric Power Authority Cambalache, Puerto Rico	:	Index No: CAA-02-2002-1002

COPY

STATUTORY AUTHORITY

THIS COMPLIANCE ORDER is issued to the Puerto Rico Electric Power Authority ("Respondent"), which owns and operates three simple cycle oil-fired gas turbines that are located at Respondent's electric power generating facility in Cambalache, Puerto Rico. The Order is issued under Section 113(a)(3)(B) of the Clean Air Act ("the Act"), 42 U.S.C. § 7413(a)(3), which grants the Administrator of the United States Environmental Protection Agency ("EPA") the authority to issue orders requiring persons to comply with requirements of Part C of the Act, 42 U.S.C. §§ 160-169, as well as the rules and regulations which EPA has adopted under Part C. The Administrator has delegated the authority to issue this Order to the Regional Administrator of EPA's Region II office, which enforces the Act in Puerto Rico.

STATUTORY AND REGULATORY BACKGROUND

1. Subchapter I, Part C, of the Act establishes a regulatory program, known as the "PSD Program". The program is designed to prevent significant deterioration of air quality in areas that attain the National Ambient Air Quality Standards ("NAAQS"). Section 160-169 of the Act, 42 U.S.C. Section 7470-7479. Sections 165 and 166 of the Act, 42 U.S.C. Sections 7475 and 7476, directed EPA to adopt regulations to implement the PSD program.

2. On June 19, 1978, pursuant to Part C of the Act, the Administrator of EPA promulgated 40 CFR § 52.21, PSD (43 FR 26403).

3. The regulations at 40 C.F.R. § 52.21 are applicable to any State Implementation Plan which has been disapproved with respect to PSD. 40 C.F.R. § 52.21(a). Under 40 C.F.R. §52.2729, Puerto Rico's SIP is disapproved with respect to PSD. The provisions of 40 CFR § 52.21(b) through (w) were incorporated by reference and made part of the applicable Air Quality Implementation Plan (AQIP) for Puerto Rico at 40 CFR Subpart BBB(§ 52.2729).

4. EPA has the authority to issue permits and conduct source review pursuant to 40 CFR §52.21(b) through (w) for all sources subject to PSD review in Puerto Rico.

5. Section 114 of the Act authorizes the Administrator to seek information from the owner or operator of any emission source "as he may reasonably require." 42 U.S.C. §7414(a)(1).

FINDINGS OF FACT

6. Respondent owns and operates three simple cycle, oil-fired gas turbines at its electric power generating facility located in Cambalache, Puerto Rico.

7. The EPA issued a PSD permit on July 31, 1995 to Respondent, revised December 5, 1996, authorizing the construction/operation of these gas turbines.

8. The PSD permit referenced in paragraph 7, above, required the installation of continuous emission monitors for carbon monoxide, oxygen, nitrogen oxide, ammonia and opacity for each of the units. The permit requires that all continuous emission monitoring systems be on-line and in operation 95 percent of the time when the turbines are operating. The

PSD permit also states that excess emissions indicated by monitoring systems, other than for startup and shutdown, will be considered violations.

9. The permit also requires Respondent to submit quarterly Excess Emission Reports (EERs) that must be postmarked by the 30th day after the end of each calendar quarter. These EERs must comply with the reporting requirements of 40 C.F.R. Part 60 Appendix F.

10. Based on these EERs, EPA issued a Notice of Violation (NOV) to Respondent on May 20, 1999. The NOV indicated, among other things, that Respondent had excess emissions for nitrogen oxide and ammonia.

11. In several meetings and telephone calls following issuance of the NOV, Respondent indicated that the Selective Catalytic Reduction (SCR) technology required by the PSD permit is incompatible with Respondent's turbines and that SCR does not represent Best Available Control Technology ("BACT").

12. EPA Region 2 agreed with Respondent's assessment given the excess ammonia slip and large quantities of ammonia necessary to keep the Oxides of Nitrogen (NO_x) levels below permitted limits, and to avoid potential risks to the public.

13. The parties agreed that Respondent would submit an application to revise BACT in a manner that does not include SCR.

14. Respondent submitted its revised BACT application on September 6, 2000, supplemented with additional necessary information through June 28, 2001. Region 2 is in the process of reviewing the BACT application.

ORDER

Based on the findings set forth above, and pursuant to Section 113(a)(3) of the Act, 42 U.S.C. §7413(a)(3), IT IS HEREBY ORDERED that:

I.

The provisions of this Order shall apply to Respondent and to its officers, agents, servants, employees, successors and to all persons, firms and corporations acting under, through or for Respondent .

II.

A. Respondent shall immediately cease using the SCR technology at its three simple cycle oil-fired gas turbines and must comply with the limits for NO_x, H_2SO_4, PM, and PM_{10} in Respondent's June 28, 2001 revised BACT application.

B. Within 45 days of the effective date of this Order, Respondent shall retest for emissions of H_2SO_4, NO_x, PM, and PM_{10} at each of the turbines. The testing must be conducted in accordance with the protocol approved by EPA on July 31, 2001. The tests must be conducted at spinning reserve load (60%), and at base load (100%). Within 10 days of the effective date of this Order, Respondent shall notify EPA of the date of testing.

C. Respondent must submit performance test protocols for any new or additional monitors not previously approved. These protocols must be submitted within ten (10) days of the effective date of this Order. Respondent must comply with all conditions in EPA's approval of the protocol for these monitors.

D. Within 30 days after concluding the tests in Paragraph B, above, Respondent must operate its turbines to achieve an emission rate no greater than 20% higher than the average emissions levels achieved during the test. Within 30 days after concluding the test in Paragraph B, above, Respondent must submit a revised BACT application reflecting these emission rates.

ENFORCEMENT

Section 113(a)(3) of the Act authorizes the EPA to take any of the following actions in response to Respondent's violation of the NSPS, or in response to Respondent's failure to comply with this Order:

- issue an administrative penalty order pursuant to Section 113(d) for civil administrative penalties of up to $27,500 per day of violation
- bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties of not more than $27,500 per day for each violation.

The United States may seek fines and/or imprisonment of any person who knowingly violates Part C of the Act and/or who knowingly violates an Order issued pursuant to Section 113 of the Act. Upon conviction, the facility will be declared ineligible for federal contracts, grants, and loans. EPA may also extend the ineligibility to other facilities owned or operated by Respondent. (Section 306 of the CAA, 40 C.F.R. Part 15 and Executive Order 11738).

PENALTY ASSESSMENT CRITERIA

If a penalty is assessed under Section 113(b) or (d), Section 113(e)(1) of the Act states that the Administrator or the court, as appropriate, shall, in determining the amount of penalty to be assessed, shall consider (in addition to such other factors as justice may require) the size of the business, the economic impact of the penalty on the business, the violator's full compliance history and good faith efforts to comply, the duration of the violation as established by any credible evidence (including evidence other than the applicable test method), the payment by the violator of penalties previously assessed for the same violation, the economic benefit of noncompliance, and the seriousness of the violation.

Section 113(e)(2) of the Act allows the Administrator or the court as appropriate, to assess a penalty for each day of the violation. The number of days of violation shall include the date of the notice and each and every day thereafter until Respondent achieves continuous compliance. If Respondent proves that there was an intermittent day of compliance or that the violation was not continuous in nature, then the EPA will reduce the penalty accordingly.

EFFECTIVE DATE AND OPPORTUNITY FOR CONFERENCE

Pursuant to Section 113(a)(4), Respondent may request a conference with the EPA concerning the violation(s) alleged in the above Order. Respondent may present evidence bearing on the finding of violation, the nature of the violation(s), and on any efforts Respondent may have taken or that it proposes to take to achieve compliance. Respondent may arrange to have legal representation at the conference, at its own expense.

Within ten days from receipt of this Order, Respondent may request, in writing, that a conference to be held regarding this Order. If the requested conference is held, the Order shall become effective five days after the conference is held.

If Respondent does not meet with EPA, the above Order shall become effective ten days from its receipt.

A request for a conference or other inquiries concerning this Order should be made to:

Joseph Siegel
Assistant Regional Counsel
Office of Regional Counsel
U.S. Environmental Protection
Agency – Region II
290 Broadway –16th Floor
New York, New York 10007-1866
(212) 637-3208

DATED: 10/21, 2001

Lisa P. Jackson,
Acting Director
Division of Enforcement and
Compliance Assistance
U.S.E.P.A. Region 2
290 Broadway,
New York, New York 10007-1866

TO: Mr. Hector Rosario, Executive Director
Puerto Rico Electric & Power Authority
P. O. Box 363928
San Juan, PR 00936-3928

cc: Ms. Gladys Gonzalez, Chair
Puerto Rico Environmental Quality Board

Mr. Angel O. Berrios, Director
Air Quality Area
Puerto Rico Environmental Quality Board

Puerto Rico Electric Power Authority
Cambalache, P.R.

Application to Amend the PSD Permit for PREPA's Cambalache Power Plant

ENSR Corporation
September 2003
Document Number 5559-038-100

CONTENTS

CONTENTS (Cont'd)

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION

1.1 Chronology

Pursuant to a Prevention of Significant Deterioration (PSD) permit issued to the Puerto Rico Electric Power Authority (PREPA) in July, 1995, PREPA constructed and has been operating the 248 MW Cambalache Power Plant since July, 1997. The power plant consists of three ABB GT11N combustion turbines operating in simple cycle mode. The turbines burn low sulfur distillate oil (0.15% sulfur by weight).

PREPA operated the Cambalache Power Plant with steam injection and selective catalytic reduction (SCR) for NO_x control between July 1997 and September, 2001. During this period, despite PREPA's best efforts and those of Alstom, the construction contractor and Englehard, the SCR vendor, the SCR system failed to operate near its original design specifications. In particular, the system was specified to achieve a NO_x emission rate of 10 ppmvd @15% O_2 with an ammonia slip of 10 ppmvd @ 15% O_2. The SCR system, operated in accordance with manufacturer's instructions, produced ammonia emission levels consistently in excess of 100 ppmvd @15% O_2 or more than 10 times the required level. Appendix A presents a history of the SCR performance problems at the Cambalache power plant.

PREPA met with EPA Region 2 in July 1998, March 1999, October 1999 and again in January 2000 to update them on the continuing problems with the SCR system. EPA agreed that the SCR system cannot consistently achieve the expected reductions in NO_x emissions on oil-fired turbines (EPA Region 2 NEWS, January 20, 2000).

Therefore, based on a review of the original BACT analysis and actual operating experience at Cambalache, PREPA proposed in an August, 2000 **Application to Amend The PSD Permit for PREPA's Cambalache Power Plant** (ENSR Document 5559-016-100) to comply with the BACT requirement by ceasing ammonia injection, removing the SCR system, and limiting NO_x emissions to 42 ppmvd @15% O_2 between 60 - 100% load using steam injection. Besides eliminating ammonia emissions, removal of the SCR system was expected to reduce emissions of particulate matter (PM), small particulate (PM_{10}) and possibly sulfuric acid mist.

Also during August, 2000, PREPA submitted an emissions performance test protocol to EPA Region 2. This test protocol described the testing to be performed at the three units at Cambalache in order to quantify emissions of pollutants after removal of the SCR system.

In an effort to inform EPA Region 2 of the continuing problems with the SCR system at Cambalache, PREPA met with EPA Region 2 on October 10, 2000 and again on March 21, 2001. PREPA also corresponded with EPA Region 2 on numerous occasions between the August, 2000 submittals and

June 28, 2001. On that date, PREPA submitted a letter to EPA Region 2 summarizing the outstanding PSD permitting issues. The June 28, 2001 letter contained the following proposals:

- to lower the permitted fuel bound nitrogen in the fuel oil from 0.1% to 0.055%;
- to lower PM and PM_{10} emission limits based on the 1997 performance testing (Note that a revised BACT determination submitted on July 11, 2003 and included here as Section 3 proposes lower emissions of these pollutants based on the 2001/2002/2003 performance testing);
- a total of 780 startups: 80% of the startups would last for 2-hours and 20% of the startups would last for 3-hours;
- operational changes to allow 6,000 hr/yr operation at spinning reserve for the entire power plant. The existing PSD permit allows 2,000 hr/yr operation at spinning reserve for each turbine.

Based on verbal approval from Attorney Joseph Siegel of EPA Region 2, PREPA removed the SCR system on all three combustion turbines in September, 2001.

EPA Region 2 issued Compliance Order (the "Order") CAA-02-2002-1002 on October 24, 2001. The Order required removal of the SCR system, performance testing for PM, PM_{10}, NO_x and sulfuric acid mist and submittal of a revised Best Available Control Technology (BACT) analysis. Performance testing began October 18, 2001. Due to elevated levels of PM and PM_{10}, testing for Units 2 and 3 were repeated. Testing on Unit 1 was performed in early November, 2001 with PSD compliance demonstrated. Testing on Unit 2 was performed in October 2001 and repeated in December 2001 with PSD compliance demonstrated during the December 2001 tests. Testing on Unit 3 was performed in January 2002, January 2003 and May 2003 with PSD compliance demonstrated during the May 2003 tests.

Emission performance test reports were submitted to EPA Region 2 and to EPA's Caribbean Environmental Protection Division and to the Environmental Quality Board in July, 2002. Reports summarizing the retesting of Unit 3 were submitted in March, 2003 for the January, 2003 testing and on August 19, 2003 for the May, 2003 testing.

All three units are in compliance with current PSD limits.

The Order required that PREPA must, within 30 days after concluding the emissions performance tests, operate its turbines to achieve an emission rate no greater than 20% higher than the average emission levels achieved during the tests. PREPA is complying with this requirement.

By this filing, PREPA is incorporating all previously requested changes to its current PSD permit into one document. By this filing, PREPA also proposes new emission limits that are in compliance with the Order.

1.2 Responsible Parties

The responsible person for these proposed amendments to the PSD permit for the Cambalache Power Plant is:

Mr. Jaime Plaza, Head
Environmental Protection & Quality Assurance Division
Puerto Rico Electric Power Authority (PREPA)
P.O. Box 364267
San Juan, PR 00936-4267
Tel: 787-289-4959
Fax: 787-289-4999

ENSR Consulting and Engineering (ENSR) has prepared this document.

The responsible person at ENSR is:
David M. Shea, Senior Program Manager
ENSR International
2 Technology Park Drive
Westford, MA 01886
Tel: 978-589-3113
Fax: 978-635-9180

Technical communications should be directed to Jaime Plaza at PREPA with copies to Dave Shea at ENSR.

1.3 Report Organization

Section 2 of this application presents a regulatory review. Section 3 contains the revised BACT application and the proposed changes to the existing PSD permit. Section 4 presents the dispersion modeling results for NO_x (as NO_2).

2.0 REGULATORY REVIEW

The NO_x emission changes at the Cambalache Power Plant are subject to both Federal and Commonwealth of Puerto Rico air quality regulations. The standards and regulations that pertain to the facility are:

- New Source Performance Standards (NSPS) which impose emission standards on new facilities (Clean Air Act Section 111; 40 CFR Subparts GG).
- National Ambient Air Quality Standards (NAAQS) established by the U.S. Environmental Protection Agency (EPA) for specific criteria pollutants (40 CFR 50).
- Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21).
- Puerto Rico Air Pollution Control Regulations.

The proposed National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines (Combustion Turbine MACT, 40 CFR Part 63 Subpart YYYY, published in Federal Register January 14, 2003) does not apply to the Cambalache power plant because the power plant is not a major source of hazardous air pollutants (HAPs) as defined by the 10/25 ton per year definition for one/total HAPs.

2.1 New Source Performance Standards (NSPS)

The New Source Performance Standards (NSPS) constitute a set of national emission standards that apply to specific categories of new sources. The NSPS for stationary combustion turbines is contained in 40 CFR60, Subpart GG. These standards impose maximum allowable emissions for nitrogen oxides and sulfur dioxide from turbines with a heat input at peak load greater than 100 MMBtu/hr. The Cambalache Power Plant currently meets these NSPS. The NO_x emission standard applicable to the combustion turbines is 111 ppmvd corrected to 15 percent oxygen. The proposed NO_x emission rate of 42 ppmvd for distillate oil firing is well below the NSPS of 111 ppmvd. For sulfur dioxide, the NSPS requires an SO_2 emission limitation of 150 ppmvd and/or a maximum fuel sulfur content of 0.8 weight percent. The $\leq$0.15 weight percent sulfur content of the light distillate oil fired in the combustion turbines is well below the NSPS level of 0.8 weight percent.

2.2 National Ambient Air Quality Standards

Ambient air impacts from the existing facility meet the NAAQS for all pollutants emitted by the facility. It will be demonstrated that the total NO_x emissions associated with use of steam injection to control NOx will produce insignificant ambient air quality impacts. Thus, the Cambalache Power Plant will continue to produce insignificant impacts and to maintain compliance with the NAAQS. The modeling results for NO_2 that were submitted with the August, 2000 **Application to Amend the PSD Permit for PREPA's Cambalache Power Plant** are being resubmitted with this application.

2.3 Prevention of Significant Deterioration (PSD) Regulations

The existing Cambalache Power Plant was subject to PSD review for NO_x and other pollutants. The proposed revision to the NO_x emission rate is therefore also subject to review under the Federal PSD regulations (40 CFR 52.21). The current PSD permit limits annual NO_x emissions from the Cambalache Power Plant to 460 tpy. The PSD permit limits the NO_x concentration in the flue gas from each combustion turbine to 10 ppm by volume on a dry basis (ppmvd) referenced to 15% oxygen (O_2). The proposed limit of 42 ppmvd at 15% O_2 between 60 - 100% load results in a proposed new limit of 1,801 ton/yr of NO_x.

The following analyses were included in the original PSD permit application:

- a Best Available Control Technology (BACT) evaluation;
- an evaluation of the existing air quality in the vicinity of the source;
- a demonstration that ambient NO2 impacts are insignificant, as defined by EPA, thus eliminating the requirement to demonstrate compliance with the PSD increments and the NAAQS;
- an evaluation of visibility impacts at the nearest Class I area;
- an evaluation of project impacts on soils and vegetation; and
- an analysis of the air quality impacts associated with growth caused as a result of the facility expansion.

This document contains revised text for the above analyses that is consistent with the new NO_x limits.

Best Available Control Technology (BACT)

BACT is defined in the Federal PSD regulations as follows:[1]

"An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-

[1] 40 USC § 7479(3)

case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning, fuel quality, or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard established pursuant to § 7411 or 7412 or this title.

BACT must be at least as stringent as the applicable New Source Performance Standard (see Section 2.1).

Two standard guidance documents, the "Guidelines for Determining BACT" and the draft "PSD Workshop Manual" were published by the EPA to assist states or the regional EPA offices in making BACT determinations (EPA 1987a, EPA 1990). The BACT requirements are intended to ensure that the control system incorporated in the design of a proposed facility reflects the latest technology used in a particular industry, in keeping with local air quality, energy, economic, and other environmental considerations.

Guidance on the conduct of BACT evaluations has been further articulated by U.S. EPA in a December 1, 1987 memorandum to all EPA Regional Administrators (EPA, 1987b). The memorandum directs EPA staff to implement a "top down" approach to determine BACT. The first step in the top down approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the emission unit in question, then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated because of any substantial or unique technical, environmental, or economic objection.

<u>Existing Ambient Air Quality Analysis</u>

An ambient air quality assessment was included in the original PSD application. Air quality data, measured between August 1992 - August 1993, indicated that existing NO_2 concentrations are less than 9% of the 100 ug/m^3 NAAQS. The on-site air quality and meteorological data gathered during this period were reviewed and approved by EPA Region 2 as PSD quality data (RTP, 1993, U.S. EPA, 1993). There have been no new major sources in the Arecibo region since this monitoring program ended. Thus, the preconstruction monitoring data is adequate to represent existing air quality. Furthermore, since the annual average NO_2 impacts from the power plant at 42 ppmvd @ 15% O_2 are predicted to be insignificant, there is no requirement to provide updated air quality monitoring data.

PSD Increment/NAAQS Impact Analysis

The maximum predicted annual average impact of 0.6 µg/m^3 for NO_2 is less than EPA's significant impact level of 1 µg/m^3. Therefore, NAAQS and PSD increment compliance analyses are not required.

Visibility Analysis

The 1994 PSD application for the Cambalache Power Plant included a visibility screening analysis. Results indicated that there were no visibility impacts in the Virgin Islands National Park Class 1 area. An updated visibility analysis for the National Park is not necessary because the persistent trade winds transport the Cambalache Power Plant emissions away from the National Park.

Impacts on Soils and Vegetation

PREPA will demonstrate that the 42 ppmvd @15% O_2 between 60 - 100% load NO_x emissions limit will produce no discernible impact upon soils and vegetation in the area.

Growth Analysis

The previous PSD application demonstrated that air quality impacts associated with growth in the community as a result of an applicant's project were negligible. This application to cease use of SCR does not change that conclusion.

2.4 Commonwealth of Puerto Rico Environmental Quality Board Regulations

The existing power plant maintains compliance with EQB's air emission regulations. PREPA will confer with EQB to incorporate the proposed change in NO_x emissions into PREPA's Operating Permit.

3.0 BEST AVAILABLE CONTROL TECHNOLOGY AND REVISED EMISSION RATES

3.1 Introduction

PREPA's decision to build the Cambalache simple cycle combustion turbine plant was based on a December 1989 Master Plan. The Preliminary Environmental Impact Statement was completed in August 1993. PREPA's plan was to control NO_x emissions using steam injection to achieve a Best Available Control Technology (BACT) emission rate of 50 ppmvd @ 15% O_2. Based on a request from EPA Region 2, the final PSD permit application, which was submitted in January 1994, included selective catalytic reduction (SCR) to limit NO_x emissions to 10 ppmvd @15% O_2. The PSD permit was issued in July 1995 and the Cambalache plant began commercial operation in mid 1997.

Based on review of the original BACT analysis and actual operating experience at Cambalache, PREPA proposed in an August, 2000 **Application to Amend The PSD Permit for PREPA's Cambalache Power Plant** (ENSR Document 5559-016-100) to comply with the BACT requirement by ceasing ammonia injection, removing the SCR system, and limiting NO_x emissions to 42 ppmvd @15% O_2 between 60 - 100% load using steam injection. This emission level is currently deemed Best Available Control Technology (BACT) by EPA regions throughout the United States for simple cycle combustion turbines when firing distillate oil. The EPA has stated that SCR cannot consistently achieve the expected reductions in NO_x emissions on oil-fired turbines (EPA Region 2 NEWS, January 20, 2000).

In Compliance Order CAA-02-2002-1002 dated October 24, 2001, EPA Region 2 required PREPA to do the following:

- cease using the SCR technology;
- comply with limits for NO_x, sulfuric acid mist, PM and PM_{10} in PREPA's June 28, 2001 revised BACT application;
- retest for emissions of NO_x, sulfuric acid mist, PM and PM_{10} according to approved protocols;
- After testing, operate the turbines to achieve an emissions rate no greater than 20% higher than the average emission levels achieved during the test; and
- Submit a revised BACT application reflecting these emission rates.

This revised BACT analysis was submitted on July 11, 2003 in fulfillment of the Order.

3.2 Top-Down BACT

For attainment pollutants, BACT requirements are intended to ensure that a proposed facility will incorporate control systems that reflect the latest demonstrated practical techniques for a particular process and do not result in the exceedance of a NAAQS or other standards imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each attainment pollutant control technology applicable to the combustion turbines.

EPA recommended that a "top-down" approach be taken when evaluating available air pollution control technologies. This approach to the BACT process involves determining the most stringent control technique available (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the particular source, then the next most stringent level of control is determined and similarly evaluated. The process continues until a control technology and associated emission level is determined which cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in the U.S. EPA draft document "New Source Review Workshop Manual (U.S. EPA, October 1990). The five steps involved in a top-down BACT evaluation are:

- Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank remaining control technologies by control effectiveness;
- Evaluate most effective controls and document results; if top option is not selected as BACT, evaluate next most effective control option; and
- Select BACT, which will be the most effective option not rejected, based on energy, environmental, and economic impacts.

The "top-down" approach was used in this analysis to evaluate available pollution controls for NO_x.

3.2.1 BACT for NO_x Emissions – Normal Operations

Lists of previous BACT/LAER determinations for combustion turbine units that burn oil are presented in Appendix B. These tables are compiled from EPA's RACT/BACT/LAER Clearinghouse and a Midwestern state agency. The RACT/BACT/LAER Clearinghouse keeps a listing of RACT/BACT/LAER determinations by governmental agencies for many types of air emission sources. The determinations are available in hard copy or through a computerized database. While the RACT/BACT/LAER Clearinghouse covers information from the past 15 years, only the more recent decisions (1993-present) have been included in Appendix B.

The RACT/BACT/LAER Clearinghouse data show NO_x emission limits ranging from 9 ppmvd @ 15% O_2 to 85 ppmvd @ 15% O_2. The vast majority of BACT determinations are for 42 ppmvd @15% O2. The few projects for which BACT levels are higher or lower reflect the fact that BACT is a case-by-case determination.

The latest BACT determination made by EPA Region 2 for an oil-fired simple cycle combustion turbine was in 2001 for a 24 MW machine operated by the Virgin Islands Water and Power Authority (VIWAPA) at the Krum Bay St. Thomas Generating Station. For that project, BACT for NO_x was determined to be 42 ppmvd @15% O_2. This emission rate is to be achieved through water injection. The proposed 42 ppmvd @15% O_2 NO_x limit at the Cambalache Power Plant is consistent with EPA's BACT determination for VIWAPA.

Other BACT/LAER decisions through 1999, compiled by a Midwestern State agency, are included in Appendix B. These decisions are typically 42 ppmvd when burning oil, although there are a few lower limits.

None of the NO_x emission limits in Appendix B that are based on the use of SCR are directly applicable to setting a precedent for Cambalache. First, Cambalache burns 100% oil; none of the other SCR applications involve 100% oil combustion or even a substantial annual percentage of total operation on oil. Although permits for some of the facilities in Appendix B may allow 30 to 90 days of oil combustion, actual oil combustion does not exceed more than a few days per year. The combustion turbines that use SCR burn natural gas, a cleaner fuel. Second, Cambalache is a simple cycle turbine that produces a high temperature flue gas stream. Almost all of the systems listed in Appendix B and that use SCR are combined cycle plants. When SCR is used on these plants it is applied at a more conventional and lower temperature.

Cambalache is the only application of SCR to a simple cycle gas turbine that only burns oil. In the original Cambalache PSD permit application, four combustion turbine projects were cited as precedents to indicate that SCR was BACT for Cambalache. However, detailed review of these four projects shows that they do not support SCR as BACT for Cambalache as discussed below.

The first project is Maui Electric. A July 1992 permit requires a demonstration project on a 28 MW turbine. Similar to Puerto Rico, turbines in Hawaii burn oil. On January 19, 2000, ENSR talked to Stuart Soji at the Hawaii Department of Health (808-586-4200). He told us that they have no SCR systems on oil fired turbines in Hawaii.

However, according to Engelhard, there was an SCR demonstration project at Maui Electric. Engelhard's standard temperature vanadia and high temperature catalysts were installed in a gas turbine at this facility. The demonstration project lasted for approximately 1-year. According to Engelhard, masking of the catalyst was not observed at Maui Electric. Also according to Engelhard, there was, however, the same rate of catalyst deactivation at Maui Electric as occurred at

Cambalache. As mentioned in Section 1 of this document, the SCR catalyst at Cambalache showed degradation within 1-2 months after startup of the power plant and within 1-2 months after chemical washing of the catalyst. In fact, PREPA was able to maintain a 10 ppmvd @15% O_2 ammonia slip for only 1-2 months after chemical washing of the catalyst.

The second project is a March 1992 permit for Bermuda Hundred Energy in Chesterfield, Virginia. This project is described in the Cambalache PSD permit application as an 80 MW gas or oil fired combustion turbine. ENSR talked to James Kyle (804-527-5047) at the Virginia agency about this project. Mr. Kyle stated that the project was never built. In our opinion, issuance of a permit for a project that may burn gas or oil does not demonstrate that SCR is technically feasible for a simple cycle project that only burns oil.

The third project is a September 1992 permit for two ABB GT11N combustion turbines in Lakewood Township, New Jersey. This project is described in the Cambalache PSD permit as permitted to burn oil for up to 5,957 hr/yr. However, in January 2000, ENSR talked to David Thomas, the plant manager, (723-901-2116). He informed us that they only burn oil for approximately five days per year. They have not had problems with burning oil and meeting their NO_x emission limit of 21 ppmvd @ 15% O_2. In our opinion, this project does not support SCR as BACT for Cambalache. First, the emission limit is higher. Second, there was no actual operating experience burning oil when Cambalache was permitted. Third, operating experience on oil over the life of the catalyst is probably only equivalent to one month of operation at Cambalache. Fourth, this is a combined cycle plant not a simple cycle turbine.

Therefore, Lakewood does not burn oil for a significant amount of time, does not use a high temperature SCR and does not achieve NO_x emissions of 10 ppmvd @15% O_2.

The fourth and last project is a July 1991 permit for Kingston Power Associates in Rhode Island. This project is described in the Cambalache PSD permit application as an 80 MW gas or oil fired combustion turbine. Firing of oil was limited to 2,160 hr/yr. Doug McVay (401-222-6800) at the Rhode Island agency stated that the project was never built. Issuance of a permit for a project that may burn gas or oil does not demonstrate that SCR is technically feasible for a project that only burns oil.

Therefore, there were and are currently no combustion turbine projects that would support a conclusion that SCR is BACT for a simple cycle combustion turbine burning 100% oil. In fact, EPA Region 2's most recent BACT ruling for the VIWAPA combustion turbine required water injection for NO_x control.

3.2.2 NO_x Formation and Available Control Technologies

NO_x is primarily formed in combustion processes in two ways:

1. the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and

2. the oxidation of nitrogen contained in the fuel (fuel NO_x).

Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (Rasnic 1987). Therefore, NO_x emissions from natural gas fired combustion turbines originate as thermal NO_x. Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_x from distillate oil fired turbines may become significant in turbines equipped with a high degree of thermal NO_x control (EPA 1998)

The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. "Front-end" NO_x control techniques are aimed at controlling one or more of these variables. The primary front-end combustion controls for oil-fired turbines include water or steam injection. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls thermal NO_x formation by quenching peak flame temperature. This technique can be operationally very hard on the turbine and combustors due to vibration and flame instability.

The only technologies that can be considered for Cambalache are combustion practices with water or steam injection. Water or steam injection provides similar NO_x control. Therefore, the following discussion of achievable NO_x emission rates focuses primarily on combustion practices with steam injection.

3.2.3 BACT – Achievable NO_x Emission Rates

The ABB GT11N and GT11N1 are essentially the same engine. The first GT11N was the Midland, Michigan Cogeneration project in 1989. Alstom (then called ABB) stopped producing these turbines in 1996 or 1997, about 6 to 7 years ago. The only exception is a recent GT11N that Alstom was required to be manufactured due to an option in an old contract. Therefore, fairly recently they made one engine that was a carbon copy of a 1993 engine

Alstom has identified the following US GT11N installations with steam injection and their performance guarantees:

- Cambalache, Puerto Rico – 50 ppmvd on oil only
- Belle Mead, Virginia – 65 ppmvd on oil, 42 ppmvd on gas

- Midland, Michigan - 42 ppmvd on gas only
- Hopewell, Virginia – 65 ppmvd on oil, 42 ppmvd on gas
- Kalaeloa, Hawaii – actual emissions are 130 ppmvd on oil

In addition, Alstom identified the following installations with water injection and their performance guarantees:

- Concord, Wisconsin – 65 ppmvd on oil and 25 ppmvd on gas with water injection on both fuels
- Fond du Lac, Wisconsin – 65 ppmvd on oil and 25 ppmvd on gas with water injection on both fuels
- Lakewood, NJ – 65 ppmvd on oil and 25 ppmvd on gas with dry low NO_x combustors
- Woodsdale, Ohio– 65 ppmvd on oil and 42 ppmvd on gas with water injection on both fuels
- Paris, Wisconsin– 65 ppmvd on oil and 25 ppmvd on gas with water injection
- McIntosh, Georgia – 42 ppmvd on oil and 25 ppmvd on gas with water injection
- Rokeby, Nebraska – 42 ppmv on oil and 25 ppmv on gas with dry low NO_x combustors

After consultation with Alstom, it is PREPA's and ENSR's opinion that the best emission rate that can currently be guaranteed for the ABB GT11N gas turbines at Cambalache is 50 ppmvd @ 15% O_2 between 60 - 100% load. However, since the Fall of 2001 after the SCR system was removed, PREPA has maintained a NO_x emissions level of 42 ppmvd @15% O_2 on all three units at Cambalache. PREPA has achieved this emissions level with proper tuning of the combustion/steam injection system. PREPA is maintaining stable, safe, and reliable operation without pulsation at this lower emission rate.

Therefore, PREPA proposes a NO_x BACT emission limit of 42 ppmvd @ 15% O_2 between 60 - 100% load. This emission concentration corresponds to a NO_x emission rate of 147.7 lb/hr at 85 ° F ambient temperature.

3.2.4 Energy Impacts and Other Environmental Impacts

Removal of the SCR system has enabled more efficient gas turbine operation by decreasing backpressure. In addition, it may have improved steam generation because deposits on the once through steam generator heat transfer surfaces are likely reduced. Emissions of PM and PM_{10} have been reduced. Also, ammonia emissions have been eliminated. Finally, the potential for an accidental release of ammonia during transport or handling has been eliminated. No adverse energy or other environmental impacts have been identified. Therefore, NO_x control using only steam injection offers positive energy and other environmental impacts.

3.2.5 BACT for NO_x – Startup/Shutdown Conditions

As stated in the original PSD permit application in 1994, the intent of building the Cambalache plant was to maintain adequate system reliability and instantaneous (five second response) spinning reserve during periods of high daily demand and peak demand hours. A large number of startup/shutdown events was anticipated and this information was communicated to EPA in the original PSD permit application. However, the original PSD permit application and the permit also allowed for the possibility that the Cambalache plant might operate continuously for extended periods of time by allowing up to 8,760 hr/yr per turbine.

With regard to startups and shutdowns, PREPA is not changing the operation of the plant or emissions. In accordance with current EPA policy, PREPA is now accounting for the effect of startups and shutdowns on annual emissions. Currently, the Cambalache units are typically operating as RSR or peaking units as originally planned. However, if adequate capacity is not available either as a short-term situation due to plant availability or to demand growth, the Cambalache plant may operate similar to a base load plant.

Table 3-1 presents PREPA's latest projection of when new generation will become available. It indicates that new capacity will become available over the next several years to keep pace with increasing demand. If this is the case, Cambalache would typically operate in the RSR mode with daily startup and shutdown.

Therefore, maximum potential emissions of NO_x and CO, the emissions affected by startup, are based on the maximum emissions that would occur with either the maximum number of startups or continuous operation.

PREPA has determined that the maximum number of startup/shutdown events can be limited to an average of 780 startup/shutdown events per year for the facility. The proposed 780 startup/shutdown events per year is less than the 900 events implied by information in the original PSD permit application. PREPA proposes startups based on 20% lasting for 3 hours and 80% lasting for 2 hours.

A test program was conducted in late October and early November 2000 to determine startup and shutdown emission rates. At that time, data collected by the plant's CEMS were not designed to determine startup and shutdown emissions. The CEMs will be reconfigured to determine startup and shutdown emissions. The available startup and shutdown emission data are summarized in Tables 3-2 and 3-3.

Table 3-4 presents the revised maximum potential emissions. Maximum potential NO_x emissions of 1,801 ton/yr are based on the higher emissions from two scenarios: a) 1,643 ton/yr when accounting for the 780 startup/shutdown events (20% at 3 hours and 80% at 2 hours) and b) 1,801 ton/yr assuming continuous operation for the entire year. Similarly, the 713 ton/yr maximum potential CO emissions are based on the higher emissions from the same two scenarios: a) 713 ton/yr that accounts for the 780 startup/shutdown events (20% at 3 hours and 80% at 2 hours) and b) 514.8 ton/yr for continuous operation. Note that it is impossible to avoid the appearance of increasing the maximum annual potential CO emissions given EPA's current policy of including startup/shutdown emissions. Even 1 startup/shutdown event will increase maximum potential CO emissions.

PREPA proposes the following emissions and startup/shutdown events per year for the entire facility:

- 156 startup/shutdown events with startups lasting up to 3-hours;
- 624 startup/shutdown events with startups lasting up to 2-hours;
- Shutdowns shall not exceed 1-hour in duration;
- Startup emissions shall be limited to 305 lb/hr (NO_x) and 181 lb/hr (CO)
- Shutdown emissions shall be limited to 137 lb/hr (NO_x) and 273 lb/hr (CO)

3.3 PM, PM_{10} and Sulfuric Acid Mist Emissions

PREPA conducted stack tests to establish new BACT emission rates for PM, PM_{10} and sulfuric acid mist based on the lowest emission levels achievable at the Cambalache plant. Testing indicated that the removal of the high temperature SCR likely reduced PM and PM_{10} emissions but had no effect on sulfuric acid mist emissions. Existing permit limits, the original 1997 stack test results with SCR, the new stack test results without SCR, and PREPA's proposed BACT emission limits are summarized in Table 3-5.

For PM_{10}, PREPA proposes to reduce the emission limits from 72 lb/hr at full load and 55 lb/hr at rapid spinning reserve (RSR) load to 51 lb/hr at both loads. For PM, PREPA proposes to reduce the emission limits from 72 lb/hr at full load and 55 lb/hr at RSR load to 20 lb/hr at both loads. The test data for sulfuric acid mist emissions show that it is not possible to propose an emission reduction from the current permit limit of 32 lb/hr.

3.3.1 PM_{10} Emissions

Table 3-6 summarizes PM_{10} test results at full load. Initial testing on Unit 1 indicated compliance with existing PSD limits. Initial testing of Units 2 and 3 indicated elevated PM_{10} levels. Subsequent testing of these units resulted in compliance with the PSD limits.

The 3-run average emissions for the three units at full load are listed below:

- Unit 1 = 35.93 lb/hr
- Unit 2 = 33.46 lb/hr
- Unit 3 = 42.48 lb/hr

Initial performance testing conducted in 1997 produced 3-run average PM_{10} emissions at full load ranging from 25.35 lb/hr to 44.0 lb/hr, all of which are comparable to the latest testing conducted in 2001 – 2003.

The existing PSD limit for these units is 72 lb/hr at full load.

A PM_{10} emission rate of 51 lb/hr at full load is proposed. This limit is 20% higher than the highest 3-run average for the three units (42.48 lb/hr x 1.2 = 51 lb/hr). The use of 20% is consistent with Section II. D. of EPA Region 2's October 24, 2001 Compliance Order No. CAA-02-2002-1002.

Table 3-7 summarizes PM_{10} test results at RSR load. Initial testing on all three units indicated compliance with existing PSD limits.

The 3-run average emissions for the three units at RSR load are listed below:

- Unit 1 = 10.26 lb/hr
- Unit 2 = 20.24 lb/hr
- Unit 3 = 41.49 lb/hr

Initial performance testing conducted in 1997 produced 3-run average PM_{10} emissions at RSR load ranging from 28.88 lb/hr to 54.67 lb/hr, all of which are comparable to the latest testing conducted in 2001 – 2003.

The existing PSD limit for these units is 55 lb/hr at RSR load.

A PM_{10} emission rate of 51 lb/hr is proposed for RSR load. This limit is approximately 20% higher than the highest 3-run average for the three units (41.49 lb/hr x 1.2 = 49.8 lb/hr).

PREPA is proposing a 51 lb/hr emission limit for full load and RSR load in order to simplify compliance issues. The use of 20% is consistent with Section II. D. of EPA Region 2's October 24, 2001 Compliance Order No. CAA-02-2002-1002.

3.3.2 PM Emissions

Table 3-8 summarizes PM test results at full load. Initial testing of Units 1 and 3 indicated compliance with existing PSD limits. Initial testing of Unit 2 indicated elevated PM levels. Subsequent testing of this unit resulted in compliance with the PSD limits. Unit 3 was tested a second time in May, 2003 using Methods 5/202 in conjunction with Methods 201A/202 for PM_{10}. The results of the Method 5 testing in May, 2002 are listed in Table 3-8.

The 3-run average emissions for the three units at full load are listed below:

- Unit 1 = 2.31 lb/hr (November, 2001)
- Unit 2 = 4.66 lb/hr (second test – December, 2001)
- Unit 3 = 3.81 lb/hr (first test – January, 2002)
- Unit 3 = 11.00 lb/hr (second test – May, 2003)

Initial performance testing conducted in 1997 produced 3-run average PM emissions ranging from 30.94 lb/hr to 53.53 lb/hr. The 1997 testing results are generally a factor of ten higher than the latest results from the 2001 – 2003 testing. The higher PM results in 1997 could be due to additional particulate produced by the SCR system.

The existing PSD limit for these units is 72 lb/hr at full load.

A PM emission rate of 20 lb/hr at full load is proposed. This limit will account for the variability in the testing results. A review of Table 3-8 indicates that the second PM test on Unit 3 performed in May, 2003 produced full load PM emissions of 11.90 lb/hr, 15.89 lb/hr and 5.21 lb/hr for the three test runs. The standard deviation of these three test runs is 5.4 lb/hr. The addition of one standard deviation to the average of 11.00 lb/hr results in a total emission of 16.4 lb/hr. Scaling this value by the EPA recommended 20% produces a 20 lb/hr emission rate.

Thus PREPA is proposing a 20 lb/hr emission rate for PM at full load to allow for possible variations in PM emissions and to simplify compliance issues. The 20 lb/hr limit is also considerably lower than the existing PSD limit of 72 lb/hr at full load and considerably lower than the 1997 testing results.

Table 3-9 summarizes PM test results at RSR load. Initial testing on all three units indicated compliance with existing PSD limits.

The 3-run average emissions for the three units at RSR load are listed below:

- Unit 1 = 2.81 lb/hr

- Unit 2 = 4.13 lb/hr
- Unit 3 = 3.27 lb/hr

Initial performance testing conducted in 1997 produced 3-run average PM emissions ranging from 13.13 lb/hr to 15.87 lb/hr at RSR load, all of which are factors of 3-4 higher than the most recent testing conducted in 2001 – 2003.

The existing PSD limit for these units is 55 lb/hr at RSR load.

A PM emission rate of 20 lb/hr is proposed at RSR load. This limit is more than 20% higher than the highest 3-run average for the three units (4.13 lb/hr x 1.2 = 5.0 lb/hr).

Similar to the pollutant PM_{10}, PREPA is proposing a single limit for PM at full load and RSR load to simplify compliance issues and to allow for significant variability in test results. The 20 lb/hr limit is also considerably lower than the existing PSD limit of 55 lb/hr at RSR load.

3.3.3 Sulfuric Acid Mist Emissions

Table 3-6 summarizes sulfuric acid mist test results at full load. Initial testing on all three units indicated compliance with the PSD limits.

The 3-run average emissions for the three units at full load are listed below:

- Unit 1 = 11.39 lb/hr
- Unit 2 = 14.81 lb/hr
- Unit 3 = 11.54 lb/hr

Initial performance testing conducted in 1997 produced 3-run average sulfuric acid mist emissions at full load ranging from 7.27 lb/hr to 24.11 lb/hr, all of which are comparable to the latest testing conducted in 2001 – 2003.

The existing PSD limit for these units is 32 lb/hr at full load.

During the year 2001 – 2003 performance testing, the combustion turbines were burning distillate oil with fuel sulfur contents of 0.08% – 0.09%. The PSD permit allows fuel with a sulfur content of 0.15% to be burned. Scaled to this sulfur content, the sulfuric acid mist emissions at full load during the 2001 – 2003 testing would have been:

- Unit 1 = 18.98 lb/hr

- Unit 2 = 27.77 lb/hr
- Unit 3 = 19.23 lb/hr

Given the variability of sulfuric acid mist emissions, PREPA proposes to maintain its current 32 lb/hr PSD limit at full load.

Table 3-7 summarizes sulfuric acid mist test results at RSR load. Initial testing on all three units indicated compliance with existing PSD limits.

The 3-run average emissions for the three units at RSR load are listed below:

- Unit 1 = 6.38 lb/hr
- Unit 2 = 16.83 lb/hr
- Unit 3 = 6.29 lb/hr

Initial performance testing conducted in 1997 produced 3-run average sulfuric acid mist emissions at RSR load ranging from 5.26 lb/hr to 24.65 lb/hr, all of which are comparable to the latest testing conducted in 2001 – 2003.

The existing PSD limit for these units is 32 lb/hr at RSR load.

During the year 2001 – 2003 performance testing, the combustion turbines were burning distillate oil with fuel sulfur contents of 0.08% – 0.09%. The PSD permit allows fuel with a sulfur content of 0.15% to be burned. Scaled to this sulfur content, the sulfuric acid mist emissions at RSR load during the 2001 – 2003 testing would have been:

- Unit 1 = 10.63 lb/hr
- Unit 2 = 31.55 lb/hr
- Unit 3 = 11.79 lb/hr

Given the variability of sulfuric acid mist emissions, PREPA proposes to maintain its current 32 lb/hr PSD limit at RSR load.

3.4 Summary of Requested Amendments to the PSD Permit

PREPA proposes the following amendments to its current PSD permit for Cambalache:

Table 3-1 Puerto Rico Electric Power Authority Generation Capacity vs. Demand

Fiscal Year	Demand (MW)	Added Capacity	Installed Capacity	Spare Capacity
	(MW)		(MW)	(MW)
1996-1997	2,894		4,148	1,254
1997-1998	3,021	248 MW Cambalache	4,396	1,375
1998-1999	3,057		4,396	1,339
1999-2000	3,133	507 MW Ecoelectrica	4,903	1,770
San Juan Repowering not online 464 MW				
2000-2001	3,202		4,903	1,701
AES not online 454 MW				
2001-2002	3,378		4,903	1,525
2002-2003*	3,439	454 MW AESPR	5,357	1,918
2003-2004*	3,559		5,357	1,798
2004-2005*	3,687		5,357	2,134
2005-2006*	3,822	464 MW San Juan Combined Cycle Project	5,821	1,999
* -Projected Values				

Currently the Cambalache units are typically operating as RSR or peaking units as originally planned. However, if adequate capacity is not available either as a short term situation due to plant availability or to demand growth, the Cambalache plant may operate similar to a base load plant.

Table 3-2 Summary of NO_x and CO Startup Emissions

Unit	Date	NOx Emissions lb/hr	CO Emissions lb/hr
1	10/31/00	286	154
1	11/02/00	240	167
Unit 1 Average		263	161
2	10/26/00	363	195
2	10/27/00	317	267
2	10/28/00	248	207
2	10/30/00	359	180
Unit 2 Average		322	212
3	10/19/00	300	164
3	10/20/2000	301	166
3	10/22/2000	393	128
3	10/23/2000	356	192
3	10/24/2000	296	196
Unit 3 Average		329	169
Average of 3 Units		**305**	**181**

Table 3-3 Summary of NO_x and CO Shutdown Emissions

Unit	Date	NOx Emissions	CO Emissions
		lb/hr	lb/hr
1	10/30/2000	92	197
1	11/01/00	79	235
Unit 1 Average		86	216
2	10/26/00	225	229
2	10/28/00	200	401
2	10/30/00	225	401
Unit 2 Average		217	344
3	10/18/00	112	266
3	10/19/00	115	265
3	10/20/2000	108	255
3	10/22/2000	99	257
3	10/23/2000	103	249
Unit 3 Average		107	258
Average of 3 Units		**137**	**273**

Table 3-4 Annual Potential to Emit Calculation Including Startups and Shutdowns

Parameter	NOx			CO		
Emissions without startups/shutdowns	**hr/yr**	**lb/hr**	**ton/yr**	**hr/yr**	**lb/hr**	**ton/yr**
Base load	6,760	147.7	499.2	6,760	20.0	67.6
RSR load	2,000	101.0	101.0	2,000	104.0	104.0
Total for one turbine	**8,760**		**600.2**	**8,760**		**171.6**
Total for three turbines			**1,801**			**514.8**
Emissions with startups and shutdowns						
Average number of starts per turbine	260			260		
Maximum average startup duration, hr	2.20 (a)			2.2 (a)		
Maximum shutdown duration, hr	1			1		
Time not operating per start	5			5		
Normal operating hours, hr/yr	6,628			6,628		
Startup/shutdown emissions per turbine						
Startup emission rate, lb/hr lb/start	305	671 (a)		181	398 (a)	
Startup emission emissions, ton/yr		87.2			51.8	
Shutdown emission rate, lb/hr lb/start	137	137 (a)		273	273 (a)	
Shutdown emission emissions, ton/yr		17.8			35.5	
Offline (non-operating) hours, hr/yr	1,300			1,300		
Startup/shutdown hours, hr/yr	832			832		
Base load operating hours	4,628			4,628		
Base load emission rate, lb/hr	147.7			20.0		
Base load emissions, ton/yr		341.8			46.3	
RSR load operating hours	2,000			2,000		
RSR load emission rate, lb/hr	101.0			104.0		
RSR load emissions, ton/yr		101.0			104.0	
Total emissions with startups/shutdowns for one turbine, ton/yr		**548**			**238**	
Total emissions with startups/shutdowns for three turbines, ton/yr		**1,643**			**713**	
Maximum potential to emit, ton/yr (b)		**1,801**			**713**	

(a) Annual average (365 day rolling average) emissions per startup or shutdown.

(b) Either continuous operation (emissions without startups or shutdowns) or emissions with startups and shutdowns, whichever is higher.

Table 3-5 Summary of Emission Test Results and Proposed Emission Limits

Pollutant	Load	Existing Permit Limit	1997 Test Result		Test Result after SCR Removal		Proposed Emission Limit
			Maximum 3-Run Average	Maximum Run	Maximum 3-Run Average	Maximum Run	
		lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
PM10	Full load	72	44	46	43 (a)	49 (a)	51
	RSR	55	54	88	42	52	51
PM	Full load	72	54	64	11	16	20
	RSR	55	16	18	3.4	4	20
Sulfuric acid mist	Full load	32	24	33	28 (b)	29 (b)	32
	RSR	32	17	33	32 (b)	72 (b)	32

(a) Valid test results only.
(b) Adjusted to 0.15% S in fuel.

Table 3-6 PM10 and Sulfuric Acid Mist Test Results at Full Load

Unit 1 Full Load

Run No.	Units	Run 1	Run 2	Run 3	Average	1997 result
Date		02-Nov-01	02-Nov-01	02-Nov-01		
Start Time		10:00	12:46	17:15		
Stop Time		12:52	16:38	19:58		
Sampling Parameters (a)						
Barometric Pressure	in. Hg	29.95	29.95	29.95	29.95	
Volume Metered	dcf	67.434	67.041	68.498	67.650	
Volume of Gas Collected	dscf	64.399	63.468	65.763	64.544	
Moisture	% v/v	13.9	14.1	13.7	13.9	
O_2 at Stack	% dry	14.82	14.73	14.81	14.79	
CO_2 at Stack	% dry	3.80	3.80	3.80	3.77	
Avg. Stack Temp.	°F	749	750	750	750	
Stack Flowrate	dscfm	818,262	811,611	829,397	819,757	
Stack Flowrate	dscfm at 15% O2	834,178	834,919	846,445	838,514	
PM10 Solid	lb/hr	8.30	6.68	10.03	8.38	4.69
PM10 Aqueous Condensible	lb/hr	0.88	18.16	14.86	10.57	28.81
PM10 Organic Condensible	lb/hr	2.14	26.00	23.61	16.68	2.68
Total PM10	lb/hr	11.28	47.87	48.50	35.93	32.58
Sulfuric acid mist	lb/hr	13.98	11.77	8.11	11.28	7.27
Fuel sulfur	wt.%	0.09	0.09	0.09	0.08	
Sulfuric acid mist at 0.16% S	lb/hr	22.13	19.82	15.16	18.98	

Unit 2 Full Load (First Test)

Run No.	Units	Run 1	Run 2	Run 3	Average
Date		19-Oct-01	19-Oct-01	19-Oct-01	
Start Time		11:30	16:30	11:08	
Stop Time		15:27	20:09	13:55	
Sampling Parameters (a)					
Barometric Pressure	in. Hg	29.93	29.93	29.95	29.85
Volume Metered	dcf	58.682	58.404	61.913	58.388
Volume of Gas Collected	dscf	57.699	57.812	50.501	55.337
Moisture	% v/v	12.1	13.6	14.7	13.8
O_2 at Stack	% dry	16.00	16.16	16.01	16.06
CO_2 at Stack	% dry	3.53	3.80	3.83	3.72
Avg. Stack Temp.	°F	738	739	739	738
Stack Flowrate	dscfm	632,773	625,928	619,987	626,089
Stack Flowrate	dscfm at 15% O2	632,773	609,888	518,687	620,447
PM10 Solid	lb/hr	Tests were determined to be invalid.			
PM10 Aqueous Condensible	lb/hr				
PM10 Organic Condensible	lb/hr				
Total PM10	lb/hr				
Sulfuric acid mist	lb/hr	14.41	15.60	14.42	14.81
Fuel sulfur	wt.%	0.08	0.08	0.08	0.08
Sulfuric acid mist at 0.16% S	lb/hr	27.02	28.25	27.04	27.77

Unit 2 Full Load (Second Test)

Run No.	Units	Run 1	Run 2	Run 3	Average	1997 result
Date		14-Dec-01	14-Dec-01	14-Dec-01		
Start Time		08:49	13:51	17:17		
Stop Time		11:21	16:17	19:38		
Sampling Parameters (a)						
Barometric Pressure	in. Hg	29.95	29.95	29.95	29.95	
Volume Metered	dcf	57.160	65.987	62.216	63.121	
Volume of Gas Collected	dscf	55.531	54.273	50.711	53.505	
Moisture	% v/v	13.0	13.4	12.7	13.1	
O_2 at Stack	% dry	16.47	16.33	16.33	16.39	
CO_2 at Stack	% dry	3.97	3.87	4.00	3.98	
Avg. Stack Temp.	°F	717	716	711	714	
Stack Flowrate	dscfm	594,317	630,060	631,280	683,679	
Stack Flowrate	dscfm at 15% O2	637,769	657,057	658,284	651,037	
PM10 Solid	lb/hr	11.25	8.70	13.70	11.57	4.77
PM10 Aqueous Condensible	lb/hr	11.39	18.61	27.40	19.10	34.67
PM10 Organic Condensible	lb/hr	3.33	0.57	4.48	2.79	4.58
Total PM10	lb/hr	25.97	28.85	46.66	33.46	44.00
Sulfuric acid mist	lb/hr					24.11
Fuel sulfur	wt.%	0.10	0.10	0.10	0.10	
Sulfuric acid mist at 0.16% S	lb/hr					

Unit 3 Full Load (First Test)

Run No.	Units	Run 1	Run 2	Run 3	Average
Date		30-Jan-02	30-Jan-02	30-Jan-02	
Start Time		10:58	15:45	08:30	
Stop Time		14:02	18:37	13:34	
Sampling Parameters (a)					
Barometric Pressure	in. Hg	29.83	29.80	29.90	29.83
Volume Metered	dcf	59.602	59.615	59.212	59.476
Volume of Gas Collected	dscf	57.547	57.565	57.121	57.418
Moisture	% v/v	11.4	11.9	11.2	11.6
O_2 at Stack	% dry	15.40	16.37	16.30	16.36
CO_2 at Stack	% dry	4.00	3.97	4.10	4.02
Avg. Stack Temp.	°F	728	724	720	724
Stack Flowrate	dscfm	632,276	587,052	653,400	685,243
Stack Flowrate	dscfm at 15% O2	652,134	650,236	658,492	653,614
PM10 Solid	lb/hr	Tests were determined to be invalid.			
PM10 Aqueous Condensible	lb/hr				
PM10 Organic Condensible	lb/hr				
Total PM10	lb/hr				
Sulfuric acid mist	lb/hr	12.68	8.59	12.87	11.64
Fuel sulfur	wt.%	0.09	0.09	0.08	0.09
Sulfuric acid mist at 0.16% S	lb/hr	21.80	14.46	21.62	19.23

Unit 3 Full Load (Second Test)

Run No.	Units	Run 1	Run 2	Run 3	Run 4	Average
Date		30-Jan-03	30-Jan-03	30-Jan-03	30-Jan-03	
Start Time		08:32	12:13	11:21	14:35	
Stop Time		11:09	14:38	13:41	17:00	
Sampling Parameters (a)						
Barometric Pressure	in. Hg	30.00	30.00	30.00	29.88	29.98
Volume Metered	dcf	65.891	68.314	57.935	69.414	68.528
Volume of Gas Collected	dscf	66.747	65.257	65.627	67.163	66.016
Moisture	% v/v	11.8	11.8	12.2	12.2	12.1
O_2 at Stack	% dry	13.13	13.23	14.43	14.43	14.03
CO_2 at Stack	% dry	3.50	4.20	4.60	3.43	3.84
Avg. Stack Temp.	°F	741	749	754	745	750
Stack Flowrate	dscfm	534,232	575,702	567,764	587,048	570,838
Stack Flowrate	dscfm at 15% O2	763,561	749,413	622,815	713,630	694,853
PM10 Solid	lb/hr	Tests were determined to be invalid.				
PM10 Aqueous Condensible	lb/hr					
PM10 Organic Condensible	lb/hr					
Total PM10	lb/hr					
Sulfuric acid mist	lb/hr					
Fuel sulfur	wt.%	0.12	0.12	0.12	0.12	0.12
Sulfuric acid mist at 0.16% S	lb/hr					

Unit 3 Full Load (Third Test-201A/202)

Run No.	Units	Run 1	Run 2	Run 3	Average
Date		29-May-03	29-May-03	29-May-03	
Start Time		08:09	12:38	15:52	
Stop Time		11:47	15:15	18:10	
Sampling Parameters (a)					
Barometric Pressure	in. Hg	29.65	29.63	29.63	29.63
Volume Metered	dcf	68.140	68.383	56.532	64.352
Volume of Gas Collected	dscf	63.494	63.707	52.636	60.625
Moisture	% v/v	12.5	12.4	12.2	12.4
O_2 at Stack	% dry	12.40	12.63	13.40	12.88
CO_2 at Stack	% dry	3.68	3.90	3.70	3.77
Avg. Stack Temp.	°F	723	723	718	721
Stack Flowrate	dscfm	583,774	592,050	580,093	590,320
Stack Flowrate	dscfm at 15% O2	848,230	809,861	750,119	802,738
PM10 Solid	lb/hr	1.84	2.45	3.29	2.48
PM10 Aqueous Condensible	lb/hr	30.88	39.66	39.43	39.73
PM10 Organic Condensible	lb/hr	2.84	2.45	4.56	3.27
Total PM10	lb/hr	35.76	44.41	47.27	42.48
Sulfuric acid mist	lb/hr				
Fuel sulfur	wt.%	0.14	0.14	0.14	0.14
Sulfuric acid mist at 0.16% S	lb/hr				

Unit 3 Full Load (Third Test-5/202)

Run No.	Units	Run 1	Run 2	Run 2	Average	1997 result	Proposed Emission Limit
Date		29-May-03	29-May-03	29-May-03			
Start Time		08:09	12:39	15:52			
Stop Time		11:23	16:13	19:10			
Sampling Parameters (a)							
Barometric Pressure	in. Hg	29.63	29.63	29.63	29.63		
Volume Metered	dcf	92.717	94.626	95.679	94.368		
Volume of Gas Collected	dscf	65.695	59.632	65.874	60.623		
Moisture	% v/v	12.4	12.6	12.6	12.4		
O_2 at Stack	% dry	12.40	12.63	13.40	12.83		
CO_2 at Stack	% dry	3.69	3.60	3.70	3.77		
Avg. Stack Temp.	°F	720	718	714	721		
Stack Flowrate	dscfm	583,170	593,830	568,948	590,320		
Stack Flowrate	dscfm at 15% O2	811,347	771,232	720,570	767,716		
PM10 Solid	lb/hr	11.90	15.68	5.05	10.88	3.87	
PM10 Aqueous Condensible	lb/hr	44.29	54.18	43.44	47.41	20.05	
PM10 Organic Condensible	lb/hr	22.93	1.28	1.35	8.43	1.43	
Total PM10	lb/hr	79.18	71.13	49.84	66.70	25.35	51
Sulfuric acid mist	lb/hr					17.67	
Fuel sulfur	wt.%	0.14	0.14	0.14	0.14		
Sulfuric acid mist at 0.16% S	lb/hr						32

(a)

Table 3-7 PM10 and Sulfuric Acid Test Results at Rapid Spinning Reserve Load

		Unit 1 RSR Load					Unit 2 RSR Load					Unit 3 RSR Load					Proposed Emission Limit
Run No.		Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	Run 4	Run 2	Run 3	Average	1997 result	
Date		01-Nov-01	01-Nov-01	01-Nov-01			19-Oct-01	20-Oct-01	20-Oct-01			31-Jan-02	30-Jan-02	31-Jan-02			
Start Time	Units	14:02	17:42	21:03			18:07	06:55	11:10			12:33	19:39	08:58			
Stop Time		16:35	20:20	23:55			21:01	09:33	13:57			15:05	22:45	11:51			
Sampling Parameters –																	
Barometric Pressure	in. Hg	29.95	29.95	29.95	29.95		29.95	29.95	29.95	29.95		29.75	29.75	30.05	29.85		
Volume Metered	dcf	53.798	55.377	54.950	54.708		55.735	50.463	51.098	52.431		52.313	54.461	51.393	52.722		
Volume of Gas Collected	dscf	51.140	54.889	54.658	53.562		54.679	49.247	49.703	51.210		49.609	52.682	49.713	50.668		
Moisture	% v/v	10.9	10.4	10.7	10.7		10.5	9.3	11.2	10.3		9.3	9.1	9.3	9.3		
O_2 at Stack	% dry	16.99	16.99	16.91	16.96		16.93	17.02	17.01	16.99		16.90	16.90	16.90	16.90		
CO_2 at Stack	% dry	3.90	4.00	4.00	3.97		3.03	2.57	2.93	2.84		3.11	3.09	3.11	3.10		
Avg. Stack Temp.	°F	596	594	593	594		592	592	593	592		605	607	604	606		
Stack Flowrate	dscfm	562,411	584,961	578,453	575,275		576,013	567,520	560,099	567,877		530,187	570,758	532,295	544,414		
Stack Flowrate	dscfm at 15% O2	372,717	387,660	391,191	383,856		387,588	373,216	369,286	376,697		359,449	386,955	360,878	369,094		
PM10 Solid	lb/hr	0.29	4.50	3.63	2.81	4.42	8.62	0.61	2.83	4.02	3.47	0.85	1.00	0.00	0.62	4.51	
PM10 Aqueous Condensible	lb/hr	3.92	0.84	2.10	2.29	28.15	11.82	10.04	11.16	11.01	42.58	26.52	35.32	12.16	24.67	23.41	
PM10 Organic Condensible	lb/hr	10.16	2.39	2.93	5.16	1.00	7.79	5.17	2.68	5.21	8.62	12.41	15.45	20.78	16.21	0.96	
Total PM10	lb/hr	14.37	7.74	8.66	10 26	33.57	28.23	15.82	16.66	20.24	54.67	39.78	51.77	32.93	41.49	28.88	51
Sulfuric acid mist	lb/hr	4.64	8.48	6.02	6.38	5.26	38.66	5.97	5.85	16.83	24.65	5.03	7.93	5.91	6.29	17.87	
Fuel sulfur	wt %	0.09	0.09	0.09	0.09		0.08	0.08	0.08	0.08		0.08	0.08	0.08	0.08		
Sulfuric acid mist at 0.15% S	lb/hr	7.73	14.13	10.03	10.63		72.49	11.19	10.97	31.55		9.43	14.87	11.08	11.79		32

Table 3-8 PM Test Results at Full Load (a)

		Unit 1 Full Load					Unit 2 Full Load (Second Test)					Unit 3 Full Load (First Test)					Unit 3 Full Load (Third Test)					Proposed Emission Limit
Run No.		Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	
Date		02-Nov-01	02-Nov-01	02-Nov-01			14-Dec-01	14-Dec-01	14-Dec-01			29-Jan-02	29-Jan-02	30-Jan-02			29-May-03	29-May-03	29-May-03			
Start Time		10:00	13:46	17:15			08:49	13:51	17:17			10:56	15:45	09:30			09:09	12:39	15:52			
Stop Time		12:48	16:23	19:53			11:16	16:12	19:34			14:14	18:37	12:34			11:23	15:13	18:10			
Sampling Parameters --																						
	Units																					
Barometric Pressure	in. Hg	29.95	29.95	29.95	29.95		29.95	29.95	29.95	29.95		29.95	29.80	29.90	29.88		29.85	29.85	29.85	29.85		
Volume Metered	dcf	92.684	94.603	91.048	92.778		86.683	85.953	87.231	86.622		88.193	89.691	87.147	88.344		92.717	94.625	95.670	94.337		
Volume of Gas Collected	dscf	86.776	87.276	85.810	86.621		85.259	84.510	86.074	85.281		86.157	87.137	85.040	86.111		85.595	86.952	88.874	87.140		
Moisture	% v/v	14.8	14.5	14.6	14.6		12.8	13.0	13.1	13.0		12.3	12.4	12.6	12.4		12.4	12.5	12.5	12.5		
O_2 at Stack	% dry	14.82	14.73	14.81	14.79		15.47	15.33	15.33	15.38		15.40	15.37	15.30	15.36		12.40	12.83	13.40	12.88		
CO_2 at Stack	% dry	3.90	3.80	3.60	3.77		3.97	3.97	4.00	3.98		4.00	4.00	4.10	4.03		3.80	3.80	3.70	3.77		
Avg. Stack Temp.	°F	755	755	748	752		716	715	716	716		724	723	728	725		720	718	714	717		
Stack Flowrate	dscfm	490,369	490,192	487,309	489,290		551,416	542,601	546,818	546,945		553,854	560,780	553,379	556,008		563,170	563,850	566,848	564,623		
PM	lb/hr	2.16	2.37	2.40	2.31	45.73	5.55	4.83	3.61	4.66	30.94	3.73	3.57	4.12	3.81	53.53	11.90	15.89	5.21	11.00	53.53	20

(a) Unit 2 First Test was considered to be invalid. No PM testing was conducted during Unit 3 (Second Test).

Table 3-9 PM Test Results at Rapid Spinning Reserve Load

		Unit 1 RSR Load					Unit 2 RSR Load					Unit 3 RSR Load					Proposed Emission Limit
Run No.		Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	Run 1	Run 2	Run 3	Average	1997 result	
Date		01-Nov-01	01-Nov-01	01-Nov-01			19-Oct-01	20-Oct-01	20-Oct-01			30-Jan-02	30-Jan-02	31-Jan-02			
Start Time		07:23	17:42	21:03			18:07	08:55	11:10			14:54	19:39	08:58			
Stop Time		09:30	20:19	23:48			20:58	09:45	13:53			18:26	22:44	12:05			
Sampling Parameters –	Units																
Barometric Pressure	in. Hg	29.95	29.95	29.95	29.95		29.95	29.95	29.95	29.95		29.75	29.75	29.75	29.75		
Volume Metered	dcf	90.100	83.750	89.430	87.760		98.535	97.755	95.019	98.436		86.687	87.978	84.547	86.404		
Volume of Gas Collected	dscf	87.560	82.521	88.303	86.128		93.057	93.987	91.808	92.944		84.459	85.648	82.214	84.107		
Moisture	% v/v	10.9	10.9	11.3	11.0		10.8	10.8	11.4	11.0		10.1	9.9	9.9	10.0		
O_2 at Stack	% dry	16.99	16.99	16.91	16.98		16.93	17.02	17.01	16.99		16.90	16.90	16.90	16.90		
CO_2 at Stack	% dry	3.90	4.00	4.00	3.97		3.03	2.57	2.93	2.84		3.09	3.09	3.11	3.10		
Avg. Stack Temp.	°F	600	600	600	600		595	596	598	596		611	610	610	610		
Stack Flowrate	dscfm	548,032	562,705	553,597	554,778		557,325	559,877	548,067	555,090		554,202	561,571	547,779	554,517		
PM	lb/hr	2.07	4.05	2.32	2.81	13.13	6.01	2.99	3.39	4.13	13.49	3.72	3.81	2.29	3.27	15.87	20

ATTACHMENT I

GENERAL PROJECT DESCRIPTION

The last sentence should read: "*In addition, the facility will be allowed to operate in a spinning reserve mode (60 percent load) for up to 6,000 hours per year total for the facility*".

PSD-Affected Pollutants Emitted at the PREPA Cambalache Combustion Turbine Project:

- Increase NO_x emissions from 460 tons per year (tpy) to 1,801 tpy
- Increase CO emissions from 515 tpy to 713 tpy*
- Reduce PM emissions from 946 tpy to 263 tpy
- Reduce PM_{10} emissions from 946 tpy to 670 tpy

*Note that the increase in CO emissions is due to emissions from startups and shutdowns. This activity is specifically authorized in the current PSD permit with no limit to their number. PREPA has been operating the Cambalache power plant since 1997 with frequent startups and shutdowns. However, the emissions from startups and shutdowns were not included in the PSD permit because EPA did not include them in 1995.

Attachment II

No changes to Section I., II., III., IV., V., and VI.

VII. Operating Requirements

No changes to 1., 2a., 3. and 4.

2b. Replace *0.10 percent nitrogen by weight* with *0.055 percent nitrogen by weight*

5. Replace the first sentence with the following two sentences: *"The facility will be allowed to operate for up to 6,000 hours per year at the "spinning reserve" mode heat input level. The 6,000 hours represents the total for the three turbines."*

6. a. Replace the last sentence with the following two sentences: *"The facility will be limited to 780 startups per year. The duration of 80 % of the startups shall not exceed two (2) hours and the duration of 20% of the startups shall not exceed three (3) hours for any given combustion turbine startup."*

b. Replace the last sentence with the following two sentences: "*The facility will be limited to 780 shutdowns per year. The duration of the shutdowns shall not exceed one (1) hour for any given combustion turbine shutdown.*"

VIII. Emission Limitations for Each ABB GT 11N Combustion Turbine

1. Oxides of Nitrogen

a. Increase NO_x emissions from 35 pounds per hour (lbs/hr) to 147.7 lbs/hr

b. Increase the NO_x concentration in the exhaust gas from 10 parts per million by volume on a dry basis (ppmdv), corrected to 15% oxygen (O_2) to 42 ppmvd @ 15% O_2.

c. (new). Add the following: "*NO_x emissions shall not exceed 305 lb/hr during startup and shall not exceed 137 lb/hr during shutdown.*"

2. Sulfur Dioxide (SO_2)

No changes

3. Sulfuric Acid Mist

No changes

4. Carbon Monoxide

c. (new) Add the following: "*CO emissions shall not exceed 181 lb/hr during startup and shall not exceed 273 lb/hr during shutdown.*"

5. Particulate Matter (PM)

a. The PM emissions shall not exceed 20 lbs/hr at the "spinning reserve" mode and at the base load heat input levels;

b. The concentrations of PM in the exhaust gas, corrected to 15% oxygen, shall not exceed:

(i) 0.0055 grains per dry standard cubic feet (gr/dscf) at the "spinning reserve" mode heat Input level; and

(ii) 0.0047 gr/dscf at the base load heat input level

6. **Particulate Matter < 10 microns (PM-10)**

a. The PM-10 emissions shall not exceed 51 lbs/hr at the "spinning reserve" and base load heat input levels.

b. The concentration of PM-10 in the exhaust gas, corrected to 15% oxygen, shall not exceed:

(i) 0.0141 gr/dscf at the "spinning reserve" mode heat Input level; and

(ii) 0.0120 gr/dscf at the base load heat input level

7. **Volatile Organic Compounds (VOC)**

No changes

8. **Lead**

No changes

9. **Ammonia**

Delete

10. **Opacity limitation**

No changes

IX. <u>Pollution Control Equipment</u>

1. remove b.

2. no changes

3. remove

4. a. No changes

b. Decrease fuel nitrogen content from 0.1% to 0.055%.

5. No changes

X. Fuel Sampling Requirements

No changes

XI. Continuous Emission Monitoring (CEM) Requirements

1. Remove e.

No other changes

XII. Performance Testing Requirements for Each Combustion Turbine

No changes

XIII. Recordkeeping Requirements

No changes

XIV. REPORTING REQUIREMENTS

No changes

XV. OTHER REQUIREMENTS

No changes

4.0 SUMMARY OF MODELING METHODOLOGY

4.1 Required Ambient Air Quality Analyses

Dispersion modeling was performed to determine if the Cambalache Power Plant would have significant impacts for NO_x (as NO_2), the only pollutant subject to PSD review. If impacts are predicted to be below EPA's significant impact levels (SILs), no further analysis would be needed. If predicted impacts are at or above the SILs, an analysis of PSD increment consumption and a demonstration of compliance with the NAAQS would be required. An ambient air quality analysis would also be required to establish background concentrations.

Removal of the SCR has resulted in elimination of ammonia emissions. Therefore, PREPA has performed modeling to assess the ammonia impacts associated with SCR operation in order to determine the benefits that have occurred through the elimination of ammonia emissions.

The air quality impact analysis requirements of PSD review also specify that an applicant evaluate:

- the Project's impact on soils and vegetation;
- visibility impacts in the project area; and
- the air quality impacts associated with growth caused as a result of operation of the facility.

No Class 1 areas are located within 100 km of the Project site. Therefore, the Class 1 impact analysis requirements of the PSD regulations do not apply.

4.2 Description of Project Area

The site is located on the northwest coast of Puerto Rico, in the valley and floodplain of the Rio Grande de Arecibo, in the Coastal Lowlands Province. The Rio Grande de Arecibo originates in Cordillera Central Province, and flows north through the Carbonate Province, where it has carved through the mature karst. Approximately three miles from the coast, the River opens into a broad lowland typical of the North Coastal Lowlands Province.

Terrain within 3.5 km of the Power Plant stack is flat to gently rolling. Hilly terrain is located beyond 3.5 km to the southwest through southeast. This terrain reaches stack height elevation (33.5 meters, msl) at approximately 3.5 km to the southwest. Terrain rises abruptly further to the southwest, reaching 200 meters at 6.75 km and 300 meters at approximately 10.5 km.

The EQB source inventory lists several major sources of air pollution in the project area, including:

- Best Foods Caribbean;
- Global Fibers; and
- Kayser-Roth Hosiery

All of these sources were operating at the time ambient air quality monitoring data were obtained by PREPA in support of the proposed Cambalache Power Plant from August, 1992 - August, 1993. The data from the monitoring program indicate that the area has excellent air quality. In particular, the maximum monitored 1-hour and annual average NO_2 concentrations were 56 ug/m^3 and 8 ug/m^3, respectively. The NAAQS for NO_2 is 100 ug/m^3 based on the annual averaging period.

4.3 Good Engineering Practice Stack Height and Cavity Analysis

GEP Analysis

A GEP stack height analysis was presented in the 1994 PSD application. The analysis was performed in accordance with EPA's Guideline for Determination of Good Engineering Practice Stack Height (EPA 1985). The analysis concluded that GEP height for each of the three stacks is 33.39 meters, above local grade. Since the stacks are each 30.5 meters above local grade, they could experience aerodynamic downwash under certain meteorological conditions. Therefore, building dimensions were input to the dispersion model to simulate downwash. The building dimensions used in the modeling are the same as those used in the 1994 modeling. The dimensions are included as part of the model output included in Appendix C.

Cavity Analysis

Emissions from a source located near a structure could be influenced by wind flow altered by the presence of the structure if the release height is less than GEP height. An area of recirculating air, referred to as the cavity region, is often present on the leeward side of a building. Effluent released into the cavity may result in elevated ambient concentrations. There are no cavity areas that extend off the property in any direction.

4.4 Dispersion Coefficients

For air quality dispersion modeling, existing land use around the site must be classified. The recommended EPA procedure, as proposed by Auer (1978), involves classifying land use types within a three-km radius of the site as either urban or rural. In general, heavy industrial, light industrial, commercial, and single and multi-family compact residential areas are considered urban. All other areas are characterized as rural. If urban-type land uses make up more than 50 percent of the total area, urban dispersion coefficients are used in modeling; otherwise, appropriate rural dispersion coefficients are used. As shown in the 1994 PSD application, land use within a three-km radius of the site consists of approximately 90% rural and 10% urban uses. The land use in the area has not changed since 1994. Therefore, the dispersion environment can be classified as rural and appropriate rural dispersion coefficients were used in air modeling.

4.5 Dispersion Model

The EPA ISCST3 model (Version 99155) was used to estimate ground-level concentrations of NO_2 emitted as NOx from the Cambalache Power Plant. ISCST3 is a steady-state Gaussian model that was developed for the EPA to simulate dispersion from a variety of source types. ISCST3 was selected because it is a multiple-source model that can simulate diffusion in simple terrain (terrain below stack height), in intermediate terrain (terrain between stack top and plume height) and complex terrain (above plume height). ISCST3 was run in regulatory default mode and using the complex terrain option.

4.6 ISCST3 Receptor Grids

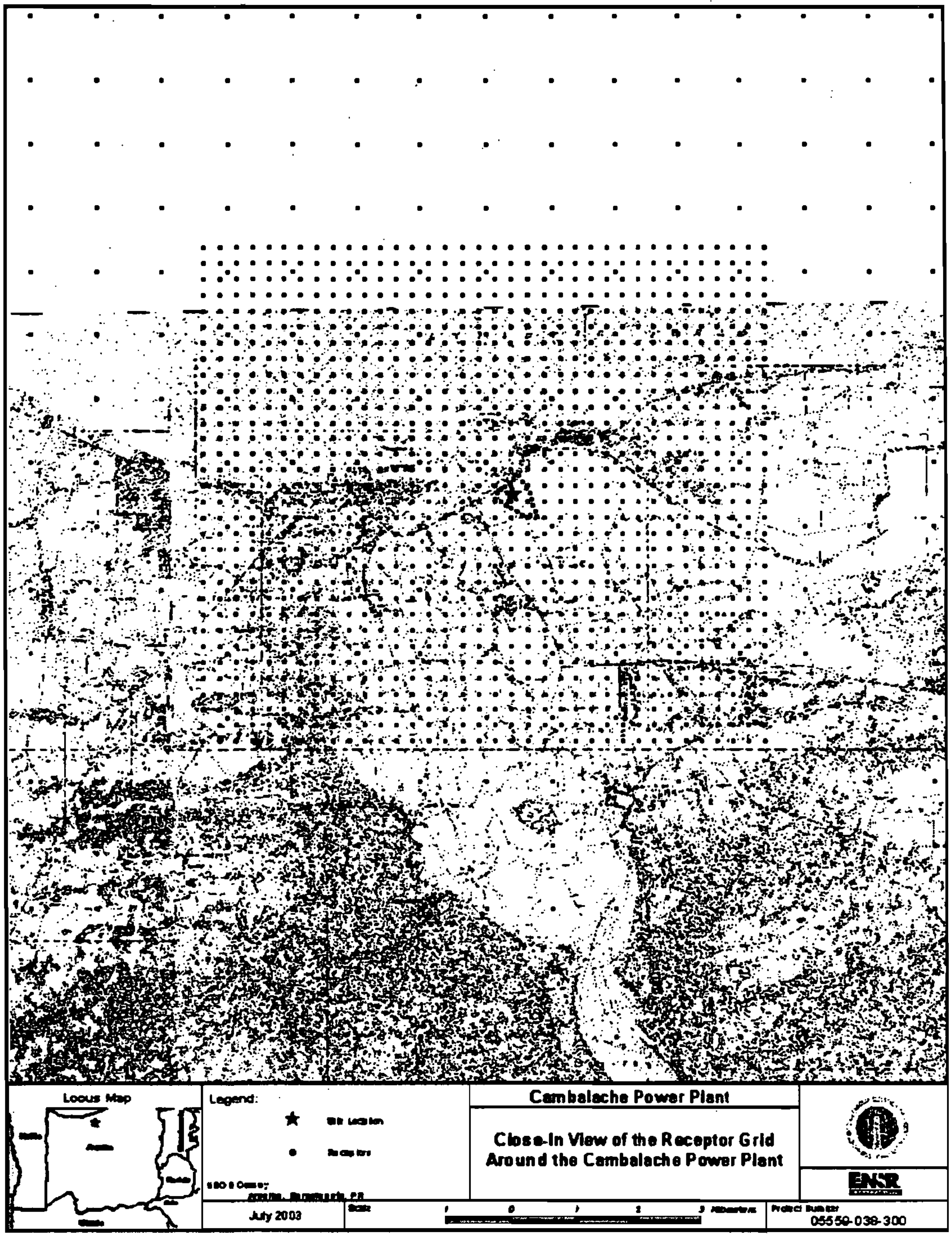
ISCST3 modeling was performed using the same set of coarse, medium and refined grids used in the 1994 PSD application. The coarse and medium grids served to pinpoint the location of maximum impact. Plant related NO_2 impacts used to assess significance were based on results of the dense grid modeling.

The coarse grid consisted of a 31 x 31 km Cartesian grid centered on the power plant stacks with a 1 km spacing between receptors. The stacks and receptors were assigned locations using UTM coordinates. Elevations assigned to each receptor are the highest within the area located halfway to the nearest receptor. A close-in view of the dense grid is shown in Figure 4.6-1.

Several medium density grids were also included in the modeling. The largest consisted of a 9 x 8-km Cartesian grid centered on the power plant stacks with a 250 meter spacing between receptors. In addition to the Cartesian grids, discrete receptors were placed at 100-meter intervals along the property line. A close-in view of the largest medium density grid that surrounds the power plant is shown in Figure 4.6-1.

The maximum annual average NO_2 concentration was predicted approximately 5-km west-southwest of the power plant at the edge of the medium density grid. A 1000 x 1000-meter refined grid with 100-meter spacing surrounding the point of maximum impact was used in calculating the maximum NO_2 impact from the facility.

Figure 4.6-1 Close-in View of the Receptor Grid Around the Cambalache Power Plant



A full listing of the coarse, medium and refined grids is included in Appendix C.

4.7 Meteorological Data Used in the Detailed Modeling

ISCST3 modeling was performed using one year (August 12,1992 to August 11, 1993) of on-site meteorological from the PSD preconstruction monitoring program for the Cambalache Combustion Turbine Project. EPA Region 2 approved this database for use in PSD type modeling (EPA, 1993). Wind speed and direction were measured at 10 meters and 30 meters above ground level. The wind data from the 30 meter level of the tower was used in the modeling because it is the same height as the stacks.

4.8 Worst-Case Load Modeling

The only sources of NO_x and ammonia emissions at the Cambalache Power Plant are the three combustion turbines. All of these sources were modeled in this analysis.

Table 4.8-1 presents stack and flue gas exit parameters for the combustion turbines at base load and at "spinning reserve" (60% load) conditions. The PSD permit allows operation only at these two loads. Table 4.8-2 presents more detailed performance data for the turbines. According to Figure 6.2-2 in the 1994 PSD Application, the combustion turbine stacks are 20 meters apart. The stacks have inner diameters of 4.72 meters at the exit. The distance between the stacks is a factor of five greater than the stack diameters. According to EPA Region 2 (EPA, 2000), stacks located more than one stack diameter apart must be modeled assuming no plume rise enhancement from adjacent stack gases. Therefore, in the current modeling, multiple stacks were modeled as one stack (i.e. all three stacks were assumed to be co-located) and with the stack diameter set to 4.72 meters. The NO_x emission rate assigned to that stack equaled the combined rate from two stacks or from three stacks, depending upon the case being modeled.

Emissions of ammonia average 150 ppmvd @ 15% O_2 (see Figures 1-1, 1-2, and 1-3). Allowing for the molecular weight differences between ammonia (17 lb/lb-mole) and NO_x (46 lb/lb-mole), ammonia is currently released at the following rates (assuming 59 °F ambient temperature):

- Case 1 - One CGT at base load: 25.97 gram/sec
- Case 2 - One CGT at 60% load: 17.85 gram/sec
- Case 3 - Two CGTs at base load: 51.93 gram/sec
- Case 4 - ; Two CGTs at 60% load: 35.69 gram/sec
- Case 5 - Three CGTs at base load: 77.91 gram/sec
- Case 6 - Three CGTs at 60% load: 53.54 gram/sec

Coarse and medium density grid modeling was performed to determine the worst case emission configuration for the combustion turbines. Modeling was performed for the eighteen cases listed in

Table 4.8-1 Plume Characteristics for Modeling Cambalache Power Plant

Parameter	Units	Value
Stack Location		
UTM Easting	meters	742902
UTM Northing	meters	2043981
Stack Inner Diameter	meters	4.72
Stack Height	meters	30.48
Stack Base Elevation	meters	3.05

Load Condition - Base	Units	Value		
		59F	85F	90F
Exit Temperature	K	648	654	654
Exit Velocity	meters/sec	35.9	34.6	34.3
NO_x	Ppmvd @ 15% O_2	42	42	42
NO_x	Gram/sec (I unit)	19.67	18.6	18.11
NO_x	Gram/sec (2 units)	39.35	37.21	36.23
NO_x	Gram/sec (3 units)	59.02	55.81	54.34

Load Condition - 60%	Units	Value		
		59F	85F	90F
Exit Temperature	K	578	622	624
Exit Velocity	meters/sec	26.6	27.4	27.3
NO_x	Ppmvd @ 15% O_2	42	42	42
NO_x	Gram/sec (I unit)	13.52	12.72	12.67
NO_x	Gram/sec (2 units)	27.04	25.45	25.33
NO_x	Gram/sec (3 units)	40.56	38.17	38.00

Table 4.8-2 Cambalache Power Plant Emissions and Performance Data

Parameter	Base Load Emissions			60 % Load Emissions		
Fuel heating value, Btu/lb LHV	18,586	18,586	18,586	18,586	18,586	18,586
Fuel heating value, Btu/lb HHV	**19,754**	**19,754**	**19,754**	**19,754**	**19,754**	**19,754**
Compressor inlet temperature, F	59	85	90	59	85	90
Inlet pressure loss, inches water	4.0	4.0	4.0	4.0	4.0	4.0
Exhaust pressure, inches water	8.0	8.0	8.0	8.0	8.0	8.0
Relative humidity, %	70	70	70	70	70	70
Net power output, kW	90,400	82,970	81,530	54,005	49,540	48,680
Heat rate, Btu/kWh LHV	10,000	10,210	10,250	11,450	11,730	11,795
Exhaust temperature, F	942	956	959	824	843	847
Stack gas temperature, F	706	717	718	580	660	663
Fuel flow, lb/hr	48,639	45,579	44,936	33,270	31,266	30,893
Heat input, MMBtu/hr LHV	904	847	836	618	581	574
Heat input, MMBtu/hr HHV	**961**	**900**	**888**	**657**	**618**	**610**
Steam injection rate, lb/hr	127,950	119,830	118,300	87,490	82,240	81,250
Exhaust gas						
Oxygen dry basis	**15.09%**	**15.06%**	**15.13%**	**16.20%**	**16.21%**	**16.17%**
Oxygen	13.20%	13.00%	13.00%	14.50%	14.30%	14.20%
Carbon dioxide	3.70%	3.70%	3.70%	3.10%	3.00%	3.00%
Water	12.50%	13.70%	14.10%	10.50%	11.80%	12.20%
Nitrogen	69.80%	68.80%	68.50%	71.10%	70.00%	69.70%
Argon	0.80%	0.80%	0.80%	0.80%	0.80%	0.80%
Exhaust flow, lb/hr	2,622,000	2,493,000	2,467,000	2,192,000	2,085,000	2,064,000
Exhaust flow, wscfm	602,220	575,222	569,468	500,670	479,331	475,250
Exhaust flow, dscfm	526,943	496,417	489,173	448,100	422,770	417,270
MW	**27.98**	**27.85**	**27.84**	**28.13**	**27.95**	**27.91**
Exhaust flow, lb mole/hr	**93,720**	**89,518**	**88,623**	**77,916**	**74,595**	**73,960**
Exhaust flow, dry lb mole/hr	**82,005**	**77,254**	**76,127**	**69,735**	**65,793**	**64,937**
Exhaust flow, dry lb mole/hr @15% O2	**80,813**	**76,420**	**74,400**	**55,538**	**52,265**	**52,025**
Emissions						
NOx, ppmvd @15% O2	42	42	42	42	42	42
NOx, lb/hr	**156.2**	**147.7**	**143.8**	**107.3**	**101.0**	**100.5**
NOx, lb/MMBtu HHV	**0.163**	**0.164**	**0.162**	**0.163**	**0.164**	**0.165**
Summary for One Turbine						
Stack diameter, m	4.72	4.72	4.72	4.72	4.72	4.72
Exit temperature, K	648	654	654	578	622	624
Exit velocity, m/s	**35.87**	**34.59**	**34.27**	**26.60**	**27.42**	**27.26**
NOx, g/s	**19.67**	**18.60**	**18.11**	**13.52**	**12.72**	**12.67**
Summary for Two Turbines						
Stack diameter, m	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**	**6.68**
Exit temperature, K	648	654	654	578	622	624
Exit velocity, m/s	**71.7**	**69.2**	**68.5**	**53.2**	**54.8**	**54.5**
NOx, g/s	**39.35**	**37.21**	**36.23**	**27.04**	**25.45**	**25.33**
Summary for Three Turbines						
Stack diameter, m	**8.18**	**8.18**	**8.18**	**8.18**	**8.18**	**8.18**
Exit temperature, K	648	654	654	578	622	624
Exit velocity, m/s	**107.6**	**103.8**	**102.8**	**79.8**	**82.3**	**81.8**
NOx, g/s	**59.02**	**55.81**	**54.34**	**40.56**	**38.17**	**38.00**

Note: Bold data are calculated values, all others except stack diameter are from ABB GT Performance Data, 01/12/94. Stack diameter based on original PSD permit application. NO_x emissions of 42 ppmvd @ 15% O_2 are expected based on experience at Cambalache.

Table 4.8-1 assuming an ambient temperature of 59°F, 85°F, and 90°F. The worst-case modeling described in the 1994 PSD application found that highest impacts from the combustion turbines were associated with the 59°F ambient temperature cases as well. The load that produces the highest ground-level concentrations is defined as the worst-case load.

Table 4.8-3 presents the highest ISCST3 predicted concentrations for the annual averaging period. Maximum ISCST3 concentrations are predicted for Case 6: three CGTs at 60% load. Therefore, final refined grid modeling was performed for Case 6 to assess significant impacts. Appendix C is a diskette containing model results from the coarse and refined grid modeling.

4.9 NO_x to NO_2 Conversion

To maintain consistency with the 1994 modeling, 100% conversion of NO_x to NO_2 was assumed. However, a value of 39% conversion of NO_x to NO_2 could have been used based on results of the PSD monitoring program, as discussed below.

Most of the oxides of nitrogen emitted from combustion sources is nitrogen oxide (NO). With travel time, some of the NO is converted to NO_2 in the ambient air. EPA's Modeling Guidelines allow use of representative ambient monitoring of NO and NO_2 in order to determine the proper conversion rate of NO_x (NO + NO_2) in the flue gas to NO_2 in the ambient air. The model predicted ambient NO_x concentrations are then scaled by this conversion rate to arrive at an ambient NO_2 concentration.

Hourly average NO and NO_2 concentrations were monitored for 1-year in the Cambalache PSD preconstruction monitoring program. Computer files of hourly average NO and NO_2 concentrations were obtained and analyzed in order to develop a representative NO_x to NO_2 conversion rate.

A continuous NO/NO_2 analyzer is able to reliably detect down to 1% of the full-scale range of the instrument. Since these analyzers usually operate in the 0 - 500 ppb range, the minimum detectable level is 5 ppb. To accurately determine the NO_x to NO_2 conversion ratio in the ambient air, only those hours in which the NO_2 and NO_x concentrations were at least 5 ppb should be analyzed. The results of this analysis are shown below:

Pollutant	NO	NO_2
Hours of valid data	7,375	7,375
Hours <5 ppb	5,463	4,618
Hours >=5 ppb	1,912	2,757

Table 4.8-3 ISCST3 Modeling Results (Coarse/Medium Grids)

Case	No. of Units	Load	Ambient Temperature (F)	Maximum Impact (ug/m³)		Location (meters)		Elevation (meters)
				1-hour	Annual	UTM East	UTM North	
1	1	Base	59	50.28	0.17	729500 740500	2038500 2037500	230 230
2	1	60%	59	43.66	0.20	737500 740500	2041500 2038500	100 200
3	2	Base	59	100.56	0.35	729500 740500	2038500 2037500	230 230
4	2	60%	59	87.33	0.41	737500 740500	2041500 2038500	100 200
5	3	Base	59	150.84	0.52	729500 740500	2038500 2037500	230 230
6	3	60%	59	130.99	0.61	737500 740500	2041500 2038500	100 200

Significant Impact Level = 1 μg/m³ annual average

These data indicate that, for the majority of the hours, ambient NO_2 concentrations are below the minimum detectable levels and are thus very far below the NAAQS (50 ppb). In fact, the annual average NO_2 concentration was 4.34 ppb. This value is less than 9% of the NAAQS.

The conversion rate of NO_x to NO_2 is calculated as the ratio of NO_2 / (NO + NO_2). Annual average concentrations of NO and NO_2 (in ppb) were used to calculate the ratio. The results of the analysis are shown below.

NO_2/NO_x Ratio Using All Hours = 4.34ppb/(4.30ppb + 4.34 ppb) = 0.50.

NO_2/NO_x Ratio Using Hours With NO_2>=5ppb = 8.00 ppb/(12.6 ppb + 8.00 ppb) = 0.39.

4.10 Detailed Modeling Results

4.10.1 Objectives and Methodology

This section presents methodologies followed and results of the following analyses:

- Comparison with EPA-defined significant impact levels (SILs) for criteria pollutants;
- Impacts on soils and vegetation;
- Visibility analysis; and

- analysis of indirect growth due to the project

4.10.2 Comparison to EPA's Significant Impact Levels

The maximum predicted NO_2 concentration from the refined grid modeling is the same as the concentration predicted from the coarse/medium density grid modeling: 0.6 ug/m^3. This concentration was predicted in the fine grid at UTM coordinates 737100 meters Easting and 2041300 meters Northing at an elevation of 100 meters, msl. This concentration is far below EPA's 1 ug/m^3 SIL.

4.10.3 Impacts on Soils and Vegetation

4.10.3.1 Description of Soils

Puerto Rico is divided into three physiographic provinces: the Cordillera Central Province, the Carbonate Province, and the Coastal Lowlands Province. The Cordillera Central Province is the east-west mountainous chain that forms the backbone of the island. The Carbonate Province consists of middle to late Tertiary carbonate belts that flank the Cordillera Central Province to the north and south. The Coastal Lowlands Province is characterized by piedmont alluvial fans, mangrove swamps, marshes, and beach ridges.

The proposed site is located on the northwest coast of Puerto Rico, in the valley and floodplain of the Rio Grande de Arecibo, in the Coastal Lowlands Province. The Rio Grande de Arecibo originates in Cordillera Central Province, and flows north through the Carbonate Province, where it has carved through the mature karst. Approximately three miles from the coast, the River opens into a broad lowland typical of the North Coastal Lowlands Province.

The USDA Soil Conservation Service general soil maps indicate that the Rio Grande de Arecibo flood plain consists of flood plain alluvium deposits. Most of the flood plain soils in the Arecibo valley are considered to be of the Toa-Coloso-Bajura association.

According to the USDA Soil Conservation Service, the Toa-Coloso-Bajura association is characterized by deep, nearly level, poorly drained, loamy to clayey soils. The soils of the Toa series are fine, mixed, isohyperthermic Fluventic Hapludous. They formed in fine textured and moderately fine textured stratified alluvial sediments of mixed origins. They are deep and well drained and are mainly used for sugarcane. Some areas can be found in pasture and food crops. The Toa has the thickest solum of the three associated soils, ranging from two to three feet. The Coloso series is fine, mixed, nonacid, isohyperthermic Aeric Tropic Fluvaquents. They form under the same characteristics as the Toa and are also deep and somewhat poorly drained. The thickness of the solum ranges from less than one foot to a foot and a half The soils from the Bajura series are also considered to be fine, mixed, and nonacid, but they are isohyperthermic Vertic Tropaquepts. They are deeper and more poorly drained, than the Toa or the Coloso soils. The thickness of the solum ranges from I to 1.3 feet. (USDA Soil Conservation Service, 1982)

According to the soil survey of the Arecibo area (USDA Soil Conservation Service) the project site and most of the area crossed by offsite facilities are on Coloso silty clay. According to the USDA soil profile, these clayey soils range from well drained to poorly drained and are considered suitable for agriculture. The soils fertility particularly favors row crop cultivation and pasture. Onsite data indicate that the soils on the southern portion of the project site is mostly Coloso silty clay with some Toa silty clay loam found on the western side of the plant alongside the Rio Grande de Arecibo. On the southeastern side of the site, Vega Baja clay with 2 to 5 percent slopes can be found. Toa and Coloso are also common on the north side of the site. Near Santa Barbara there are areas of frequently flooded Hydraquents.

Toa, Coloso and Vivi loam, characterize the western side of the Rio Grande. The soils of the Vivi series are coarse-loamy, mixed, isohyperthermic Fluventic HapludoHs. They are deep and excessively drained and are mainly used for sugarcane and pasture. Further north of the project, the soils are similar to those on the project, becoming Bajura clay, sand, and pits closer to the coastal beaches.

4.10.3.2 Impacts of PSD Applicable Pollutants on Soils

The predicted impact of NO_2, the only PSD applicable pollutant, is below the SIL. Therefore, one would not expect any measurable impact on local soils from the proposed facility.

4.10.3.3 Impacts of Acid Precursors on Soils

According to N.C. Brady in The Nature and Properties of Soils (Ninth Ed., 1984), a marked change in the pH of soil affects the availability of several plant nutrients and other elements that may be toxic to high plants and microorganisms. Thus, higher plants and microorganisms may be affected by rapid changes in pH either directly due to changes in hydrogen ion concentration, or indirectly, due to nutrient deficiency or chemical toxicities. The stabilization of soil pH through buffering systems is an effective guard against these difficulties. The greater the buffering capacity of the soil, the larger amounts of lime or sulfur necessary to effect a given change in pH.

Nitrate is part of a cycle within the soil and between the soil, atmosphere and the oceans. According to H.L. Bohn in Soil Chemistry (1979), the atmosphere contributes about 1-2 kilograms of nitrogen per hectare per year (kg/ha/yr) to the soil. This represents about 1% of the nitrogen turnover in the soil. Using the U.S. Department of Agriculture, Forest Service Handbook 2509-19, the amount of nitrogen deposited on local soils from the proposed facility was calculated to be 1.17 kg/ha/yr at the maximum impact point. This value is the same as contributed from the atmosphere and will not cause any meaningful change in pH. Therefore, the facility's emission of NO_x would not meaningfully affect the availability of plant nutrients and would not cause an increase in chemical toxicity to plant species.

4.10.3.4 Description of Vegetation

The power plant site is currently developed. Typical vegetation at site boundaries include: camphorweed (*Pluchea fisbergii*), capeweed (*Phyla nodiflora*), *Cypersus spp.* and *Paspalum spp.*. Morning glory (*Ipomoea spp.*) and the "sensitive plant" *(Mimosa sp.)* occur along upland portions of the levee, and white mangrove (*Laguncularia racemosa*) along both sides of the agricultural drainage canal (Cano Suroeste).

The banks of the Rio Grande de Arecibo are somewhat incised, with grasses growing along the upper bank (e.g., *Panicum maximum)* and a variety of aquatic vegetation in, or immediately adjacent to, the river itself (e.g., water hyacinth - *Eichhomia crassipes,* water lettuce - *Pistia stratiodes,* and smartweed - *Polygonum* sp.). Away from the river, wetland species are found along the banks of the drainage ditches and in small depressional areas.

No endangered or threatened species are known to occur on the Project site. Studies conducted for the Cambalache Combustion Turbine Project (PREPA 1993) have reached similar conclusions.

PSD review requires the analysis of vegetative stress from new or modified sources of air pollution. EPA's guidance document recommends that total pollutant impacts be compared with threshold levels to assess vegetative stress. The threshold levels developed by EPA represent the minimum ambient levels at which visible damage or growth retardation may occur, or the minimum levels at which injury and mortality have been reported. The values are generally the lowest consistently reported in the literature on plant response to pollutant exposure.

The results of the vegetative stress analysis are listed below. Maximum ambient background concentrations monitored as part of the PSD permit application for the Cambalache power plant were added to maximum NO_2 impacts from the proposed facility. Predicted total impacts are substantially below the most sensitive vegetative stress levels for all PSD applicable pollutants.

Table 4.10-1 Comparison of Air Contaminant Concentrations and Vegetative Stress Analysis

Pollutant	Averaging Period	Secondary NAAQS (a)	Maximum Existing Concentration	Maximum Facility Impact	Worst Case Total	Plant Damage Threshold	References
NO2	1-hour	None	56	150.9	206.9	7,500	Heck, Tingey, 1979
NO2	Annual	100 (b)	8	0.6	8.6	120	Spierings, 1971: Thompson et al, 1974

4.10.3.5 Conclusion

Based on the above screening analysis, it can be concluded that there will be no significant adverse impacts to soils and vegetation from the power plant's NO_x emissions.

4.10.4 Impact of Emissions from Residential, Commercial and Industrial Growth Associated with the Project

According to EPA's 1990 Draft New Source Review Workshop Manual, the PSD regulations require the applicant "to predict how much new growth is likely to occur to support the source or modification under review, and then to estimate the emissions which will result from that associated growth". The amended PSD application involves only the elimination of SCR from the facility. Therefore, there will be no impact on growth in the area.

4.10.5 Visibility Analyses

The previous PSD application included a visibility analysis using the VISCREEN model in accordance with recommendations of the U.S. Environmental Protection Agency (EPA 1992a and b, Workbook for Plume Visual Impact Screening Analysis (Revised)). The analysis results indicated that there will be no impact on the visibility in any Class 1 area as a result of the Power plant. The increase in NO_x emissions associated with this amended application will likewise have no impact on visibility in any Class 1 area.

4.11 Elimination of Ammonia Impacts

After removal of the SCR system, ammonia emissions and resulting ambient air impacts were eliminated. Just prior to SCR removal, ammonia emissions were approximately 150 ppmvd @ 15% O_2. These emissions produced maximum ammonia impacts for 1-hour and annual averaging periods of:

- 1-hour: 199.0 ug/m^3 (3 units operating at base load)
- Annual average: 0.80 ug/m^3 (3 units operating at 60% load)

The New York State Department of Environmental Conservation's(NYSDEC) Air Guide-1 (October 16,1995) lists short-term guideline concentrations (SGCs) and annual average guideline concentrations (AGCs) for ammonia. The SGC is 4000 ug/m^3 and the AGC is 100 ug/m^3. Predicted ammonia impacts were far below these levels. Model results for ammonia are contained in Appendix C.

4.12 Conclusions

Predicted impacts of NO_2, the only PSD affected pollutant, is below EPA's SIL. This means that the following PSD requirements do not apply to this project:

- Ambient air quality analysis;
- PSD increment compliance; and
- NAAQS compliance.

Furthermore, due to the fact that there are no Class 1 areas within 100 km of the proposed facility, a Class I visibility and Air Quality Related Values analysis is not required.

Additional analyses were performed. As demonstrated, Project related NO_x emissions do not significantly impact soils, vegetation and visibility. Furthermore, the Project will not induce growth in the area, thus, the Project will not induce growth related air emissions. Finally, the elimination of the SCR system has eliminated potential safety issues related to ammonia transportation and handling as well as eliminated ammonia emissions.

5.0 REFERENCES

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APPENDIX A

HISTORY OF PROBLEMS WITH SCR AT CAMBALACHE

Cambalache Combustion Turbines Facility

Commissioned - Jul 97

Problem identified - Aug 97

Engelhard took core samples and develop a cleaning procedure (Air Blowing) - Oct 97

Units #1 & #2 cleaned - Dec 97

New procedure submitted by Engelhard (SCR Decoking) - Jan 98

Units #1 & #2 cleaned (Air Blowing) - Feb 98

Cambalache Combustion Turbines Facility

Units #1, #2 & #3 silencers removed - Mar 98

Units #1 & #2 cleaned (Air Blowing) - Mar 98

Unit #1 Heat Treated (SCR Decoking) - Apr 98

New procedure submitted by Engelhard (Acid Washing) - June 98

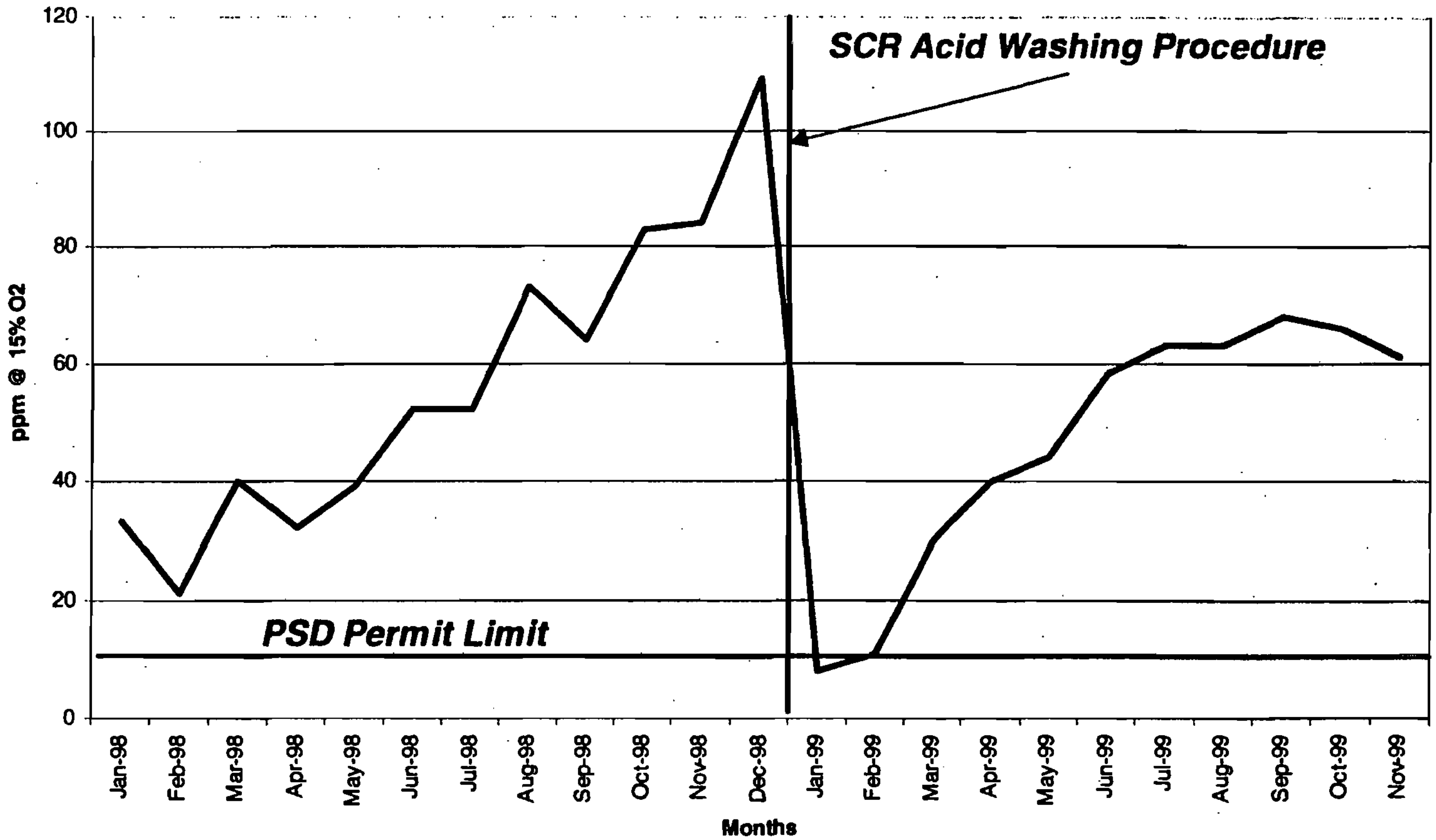
Unit #3 cleaned - Aug 98

Unit #2 cleaned - Nov 98

Unit #1 cleaned - Dec 98

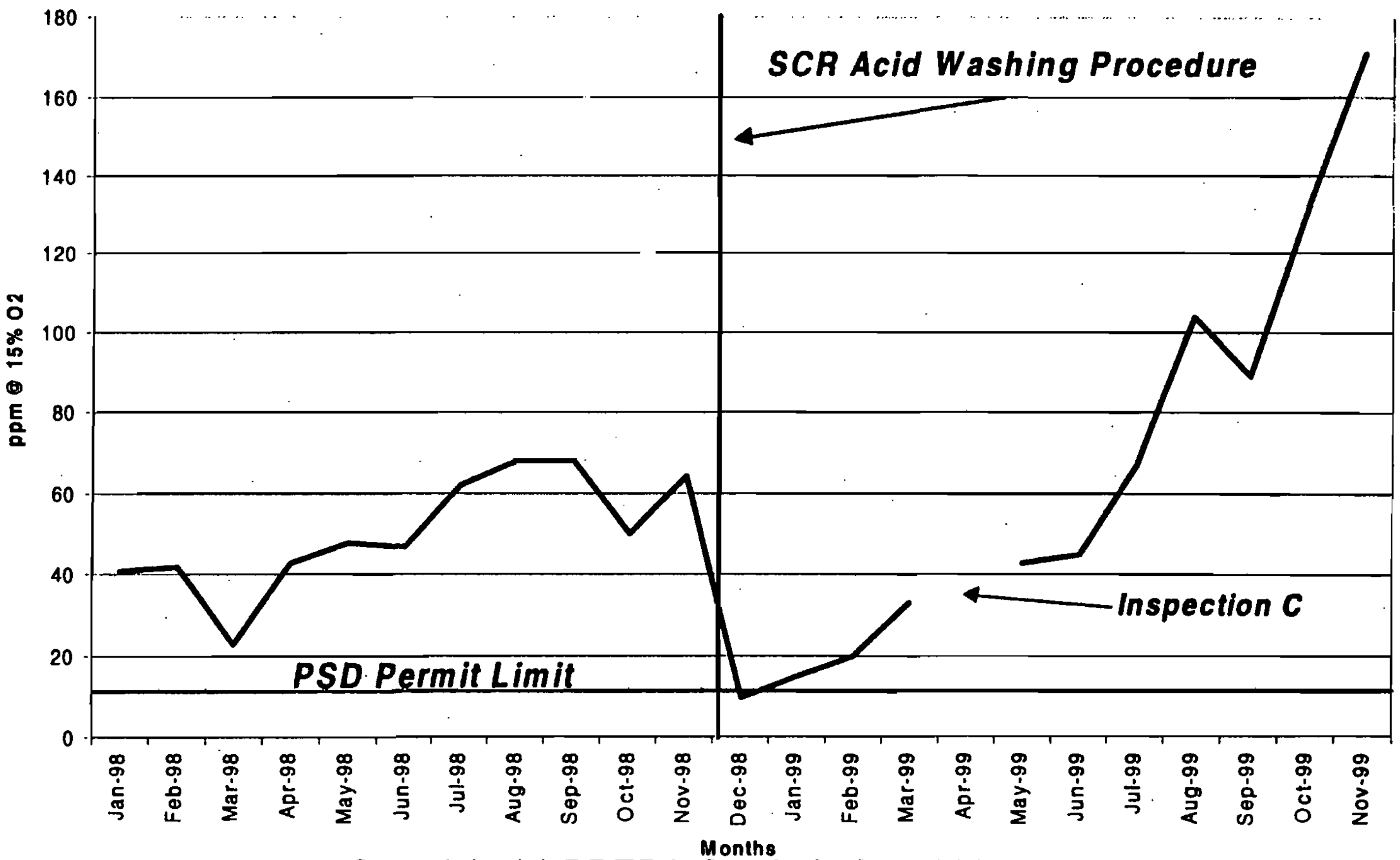
Cambalache Combustion Turbines Facility

Unit #1 NH_3 slip History



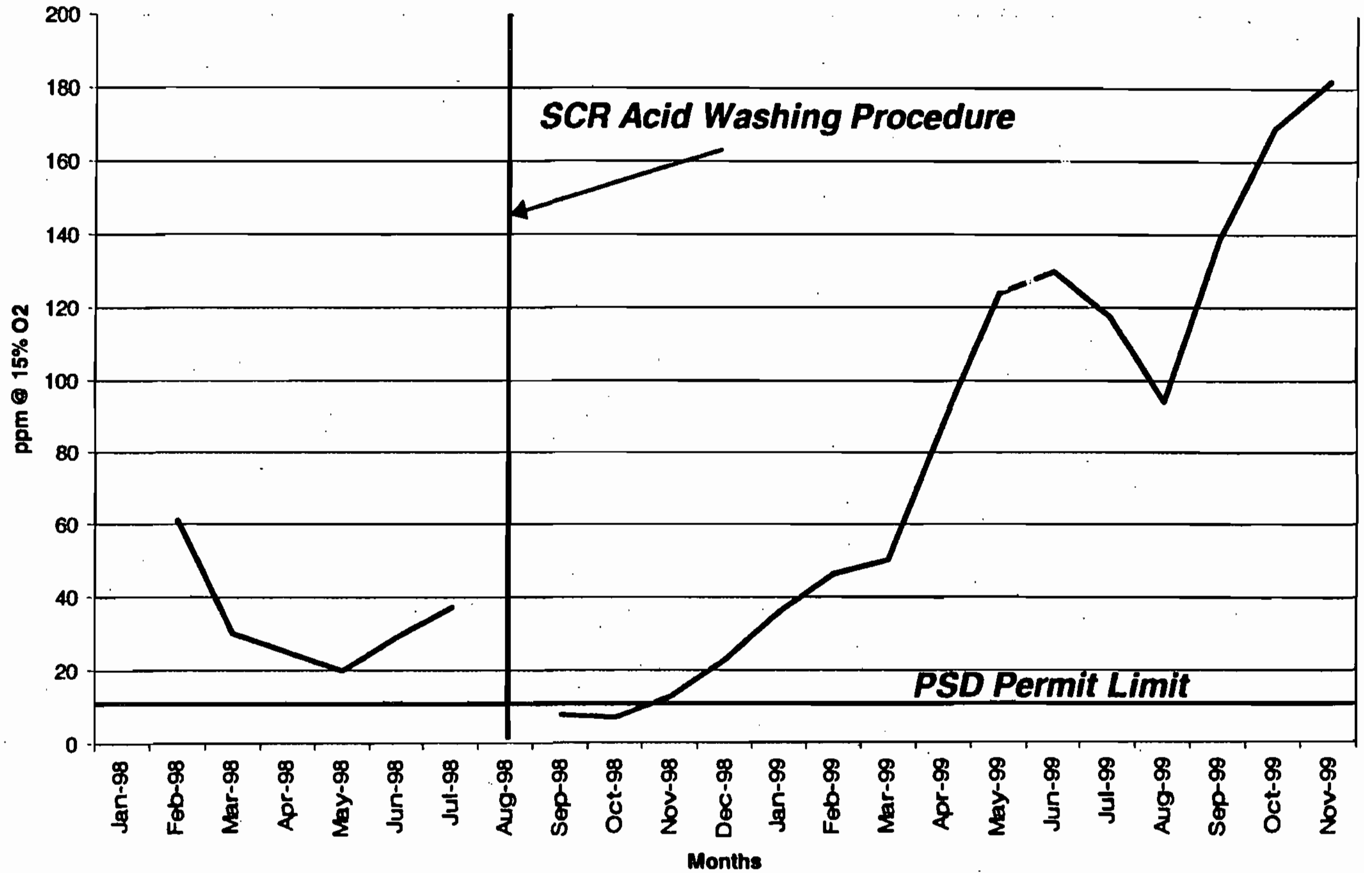
Cambalache Combustion Turbines Facility

Unit #2 NH_3 slip History



Cambalache Combustion Turbines Facility

Unit #3 NH_3 slip History



APPENDIX B

RACT/BACT/LAER CLEARINGHOUSE

RACT/BACT/LAER Clearinghouse
Results for Natural Gas and Oil Fired Combustion Turbines That Burn Oil (NO_x)

Facility	City	St.	Permit Number	Permit Date	Process	Listed Fuel	Assumed Fuel	Process Type	Throughput	Throughput Units	Emission	Emission Unit	Standardized Emission	Standardized E.U.	Control Description	Basis
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN	MD		7/13/1993	TURBINE, 140 MW OIL FIRED ELECTRIC	OIL	OIL	15.002	140.0	MW	65.0	PPMVD @ 15% O2	65.0	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	226001 0285 00001	1/18/1994	GE FRAME 6 GAS TURBINE	BOTH	OIL	15.007	491.0	BTU/HR	42.0	PPM, 78.6 LB/HR	42.0	PPMVD @ 15 %O2	STEAM INJECTION	BACT
KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	NY	226001 0285 00001	1/18/1994	STACK (GAS TURBINE & DUCT BURNER) "SEE NOTE #3"	BOTH	OIL	11.004	540.0	LB/MMBTU	42.0	PPM, 87.4 LB/HR	42.0	PPMVD @ 15 %O2	NO CONTROLS	BACT-OTHER
TECO POLK POWER STATION	BARTOW	FL	PSD-FL-194	2/24/1994	TURBINE, FUEL OIL	OIL	OIL	15.006	1765.0	MMBTU/H	42.0	PPMVD @ 15 % O2	42.0	PPMVD@15% O2	WET INJECTION	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	PSD-FL-195	2/25/1994	TURBINE, FUEL OIL (2)	OIL	OIL	15.006	1730.0	MMBTU/H	42.0	PPMVD @ 15 %O2	42.0	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	0594-035	5/17/1994	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	BOTH	OIL	15.007	1345.0	MMBTU/HR	1135.0	TPY	49.7	PPMVD @ 15 %O2	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
CAROLINA POWER AND LIGHT	HARTSVILLE	SC	0820-0033	8/31/1994	STATIONARY GAS TURBINE	BOTH	OIL	15.007	1520.0	MMBTU/H	62.0	PPMDV @ 15% O2	62.0	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
LEDERLE LABORATORIES	PEARL RIVER	NY	392400 0095	8/15/1994	(2) GAS TURBINES (EP #S 00101&102)	BOTH	OIL	15.007	110.0	MMBTU/HR	42.0	PPM, 18 LB/HR	42.0	PPMVD @ 15 %O2	STEAM INJECTION	BACT-PSD
INDECK-OSWEGO ENERGY CENTER	OSWEGO	NY	351200 0211 00001	10/6/1994	GE FRAME 6 GAS TURBINE	BOTH	OIL	15.007	533.0	LB/MMBTU	42.0	PPM, 75.00 LB/HR	42.0	PPMVD @ 15 %O2	STEAM INJECTION	BACT
EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	MO	0395-015	2/28/1995	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	BOTH	OIL	15.007	88.8	MW	360.0	TPY			WATER INJECTION.	BACT-PSD
GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	FL	PSD-FL-212	4/11/1995	OIL FIRED COMBUSTION TURBINE	OIL	OIL	15.006	74.0	MW	42.0	PPM AT 15% OXYGEN	42.0	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	NY	2-6101-00185/00002-9	6/8/1995	TURBINE, OIL FIRED	OIL	OIL	15.002	240.0	MW	10.0	PPM @ 15% O2	10.0	PPMVD @ 15 %O2	SCR	LAER
HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	MO	0795-0023	7/27/1995	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	BOTH	OIL	15.007	49.1	MW	42.0	PPM BY VOL 1 HR AVG	42.0	PPMVD @ 15 %O2	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	BACT-PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	MO	0795-0023	7/27/1995	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	BOTH	OIL	15.007	49.1	MW	75.0	PPM BY VOL 1 HR AVG	75.0	PPMVD @ 15 %O2	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	PR	PR-0100	7/31/1995	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	OIL	OIL	15.006	248.0	MW	35.0	LB/HR AS NO2	10.0	PPMVD @ 15 %O2	STEAM INJECTION PLUS SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM. USE OF NO. 2 FUEL OIL WITHNITROGEN CONTENT NOT TO EXCEED 0.10% BY WEIGHT.	BACT-PSD
MID-GEORGIA COGEN.	KATHLEEN	GA	4911-076-11753	4/3/1996	COMBUSTION TURBINE (2), FUEL OIL	OIL	OIL	15.006	116.0	MW	20.0	PPMVD	20.0	PPMVD @ 15 %O2	WATER INJECTION WITH SCR	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	1812	4/11/1996	COMBUSTION TURBINE, 4 EACH	BOTH	OIL	15.007	1907.6	MMBTU/HR	156.0	LB/HR	21.3	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
CAROLINA POWER & LIGHT	GOLDSBORO	NC	1812	4/11/1996	COMBUSTION TURBINE, 4 EACH	BOTH	OIL	15.007	1907.6	MMBTU/HR	512.3	LB/HR	69.2	PPMVD @ 15 %O2	WATER INJECTION; FUEL SPEC: 0.04% N FUEL OIL	BACT-PSD

RACT/BACT/LAER Clearinghouse
Results for Natural Gas and Oil Fired Combustion Turbines That Burn Oil (NO_x)

Facility	City	St.	Permit Number	Permit Date	Process	Listed Fuel	Assumed Fuel	Process Type	Throughput	Throughput Units	Emission	Emission Unit	Standardized Emission	Standardized E.U.	Control Description	Basis
GENERAL ELECTRIC GAS TURBINES	GREENVILLE	SC	1200-0094	4/19/1996	I.C. TURBINE	BOTH	OIL	15.007	2700.0	MMBTU/HR	685.3	LB/HR	84.5	PPMVD @ 15 %O2	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	BACT-PSD
ECOELECTRICA, L.P.	PENUELAS	PR	PR-0102	10/1/1996	TURBINES, COMBINED-CYCLE COGENERATION	OIL	OIL	15.006	461.0	MW	60.0	LB/HR	9.0	PPMVD @ 15 %O2	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR).	BACT-PSD
STAR ENTERPRISE	DELAWARE CITY	DE	APC-97/0503-CONST.(LAER) (NSPS)	3/30/1998	TURBINES, COMBINED CYCLE, 2	BOTH	OIL	15.007	826.6	MMBTU/H	42.0	PPM @ 15% O2, DIESEL	42.0	PPMVD @ 15 %O2	NITROGEN INJECTION WHILE FIRING SYNGAS AND STEAM INJECTION WHILE FIRING LSDF	LAER
ANDROSCOGGIN ENERGY LIMITED	JAY	ME	A-718-71-A-N	3/31/1998	GAS TURBINES, COGEN, W/DUCT BURNERS	BOTH	OIL	15.007	675.0	MMBTU/H TURBINE	42.0	PPM @ 15% O2 OIL	42.0	PPMVD @ 15 %O2	LOW NOX COMBUSTORS, LOW NOX BURNERS, WATER INJECTION DURING OIL FIRING.	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	FL	PSD-L-245	7/10/1998	WESTINGHOUSE 501G SIMPLE CYCLE UP TO 250 MW	BOTH	OIL	15.130	2174	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION AND SCR	BACT-PSD
TENUSKA GEORGIA PARTNERS	FRANKLIN	GA	4-11-149-0004-P 01-0	12/18/1998	TURBINE, COMBUSTION SIMPLE CYCLE, 6 (FUEL OIL) 160 MW	BOTH	OIL	15.130	160	MW	42	PPMVD @ 15% O2 EACH	42.00	PPMVD @ 15% O2	LOW NOX TURBINES	BACT-PSD
SOUTHERN ENERGY INC	NEENAH	WI	98-RV-152	2/25/1999	SIMPLE CYCLE COMBUSTION TURBINE (2) , BACK UP OIL 175 MW	BOTH	OIL	15.130	175	MW	NOT LISTED		NOT LISTED		DRY, LOW NOX BURNERS, WATER/STEAM INJECTION, SELECTIVE CATALYST CONTROL	BACT-PSD
AES IRONWOOD	LEBANON	PA	3805019	3/29/1999	TURBINE, OIL FIRED 235 MW	BOTH	OIL	15.130	235	MW	10	PPMVD @ 15% O2	10	PPMVD @ 15% O2	SCR AND WATER INJECTION	LAER
NORTHERN STATE POWER CO- WHEATON GEN PLANT	EAU CLAIRE	WI	99 JCH 043	5/25/1999	SIMPLE CYCLE COMBUSTION TURBINE 6 TURBINES 72 MW	OIL	OIL	15.130	72	MW	410.9	LB/HR	43.00	PPMVD @ 15% O2		OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	FL	PSD-FL-195	5/27/1999	TURBINE, FUEL OIL 1999 MMBTU/HR	BOTH	OIL	15.130	1999	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
WEST GEORGIA GENERATING CO	FORT GREEN SPRINGS	GA	4911-293-0027-P-01-0	6/7/1999	4 GE PG7241FA COMBUSTION TURBINES 740 MW	BOTH	OIL	15.130	740	MW	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
WESTERN RESOURCES' GORDON EVANS ENERGY CENTER	COLWICH	KS	1730012	6/16/1999	ELECTRIC GENERATION, TURBINE, FUEL OIL, E3CT 1524.9 MMBTU/HR	BOTH	OIL	15.130	1524.9	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	DRY, LOW NOX BURNERS, WATER INJECTION	BACT-PSD
LAKE ROAD GENERATING CO	KILLINGLY	CT	"067"	6/22/1999	TURBINE BACKUP DISTILLATE OIL 2181 MMBTU/HR	BOTH	OIL	15.130	2181	MMBTU/HR	NOT LISTED		NOT LISTED		LOW NOX BURNER, SCR, EMISSION OFFSET	LAER
VIRGINIA POWER DOMINION REMINGTON CT STATION/ DOMINION REMINGTON COMBUSTION TURBINE STATION	REMINGTON	VA	40981	6/25/1999	5 GE MODEL PG7241 FA SIMPLE CYCLE DUAL FUEL FIRED COMBUSTION TURBINE, 1761 MMBTU/HR	BOTH	OIL	15.130	1761	MMBTU/HR	42	PPMVD @ 15% O2 #2 FUEL OIL	42.00	PPMVD @ 15% O2 #2 FUEL OIL	WATER INJECTION WHILE FIRING #2 DISTILLATE OIL, GOOD COMBUSTION PRACTICES, CLEAN FUELS	BACT-OTHER
OMAHA PUBLIC POWER DISTRICT	LINCOLN	NE	NONE	7/29/1999	PEAKING TURBINE CT-3 FUEL OIL 100 MW	BOTH	OIL	15.130	100	MW	42	PPM	42.00	PPMVD @ 15% O2	CLEAN FUEL, WATER INJECTION	BACT-PSD
GEORGIA POWER-JACKSON CITY COMBUSTION TURBINE PLT/GEORGIA POWER CO-JACKSON COUNTY	ATLANTA	GA	4911-157-0034-P-01-0	8/9/1999	TURBINE CT 1-16 (16 TURBINES) FUEL OIL978.3 MMBTU/HR	BOTH	OIL	15.130	978.3	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	N/A	BACT-PSD

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Facility	City	St.	Permit Number	Permit Date	Process	Listed Fuel	Assumed Fuel	Process Type	Throughput	Throughput Units	Emission	Emission Unit	Standardized Emission	Standardized E.U.	Control Description	Basis
TAMPA ELECTRIC CO(TEC)/TECO-POLK POWER STATION/MULBERRY	MULBERRY	FL	PSD-FL-263	10/8/1999	TWO NOMINAL 165 MW GAS SIMPLE CYCLE COMBUSTION TURBINE	BOTH	OIL	15.130	165	MW	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	DLN GE DLB2.6	BACT-PSD
TECO/HARDEE POWER SERVICES/ HARDEE POWER STATION	FORT GREEN SPRINGS	FL	PSD-FL-140A	10/8/1999	75 MW SIMPLE CYCLE GE MODEL 7EA	BOTH	OIL	15.130	75	MW	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
JACKSONVILLE ELECTRIC AUTHORITY// JEA/BRANDY GENERATING STATION	BALDWIN	FL	PSD-FL-267	10/14/1999	TURBINE, BACKUP OIL 170 MW	BOTH	OIL	15.130	170	MW	42	PPM	42.00	PPMVD @ 15% O2	WATER INJECTION WHEN FIRING OIL	BACT-PSD
CAROLINA POWER & LIGHT CO/ RICHMOND CNTY COMBUSTION TURBINE FACILITY	MARK'S CREEK TOWNSHIP	NC	08759R00	11/5/1999	COMBUSTION TURBINES, NO. 2 FUEL OIL (7) 1100MW TOTAL	BOTH	OIL	15.130	1100	MW	0.176	LB/MMBTU	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
CAROLINA POWER & LIGHT CO/ ROWAN CNTY COMBUSTION TURBINE FACILITY	RALEIGH	NC	08756R00	11/5/1999	COMBUSTION TURBINES, NO. 2 FUEL OIL (5) 1875 MMBTU/HR EACH	BOTH	OIL	15.130	1875	MMBTU/HR	0.176	LB/MMBTU	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
CANE ISLAND POWER PARK- UNIT 3	INTERCESSION CITY	FL	PSD-FL-254	11/24/1999	TURBINE, SIMPLE CYCLE, FUEL OIL, 1910 MMBTU/HR	BOTH	OIL	15.130	1910	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
IPS AVON PARK CORP/ IPS VANDOLAH POWER	WAUCHULA	FL	PSD-FL-275	12/16/1999	4 DUAL FUEL NOMINAL 170 MW GE PG7241FA COMBUSTION TURBINES	BOTH	OIL	15.130	170	MW	42	PPMVD	42.00	PPMVD @ 15% O2	WATER INJECTION SYSTEM WHEN FIRING OIL & LIMITED FUEL OIL USAGE	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	FL	FL-PSD-182	12/21/1999	TURBINE, FUEL OIL, 371 MMBTU/HR	BOTH	OIL	15.130	371	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)/SAN JUAN REPOWERING PROJECT	MONACILLOS	PR	5	3/2/2000	2 COMBUSTION TURBINES 232 MW EACH	OIL	OIL	15.130	232	MW	0.131	LB/MMBTU	32.20	PPMVD @ 15% O2	STEAM INJECTION	BACT-PSD
SANTEE COOPER/ RAINEY GENERATING STATION	STARR	SC	0200-0144-CA	4/3/2000	TURBINES, SIMPLE CYCLE, DISTILLATE FUEL OIL (2), 170 MW EACH	BOTH	OIL	15.130	170	MW	341	LB/H EACH	42.00	PPM @15% O2 EACH	DRY LOW NOX BURNERS, WATER INJECTION	BACT-PSD
DOSWELL LIMITED PARTNERSHIP	ASHLAND	VA	51016	4/7/2000	GE MODEL PG 7241 (FA)	BOTH	OIL	15.130	1940	MMBTU/HR	42	PPMVD @ 15% O2	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
LAKEFIELD JUNCTION LP GENERATING STATION	TRIMONT	MN	09100058-002	5/4/2000	6 TURBINES FUEL OIL 92 MW EACH	BOTH	OIL	15.130	92	MW	42	PPMVD @ 15% O2 (3- H AVG)	42.00	PPMVD @ 15% O2 EACH	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES	BACT-PSD
VIRGINIA POWER CAROLINE COMBUSTION TURBINES/VIRGINIA POWER LADYSMITH	GLEN ALLEN	VA	40960	7/31/2000	5 GE MODEL PG7241 (FA) TURBINES	BOTH	OIL	15.130	1910	MMBTU/HR	42	PPM @15% O2	42.00	PPM @ 15% O2	WATER INJECTION	BACT-OTHER
SOUTHAVEN ENERGY FACILITY	SOUTHAVEN	MS	68000097	10/6/2000	EIGHT 80 MW SIMPLE CYCLE COMBUSTION TURBINES	BOTH	OIL	15.130	80	MW	42	PPM	42.00	PPMVD @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
CONECTIV ENERGY INC/ HAY ROAD POWER COMPLEX UNITS 5-8	WILMINGTON	DE	APC-2000/0281-C(EOP)(PSD)(NSPS)	10/17/2000	TURBINES, SIMPLE & COMBINED CYCLE	BOTH	OIL	15.130	500	MW	42	PPM @ 15% O2	42.00	PPMV @15% O2	LSLPP, DRY LOW NOX BURNERS, DIFFUSION MODE ON OIL	LAER
CALHOUN POWER CO	ANNISTON	AL	301-0073-X001	1/26/2001	TURBINES, SIMPLE CYCLE, DISTILLATE FUEL OIL, 193 MW	BOTH	OIL	15.130	193	MW	12	PPMVD @ 15% O2	12.00	PPMVD @ 15% O2 EACH TURBINE	DRY LOW NOX BURNERS, STEAM INJECTION, PROPER OPERATION & MAINTENANCE	BACT-PSD

RACT/BACT/LAER Clearinghouse
Results for Natural Gas and Oil Fired Combustion Turbines That Burn Oil (NO_x)

Facility	City	St.	Permit Number	Permit Date	Process	Listed Fuel	Assumed Fuel	Process Type	Throughput	Throughput Units	Emission	Emission Unit	Standardized Emission	Standardized E.U.	Control Description	Basis
VIRGIN ISLANDS WATER AND POWER AUTHORITY - KRUM BAY ST. THOMAS GENERATING STATION	ST. THOMAS	VI	ARBITRARILY ASSIGNED PERMIT NO. 8 BY EPA REGION 2	1/30/2001	TURBINE, 24 MW OIL FIRED SIMPLE CYCLE ELECTRIC	OIL	OIL	15.006	24.0	MW	42.0	PPMVD @ 15% O2	42.0	PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
DUKE ENERGY KNOX LLC	WHEATLAND	IN	083-12674-00043	5/1/2001	TURBINE, DIESEL FUEL, SIMPLE CYCLE, 1158 MMBTU/HR	BOTH	OIL	15.130	1158	MMBTU/HR	42	PPMVD @ 15% O2	42	PPMVD @ 15% O2	WATER INJECTION LB/H LIMIT FOR EACH CT.	BACT-PSD
KEYSPAN ENERGY-RAVENSWOOD GENERATING STATION/KEYSPAN RAVENSWOOD	LONG ISLAND CITY	NY	2-6304-00024/00035	9/7/2001	TURBINE WITHOUT DUCT BURNER (KEROSENE)	BOTH	OIL	15.130	250	MW	9	L/H	1.00	PPM @ 15% O2	SCR	LAER
TENASKA VIRGINIA II PARTNERS/ TENASKA BEAR GARDEN STATION	NEW CANTON	VA	32004	4/30/2002	3 GE 7FA DUAL FUEL COMBUSTION TURBINES W/SUPP DUCT BURNERS RATED AT 550 MMBTU/HR	BOTH	OIL	15.130	2026	MMBTU/HR	2.5	PPM 3 HR BLOCKS			SCR & CEM	BACT-PSD
DAYTON POWER AND LIGHT CO	MIAMISBURG	OH	08-04380	6/4/2002	(2) 80 MW COMBUSTION TURBINES W/WATER INJECTION 1115 MMBTU/HR	BOTH	OIL	15.130	1115	MMBTU/HR	195	LB/HR	42.00	PPMVD @ 15% O2	WATER INJECTION	BACT-PSD
WHITE OAK POWER CO/ WHITE OAK POWER	LYNCHBURG	VA	32005	8/29/2002	TURBINES, SIMPLE CYCLE, FUEL OIL, (4) 1888 MMBTU/HR	BOTH	OIL	15.130	1888	MMBTU/HR	50	PPMVD @ 15% O2	50	PPMVD @ 15% O2	LOW NOX BURNERS & CEM	BACT-PSD
INTERSTATE POWER & LIGHT/ POWER IOWA ENERGY CENTER	MASON CITY	IA	02-357	12/20/2002	GE PG 7241	BOTH	OIL	15.004			0.1502	LB/MMBTU	42.00	PPM	WATER INJECTION	BACT-OTHER
DOMINION POWER/ CHICKAHOMINY POWER		VA	51958	1/10/2003	(4) 501F SIMPLE CYCLE DUAL-FUEL COMBUSTION TURBINES 1776 MMBTU/HR	BOTH	OIL	15.130	1776	MMBTU/HR	42	PPMVD EACH UNIT	42	PPMVD @ 15% O2	WATER INJECTION & CEM	BACT-PSD
OLD DOMINION ELECTRIC COOPERATIVE/ODEC-MARSH RUN FACILITY		VA	40998	2/14/2003	TURBINE, SIMPLE CYCLE, (4) FUEL OIL 1803 MMBTU/HR	BOTH	OIL	15.130	1803	MMBTU/HR	62	PPMVD @ 15% O2	62	PPMVD @ 15% O2	DRY LOW NOX BURNERS, CLEAN BURNING FUEL, CEM	NSPS
OLD DOMINION ELECTRIC COOPERATIVE/ODEC-LOUISA FACILITY		VA	40989	3/11/2003	1 GE FA SIMPLE CYCLE TURBINE 1820 MMBTU/HR	BOTH	OIL	15.130	1820	MMBTU/HR	42	PPMVD @ 15% O2	42	PPMVD @ 15% O2	GOOD COMBUSTION PRACTICES & CEM SYSTEM	NSPS

RECENT BEST AVAILABLE CONTROL TECHNOLOGY ASSESSMENTS FOR COMBUSTION TURBINE PROJECTS

4/21/99

State	Permit Date	Facility	Turbine Model	Fuel	Mode	Hours	NO_x Limit	CO Limit
AL	12-17-97	AL Power - Olin Cogeneration (PSD-AL-187); McIntosh, AL (1 turbine and duct burner, power augmentation)	GE 7EA (80 MW)	NG	CC	8,760	15 ppm (DLN)	0.07 lb/MMBtu
AL	5-27-98	AL Power - GE Plastics Cogeneration (PSD-AL-189); Burkville, AL (1 turbine and duct burner, no power augmentation)	GE 7EA (80 MW)	NG	CC	8,760	9 ppm (DLN); (0.20 lb/MMBtu duct burner	0.08 lb/MMBtu (combined)
AL	8-7-98	AL Power - Plant Barry (PSD-AL-197); Bucks, AL (3 turbines and duct burners)	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (DLN, SCR) / 0.013 lb/MMBtu	0.057 lb/MMBtu
AL	1-5-99	Mobile Energy LLC, (PSD-AL-199), Mobile, AL (1 turbine and duct burner)	GE 7FA (168 MW)	NG, FO	CC	8,760; 675 FO	3.5 ppm (DLN, SCR); 41 ppm w/ FO	0.040 lb/MMBtu
AL	3-16-99	AL Power - Theodore Cogeneration Facility (PSD-AL-203); Theodore, AL (1 turbine and duct burner)	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (DLN,SCR)/ 0.013 lb/MMBtu	0.086 lb/MMBtu
FL	7-10-98	City of Lakeland - McIntosh Power Plant (PSD-FL-245); Lakeland, FL (1 turbine w/ power augmentation)	Westinghouse 501G (230 MW)	NG, FO	SC (later CC)	7,008; 250 while using FO	25 ppm (DLN) until 5/2002: after then 9 ppm (DLN or hot SCR); 7.5 ppm (SCR) if CC. 42 ppm (WI) FO or 15 ppm (w/SCR)	25 ppm NG; 90 ppm FO
FL	12-4-98	Santa Rosa Energy Center, Sterling Fibers Mfg Facility (PSD-FL-253); Pace, FL (1 turbine and duct burner)	GE 7FA (167 MW) (if a different CT is used SCR may be required to meet 6 ppm NOx)	NG	CC	8,760	9 ppm (DLN), 9.8 ppm combined w/ duct burner	9 ppm CT; 24 ppm CT and duct burner combined
FL	draft determ.	Kissimmee Utility Authority, Cane Island Power Park (PSD-FL-254); Intercession City, FL (1 turbine)	GE 7FA (167 MW)	NG, FO	CC	8,760; 720 FO	9 ppm (DLN) 9.4 ppm w/ duct burner or 6 ppm combined (SCR) NG; 42 ppm (WI) or 15 ppm (SCR) FO	12 ppm w/o duct burner and 20 ppm w/ duct burner NG; 30 ppm FO
FL	draft determ.	Duke New Smyrna Beach Power Company (PSD-FL-257); New Smyrna Beach, FL (2 turbines and 2 unfired HRSGs)	GE 7FA (165 MW)	NG	CC	8,760	9 ppm (DLN), or 6 ppm (SCR)	12 ppm

State	Permit Date	Facility	Turbine Model	Fuel	Mode	Hours	NO_x Limit	CO Limit
FL	applic. under review	Polk Power (TECO) (2 turbines)	GE 7 FA (165 MW)	NG, FO	SC	8,760	10.5 (DLN) NG; 42 (WI) FO	15 ppm NG; 33 ppm FO
FL	applic. under review	Oleander (5 turbines)	GE 7FA (190 MW)	NG, FO	SC	3,390; 1,000 FO	9 ppm (DLN) NG; 42 ppm (WI) FO	12 ppm NG; 20 ppm FO
FL	applic. under review	Lake Worth (1 turbine, no duct burner)	GE 7FA(170 MW)	NG, FO	CC	8,760; 1,000 FO	9 ppm (DLN) NG: 42 ppm (WI) FO	12 ppm NG: 20 ppm FO
FL	applic. under review	Polk Power, FL Power Corp. (2 turbines)	Westinghouse 501F (165 MW)	NG, FO	CC	8,760; 1,000 FO	6 ppm full load NG (SCR); 42 ppm (WI) FO	25 ppm full load NG; 30 ppm FO
GA	4-3-96	Mid-Georgia Cogeneration (PSD-GA-142); Kathleen, GA (2 turbines, no duct burners)	Westinghouse 501D5A (116 MW)	NG, FO	CC	8,760	9 ppm (DLN,SCR) / 15 ppm peak mode; 20 ppm FO (WI, SCR)	10 ppm NG; 30 ppm FO
GA	12-18-98	Tenaska Georgia Partners, L.P. (PSD-GA-159); Heard County, GA (6 turbines)	GE 7FA (160 MW)	NG, FO	SC	3,066 total at full load; (720 FO)	15 ppm (DLN); 42 ppm (WI) FO	15 ppm NG; 20 ppm FO
GA	applic. under review	Thomaston (4 turbines)	GE 7FA(170 MW)	NG, FO	SC	4,760; 1,687 FO	15 ppm (DLN) NG; 42 ppm (WI) FO	15-20 ppm NG;
GA	applic. under review	Heard County - (Phase I: 3 simple cycle turbines 510 MW total / Phase II: 2 combined cycle turbines and 1 simple cycle turbines)	Westinghouse 501FD	NG	3-SC (510 MW total)	8,760 CC; 4,000 SC each turbine	Phase I: 3-SC 15 ppm (DLN) / Phase II: 2 CC 9 ppm	SC 25 ppm; CC 70-100% 25 ppm
GA	applic. under review	Georgia Power, Jackson County (16 turbines)	GE 7EA	NG, FO	SC	8,760; 1,000 FO	15 ppm (DLN) NG [9 ppm base load/22 peak]; 42 ppm (WI) FO	50-75% load 1.05 lb/MMBtu; >75% 0.059 lb/MMBtu
MS	draft determ.	LS Power Limited Partnership (PSD-MS-083); Batesville, MS (3 turbines and duct burners)	Westinghouse 501G (281 MW)	NG, FO	CC	8,760 (up to 10% FO)	9 ppm (DLN, SCR)/42 ppm w/FO (WI)	30.3 ppm (NG)/36 (FO)
MS	draft determ.	MS Power - Plant Daniel (PSD-MS-091); Escatawpa, MS (4 turbines, with power augmentation)	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm (DLN, SCR) 0.018 lb/MMBtu	0.057 lb/MMBtu

State	Permit Date	Facility	Turbine Model	Fuel	Mode	Hours	NO_x Limit	CO Limit
C	applic. under review	Rich. County: CP&L (7 turbines)	GE 7FA	NG. FO	SC	2,000	12 ppm (DLN) NG; 42 ppm (WI) FO	15 ppm NG; 20 ppm FO
NC	applic. under review	Rowan County, CP&L (5 turbines)	GE 7FA	NG, FO	SC	2,000	12 ppm (DLN) NG; 42 ppm (WI) FO	15 ppm NG; 20 ppm FO
TN	applic. under review	TVA - Johnsonville Fossil Plant (PSD-TN-165); New Johnsonville, TN (4 turbines)	GE 7EA (85 MW)	NG, FO	SC	10% NG base mode, 10% NG peaking. 10% FO base	15 ppm NG, 42 ppm FO	25 ppm w/ NG, 20 ppm w/ FO
TN	applic. under review	TVA - Gallatin Fossil Plant (PSD-TN-166); Gallatin, TN (4 turbines)	GE 7EA (85 MW)	NG, FO	SC	10% NG base mode, 10% NG peaking, 10% FO base	15 ppm NG, 42 ppm FO	25 ppm w/ NG, 20 ppm w/ FO
TN	applic. under review	Gleason Power (4 turbines)	Westinghouse 501D5A (125 MW)	NG	SC	3,500	25 ppm (WI)	12 ppm
MI	2/99	Wyandotte energy (2 turbines)	Westinghouse 501f or GE 7F (250 MW)	NG	CC	8760	4.5 ppm Dry Low Nox and SCR	3 ppm (LAER) catalytic oxidizer
MI	8/98	Southern energy (2 Turbines)	GE 7FA (250 MW)	NG	CC	8760	3.5 ppm DLN SCR	0.056 lb/mmbtu
WI	2/99	Southern Energy (2 turbines)	GE PG 7241(FA) (360 MW)	NG, Fuel oil	SC	8760	15 ppmdv @15%O2 fuel oil, NG	12ppmdv @15%O2 NG>=50% load, no operation less than 50% load
WI	1/99	Rockgen energy Center (3 turbines, 175MW each)	GE PG 7241 (FA) (525 MW)	NG, Fuel oil back up	SC	3800 hrs 800 hr fuel oil	15ppmdv DLN	12ppmdv @ 15%O2 NG 70% cap 15ppm fuel oil, 42ppm fuel oil >=50% load

[illegible]ate	Permit Date	Facility	Turbine Model	Fuel	Mode	Hours	NO_x Limit	CO Limit
	12/98	Peoples Gas Light and Coke Company, Elwood, IL	10@250 MW, 1,763 mmBtu/hr	NG	CC	8760	4.5 ppm, SCR and DLN, BACT	54 lb/hr
IL	12/98	Peoples Gas Light and Coke Company, Elwood, IL	4@170 MW, 1763 mmBtu/hr	NG	SC	1500	0.061 lb/mmBtu input (15 ppm) DLN, BACT	54.4 lb/hr
IL	under review	LSP Kendall Energy, LLC, Minooka, IL	4@180-200 MW, 4@80-100 MW	NG	CC	8760	4.5 ppm, SCR and DLN, BACT	136.7 lb/hr, and 541 lb/hr bet 50-75% load
IL	under review	LSP Kendall Energy, LLC, Minooka, IL	same units as CC: 4@180-200 MW	NG	SC temporary until CC begins	2000 1st yr, 900 thereafter until CC begins	25 ppm, DLN	83.6 lb/hr, and 531 lb/hr bet 50-75% load
IL	under review	Reliant Energy, Roxana, IL	3@1,916 mmBtu/hr, 3@489 mmBtu/hr	NG/ RFG in duct burners	CC	8760	3.5 ppm, SCR and DLN, LAER	77.6 lb/hr /129 lb/hr for 1300 hrs

APPENDIX C

CD CONTAINING ISCST3 MODELING FILES

ATTACHMENT I

PREPA Cambalache Combustion Turbine Project
Project Description

GENERAL PROJECT DESCRIPTION: The Puerto Rico Electric Power Authority (PREPA) is proposing to install and operate a 248 megawatt (MW) combustion turbine simple cycle electric generating station on a 52-acre site in Cambalache, in the Municipality of Arecibo. The facility will produce electricity from three ABB GT 11N distillate oil fired combustion turbines, each with a power output of 83 MW. Each combustion turbine will consist of a compressor, combustor and turbine. Energy is generated at each of the combustion turbines by drawing in ambient air with the compressor, heating the air by means of burning fuel oil and expanding the hot combustion gases in a 5-stage turbine. Each combustion turbine will burn No. 2 fuel oil having a maximum sulfur content of 0.15 percent by weight. In addition, the facility will be allowed to operate in a spinning reserve mode (60 percent load) for up to 2,000 hours per year.

PSD-Affected Pollutants Emitted at the PREPA Cambalache Combustion Turbine Project: The facility is classified as a major stationary source because it has the potential to emit more than 250 tons per year of at least one pollutant regulated by the Clean Air Act. The proposed facility is subject to the Prevention of Significant Deterioration of Air Quality (PSD) standards for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns (PM_{10}), and volatile organic compounds (VOC).

Pollutant	PSD Significant Emission Rate (tons/year)	Projected Facility Emission Rate (tons/year)
Nitrogen oxides (NO_x)	40	460
Sulfur dioxide (SO_2)	40	1,800
Sulfuric acid mist (H_2SO_4)	7	420
Carbon monoxide (CO)	100	515
Particulate matter - total (PM)	25	946
Particulate matter less than 10 microns (PM_{10})	15	946
Volatile Organic Compounds (VOC)	40	180

ATTACHMENT I

PREPA Cambalache Combustion Turbine Project
Project Description

PREPA Cambalache Combustion Turbine Control Equipment: The proposed facility will employ Best Available Control Technology to control the pollutants described above.

Emissions of **nitrogen oxides** will be controlled by the use of a steam injection system and a Selective Catalytic Reduction (SCR) system. The steam to fuel ratio for each unit shall be established during performance testing and shall be incorporated into the Environmental Quality Board (EQB) operating permit. Each SCR system shall use a zeolite catalyst and shall operate in accordance with the manufacturer's design specifications.

Emissions of **sulfur dioxide** and **sulfuric acid mist** shall be controlled by the use of only low sulfur No.2 fuel oil in which the sulfur content may not exceed 0.15% by weight.

Emissions of **carbon monoxide, total particulate matter, particulate matter less than 10 microns,** and **volatile organic compounds** will be controlled by implementing good combustion practices. PREPA shall be required to operate each turbine within the designed combustion parameters of the ABB GT 11N distillate oil fired combustion turbine. In addition, PREPA shall be required to monitor the combustion temperature and volumetric flow rate of each turbine, and PREPA shall be required to maintain each turbine in good working order.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

The PREPA Cambalache Combustion Turbine Project as described in Attachment I is subject to the following conditions.

I. Permit Expiration

1. This PSD Permit shall become invalid if construction:

   a. has not commenced (as defined in 40 CFR Part 52.21(b)(9)) within 18 months after the approval takes effect;
   b. is discontinued for a period of 18 months or more; or
   c. is not completed within a reasonable time.

II. Notification of Commencement of Construction and Startup

The Regional Administrator (RA) shall be notified in writing of the anticipated date of initial startup (as defined in 40 CFR Part 60.2) of each combustion turbine not more than sixty (60) days nor less than thirty (30) days prior to such date. The RA shall be notified in writing of the actual date of both commencement of construction and startup of each combustion turbine within fifteen (15) days after such date.

III. Plant Operations

All equipment, facilities, and systems, including the combustion and electric generation units, installed or used to achieve compliance with the terms and conditions of this PSD Permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The continuous emission monitoring systems required by this permit shall be on-line and in operation 95% of the time when turbines are operating.

IV. Right to Entry

Pursuant to Section 114 of the Clean Air Act (Act), 42 U.S.C. §7414, the Administrator and/or his/her authorized representatives have the right to enter and inspect for all purposes authorized under Section 114 of the Act. The permittee acknowledges that the Regional Administrator and/or his/her authorized representatives, upon the presentation of credentials shall be permitted:

1. to enter at any time upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this PSD Permit;

2. at reasonable times to access and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method required in this PSD Permit; and

4. to sample emissions from the source relevant to this permit.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

V. Transfer of Ownership

In the event of any changes in control or ownership of facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter, a copy of which shall be forwarded to the Regional Administrator.

VI. Severability

The provisions of this PSD Permit are severable, and, if any provisions of this PSD Permit are held invalid, the remainder of this PSD Permit shall not be affected thereby.

VII. Operating Requirements

1. Each ABB GT 11N distillate oil fired combustion turbine unit shall be limited to a maximum fuel consumption rate of 6,261 gallons per hour.

2. Each ABB GT 11N distillate oil fired combustion turbine unit shall use No. 2 distillate fuel oil which contains no more than:

   a. 0.15 percent sulfur by weight; and
   b. 0.10 percent nitrogen by weight.

3. Each ABB GT 11N distillate oil fired combustion turbine unit shall be limited to a maximum heat input of 847 million British Thermal Units per hour (MM Btu/hr), based upon lower heating value (LHV).

4. Except for startup and shutdown, each ABB GT 11N distillate oil fired combustion turbine unit shall only be allowed to operate at the following two heat input levels:

   a. base load (847 MM Btu/hr); and
   b. "spinning reserve" mode (581 MM Btu/hr).

5. Each ABB GT 11N distillate oil fired combustion turbine unit shall only be allowed to operate for up to 2,000 hours per year at the "spinning reserve" mode heat input level. Daily compliance shall be determined by adding the total amount of hours operated at the "spinning reserve" mode during each calendar day to the total hours operated at the "spinning reserve" mode in the preceding 364 calendar days.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VII. Operating Requirements (cont'd)

6. For the purposes of this PSD permit, startup and shutdown shall be defined as:

   a. Startup for each ABB GT 11N distillate oil fired combustion turbine is defined as the period beginning with the initial firing of No. 2 fuel oil in the combustion turbine combustor and ending at the time when the load has increased to the "spinning reserve" mode. The duration of the startup shall not exceed six (6) consecutive hours for any given combustion turbine startup.

   b. Shutdown for each ABB GT 11N distillate oil fired combustion turbine is defined as the period of time beginning with the load decreasing from the "spinning reserve" mode and ending when the cessation of operation of the combustion turbine. The duration of the shutdown shall not exceed six (6) consecutive hours for any given combustion turbine shutdown.

7. At all times, including periods of startup, shutdown, and malfunction, PREPA shall, to the extent practicable, maintain and operate the three ABB GT 11N distillate oil fired combustion turbines including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or EQB which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the plant.

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine

1. **Oxides of Nitrogen (NO_x)**

   a. The NO_x emissions shall not exceed 35 pounds per hour (lbs/hr) calculated as NO_2.

   b. The concentration of NO_x in the exhaust gas shall not exceed 10 parts-per-million by volume on a dry basis (ppmdv), corrected to 15% oxygen.

2. **Sulfur Dioxide (SO_2)**

   a. The SO_2 emissions shall not exceed 137 lbs/hr.

   b. The concentration of SO_2 in the exhaust gas shall not exceed 28 ppmdv, corrected to 15% oxygen.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine (cont'd)

3. **Sulfuric Acid Mist (H_2SO_4)**

   a. The H_2SO_4 emissions shall not exceed 32 lbs/hr.

   b. The concentration of H_2SO_4 in the exhaust gas shall not exceed 4.3 ppmdv, corrected to 15% oxygen.

4. **Carbon Monoxide (CO)**

   a. The CO emissions shall not exceed:

      (i) 104 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 20 lbs/hr at the base load heat input level.

   b. The concentration of CO in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 71 ppmdv at the "spinning reserve" mode heat input level; and
      (ii) 9 ppmdv at the base load heat input level.

5. **Particulate Matter (PM)**

   a. The PM emissions shall not exceed:

      (i) 55 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 72 lbs/hr at the base load heat input level.

   b. The concentration of PM in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 0.0191 grains per dry standard cubic feet (gr/dscf) at the "spinning
      (ii) 0.0171 gr/dscf at the base load heat input level.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

VIII. Emission Limitations For Each ABB GT 11N Combustion Turbine (cont'd)

6. **Particulate Matter < 10 microns (PM-10)**
   a. The PM-10 emissions shall not exceed:

      (i) 55 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 72 lbs/hr at the base load heat input level.

   b. The concentration of PM-10 in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 0.0191 gr/dscf at the "spinning reserve" mode heat input level; and
      (ii) 0.0171 gr/dscf at the base load heat input level.

7. **Volatile Organic Compounds (VOC)**
   a. The VOC emissions (as methane) shall not exceed:

      (i) 11 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 13 lbs/hr at the base load heat input level.

   b. The concentration of VOC (as methane) in the exhaust gas, corrected to 15% oxygen, shall not exceed:

      (i) 13 ppmdv at the "spinning reserve" mode heat input level; and
      (ii) 11 ppmdv at the base load heat input level.

8. **Lead (Pb)**:
   a. The Pb emissions shall not exceed:

      (i) 0.016 lbs/hr at the "spinning reserve" mode heat input level; and
      (ii) 0.023 lbs/hr at the base load heat input level.

   b. The concentration of Pb in the exhaust gas, corrected to 15% oxygen, shall not exceed 5.0 μgr/dscf.

9. **Ammonia (NH_4)**: The concentration of NH_4 in the exhaust gas shall not exceed 10 ppmdv, corrected to 15% oxygen.

10. **Opacity limitation**: Opacity of emissions, as measured by 40 CFR Part 60, Method 9, shall not exceed 20%, except for one period of not more than six (6) minutes in any thirty (30) minute interval when the opacity shall not exceed 60%.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

IX. Pollution Control Equipment

1. PREPA shall install and shall continuously operate at each ABB GT 11N distillate oil fired combustion turbine the following air pollution controls:

   a. a steam injection system; and
   b. a Selective Catalytic Reduction (SCR) system.

2. The steam to fuel ratio for each unit shall be established during the performance testing. PREPA shall comply with the steam to fuel ratio determined during the performance testing and contained within the written report submitted to EPA.

3. Each SCR system shall continuously use a zeolite catalyst and shall continuously operate in accordance with the manufacturer's design specifications.

4. Each ABB GT 11N distillate oil fired combustion turbine shall continuously use No.2 fuel oil in which:

   a. the sulfur content does not exceed 0.15% by weight; and
   b. the nitrogen content does not exceed 0.10% by weight.

5. Each ABB GT 11N distillate oil fired combustion turbine shall continuously operate in accordance with its designed specified combustion parameters.

X. Fuel Sampling Requirements

1. PREPA shall sample the fuel being fired in the three ABB GT 11N combustion turbines on each occasion that fuel is transferred to the storage tanks at the facility from any other source. The fuel sampling shall include but not be limited to determining the fuel's:

   a. sulfur content (% by weight); and
   b. nitrogen content (% by weight).

2. Compliance with the sulfur content standard shall be determined using the testing methods established in 40 CFR 60.335(d).

3. Compliance with the nitrogen content standard shall be determined using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XI. Continuous Emission Monitoring (CEM) Requirements

1. Prior to the date of startup and thereafter, PREPA shall install, calibrate, maintain, and operate the following continuous monitoring systems in each of the combustion turbine exhaust stack.

   a. A continuous opacity monitoring system (COMS) to measure and record stack opacity levels. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 1).

   b. A continuous emission monitoring system (CEMS) to measure and record stack gas NO_x (as measured as NO_2) concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 2, and Appendix F).

   c. A CEMS to measure and record stack gas oxygen concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 3, and Appendix F).

   d. A CEMS to measure and record stack gas carbon monoxide concentrations. The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR Part 60.13 and 40 CFR Part 60, Appendix B, Performance Specifications 4, and Appendix F).

   e. A CEMS to measure and record ammonia slip. Upon request of EPA, PREPA shall conduct a performance evaluation of the monitor when testing procedures are formalized by the Agency in the future.

   f. A continuous monitoring system to measure and record stack gas volumetric flow rates. The system shall meet all applicable EPA monitoring performance specifications of 40 CFR Part 60, Appendix A, Method 19.

   g. Continuous monitoring systems to measure and record stack temperatures and steam to fuel ratios. Upon request of EPA, PREPA shall conduct a performance evaluation of the monitor when testing procedures are formalized by the Agency in the future.

2. Not less than 90 days prior to the date of startup of each combustion turbine, PREPA shall submit a written report to EPA of a Quality Assurance Project Plan for the certification of the combustion turbine's monitoring systems. Performance evaluation of the monitoring systems may not begin until the Quality Assurance Project Plan has been approved by EPA.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XI. Continuous Emission Monitoring (CEM) Requirements (cont'd)

3. PREPA shall conduct performance evaluations of the COMS's, CEMS's and continuous monitoring systems during the initial performance testings required under Permit Condition XII of this permit or within 30 days thereafter in accordance with the applicable performance specifications in 40 CFR Part 60, Appendix B, and 40 CFR Part 52, Appendix E. PREPA shall notify the Regional Administrator (RA) 15 days in advance of the date upon which demonstration of the monitoring system(s) performance will commence.

4. PREPA shall submit a written report to EPA of the results of all monitor performance specification evaluations conducted on the monitoring system(s) within 60 days of the completion of the tests. The monitoring systems must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

XII. Performance Testing Requirements For Each Combustion Turbine

1. Within 60 days after achieving the maximum production rate of the combustion turbine, but no later than 180 days after initial startup as defined in 40 CFR Part 60.2, and at such other times as specified by the EPA, PREPA shall conduct performance tests for SO_2, H_2SO_4, NO_x, PM, PM_{10}, CO, VOCs, Pb and opacity at the combustion turbines. All performance tests shall be conducted at base load conditions, "spinning reserve" mode (60% load) conditions and/or other loads specified by EPA.

2. Three test runs shall be conducted for each load condition and compliance for each operating mode shall be based on the average emission rate of these runs.
3. At least 60 days prior to actual testing, PREPA shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XII. Performance Testing Requirements For Each Combustion Turbine (cont'd)

4. PREPA shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA:

    a. Performance tests to determine the stack gas velocity, sample area, volumetric flow rate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR Part 60, Appendix A, Methods 1, 2, 3, and 4.

    b. Performance tests for the emissions of NO_x shall be conducted using 40 CFR Part 60, Appendix A, Method 7E.

    c. Performance tests for the emissions of SO_2 shall be conducted using 40 CFR Part 60, Appendix A, Method 8.

    d. Performance tests for the emissions of H_2SO_4 shall be conducted using 40 CFR Part 60, Appendix A, Method 8.

    e. Performance tests for the emissions of PM shall be conducted using 40 CFR Part 60, Appendix A, Method 5.

    f. Performance tests for the emissions of PM_{10} shall be conducted using 40 CFR Part 51, Appendix M, Method 201 (exhaust gas recycle) or Method 201A (constant flow rate), and Method 202.

    g. Performance tests for the emissions of CO shall be conducted using 40 CFR Part 60, Appendix A, Method 10.

    h. Performance tests for the emissions of VOCs shall be conducted using 40 CFR Part 60, Appendix A, Method 25A.

    i. Performance tests for the emissions of Pb shall be conducted using 40 CFR Part 60, Appendix A, Method 12.

    j. Performance tests for the visual determination of the opacity of emissions from the stack shall be conducted using 40 CFR Part 60, Appendix A, Method 9 and the procedures stated in 40 CFR Part 60.11.

5. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

6. Additional performance tests may be required at the discretion of the EPA or EQB for any or all of the above pollutants.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XII. Performance Testing Requirements For Each Combustion Turbine (cont'd)

7. For performance test purposes, sampling ports, platforms and access shall be provided by PREPA on each of the combustion turbine units in accordance with 40 CFR Part 60.8(e).

8. PREPA shall submit a written report to EPA of the results of all emission testing within 60 days of the completion of the performance test.

9. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

XIII. Recordkeeping Requirements

1. Logs shall be kept and updated daily to record the following:

   a. the gallons of No. 2 fuel oil fired on an hourly basis at each ABB GT 11N distillate oil fired combustion turbine;

   b. the hours of operation of each ABB GT 11N distillate oil fired combustion turbine;

   c. the sulfur content of all fuel oil burned;

   d. the amount of steam consumed at each ABB GT 11N distillate oil fired combustion turbine to control NO_x emissions;

   e. the amount of electrical output (MW) on an hourly basis from each ABB GT 11N distillate oil fired combustion turbine;

   f. any adjustments and maintenance performed on each ABB GT 11N distillate oil fired combustion turbine;

   g. any adjustments and maintenance performed on monitoring systems; and

   h. all fuel sampling results obtained pursuant to Condition X of this permit.

2. All monitoring records, fuel sampling test results, calibration test results and logs must be maintained for a period of five years after the date of record, and made available upon request.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS

1. PREPA shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter and shall include the information specified below:

   a. The magnitude of excess emissions computed in accordance with 40 CFR Part 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for each turbine unit. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.

   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

   d. When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

   e. Results of quarterly monitor performance audits, as required in 40 CFR Part 60, Appendix F.

   f. For the purposes of this PSD Permit, excess emissions indicated by monitoring systems, except during startup or shutdown, shall be considered violations of the applicable emission limits.

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XIV. REPORTING REQUIREMENTS (cont'd)

2. Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in Permit Condition VIII of this permit and actions taken on any unit must be reported by telephone within 24 hours to:

   Chief, Air Permit Division
   Puerto Rico Environmental Quality Board
   P.O. Box 11488
   Santurce, Puerto Rico 00910
   (809) 767-8071

   In addition, the Regional Administrator (RA) and Puerto Rico Environmental Quality Board (EQB) shall be notified in writing within fifteen (15) days of any such failure. This notification shall include: a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increased due to the failure; the cause of the failure; the estimated resultant emissions in excess of those allowed under Condition VIII of this permit; and the methods utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations which such malfunction may cause.

XV. OTHER REQUIREMENTS

1. PREPA shall meet all other applicable federal, state and local requirements, including but not limited to those contained in the Puerto Rico State Implementation Plan (SIP), the General Provisions of the New Source Performance Standards (NSPS) (40 CFR Part 60, Subpart A), and the NSPS for Stationary Gas Turbines (40 CFR, Part 60, Subpart GG).

2. All reports and Quality Assurance Project Plans required by this permit shall be submitted to:

   Chief, Air Compliance Branch
   United States Environmental Protection Agency
   Region II
   290 Broadway
   New York, New York 10007-1866

ATTACHMENT II

PREPA Cambalache Combustion Project
PSD Permit Conditions

XV. OTHER REQUIREMENTS (cont'd)

3. Copies of all reports and Quality Assurance Project Plans shall also be submitted to:

   a. Region II CEM Coordinator
   United States Environmental Protection Agency
   Region II
   Monitoring and Assessment Branch
   2890 Woodbridge Avenue - MS - 220
   Edison, New Jersey 08837-3679

   b. Director, Air Permit Division
   Puerto Rico Environmental Quality Board
   P.O. Box 11488
   Santurce, Puerto Rico 00910

[Issued 12/5/96]

Mr. Ismael Brito, P.E.
Project Manager, Construction Division
Puerto Rico Electric Power Authority
Caso Building, 11th Floor
1225 Ponce de León Avenue
San Juan, PR 00936-4267

Re: Prevention of Significant Deterioration of Air Quality: Revision to the July 31, 1995 Permit for the PREPA Cambalache Electric Generating Facility

Dear Mr. Brito:

The purpose of this letter is to issue to the Puerto Rico Electric Power Authority (PREPA) a revised, final Prevention of Significant Deterioration of Air Quality (PSD) permit (Attachment II) for its Cambalache Combustion Turbine Project. This permit revision is the result of a request made by Ove Nymberg of Cambalache Limited Partnership, S.P. (CLP) in a letter dated July 23, 1996.

On July 31, 1995, the United States Environmental Protection Agency (EPA), Region 2 Office, issued a final PSD permit to approve the PREPA Cambalache project. On September 5, 1995, in accordance with the procedures delineated at 40 CFR Part 124, Citizens in Defense of the Environment (CEDDA) filed an administrative appeal on the PREPA Cambalache PSD permit to the Environmental Appeals Board (EAB) in Washington, D.C. This appeal was subsequently denied by the EAB, on December 11, 1995.

The July 23, 1996 request to revise the PREPA Cambalache PSD permit relates to the substitution of a continuous emissions monitoring requirement (reference section XI.1.f of Attachment II). Specifically, CLP, on behalf of PREPA, requested EPA's approval to utilize Method 19 (from 40 CFR Part 60, Appendix A) to measure and record stack gas volumetric flow rate. The July 31, 1995 PSD permit did not specify a particular methodology to measure and record stack gas flow rate; however, the permit required that the continuous monitoring system meet all applicable performance specifications including, but not limited to, 40 CFR Part 52, Appendix E.

Based upon the information submitted by CLP on July 23, 1996, EPA has determined that use of Method 19 is an acceptable alternative to continuously monitor stack gas flow rates. Because the corresponding change to the PREPA Cambalache PSD permit is not a significant change (no increases in emissions or ambient air quality impacts will occur), public review of this PSD permit modification is not required.

This PSD permit revision is a final action under the Clean Air Act (the Act), and is based upon information that CLP submitted on July 23, 1996. This final Agency action can only be challenged by means of a request for judicial review. Under Section 307(b)(1) of the Act, judicial review of this action is available only by the filing of a petition for review in the United States Court of Appeals for the appropriate circuit within 60 days from the date on which the determination is published in the Federal Register. Under Section 307(b)(2) of the Act, this determination is not subject to later judicial review in civil or criminal proceedings for enforcement.

If you have any questions regarding this letter or the PSD permit modification, please call Mr. Steven C. Riva, Chief, Permitting Section, Air Programs Branch, at (212) 637-4074.

Sincerely,

Jeanne M. Fox
Regional Administrator

Attachment

cc: Ove Nymberg
Cambalache Limited Partnership, S.P.

Norma Burgos, Chair
Puerto Rico Planning Board

Francisco Claudio, Director
Air Permit Division
Puerto Rico Environmental Quality Board

Paul A. Eisen, Director
Environmental Sciences
SBE Environmental Company

Carl A. Soderberg, Director
Caribbean Field Office
U.S. Environmental Protection Agency

bcc: K. Callahan, 2DEPP
S. Riva, 2DEPP-APB
J. Siegel, 2ORC-AB
M. Kantz, 2DESA-MAB
I. Guzman, CEPD-ESB
File behind 3A (w/attachments)

Appendix D
USEPA March 24, 2000 Press Release

PA ISSUES FINAL PERMIT TO PREPA FOR RE-POWERING PROJECT

FOR RELEASE: Friday, March 24, 2000

(#00048) San Juan, Puerto Rico - U.S. Environmental Protection Agency (EPA) finalized its permit for the Puerto Rico Electric Power Authority's (PREPA) re-powering project in San Juan. In response to public concems and new information about the best way to control nitrogen oxide emissions from oil-fired power plants, the Agency had made changes to the draft permit to allow PREPA to increase the electric generating capacity at its San Juan Power Plant and lower total emissions by replacing two, decades-old, 44 megawatt boilers with two 232-megawatt combined cycle turbines. In addition to installing the new turbines, PREPA will install special burners to control nitrogen oxide emissions from four old boilers remaining in service. While this change will increase nitrogen oxide emissions over the levels under the original draft permit, the emissions will still be at lower levels than those from the old plant.

"By installing new turbines and better controlling pollution from the old ones, the pollution emitted from PREPA's Palo Seco plant will be significantly reduced from when the plant operated using all old boilers with no nitrogen oxide controls," said Jeanne M. Fox, EPA Region 2 Administrator. "In fact, due to some changes EPA made to our proposed permit, this final permit further decreases, from the original proposed permit, two pollutants of particular concem in the San Juan area sulfuric acid mist and fine particles."

In its draft permit, proposed in March 1999, EPA included Selective Catalytic Reduction (SCR), which uses an ammonia injection system to reduce nitrogen oxide emissions, and steam injection. However, new data indicate that, on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA has removed the SCR requirement and will instead require PREPA to install special bumers, called "low NOx bumers," on the four old boilers at its facility. PREPA would still use steam injection on its turbines.

"After carefully considering the feasibility of using SCR on an oil-fired plant and reviewing public comments, the choice to remove SCR was clear," said Jeanne M. Fox, EPA Regional Administrator. "We want to ensure that PREPA uses the most reliable pollution controls. Steam injection systems and low NOx burners are both tried and true nitrogen oxide controls."

For information on this page, contact: soderberg.carl@epa.gov

Appendix E
VIWAPA Unit 22 Permitting Documents

Mr. Raymond L. George
Executive Director
Virgin Islands Water and Power Authority
St. Thomas, U.S. Virgin Islands 00804

Re: Prevention of Significant Deterioration of Air Quality (PSD)
Final Permit for Unit 22 at the Krum Bay Facility

Dear Mr. George:

On July 27, 1999, the United States Environmental Protection Agency (EPA), Region 2 Office, received a letter from Mr. Gregory Rhymer, Manager of Environmental Affairs of the Virgin Islands Water and Power Authority (VIWAPA), requesting EPA's review of a PSD application dated June 9, 1999. This PSD application was submitted for a new 24 megawatts (MW) simple cycle oil-fired gas turbine proposed for construction at VIWAPA's Krum Bay Generating Station at St. Thomas, U.S. Virgin Islands.

On July 28, 2000, EPA issued a preliminary determination, subject to public review, to approve the PSD application. The public review period, which was initiated by the publication of an EPA public notice in the St. Thomas Daily News, started on September 13, 2000 and concluded on October 13, 2000. During the public review period, EPA received comments from you concerning the definition of maximum load and excess emissions during start-up, shutdown, and malfunction. EPA reviewed your comments and has amended the permit as appropriate.

The EPA concludes that this final permit now meets all applicable requirements of the PSD regulations codified at 40 CFR §52.21 and the Clean Air Act (the Act). Accordingly, I hereby approve VIWAPA's PSD permit for unit 22 to be located at the St. Thomas station. This letter and its attachments represent EPA's final permit decision. A project description and summary of the control technologies to be used are provided in Enclosure I. The permit conditions are found in Enclosure II. Enclosure III contains the projected air quality impacts of this project and Enclosure IV contains EPA's response to your comments on the draft permit.

This final agency decision may be challenged under the Consolidated Permit Regulations, codified at 40 CFR Part 124 which apply to EPA's processing of this permit decision. Specifically, 40 CFR §124.19 established the following procedures for administrative appeal of final PSD permit decisions. Any person who filed comments on the draft permits may petition the Environmental Appeals Board in Washington, D.C. to review any condition of the permit decision. In addition, any person who failed to file comments on the draft permit may petition for administrative review only to the extent of changes from the draft to the final permit. Any petition for review under this part must be made within thirty (30) days of the service of notice of the final permit decision by the Regional Administrator. The petition for review shall include a statement of the reasons supporting that review and shall adhere to the standards outlined in 40 CFR §124.19(a)(1) and (2).

All persons requesting administrative review must file the original and one copy of the petition for review with the Environmental Appeals Board at the following address:

For Regular Mail:

U.S. Environmental Protection Agency
Environmental Appeals Board (MC-1103B)
401 M Street, SW
Washington, D.C. 20460

For Hand-Carried and Express Mail:

U.S. Environmental Protection Agency
Environmental Appeals Board (MC-1103B)
Westory Building
607 14th Street, NW
Suite 500
Washington, D.C. 20005

Telephone number: (202) 501-7060
Fax number: (202) 501-7580

A copy of the administrative review request must also be sent to:

Steven C. Riva, Chief
Permitting Section
Air Programs Branch
U.S. Environmental Protection Agency
Region 2
290 Broadway, 25th Floor
New York, New York 10007-1866

For purposes of judicial review under the Act, final agency action occurs when a final PSD permit is issued or denied and the administrative review procedures are exhausted. Notice of the Agency's final action with respect to this permit will be published in the Federal Register. Judicial review of this final action is available by the filing of a petition for review in the United States Court of Appeals for the appropriate circuit within 60 days of the date of the Federal Register notice. Under section 307(b) of the Act, this final agency action shall not be subject to judicial review in civil or criminal proceedings for enforcement.

Since comments requesting changes to the draft permits were received and changes were made, this final permit will become effective 30 days after the service of notice unless review is requested under 40 CFR §124.19. If a petition for review of the final agency action is filed, the permit will not become effective until a decision on the petition is rendered by the Environmental Appeals Board.

If you have any questions regarding this letter, please call Mr. Steven C. Riva, Chief, Permitting Section, Air Programs Branch, at (212) 637-4074.

Sincerely,

Jeanne M. Fox
Regional Administrator

Enclosures

cc: Mr. Hollis Griffin
Virgin Islands Department of Planning
& Natural Resources

Mr. Michael E. Lukey, P.E.
Pacific Environmental Services, Inc.

bcc: S. Riva, 2DEPP-APB
S. Chan, 2DEPP-APB
A. Colecchia, 2DEPP-APB
J. Nyemchek, 2DECA-ACB
C. Soderberg, CFO
File Copy

ENCLOSURE I

PROJECT DESCRIPTION

The Virgin Islands Water and Power Authority (VIWAPA) is proposing a modification for its Krum Bay generating station in St. Thomas, U.S. Virgin Islands. This project includes the construction of a new unit, designated Unit 22, a 24 megawatts (MW) United Technologies FT8-1 Power PAC gas turbine. Unit 22 will operate under simple cycle mode, without any secondary heat recovery. Unit 22 will burn No. 2 fuel oil with a maximum sulfur content of 0.2% sulfur by weight. Due to the need for additional increments for PM_{10} and SO_2, VIWAPA has agreed to 1) permanently shut down existing Units 9 and 10; 2) reduce the maximum sulfur content of the No. 6 fuel oil to be burned in Units 11 and 13 from 0.7 percent to 0.56 percent; and 3) reduce the maximum ash content of the waste oil to be burned in Units 11 and 13 from 8 percent to 5 percent.

The VIWAPA St. Thomas facility is an existing major stationary source. Any modification to an existing major stationary source resulting in a significant net emissions increase of certain pollutants would be subject to PSD review. "Significant" is defined in the PSD regulations codified at 40 CFR Part 52.21(b)(23). The proposed Unit 22 is PSD affected for nitrogen oxides (NO_x), sulfur dioxides (SO_2), carbon monoxide (CO), particulate matter less than10 microns (PM_{10}), and volatile organic compounds (VOCs). The potential emissions from Unit 22 are tabulated below:

Pollutants	PSD Significance Levels	Proposed Unit 22 Annual Emissions
NOx	40 TPY	184 TPY
SO2	40 TPY	228 TPY
CO	100 TPY	149 TPY
PM10	15 TPY	99 TPY
VOCs	40 TPY	45 TPY

VIWAPA will employ the best available control technology (BACT) to control the pollutants described above. NO_x emissions shall be controlled through the use of water injection. SO_2 and PM_{10} emissions will be controlled through the use of low sulfur distillate fuel oil. CO and VOC emissions will be controlled by implementing good combustion practices and performing intensive maintenance.

The table below summarizes the units that are covered by this permit:

Unit	Unit Type	Maximum Fuel Use	Maximum Fuel Rate
No. 9	3 MW Diesel Generator (1963)	0 gallon per year (Shut down for credits)	0
No. 10	7.5 MW Steam boiler (1966)	0 gallon per year (Shut down for credits)	0
No. 11	18 MW Steam Boiler (1968)	See Unit 13	14,378 lb/hr
No. 13	35 MW Steam Boiler (1970)	Shares with Unit 11 a combined total of 42,800,000 gal/yr of No. 6 oil with no more than 0.56% sulfur. Shares with Unit 11 a combined total of 200,000 gal/yr of waste oil with a maximum concentration of 5% ash, 8% sulfur, and 0.4% Chlorine and an annual average of 0.05% lead.	26,000 lb/hr
No. 22	24 MW Gas Turbine	15,452,640 gal/yr of No. 2 oil with no more than 0.2% sulfur.	1,760 gal/hr

ENCLOSURE II

PERMIT CONDITIONS

I. Unit 22 (24 MW United Technologies FT-8-1 Power PAC unit)

A. Fuel Oil Usage Limit

1. The total fuel usage for Unit 22 shall not exceed 15,452,640 gallons during any consecutive 365-day period. Daily compliance shall be determined by adding the amount of fuel oil used during each calendar day to the total quantity of fuel oil used in the preceding 364 calendar days.

2. The maximum heat input shall not exceed 247 million British thermal units per hour (MMBTU/hr).

3. The maximum fuel consumption rate shall not exceed 1,764 gallons per hour (gal/hr).

4. The type of fuel is limited to No. 2 fuel oil or distillate fuel oil with a sulfur content of no more than 0.2% sulfur by weight and a nitrogen content of no more than 0.015% nitrogen by weight.

5. Tests for percent sulfur and percent nitrogen in fuel shall be conducted using testing methods established in 40 CFR 60.335.

6. The maximum capacity of Unit 22 shall be defined as the maximum energy output in megawatts (MW) as determined and fixed during the initial performance tests when the maximum amout of fuel is combusted.

7. Percent load shall be determined by the ratio of the actual load in MW to the maximum capacity in MW. The maximum capacity of Unit 22 shall be determined in accordance with Condition (I)(A)(6) above.

B. Sulfur Dioxide (SO_2) Emission Limit

1. BACT is the use of No. 2 fuel oil with a sulfur content of no more than 0.2% sulfur by weight.

2. The sulfur dioxide emissions shall not exceed 52.1 pounds per hour (lbs/hr) at all times.

3. Initial compliance with the above emission limit shall be demonstrated by stack tests using EPA Reference Method 20 (40 CFR 60 Appendix A). The initial stack test shall be conducted at various loads. These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted at various load conditions and compliance shall be based on the average SO_2 emission rate of these test runs. VIWAPA shall demonstrate subsequent compliance with the SO_2 emission rate by calculating emissions based on average weekly fuel sulfur content and flow rate. In these calculations, VIWAPA shall assume that all sulfur is converted to SO_2.

B. Nitrogen Oxides (NO_x) Emissions

1. BACT is the use of water injection to control NO_x emissions. VIWAPA must use water injection at all times except when operating at low load (less than 25% capacity) as reserve.

2. NO_x Emission Limits

   NO_x emissions shall not exceed the most stringent of the following at any time:

   a) NO_x emissions shall not exceed on a 24-hour rolling average basis, 42 lbs/hr calculated as NO_2; or

   b) Concentration of NO_x in the exhaust gas shall not exceed 42 parts per million by volume (ppmdv), on a dry basis, corrected to 15% oxygen (as determined by continuous emissions monitoring).

3. The NOx emission rate shall be tested using EPA Reference Method 20 (see 40 CFR Part 60 Appendix A). These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted at each of four different load conditions (including the minimum point in the range and peak load) and compliance shall be based on the average NO_x emission rate of these test runs.

4. The water-to-fuel ratio for various load conditions will be established during the initial performance testing and will be incorporated into VIWAPA's operating permit issued by the Virgin Islands Department of Planning and Natural Resources.

D. Carbon Monoxide (CO) Emissions

1. BACT for CO is the use and maintenance of good combustion practices at all times.

2. Emission Limits

CO emissions shall not exceed the most stringent of the following at any time:

a) CO emissions shall not exceed 34 lbs/hr; or

b) CO emissions at various percent load levels shall not exceed the following concentrations corrected to 15% oxygen as determined by continuous emission monitoring (see Condition (I)(A)(7) for the definition of percent load):

Percent Load	CO Concentration (ppmdv @ 15% O_2)
0 - 24	350
75 - 99	16
100	10

3. For any 8-hour period, Unit 22 shall not operate below a load factor of 15 percent. Unit 22 shall not be operated at synchronous idle for more than a total of 6 hours per day.

4. The CO mass emission rates at various loads will be tested using EPA Reference Method 10 (40 CFR Part 60, Appendix A). These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted for each of the three load conditions (percent loads) indicated in the above table and compliance for each operating mode shall be based on the average CO emission rate of these three test runs.

E. <u>Particulate Matter/PM_{10} Emissions</u>

1. BACT for PM/PM_{10} is the use and maintenance of good combustion practices at all times.

2. Emission Limits

a) The PM emissions shall not exceed 9 lbs/hr.

b) The PM_{10} emissions shall not exceed 22.6 lbs/hr.

3. The PM emission rate shall be determined using EPA Reference Method 5. The PM_{10} emission rate shall be determined using EPA Reference Method 201/201A and 202 (40 CFR Part 51, Appendix M). These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted for each of the three load conditions (0 - 24, 75 - 99 , and 100 percent load) and compliance shall be based on the average emission rate of these three test runs.

F. <u>Opacity</u>

1. The opacity shall not exceed 17% as determined by continuous monitoring except for 3 minutes in any consecutive 30-minute period during which 40% shall not be exceeded.

2. Visual determination of the opacity of emissions from the stack shall be conducted using 40 CFR Part 60, Appendix A, Method 9 and the procedures in accordance with 40 CFR Part 60.11.

G. <u>VOC Emissions</u>

1. BACT for VOC is the use and maintenance of good combustion practices at all times.

2. Emission Limits

VOC emissions shall not exceed the most stringent of the following at any time:

a) VOC emissions shall not exceed 10.3 lbs/hr measured as carbon; or

b) VOC emissions shall not exceed the following concentrations at the various percent load levels corrected to 15% oxygen (see Condition (I)(A)(7) for the definition of percent load):

Percent Load	Concentration of VOC (ppmdv @ 15% O_2)
0 - 24	95
75 - 99	12
100	8

3. The emission rates of VOC will be tested using EPA Reference Method 25A (40 CFR Part 60, Appendix A). VIWAPA may subtract methane and ethane emissions using EPA Reference Method 18 from the Method 25A VOC emission determination. These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted for each of the three load conditions (percent loads) indicated in the above table and compliance shall be based on the average VOC emission rate of these three test runs.

4. EPA reserves the right to require CEM for VOC in the future.

II Existing Units

A. Units 9 and 10

Units 9 and 10 shall be dismantled and permanently removed from the Krum Bay facility prior to the initial start-up of Unit 22.

A. Units 11 and 13

1. The following changes are made to Attachment II of the August 24, 1994 PSD permit:

a) VIWAPA shall use a multiclone to control the emissions of PM_{10} from Unit 13. The efficiency of the multiclone shall be maintained at no less than 80% by maintaining a pressure drop of one (1) inch of water across the multiclone at all times.

b) VIWAPA shall use only No. 6 fuel oil in which the sulfur content does not exceed 0.56 percent by weight . Fuel usage records containing the sulfur content and the number of gallons burned on an hourly basis at the two units shall be maintained for a period of at least five years.

c) VIWAPA shall use not more than 200,000 gallons of waste-oil ("used" oil, including "off-spec" oil) during any period of 365 consecutive days. Daily compliance for waste-oil use shall be determined by adding the amount of waste-oil used during each day to the total quantity of the waste-oil used in the preceding 364 calendar days.

d) VIWAPA shall implement a program to "blend" the fuel oil and the waste oil, so as to ensure that the fuel stream being fed into Unit 11 and/or Unit 13 has a sulfur content less than or equal to 1.5% by weight. VIWAPA shall monitor the sulfur content of the "blended" fuel oil/waste oil mixture to ensure that the sulfur content is not more than 1.5% by weight. VIWAPA shall not accept any shipment of waste oil that exceeds the following concentrations:

<table>
<tr><th colspan="2">Constituent</th><th>Maximum Concentration (%)</th></tr>
<tr><td rowspan="2">Ash</td><td>Maximum</td><td>5.0</td></tr>
<tr><td>Annual Average</td><td>2.5</td></tr>
<tr><td rowspan="2">Sulfur</td><td>Maximum</td><td>8.0</td></tr>
<tr><td>Annual Average</td><td>2.0</td></tr>
<tr><td colspan="2">Lead (Annual Average)</td><td>0.05</td></tr>
<tr><td colspan="2">Chlorine (Maximum)</td><td>0.4</td></tr>
</table>

e) The maximum ash content of waste oil shall not be more than 5% and the maximum sulfur content shall not be more than 8%.

2. All other conditions that apply to Units 11 and 13 as specified in the August 24, 1994 PSD permit remain unchanged and in full force.

C. Unit 14

Unit 14 shall not be operated unless one of the following units is out of service: Unit 11, Unit 13, Unit 15, Unit 18, or Unit 22.

III Testing Requirements

VIWAPA shall conduct all performance tests for Unit 22 in accordance with the following:

A. Within 60 days after achieving shakedown, but no later than 180 days after initial startup as defined in 40 CFR Part 60.2, VIWAPA shall conduct performance stack tests on Unit 22 for SO_2, NO_x, PM, PM_{10}, CO, VOCs, and opacity in accordance with the test methods published in 40 CFR Part 60, Appendix A and 40 CFR Part 51, Appendix M.

B. At least 60 days prior to the actual performance stack test, VIWAPA shall submit to the EPA for approval a Quality Assurance Project Plan (stack test protocol). The Quality Assurance Project Plan shall contain a detailed description of the sampling point location, sampling equipment, sampling and analytical procedures, data reporting forms, quality assurance procedures and operating conditions for such tests must be submitted to the EPA. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

C. Notification of the stack test must be given to EPA and VIDPNR at least 30 days prior to actual testing.

D. Provide permanent sampling and testing facilities as may be required by the EPA to determine the nature and quantity of emissions from Unit 22. Such facilities shall conform with all applicable laws and regulations concerning safe construction and safe practice.

E. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

F. Additional performance tests may be required at the discretion of the EPA for any or all of the above pollutants.

G. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purposes of a performance test.

H. Start-up for Unit 22 is defined as the period beginning with lightoff of the combustion turbine as initiated by the start cycle, followed by acceleration to 3600 revolutions per minute (RPM), closing of the breaker, and automatic loading to the pre-selected level at the pre-selected loading rate. The start-up process shall not exceed 20 minutes in duration.

I. Shutdown for Unit 22 is defined as the period of time beginning with unloading of the combustion turbine to zero power as initiated by the shutdown cycle, followed by the breaker opening, and deceleration to "gas generator idle" for a five minute cool down before fuel flow is shut off. The shutdown process shall not exceed 20 minutes in duration.

IV Monitoring Requirements

A. <u>Unit 22</u>

1. Within 180 days of the initial startup of Unit 22 and thereafter, VIWAPA shall install, calibrate, maintain and operate continuous emission monitors or monitoring systems to measure stack emissions and operating parameters indicated below:

   Continuous Emission Monitors (CEMs): CO, O_2, NO_x, and opacity.
   Continuous Monitors: Volumetric stack gas flow rate, stack temperature, water-to-fuel ratio, and fuel flow rate.

2. Not less than 90 days prior to the date of startup of Unit 22, VIWAPA must submit to the EPA a Quality Assurance Project Plan for the certification of the CEM systems. CEM performance testing may not begin until the Quality Assurance project Plan has been approved by EPA.

3. Within 180 days of the initial startup of Unit 22, VIWAPA shall install, calibrate and test each continuous emission monitor (CEM) and recorder listed above. Monitors must comply with EPA performance and siting specifications pursuant to 40 CFR Part 60, Appendix B, Performance Specifications 1-4. Equipment specifications calibration and operating procedures, and data evaluation and reporting procedures shall be submitted to EPA in a performance Specification Test protocol. EPA reserves the right to require the auditing of the CEMs by independent agents. Data collected from the CEMs will be quality controlled and quality assured in accordance with the procedures specified in 40 CFR Part 60 Appendix F and Method 203.

4. Not less than 90 days prior to the date of startup, VIWAPA must submit to the EPA a Quality Assurance Project Plan for the certification of the CEM systems. CEM performance testing may not begin until the Quality Assurance Project Plan has been approved by EPA.

5. VIWAPA shall submit a written report to EPA of the results of all monitor performance specification tests conducted on the monitoring system(s) within 45 days of the completion of the tests. The continuous emission monitors must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

6. Logs shall be kept and updated in the specified timeframe to record the following:

   a) the amount of water in gallons per hour used to control NO_x emissions and the water-to- fuel ratio on an hourly basis;

   b) the No. 2 fuel oil burned in gallons on an hourly and annual (rolling 365-day) basis;

   c) hours of operation for Unit 22 on a daily basis;

   d) exceedance of emission limits determined by continuous monitoring;

   e) the sulfur and nitrogen content of all fuel oil burned and the SO_2 emission calculations; and

   f) the amount of electrical output in MW on an hourly basis.

B. <u>Existing Units 11 and 13</u>

Log shall be kept and updated in the specified time frame to record the following:

1. the sulfur content of each shipment of No. 6 fuel oil received;

2. the amount of No. 6 fuel oil burned in gallons on an hourly and annual (rolling 365-day) basis,

3. the content of sulfur, ash, lead, and chlorine of all waste-oil burned and the list of generators for each waste-oil shipment received (to be provided by the waste-oil generator or transporter);

4. the amount of waste oil burned in gallons on an hourly and annual (rolling 365-day) basis;

5. the hourly blending ratio of fuel-oil to waste-oil in Unit 11 and 13 when waste-oil is burned;

6. the sulfur content of each blended mixture of No. 6 fuel oil and waste oil to be burned in Units 11 and 13;

7. the amount of electrical output in MW on an hourly basis; and

8. the pressure drop across the multiclone once per day.

C. <u>Unit 14</u>

Whenever Unit 14 is operated, a log shall be kept to record the following information:

1. which existing unit is being shut down and replaced by Unit 14;

2. the sulfur content of No. 2 fuel oil burned;

3. the amount of No. 2 fuel oil burned on an hourly and annual (rolling 365-day) basis;

4. the hours of operation on a daily basis; and

5. the electrical output in MW on an hourly basis.

D. All continuous monitoring records and logs specified in this section must be maintained for at least five years from the date of measurement and made available upon request.

V. Reporting Requirements

A. Results of emission testing must be submitted to EPA within 60 days after completion of the performance tests.

B. VIWAPA shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly excess emission reports shall be postmarked by the 30th day following the end of each quarter. The information specified below shall be included in the reports:

1. Specific identification of each period of excess emissions that occurred during start-ups, shutdowns, and malfunctions of the affected facility.

2. The nature and cause of any malfunction (if known) of the affected facility and the corrective action taken or preventative measures adopted.

3. For apparent excess emissions due to CEM malfunction, provide the date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repair or adjustments.

4. When no excess emissions have occurred or the CEM system has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

C. Emissions in excess of the applicable concentration limits (in ppmdv corrected to 15% oxygen) listed under Conditions (I)(C), (I)(D) and (I)(G) of this permit for Unit 22 during start-ups and shutdowns shall not be considered violation of the applicable concentration limits. See Condition (III)(H) and (III)(I) for the definition of start-up and shutdown for Unit 22.

D. Upsets/Malfunctions:

1. Malfunction means any sudden, infrequent, and not reasonably preventable failure of an air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

2. All upsets/malfunctions of any of the units (including but not limited to Units 11, 12, 13, 14, 15, 18, 22 and the HRSG) must be reported by telephone within 24 hours to the VIDPNR office listed above. A follow-up letter describing the incident, the amount of down time and the corresponding action taken must be submitted within 5 calendar days to Director, Division of Environmental Protection of the VIDPNR at the address listed above. A copy shall be submitted to Director, Caribbean Environmental Protection Division of the U.S. Environmental Protection Agency, Region II Office at the address listed below.

E. Report any deviations that occur during any one hour average when the water to fuel ratio falls below the level needed to maintain compliance as established in Condition (I)(C)(4). These deviations should be made part of the excess emission reports.

F. The quarterly excess emission reports required in this section shall be sent to the following EPA and VIDPNR personnel:

Region 2 CEM Coordinator
AWQAT MS-220
Monitoring and Management Branch
U.S. EPA Region 2
2890 Woodbridge Avenue
Edison, New Jersey 08837

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Region II Office
Centro Europa Building, Suite 417
1492 Ponce De Leon Avenue
Santurce, PR 00907-4127
(787) 729-6951

Director, Division of Environmental Protection
Virgin Islands Department of Planning and Natural Resources
Cyril E. King Airport, 2nd Floor
St. Thomas, U.S. VI 00802
(340) 774-3320

G. All emission reports, testing reports and start-up notifications required under this permit shall be submitted to Director, Caribbean Environmental Protection Division, U.S.EPA, Region II at the address listed above. Three copies of the stack test report must be submitted within 60 days after completion of the test.

H. In each report quarter, 95% quality data availability shall be maintained for all opacity monitors and 95% quality data availability shall be maintained for all gaseous monitors. There shall be a quality assurance plan coupled with a calibration and maintenance program.

VI Other Permit conditions

A. This facility is subject to the General Provisions of the NSPS (40 CFR Part 60, Subpart A), and the NSPS for Stationary Gas Turbines (40 CFR Part 60, Subpart GG).

B. VIWAPA shall meet all other applicable federal, state, and local requirements, including those contained in the Virgin Islands State Implementation Plan (VISIP).

ENCLOSURE III

Virgin Islands Water and Power Authority
Unit 22 Gas Turbine Project
Air Quality Impacts

ANALYSIS FOR NAAQS COMPLIANCE

Pollutant	Averaging Time	Monitored Background (ug/m^3)	Modeled Cumulative Impacts (ug/m^3)	Total Impact (ug/m^3) (Modeled + Background)	NAAQS (ug/m^3)
PM_{10}	Annual 24-hour	28 97	7 22	35 119	50 150
SO_2	Annual 24-hour 3-hour	5 -- --	45 283 1239	50 283 1239	80 365 1300
NO_x	Annual	8	31	39	100
CO	8-hour 1-hour	6,367 15,463	795 6,066	7,162 21,529	10,000 40,000

ANALYSIS FOR PSD INCREMENT COMPLIANCE

Pollutant	Averaging Time	Impacts from All Increment Consuming Sources (ug/m^3)	Allowable PSD Increment (ug/m^3)
PM_{10}	Annual 24-hour	5 15	17 30
SO_2	Annual 24-hour 3-hour	10 46 413	35 91 512
NO_x	Annual	4	25

[1]

[1]NAAQS and PSD increment analysis is a modeled cumulative analysis which consists of impacts from Unit 22, and other existing sources. The ambient monitored data was obtained from past PSD permit applications where the background concentration accounts for a conservative estimate of all minor and distant sources not specifically modeled.

ENCLOSURE IV

Response to Comments

Introduction

The Region 2 Office of the U.S. Environmental Protection Agency (EPA) held a public comment period from September 13, 2000 to October 13, 2000 with respect to the Prevention of Significant Deterioration of Air Quality (PSD) permit application submitted by the Virgin Islands Water and Power Authority (VIWAPA) for the construction of a 24-megawatt (MW) gas turbine (designated Unit 22) in St. Thomas, U.S. Virgin Islands. During the 30-day public comment period, EPA received comments only from VIWAPA. Below is the EPA response to comments submitted by VIWAPA on October 13, 2000.

Comment 1

The percent load at which VOC and CO emission limits were established in the PSD permit should be calculated as the ratio of the actual MW load to the rated (or design) MW capacity of the unit as opposed to the ratio of the actual MW load to the maximum capacity of the unit. VIWAPA is concerned that variations in weather conditions and fuel characteristics may affect the value of maximum capacity on the day of testing which in turn would affect the calculation of the percent load and compliance with the proper emission limits.

Response 1

There are two parts to this comment. First, by suggesting that percent loads should be calculated in terms of MW and not the amount of fuel burned as stipulated in the draft PSD permit, VIWAPA is in essence submitting that percent loads should be based on energy output rather than heat input. EPA accepts VIWAPA's comments in this regard and added Condition (I)(A)(7) to clearly define "percent load" in the final permit.

With respect to the second part of this comment, EPA disagrees that the rated capacity should be used as the basis for determining percent load because it is not a true value. The unit cannot achieve the rated capacity at any time. However, EPA agrees with VIWAPA that the value of maximum capacity should not vary with time, age, or weather. Therefore, EPA added Condition (I)(A)(6) in the final permit to clarify that the maximum capacity of the unit shall be determined during the initial performance test and be used for calculating percent loads.

Comment 2

VIWAPA wants Unit 22 to be allowed to exceed the mass, concentration, and opacity limits during start-ups, shutdowns, or malfunctions because the vendor has no emission or opacity data for these periods.

Response 2

While EPA understands that emissions generated during periods of start-ups and shutdowns do not represent normal operation, such excursions cannot be excused from meeting the pounds per hour limit for any pollutants and must comply with the opacity limit at all times. Since start-ups and shutdowns occur over a brief period of about 3 minutes as represented in VIWAPA's comment letter, there should not be any concerns over meeting a mass limit that is averaged over 60 minutes. However, EPA agrees with VIWAPA that the concentration limits (in ppmdv corrected to 15% oxygen) for NOx, CO and VOC would not apply during start-ups and shutdowns and added Condition (V)(C) to reflect that. Conditions (III)(H) and (III)(I) are also added in the final permit to define what constitutes start-up and shutdown for Unit 22.

With respect to malfunction situations, EPA disagrees with VIWAPA that a provision should be included in the permit to excuse excess emissions due to malfunctions. Rather, EPA finds it more appropriate for the permitting authorities to investigate such incidents and handle them appropriately under their enforcement programs. To clarify what constitutes a malfunction, EPA added a definition in Condition (V)(D).

The opacity limit as currently stated in the permit already allows for an excursion of a 3-minute period during which the opacity could be as high as 40%. There is no need to allow additional variance from the opacity standard.

Other Changes

9. "Prior to the initial start-up of Unit 22" has been added to Condition (II)(A) to ensure that Units 9 and 10 will be taken out of service permanently before Unit 22 starts operation as represented in the application.

10. Other changes to the final permit included typographical corrections and re-numbering the provisions under Condition (II), (III), and (V), respectively without any change in substance.

Appendix F
VIWAPA Unit 23 Permitting Documents

Federal Register

Wednesday,
December 31, 2003

Part IV

Environmental Protection Agency

40 CFR Part 69

Special Exemption From Requirements of the Clean Air Act for the Territory of United States Virgin Islands; Final Rule and Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 69

[Region 2 Docket No. VI–5–265 B, FRL–7605–6]

Special Exemption From Requirements of the Clean Air Act for the Territory of United States Virgin Islands

AGENCY: Environmental Protection Agency.

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is announcing approval of a petition, from the Governor of the Virgin Islands (US VI), which seeks an exemption of the Clean Air Act (CAA) section 165(a) requirement to obtain a Prevention of Significant Deterioration (PSD) permit to construct prior to construction of a new gas turbine at the Virgin Islands Water and Power Authority (VIWAPA) St. Thomas facility. This exemption allows for construction, but not operation, of Unit 23 prior to issuance of a final PSD permit.

DATES: This direct final rule is effective on March 1, 2004, without further notice, unless EPA receives adverse comment by January 30, 2004. If any adverse comments are received, EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** and inform the public that the rule will not take effect.

ADDRESSES: Comments may be submitted either by mail or electronically. Written comments should be mailed to Steven C. Riva, Chief, Permitting Section, Air Programs Branch, Environmental Protection Agency, Region 2 Office, 290 Broadway, New York, New York 10007–1866. Electronic comments could be sent either to *Riva.Steven@epa.gov* or to *http://www.regulations.gov* which is an alternative method for submitting electronic comments to EPA. Go directly to *http://www.regulations.gov*, then select "Environmental Protection Agency" at the top of the page and use the "go" button. Please follow the on-line instructions for submitting comments.

Copies of the Governor's petition and submittals relied upon in the approval process are available at the following addresses for inspection during normal business hours:

Environmental Protection Agency, Region 2 Office, Air Programs Branch, 290 Broadway, New York, New York 10007–1866, Attn: Umesh Dholakia.

Environmental Protection Agency, Region 2 Office, Caribbean Field Office, Centro Europa Building, Suite 417, 1492 Ponce de Leon Avenue, Stop 22, San Juan, Puerto Rico 00907–4127, Attn: John Aponte.

The U. S. Virgin Islands Department of Planning and Natural Resources (VIDPNR), Division of Environmental Protection, Cyril E. King Airport, Terminal Building, Second Floor, St. Thomas, U.S. Virgin Islands 00802, Attn: Leslie Leonard.

FOR FURTHER INFORMATION CONTACT: Umesh Dholakia, Environmental Engineer, Air Programs Branch, Division of Environmental Protection and Planning, Environmental Protection Agency, Region 2 Office, 290 Broadway, 25th Floor, New York, New York 10007–1866, (212) 637–4023 or at *Dholakia.Umesh@epa.gov.*

SUPPLEMENTARY INFORMATION: The following table of contents describes the format for the **SUPPLEMENTARY INFORMATION** section:

I. What Action Is EPA Taking Today?

EPA is approving a petition from the U.S. VI Governor seeking an exemption of the CAA requirement to obtain a PSD permit to construct prior to commencing construction of a new gas turbine at the VIWAPA St. Thomas facility.

Pursuant to section 325(a) of the CAA, on July 21, 2003, the Governor of the U.S. VI filed a petition with the Administrator seeking an exemption from the CAA section 165(a) PSD requirement to obtain a PSD permit to construct prior to commencing construction. The Governor requested the exemption on behalf of VIWAPA so that it can proceed, as quickly as possible, to construct Unit 23, a 36 megawatt (MW) gas turbine at its St. Thomas facility.

This exemption will allow for construction, not operation, prior to issuance of a final PSD permit, of Unit 23 at the VIWAPA St. Thomas facility.

II. What Are the Regulatory Requirements for Authorizing an Exemption Under the CAA?

Section 325(a) of the CAA provides the Administrator of EPA the authority to exempt sources in the U.S. VI from any requirement under the Act other than section 112 or any requirement under section 110 or part D necessary to attain or maintain National Ambient Air Quality Standard (NAAQS) provided the Administrator determines that compliance is not feasible due to unique geographical, meteorological or economic factors or such other factors deemed significant.

III. What Are the Bases for the Petitioner's Request?

The Petitioner contends that granting this exemption will not impact upon compliance with any requirement under sections 112, 110, or part D of the Act necessary to attain or maintain National Ambient Air Quality Standards. To support this contention, petitioner first acknowledges that because the exemption will not authorize operation of the unit until after receipt of the PSD permit, the exemption will not result in any violations of sections 112, 110, or part D of the Act necessary to attain or maintain a NAAQS. In addition petitioner contends that modeling, submitted in support of the permit application for the unit and supplemented since that application, demonstrates that NAAQS and PSD increments will continue to be preserved if both the new unit and all other existing units on St. Thomas are operating at maximum permitted capacity burning.

Petitioner further asserts that the exemption should be granted because of severe geographic constraints on the U.S. VI power system and because of a power crisis on St. Thomas. A summary of these assertions appears below:

a. Geographic Constraints

The petitioner contends that the exemption is necessary because of severe geographic constraints on the U.S. VI power system. The petition states that the VIWAPA St. Thomas facility is unable to interconnect with a larger power supply grid. Furthermore, the petition states that the distance between St. Thomas and St. Croix prohibit interconnection between the two VIWAPA plants. Thus, the petitioner explains, St. Thomas is serviced by a single power plant.

The petitioner also contends that when significant problems occur units must be shipped off-island for inspection and repair because vendors who provide such services are not located within the U.S. VI. The reasons it provides for this are that vendors do not have inspection and repair facilities in the U.S. VI. Thus, the petition states, major outages extend longer and cost more to correct than they would on the mainland. The petitioner explains that to account for the need to send units off-island for repair, VIWAPA developed a policy and practice of attempting to maintain sufficient reserve capacity. The petitioner goes on to state that because of the long-term loss of one unit (Unit 11) for major repairs and the imminent major repair of another unit (Unit 22), the maximum capacity of all remaining units on St. Thomas is about to drop significantly and therefore the petitioner anticipates a number of scenarios in which there will not be sufficient reserve capacity for powering St. Thomas. The petitioner points out that this will exacerbate an already problem-ridden power supply.

b. Power Crisis on St. Thomas

The petition claims that VIWAPA "no longer has sufficient capacity to ensure a continuous power supply sufficient to meet public needs. Consequently the island has been experiencing frequent power outages whenever a major unit is forced out or is taken out of service for maintenance."

The petitioner states that with Units 11 and 22 unavailable, whenever there is an outage of Unit 13 alone, or an outage of a combination of any two remaining units except 12 and 14, a serious power outage will occur. The petitioner claims the age and unreliability of a number of VIWAPA's units resulted in significant blackouts over the past 12 months even though Units 11 and 22 were available for service. These assertions are documented in three tables attached to the petition.

IV. What Is EPA's Analysis of the Petition?

EPA has reviewed the modeling submitted by VIWAPA in support of its application for a permit to construct and operate Unit 23 and in support of this petition and has determined that authorizing this exemption will not impact upon compliance with any requirement under sections 112, 110, or part D of the Act necessary to attain or maintain a NAAQS or PSD increment.

Upon consideration of VIWAPA's contentions, EPA has determined that the petition presents unique geographic and economic circumstances which meet the section 325 criteria for authorizing an exemption from the CAA section 165(a) requirement to obtain a PSD permit to construct prior to commencing construction of Unit 23 at the VIWAPA St. Thomas facility.

V. What Is EPA's Conclusion?

The EPA is approving the petition for an exemption of the CAA section 165(a) requirement to obtain a PSD permit to construct prior to commencing construction of a new gas turbine, Unit 23, at the VIWAPA St. Thomas facility. This exemption will allow for the construction, but not the operation, of Unit 23 prior to issuance of a final PSD permit.

EPA is relying on the Governor's assertion that the construction and ultimate operation of Unit 23 should provide a reliable baseload which will give VIWAPA flexibility to meet electrical demand and that the additional capacity provided by this unit would be sufficient to allow for both planned and unplanned outages of generating units at the VIWAPA St. Thomas facility. EPA believes that by accelerating the time period by which this unit can be constructed, this rulemaking may increase VIWAPA's potential to provide more reliable power in St. Thomas.

The EPA is publishing this direct final rule without prior proposal because the Agency views this as a noncontroversial approval and anticipates no adverse comments. However, in the proposed rules section of this **Federal Register** publication, EPA is publishing a separate document that will serve as the proposal to approve this same petition should adverse comments be filed. This final rule will be effective March 1, 2004, without further notice unless the Agency receives relevant adverse comments by January 30, 2004.

If the EPA receives any adverse comments, EPA will publish a notice withdrawing the final rule and inform the public that the rule did not take effect. All public comments received will then be addressed in a subsequent final rule based on the proposed rule. The EPA will not institute a second comment period on the proposed rule. Parties interested in commenting on the proposed rule should do so at this time. If no such comments are received, the public is advised that this rule will be effective on March 1, 2004, and no further action will be taken on the proposed rule.

VI. Statutory and Executive Order Review.

A. Executive Order 12866, Regulatory Planning and Review

The Office of Management and Budget (OMB) has exempted this regulatory action from Executive Order 12866, entitled "Regulatory Planning and Review."

B. Paperwork Reduction Act

Under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, OMB must approve all "collections of information" by EPA. The Act defines "collection of information" as a requirement for "answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *" 44 U.S.C. 3502(3)(A). Because the exemption only applies to one company, the Paperwork Reduction Act does not apply.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

This rule will not have a significant impact on a substantial number of small entities because the exemption applies to only one source and does not create any new requirements but simply postpones requirements that will be met. This Federal exemption does not create any new requirements; therefore, I certify that this action will not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

Under section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act"), signed into law on March 22, 1995, EPA must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in estimated costs to State, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. Under section 205, EPA must select the most cost-effective and least burdensome alternative that achieves the objectives of the rule and is consistent with statutory requirements. Section 203 requires EPA to establish a plan for informing and advising any small governments that may be significantly or uniquely impacted by the rule.

EPA has determined that the approval action does not include a Federal mandate that may result in estimated costs of $100 million or more to either State, local, or tribal governments in the aggregate, or to the private sector. This Federal action proposes to approve an exemption under Federal law, and imposes no new requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

E. Executive Order 13132, Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely approves an exemption from a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the Clean Air Act. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

F. Executive Order 13175, Coordination With Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This proposed rule does not have tribal implications, as specified in Executive Order 13175.

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. This action does not involve or impose any requirements that affect Indian tribes. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This rule is not subject to Executive Order 13045 because it does not involve decisions intended to mitigate environmental health or safety risks.

H. Executive Order 13211, Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use "voluntary consensus standards" (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. The EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. Section 804 exempts from section 801 the following types of rules: (1) Rules of particular applicability; (2) rules relating to agency management or personnel; and (3) rules of agency organization, procedure, or practice that do not substantially affect the rights or obligations of non-agency parties. 5 U.S.C. 804(3). EPA is not required to submit a rule report regarding this action under section 801 because this is a rule of particular applicability exempting Virgin Islands Water and Power Authority's St. Thomas facility, Unit 23 from obtaining a PSD permit to construct.

K. Other

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by March 1, 2004. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (*See* section 307(b)(2).)

List of Subjects in 40 CFR Part 69

Environmental protection, Air pollution control.

Dated: December 23, 2003.

Michael O. Leavitt,

Administrator.

■ Part 69 of chapter I, title 40 of the Code of Federal Regulations is amended to read as follows:

PART 69—[AMENDED]

■ 1. The authority citation for part 69 continues to read as follows:

Authority: Section 325, Clean Air Act, as amended (42 U.S.C. 7625–1).

■ 2. Section 69.41 is amended by adding paragraph (h) to read as follows:

§ 69.41 New exemptions.

* * * * *

(h) Pursuant to Section 325(a) of the Clean Air Act (CAA) and a petition submitted by the Governor of United States Virgin Islands on July 21, 2003, ("2003 Petition"), the Administrator of EPA conditionally exempts Virgin Islands Water and Power Authority

("VIWAPA") from certain CAA requirements.

(1) A waiver of the requirement to obtain a PSD permit prior to construction is granted for the electric generating unit identified in the 2003 Petition as Unit 23, St. Krum Bay plant in St. Thomas with the following condition:

(i) Unit 23 shall not operate until a final PSD permit is received by VIWAPA for this unit;

(ii) Unit 23 shall not operate until it complies with all requirements of its PSD permit, including, if necessary, retrofitting with BACT;

(iii) If Unit 23 operates either prior to the issuance of a final PSD permit or without BACT equipment, Unit 23 shall be deemed in violation of this waiver and the CAA beginning on the date of commencement of construction of the unit.

(2) [Reserved]

[FR Doc. 03–32207 Filed 12–30–03; 8:45 am]

BILLING CODE 6560–50–P

ENCLOSURE II (Final Permit)

Virgin Islands Water and Power Authority (VIWAPA), St. Thomas
Unit 23- GE Frame 6

I. Unit 23-- 39 MW General Electric Frame 6 Combustion Turbine)- Emission Limits

A. Fuel Oil Usage Limit

1. The total fuel usage for Unit 23 shall not exceed 30,283,320 gallons during any consecutive 365-day period. Daily compliance shall be determined by adding the amount of fuel oil used during each calendar day to the total quantity of fuel oil used in the preceding 364 calendar days.

2. The maximum heat input shall not exceed 484 million British thermal units per hour (MMBTU/hr).

3. The maximum fuel consumption rate shall not exceed 3,457 gallons per hour (gal/hr).

4. The type of fuel is limited to No. 2 fuel oil or distillate fuel oil with a sulfur content of no more than 0.15% sulfur by weight and a nitrogen content of no more than 1000 ppm nitrogen by weight.

5. Tests for percent sulfur in fuel shall be conducted using testing methods established in 40 CFR 60.335. The test for nitrogen in fuel oil can be any one of the ASTM methods from ASTM D6366-99, D4629-02, or D5762-02. VIWAPA shall test for the fuel's nitrogen content daily. The fuel sample shall be drawn from the day or the holding tank that supplies fuel oil to this unit.

6. The maximum capacity of Unit 23 shall be defined as the maximum energy output in megawatts (MW) as determined and fixed during the initial performance tests when the maximum amount of fuel is combusted.

7. Percent load shall be determined by the ratio of the actual load in MW to the maximum capacity in MW. The maximum capacity of Unit 23 shall be determined in accordance with Condition (I)(A)(6) above.

8. Unit 23 shall not operate at a capacity of less than 25% except during periods of startup and shutdown as specified in paragraphs II B H and II B I.

B. Sulfur Dioxide (SO_2)/Sulfuric Acid Mist

1. Best Available Control Technology (BACT) is the use of No. 2 fuel oil with a sulfur content of no more than 0.15% sulfur by weight.

2. The sulfur dioxide emissions shall not exceed 71.4 pounds per hour (lbs/hr) at all times. The sulfuric acid mist emissions shall not exceed 7.5 lbs/hr.

3. Initial compliance with the above emission limit shall be demonstrated by stack tests using EPA Reference Method 20 (40 CFR 60 Appendix A). The initial stack test shall be conducted at various loads. These tests shall be conducted according to a written protocol approved by EPA prior to any testing and the requirements in Section II of this permit. Three test runs shall be conducted at four load conditions and compliance shall be based on the average SO_2 emission rate of these test runs. VIWAPA shall demonstrate subsequent compliance with the SO_2 emission rate by calculating emissions based on the maximum delivered fuel sulfur content for the prior 12 months and the maximum hourly usage rate for the week. In these calculations, VIWAPA shall assume that all sulfur is converted to SO_2.

C. Nitrogen Oxides (NO_x)

1. BACT is the use of water injection to control NO_x emissions. VIWAPA must use water injection at all times except during periods of startup and shutdown where the load is less than 25% of capacity.

2. NO_x Emission Limits

   NO_x emissions shall not exceed the following at any time:

   a) NO_x emissions shall not exceed 135 lbs/hr calculated as NO_2; and

   b) Concentration of NO_x in the exhaust gas shall not exceed by volume (ppmdv), on a dry basis, corrected to 15% oxygen (as determined by continuous emissions monitoring) on an hourly average basis as follows:

      NOx (ppm) = 42, when fuel oil's nitrogen content is 150 ppm or below; or

      NOx (ppm) = 42 + [((N/10,000)-0.015) x 470.59], where N is the fuel oil's nitrogen content in ppm and it is above 150 ppm

      The NOx concentration value obtained from this equation then shall be used in the equation in 40 CFR 60, Appendix A, Method 19 to calculate the pounds per hour NOx emission limit.

c) The compliance with NOx emissions on an hourly average basis shall be determined as follows: VIWAPA shall analyze the nitrogen content of the fuel oil daily in accordance with condition (I)(A)(5). The daily nitrogen content of the fuel oil in ppm shall be used to calculate the maximum allowable hourly NOx emissions using the equations specified in (I)(C)(2)(b) and shall remain in effect until the next fuel sample is collected thereby repeating this process. VIWAPA shall also obtain averages of the measured nitrogen oxide concentrations (in ppmdv) and lbs/hr rate for every hour.

3. The NOx emission rate shall be tested using EPA Reference Method 20 (see 40 CFR Part 60 Appendix A). These tests shall be conducted according to a written protocol approved by EPA prior to any testing and the requirements in Section II of this permit. Three test runs shall be conducted at four different load conditions (including the minimum point in the range and peak load) and compliance shall be based on the average NO_x emission rate of these test runs.

4. The water-to-fuel ratio for various load conditions will be established during the initial performance testing and reestablished or verified during any subsequesnt testing. The water-to-fuel ratio values contained in the initial performance test reports required to be submitted to EPA, will become enforceable condition of this permit. In addition, they will be incorporated into VIWAPA's operating permit issued by the Virgin Islands Department of Planning and Natural Resources.

D. Carbon Monoxide (CO)

1. BACT for CO is the use and maintenance of good combustion practices at all times.

2. Emission Limits

   CO emissions shall not exceed at any time:

   a) CO emissions shall not exceed 81 lbs/hr; and

   b) CO emissions at various percent load levels shall not exceed the following concentrations corrected to 15% oxygen as determined by continuous emission monitoring (see Condition (I)(A)(7) for the definition of percent load):

Percent Load	CO Concentration (ppmdv @ 15% O_2)
0 - 29	174
30-79	44
80-99	18
Max	14

3. The CO mass emission rates at various loads will be tested using EPA Reference Method 10 (40 CFR Part 60, Appendix A). These tests shall be conducted according to a written protocol approved by EPA prior to any testing and the requirements in Section II of this permit. Three test runs shall be conducted for each of the four load conditions (percent loads) indicated in the above table and compliance for each operating mode shall be based on the average CO emission rate of these three test runs.

E. Particulate Matter/PM_{10}

1. BACT for PM/PM_{10} is the use and maintenance of good combustion practices at all times.

2. Emission Limits

   The PM/PM_{10} emissions shall not exceed 30 lbs/hr.

3. The PM emission rate shall be determined using EPA Reference Method 5. The PM_{10} emission rate shall be determined using EPA Reference Method 201/201A and 202 (40 CFR Part 51, Appendix M). These tests shall be conducted according to a written protocol approved by EPA prior to any testing and the requirements in Section II of this permit.. Three test runs shall be conducted at four load conditions and compliance shall be based on the average emission rate of these three test runs.

F. Opacity

1. The opacity shall not exceed 17% as determined by continuous emission monitoring except for 3 minutes in any consecutive 30-minute period during which 40% shall not be exceeded.

2. Visual determination of the opacity of emissions from the stack shall be conducted using 40 CFR Part 60, Appendix A, Method 9 and the procedures in accordance with 40 CFR Part 60.11 and the requirements in Section II of this permit.

VOC

3. BACT for VOC is the use and maintenance of good combustion practices at all times.

4. Emission Limits

   VOC emissions shall not exceed the following at any time:

   a) VOC emissions shall not exceed 15 lbs/hr measured as carbon; and

   b) VOC emissions shall not exceed the following concentrations at the various percent load levels corrected to 15% oxygen (see Condition (I)(A)(7) for the definition of percent load):

Percent Load	Concentration of VOC (ppmdv @ 15% O_2)
0 - 29	53
30-Max	9

5. The emission rates of VOC will be tested using EPA Reference Method 25A (40 CFR Part 60, Appendix A) and the requirements in Section II of this permit. VIWAPA may subtract methane and ethane emissions using EPA Reference Method 18 from the Method 25A VOC emission determination. These tests shall be conducted according to a written protocol approved by EPA prior to any testing. Three test runs shall be conducted at four load conditions (percent loads) indicated in the above table and compliance shall be based on the average VOC emission rate of these three test runs.

II Unit 23 (39 MW- General Electric Frame 6)- Testing Requirements

VIWAPA shall conduct all performance tests for Unit 23 in accordance with the following:

A. Within 60 days after achieving maximum production, but no later than 180 days after initial startup as defined in 40 CFR Part 60.2, VIWAPA shall conduct performance stack tests and submit stack test results, on Unit 23 for SO_2, NO_x, PM, PM_{10}, CO, VOCs, and opacity in accordance with the test methods published in 40 CFR Part 60, Appendix A and 40 CFR Part 51, Appendix M.

B. At least 60 days prior to the actual performance stack test, VIWAPA shall submit to the EPA for approval a Quality Assurance Project Plan (stack test protocol). The Quality Assurance Project Plan shall contain a detailed description of the sampling point location, sampling equipment, sampling and analytical procedures, data reporting forms, quality assurance procedures and operating conditions for such tests must be submitted to the EPA. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

C. Notification of the stack test must be given to EPA and VIDPNR at least 30 days prior to actual testing.

D. Provide permanent sampling and testing facilities as may be required by the EPA to determine the nature and quantity of emissions from Unit 23. Such facilities shall conform with all applicable laws and regulations concerning safe construction and safe practice.

E. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

F. Additional performance tests may be required at the discretion of the EPA for any or all of the above pollutants.

G. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purposes of a performance test.

H. Start-up for Unit 23 is defined as a period beginning with the turbine ignition to the generator loading to 25% load. The start-up process shall not exceed 16 minutes in duration.

I. Shutdown for Unit 23 is defined as a period beginning to reduce load from 25% to bringing turbine to no load and zero speed. The shutdown process shall not exceed 20 minutes in duration.

III Unit 23 (39 MW- General Electric Frame 6)- Monitoring Requirements

A. Unit 23

1. Within 180 days of the initial startup of Unit 23 and thereafter, VIWAPA shall install, calibrate, maintain and operate continuous emission monitors or monitoring systems to measure stack emissions and operating parameters indicated below:
   Continuous Emission Monitors (CEMs): CO, O_2, NO_x, and opacity.
   Continuous Monitors: Volumetric stack gas flow rate, stack temperature, water-to-fuel ratio, and fuel flow rate.

2. Not less than 90 days prior to the date of startup of Unit 23, VIWAPA must submit to the EPA a Quality Assurance Project Plan for the certification of the CEM systems.

CEM performance testing may not begin until the Quality Assurance project Plan has been approved by EPA.

3. Within 180 days of the initial startup of Unit 23, VIWAPA shall install, calibrate and test each continuous emission monitor (CEM) and recorder listed above. Monitors must comply with EPA performance and siting specifications pursuant to 40 CFR Part 60, Appendix B, Performance Specifications 1-4. Equipment specifications calibration and operating procedures, and data evaluation and reporting procedures shall be submitted to EPA in a performance Specification Test protocol. VIWAPA shall permit the on-site auditing of the CEMs by independent agents of EPA. Data collected from the CEMs will be quality controlled and quality assured in accordance with the procedures specified in 40 CFR Part 60 Appendix F and Method 203.

4. VIWAPA shall submit a written report to EPA of the results of all monitor performance specification tests conducted on the monitoring system(s) within 45 days of the completion of the tests. The continuous emission monitors must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

5. Logs shall be kept and updated in the specified time frame to record the following:

   a) the amount of water in gallons per hour used to control NO_x emissions and the water-to- fuel ratio on an hourly basis;

   b) the No. 2 fuel oil burned in gallons on an hourly and annual (rolling 365-day) basis;

   c) hours of operation for Unit 23 on a daily basis;

   d) exceedance of emission limits determined by continuous monitoring measured in the appropriate units;

   e) the sulfur and nitrogen content of all fuel oil burned and the SO_2 emission calculations; and

   f) the amount of electrical output in MW on an hourly basis

B. All continuous monitoring records and logs specified in this section must be maintained for at least five years from the date of measurement and made available upon request.

IV. Unit 23 (39 MW- General Electric Frame 6)- Reporting Requirements

A. VIWAPA shall conduct performance stack tests and submit stack test results within 60 days after achieving maximum production, but no later than 180 days after initial startup as defined in 40 CFR 60.2 in accordance with 40 CFR 60.8(a).

B. VIWAPA shall submit a written report of all excess emissions, expressed in both ppm and lbs/hr, to EPA for every calendar quarter. All quarterly excess emission reports shall be postmarked by the 30th day following the end of each quarter. The information specified below shall be included in the reports:

1. Specific identification of each period of excess emissions that occurred during start-ups, shutdowns, and malfunctions of the affected facility.

2. The nature and cause of any malfunction (if known) of the affected facility and the corrective action taken or preventative measures adopted.

3. For an excess emissions due to CEM malfunction, provide the date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repair or adjustments.

4. When no excess emissions have occurred or the CEM system has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

5. The results of quarterly monitoring performance audits, as required in 40 CFR Part 60, Appendix F (including the Data Assessment Report) and all reporting specified in 40 CFR 60.7 including the submission of excess emissions summary sheets and monitor downtime summary sheets.

C. Upsets/Malfunctions:

1. Malfunction means any sudden, infrequent, and not reasonably preventable failure of an air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

2. All upsets/malfunctions must be reported by telephone within 24 hours to the VIDPNR office listed above. A follow-up letter describing the incident, the amount of down time and the corresponding action taken must be submitted within 5 calendar days to Director, Division of Environmental Protection of the VIDPNR at the address listed above. A copy shall be submitted to Director, Caribbean Environmental Protection Division of the U.S. Environmental Protection Agency, Region 2 Office at

the address listed below.

D. Report any deviations that occur during any one hour average when the water to fuel ratio falls below the level needed to maintain compliance as established in Condition (I)(C)(5). These deviations should be made part of the excess emission reports.

E. The quarterly excess emission reports required in this section shall be sent to the following EPA and VIDPNR personnel:

Region 2 CEM Coordinator
AWQAT MS-220
Monitoring and Management Branch
U.S. EPA Region 2
2890 Woodbridge Avenue
Edison, New Jersey 08837

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Region 2 Office
Centro Europa Building, Suite 417
1492 Ponce De Leon Avenue
Santurce, PR 00907-4127
(787) 729-6951

Director, Division of Environmental Protection
Virgin Islands Department of Planning and Natural Resources
Cyril E. King Airport, 2nd Floor
St. Thomas, U.S. VI 00802
(340) 774-3320

F. All emission reports, testing reports and start-up notifications required under this permit shall be submitted to Director, Caribbean Environmental Protection Division, U.S.EPA, Region 2 at the address listed above. VIWAPA shall conduct performance stack tests and submit three copies of stack test results within 60 days after achieving maximum production, but no later than 180 days after initial startup as defined in 40 CFR 60.2 in accordance with 40 CFR 60.8(a).

G. In each report quarter, 95% quality data availability shall be maintained for all opacity monitors and 95% quality data availability shall be maintained for all gaseous monitors. There shall be a quality assurance plan coupled with a calibration and maintenance program.

V. Unit 23 (39 MW- General Electric Frame 6)- Other Permit conditions

A. This facility is subject to the General Provisions of the NSPS (40 CFR Part 60, Subpart A), and the NSPS for Stationary Gas Turbines (40 CFR Part 60, Subpart GG).

B. VIWAPA shall meet all other applicable federal, state, and local requirements, including those contained in the Virgin Islands State Implementation Plan (VISIP).

C. This PSD Permit shall become invalid if construction; 1) has not commenced (as defined in 40 CFR Part 52.21(b)(9)) within 18 months after the approval takes effect; 2) is discontinued for a period of 18 months or more; or 3) is not completed within a reasonable time.

D. The Regional Administrator (RA) shall be notified in writing of the anticipated date of initial startup (as defined in 40 CFR Part 60.2) of the combustion turbine not more than sixty (60) days nor less than thirty (30) days prior to such date. The RA shall be notified in writing of the actual date of both commencement of construction and startup of the combustion turbine within fifteen (15) days after such date.

E. All equipment, facilities, and systems, including the combustion and electric generation units, installed or used to achieve compliance with the terms and conditions of this PSD Permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The continuous emission monitoring systems required by this permit shall be on-line and in operation 95% of the time when turbines are operating.

F. Pursuant to Section 114 of the Clean Air Act (Act), 42 U.S.C. §7414, the Administrator and/or his/her authorized representatives have the right to enter and inspect for all purposes authorized under Section 114 of the Act. The permittee acknowledges that the Regional Administrator and/or his/her authorized representatives, upon the presentation of credentials shall be permitted:
   1. to enter at any time upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this PSD Permit;
   2. at reasonable times to access and to copy any records required to be kept under the terms and conditions of this PSD Permit;
   3. to inspect any equipment, operation, or method required in this PSD Permit; and
   4. to sample emissions from the source relevant to this permit.

G. In the event of any changes in control or ownership of facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. The applicant shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter, a copy of which shall be forwarded to the Regional Administrator.

Appendix G
Commonwealth Chesapeake Power Station
Permitting Documents

Virginia Acid Rain Operating Permit

Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13, §10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, 9 VAC 5-80-360 through 9 VAC 5-80-700 and 9 VAC 5-140-10 through 9 VAC 5-140-900 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution of the Commonwealth of Virginia.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name:	Commonwealth Chesapeake Company, LLC
Facility Operator:	TECO Power Services Virginia Operations Company
Facility Name:	Commonwealth Chesapeake Power Station
Facility Location:	3415 White Oak Way New Church, VA 23425-2948
Registration Number:	40898
Permit Number:	TRO-40898

May 2, 2003
Effective Date

December 31, 2004
Expiration Date

May 2, 2003
Signature Date

________________________________ (for)
Robert G. Burnley
Director, Department of Environmental Quality

Table of Contents

I. Facility Information

Permittee
Commonwealth Chesapeake Company, LLC
3415 White Oak Way
New Church, VA 23425-2948

Responsible Official
Thomas A. Larson
General Manager, Commonwealth Chesapeake Company, LLC
US EPA AAR ID No.: 2110

Facility Operator
TECO Power Services Virginia Operations Company

Facility
Commonwealth Chesapeake Power Station
3415 White Oak Way
New Church, VA 23415-2948

Contact Person
Dan Runde
Manager, Commonwealth Chesapeake Power Station
Phone Number: (757) 824-3340

AFS Identification Number: 51-001-00030

ORIS Code ID: 055381

NATS Facility Identification Number: 055381

Facility Description: SIC Code 4911.
Commonwealth Chesapeake Power Station functions as a peaker plant with seven GE LM6000 simple cycle combustion turbines to generate electricity.

II. Emission Units

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Combustion Turbines							
CT-1 thru 7	CT 1-7	GE LM6000. CT 1 thru 3. Installed 2000. CT 4 thru 7. Installed 2001.	Each 43.3 megawatts at ISO conditions	GE water injection on each CT, 2000 and 2001.	WI 1-7	NOx	NSR Permit of 10/05/2000, and Acid Rain Permit of 12/27/2000
Distillate Oil Storage Tanks							
T-1, 2, & 3	T 1-3	Above ground fixed roof tanks. 2000 & 2001	Each at 2.2 million gal	N/a	N/a	N/a	NSR Permit of 10/05/2000.
T-4 & 5	T 4 & 5	Above ground fixed roof tanks. 2001	Each at 200 K gal	N/a	N/a	N/a	NSR Permit of 10/05/2000.

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

III. NSR PERMIT OF OCTOBER 5, 2000

A. Limitations

1. The permittee shall meet all the applicable requirements of 40 CFR 60, Subpart GG Standards of Performance for Stationary Gas Turbines; and, 40 CFR Part 60, Subpart Kb [60.116b, paragraphs (a) and (b)] - Standards of Performance for Volatile Organic Liquid Storage Vessels.
(9 VAC 5-80-490 B & C and Condition 3 of NSR permit issued 10/05/2000)

2. Particulate matter emissions from each combustion turbine shall be controlled by the use of distillate oil, a clean burning fuel. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-490 B & C and Condition 4 of NSR permit issued 10/05/2000)

3. Sulfur dioxide and sulfuric acid mist emissions from each combustion turbine shall be controlled by the use of distillate oil with sulfur not to exceed 0.05% by weight.
(9 VAC 5-80-490 B & C and Condition 5 of NSR permit issued 10/05/2000)

4. Nitrogen oxide emissions from each combustion turbine shall be controlled by water injection except during startup and shutdown when the use of water injection would interfere with turbine operations. The rate of water injection shall be at least that established during emissions tests as being sufficient to meet the emissions standards set forth in this permit.
(9 VAC 5-80-490 B & C and Condition 6 of NSR permit issued 10/05/2000)

5. Carbon monoxide and volatile organic compound emissions from each combustion turbine shall be controlled by the use of good combustion operating practices.
(9 VAC 5-80-490 B & C and Condition 7 of NSR permit issued 10/05/2000)

6. Combustion turbines CT-1, 2, 3, 4, 5, 6, and 7 (combined) shall not use more than 42.0 million gallons of distillate oil each year, calculated as the sum of each consecutive 12 month period.
(9 VAC 5-80-490 B &C and Condition 9 of NSR permit issued 10/05/2000)

7. Combustion turbines 1-3 (combined) shall not operate more than 6,000 hours per year, and combustion turbines 4-7 (combined) shall not operate more than 8,000 hours per year, which means that the seven turbines can be operated simultaneously for up to 2000 hours per year. The number of operating hours for each combustion turbine shall be calculated as the sum of each consecutive 12-month period.
(9 VAC 5-80-490 B&C Condition 10 of NSR permit issued 10/05/2000)

8. Except during startup and shutdown, each combustion turbine shall not operate at less than 70% of capacity.
(9 VAC 5-80-490 B &C and Condition 11 of NSR permit issued 10/05/2000)

9. The permittee is authorized to store distillate oil in storage tanks with Unit Reference Nos. T-1 through T-5. A change in the materials stored may require a permit to modify and operate.
(9 VAC 5-80-490 B &C and Condition 12 of NSR permit issued 10/05/2000)

10. Emissions from the operation of the combustion turbines CT 1, 2, and 3 shall not exceed the limits as specified below:

	(each at 100% of capacity) lb/hr	(combined total) tons/yr
Particulate Matter	10.3	30.9
PM-10	10.3	30.9
Sulfur Dioxide	23.9	65.1
Nitrogen Oxides (as NO_2)	(42 ppmvd* for FBN ≤ 0.015%) 85.1	243.6**
Nitrogen Oxides (as NO_2)	(42 + 400 FBN) ppmvd* for 0.015% < FBN ≤ 0.05% 125.6	243.6**
Carbon Monoxide	30.0	90.0
Volatile Organic Compounds	5.6	16.8
Sulfuric Acid Mist	2.7	7.4

(Yearly is calculated as the sum of each consecutive 12-month period.)
*(one hour average at 15% oxygen, adjusted to ISO standard ambient conditions)
**(includes all operating hours per year--normal operations with the water injection system and startup, shutdown, or any malfunctions when the water injection system is not used)
FBN - Fuel Bound Nitrogen, percent by weight.
(9 VAC 5-80-490 B & C and Condition 20 of NSR permit issued 10/05/2000)

11. Emissions from the operation of the combustion turbines CT 4, 5, 6, and 7 shall not exceed the limits as specified below:

	(each at 100% of capacity) lb/hr	(combined total) tons/yr
Particulate Matter	10.3	41.2
PM-10	10.3	41.2
Sulfur Dioxide	23.9	86.8
Nitrogen Oxides (as NO_2)	(42 ppmvd* for FBN $\leq$ 0.015%) 85.1	322.4**
Nitrogen Oxides (as NO_2)	(42 + 400 FBN) ppmvd* for 0.015% < FBN $\leq$ 0.05% 125.6	476.0**
Carbon Monoxide	30.0	120.0
Volatile Organic Compounds	5.6	22.4
Sulfuric Acid Mist	2.7	9.9

(Yearly is calculated as the sum of each consecutive 12-month period.)
*(one hour average at 15% oxygen, adjusted to ISO standard ambient conditions)
**(includes all operating hours per year--normal operations with the water injection system and startup, shutdown, or any malfunctions when the water injection system is not used)
FBN - Fuel Bound Nitrogen, percent by weight.
(9 VAC 5-80-490 B &C and Condition 21 of NSR permit issued 10/05/2000)

12. Emissions from the operation of the combustion turbines CT 1-7 shall not exceed the limits as specified below:

	(each at 100% of capacity) lb/hr	(combined total) tons/yr
Hazardous Air Pollutants (as VOC)		
Formaldehyde	0.1	0.8
Hazardous Air Pollutants (as PM-10)		
Lead	0.006	0.04
Arsenic	0.005	0.03
Beryllium	0.0001	0.0009
Cadmium	0.002	0.01
Chromium	0.005	0.03
Manganese	0.4	2.3
Mercury	0.0005	0.004
Selenium	0.01	0.07

These emissions are derived from the estimated overall emission contribution from operating limits and emission factors supplied by the permittee. Exceedances of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions II and III.A.6.
(Yearly is calculated as the sum of each consecutive 12-month period.)
(9 VAC 5-80-490 B & C and Condition 35 of NSR permit issued 10/05/2000)

13. Emissions from the operation of the fuel oil storage tanks T 1-5 (combined) shall not exceed the limits as specified below:

Volatile Organic Compounds	1.8 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits and emission factors supplied by the permittee. Exceedances of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition numbers II and III.A.6.
(9 VAC 5-80-490 B & C and Condition 22 of NSR permit issued 10/05/2000)

14. Visible emissions from each combustion turbine exhaust stack shall not exceed ten (10) percent opacity as determined by EPA Method 9 (Reference 40 CFR 60, Appendix A). This condition applies at all times except during start-up, shut-down or malfunction.
(9 VAC 5-80-490 B & C and Condition 23 of NSR permit issued 10/05/2000)

15. In order to minimize the duration and frequency of excess emissions due to malfunctions of process equipment or air pollution control equipment, the permittee shall:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance;

    b. Maintain an inventory of spare parts that are needed to minimize durations of air pollution control equipment breakdowns.

    (9 VAC 5-80-490 B & C and Condition 29 of NSR permit issued 10/05/2000)

16. Operators shall be trained in the proper operation of all related air pollution control equipment and shall be familiar with the written operating procedures. These procedures shall be based on the manufacturer's recommendations, at a minimum.
(9 VAC 5-80-490 B & C and Condition 30 of NSR permit issued 10/05/2000)

17. The sulfur content and fuel-bound nitrogen content of the distillate oil to be burned in the combustion turbines shall not each exceed 0.05 percent by weight per shipment.
(9 VAC 5-80-490 B & C and Condition 13 of NSR permit issued 10/05/2000)

B. Monitoring

1. Scenario #1 for sulfur and nitrogen content of fuel oil: The permittee shall obtain a fuel certification from the fuel supplier with each shipment of distillate oil delivered to each turbine fuel storage tank. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the distillate oil was received;

    c. The volume of distillate oil delivered in the shipment;

    d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications for numbers 1 or 2 fuel oil;

e. The sulfur content of the distillate oil and indicate which ASTM method was used to determine the sulfur content: ASTM D 2880-71, 78, or 96, ASTM D-1552, ASTM D-129, or other approved method,

f. The nitrogen content of the distillate oil and indicate which ASTM method was used to determine the nitrogen content: ASTM D-3228, ASTM D-5291, or other approved method.

(9 VAC 5-80-490 E and Condition 13 of NSR permit issued 10/05/2000)

2. Scenario #2 for sulfur and nitrogen content of fuel oil: If the permittee does not obtain a fuel certification from the fuel supplier with each shipment of distillate oil delivered to the turbine fuel storage tank(s) under Scenario #1, the permittee shall sample and analyze the fuel from the tank(s) after each filling process has been completed to determine:

   a. The distillate oil complies with the American Society for Testing and Materials specifications for numbers 1 or 2 fuel oil;

   b. The sulfur content of the distillate oil by using ASTM D 2880-71, 78, or 96, ASTM D-1552, ASTM D-129, or other approved method,

   c. The nitrogen content of the distillate oil by using ASTM D-3228, ASTM D-5291, or other approved method.

   (9 VAC 5-80-490 E and Condition 13 of NSR permit issued 10/05/2000)

3. The continuous monitoring systems shall be installed and operated to monitor and record the fuel consumption and ratio of water injected to fuel being fired in each combustion turbine. These monitoring systems shall be operated at all times that water is being injected into the combustion turbines and shall be accurate to within ± 5.0 percent. The systems shall be maintained and calibrated in accordance with manufacturer's specifications. As a minimum, calibration shall be done prior to the initial performance test and at least annually thereafter.

   (9 VAC 5-80-490 E and Condition 17 of NSR permit issued 10/05/2000)

4. The permittee shall perform monthly visual observations on each turbine stack exhaust during daylight hours of normal operations for visible emissions. If visible emissions are noted from the stack, a visible emissions evaluation (VEE) shall be immediately conducted on the stack for at least six minutes in accordance with Method 9 (40 CFR 60, Appendix A). If the VEE opacity average exceeds five (5) percent, the VEE shall continue for one hour from initiation on the turbine stack to determine compliance with the opacity limit. The permittee shall record the details of the visual observations, VEE, and any maintenance actions to reduce opacity.
(9 VAC 5-80-490 E)

C. Recordkeeping

The permittee shall maintain records of all emission data and operating parameters necessary to demonstrate compliance with this permit. The content of and format of such records shall be arranged with the Director, Tidewater Regional Office. These records shall include, but are not limited to:

1. The total operating hours per year for each combustion turbine with combined operating hours for CT 1-3 and CT 4-7, calculated as the sum of each consecutive 12-month period;

2. All the fuel oil analysis reports for sulfur and nitrogen content in accordance with Condition III.B.1 and/or 2;

3. Oil shipments purchased, indicating the name of the supplier, date of purchase, type and volume of fuel per each shipment;

4. Annual amount of distillate oil consumed by all turbines, calculated as the sum of each consecutive 12-month period;

5. Monthly and annual NOx and SO2 emission calculations. Monthly and annual emissions calculations for all other pollutants listed in Conditions III.A.10, 11, 12, and 13 based on the usage of DEQ approved emission factors;

6. Listing of DEQ approved emission factors for pollutants listed in Condition III.A10, 11, 12, and 13;

7. Records of products stored in tanks T 1-5, dimensions and storage capacity of each tank;

8. Semi-annual excess emissions reports;

9. The records of the required training including a statement of time, place and nature of the training provided;

10. The written operating procedures for related air pollution control equipment;

11. Records of scheduled and unscheduled maintenance on turbines and air pollution control equipment;

12. Turbine stack visual observations and VEEs;

13. All records required by this condition shall be kept at the facility and made available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-490 C & F, Conditions 13 25, 29, 30, and 36 of NSR permit issued 10/05/2000, and 40 CFR 60, Subpart Kb, Para 60.116.b)

D. Testing

1. After the initial performance tests, performance tests shall be conducted on one combustion turbine each calendar year. A different turbine shall be selected each year such that each turbine selected shall be tested about every seven years for nitrogen oxides while operating at 70% and 100% of capacity by using Method 20 (40 CFR Part 60, Appendix A) to determine compliance with NO_x limits specified in Conditions III.A. 10 or 11. The tests shall be performed anytime during each calendar year following the initial performance test year. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Tidewater Regional Office.
(9 VAC 5-80-490 E & F and Condition 15 of NSR permit issued 10/05/2000)

2. Concurrently with the annual performance tests for each turbine being tested, a Visible Emission Evaluation (VEE) in accordance with 40 CFR, Part 60, Appendix A, Method 9, shall also be conducted on each combustion turbine stack while operating at 70% and 100% of capacity. The test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield 6-minute averages.
(9 VAC 5-80-490 E & F and Condition 16 of NSR permit issued 10/05/2000)

3. If additional testing to demonstrate compliance is conducted in addition to the monitoring specified in this permit, the permittee shall use the following methods or other approved methods in accordance with procedures approved by the DEQ as follows:

Pollutant	Test Method
VOC	EPA Methods 18, 25, or 25A and 19
NO_x	EPA Method 20
SO_2	EPA Methods 6, or 6C and 19
CO	EPA Method 10 and 19
PM/PM-10	EPA Methods 5/201
Visible Emission	EPA Method 9

(9 VAC 5-80-490 E & F)

E. Reporting

1. The permittee shall submit a protocol for the annual combustion turbine test, required by Condition III.D.1, at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Tidewater Regional Office within 45 days after test completion and shall conform to the test report format enclosed with this permit. (9 VAC 5-80-490 F and Condition 15 of NSR permit issued 10/05/2000)

2. A copy of the visible emissions test results, required by Condition III.D.2, shall be submitted to the Director, Tidewater Regional Office within 45 days after test completion and shall conform to the test report format enclosed with this permit. (9 VAC 5-80-490 F and Condition 16 of NSR permit issued 10/05/2000)

3. Should conditions prevent accomplishing concurrent opacity observations with the annual performance test of the turbine, the Director, Tidewater Regional Office shall be notified in writing, within 7 days, and visible emissions testing to be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests and annual tests. (9 VAC 5-80-490 F and Condition 16 of NSR permit issued 10/05/2000)

4. Semi-annual reports of excess emissions shall be submitted to the Director, Tidewater Regional Office in accordance with 40 CFR Part 60, Section 7(c). The time periods shall be the same as those listed in Condition VII.C. In addition to the information required by 40 CFR Part 60, Section 7(c), each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions. For the purpose of this report, periods of excess emissions are defined as follows:

a. Any one hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the average water- to-fuel ratio determined to demonstrate compliance with the nitrogen oxide PPMvd limits specified in Condition III.A.10 or 11 during the most recent compliance test.

b. Any period during which the sulfur content of the distillate oil being fired in the combustion turbines exceeds 0.05 percent by weight.

c. Any period during which the nitrogen content of the distillate oil being fired in the gas turbines exceeds 0.05 percent by weight.

(9 VAC 5-80-490 F and Condition 19 of NSR permit issued 10/05/2000)

IV. PHASE II ACID RAIN PERMIT OF DECEMBER 27, 2000

The attached Phase II Acid Rain permit is incorporated into this permit by reference. The owners and operators of the source shall comply with the standard requirements and special provisions set forth in the application.
(9 VAC 5-80-440 and 9 VAC 5-80-490 A.4.a and c, B, C, E, F, M, O and P)

V. Insignificant Emission Units

The following emission units at the facility are identified in the application as insignificant emission units under 9 VAC 5-80-720:

Emission Unit No.	Emission Unit Description	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
FP-1	Diesel engine for fire pump		300 HP/hr
LO 1-7	CT lube oil tanks	VOC	4000 gal each
FPT-1	Fire pump diesel fuel tank	VOC	500 gal
Fugitive-1 (fuel oil)	Fugitives from unloading, processing and handling of distillate fuel oil	VOC	N/A
Fugitive-2 (fuel oil)	Fugitives from small distillate oil storage tanks	VOC	Each less than 500 gal
Fugitive-3 (Oil/water separator)	Fugitives from oil/water separator	VOC	N/A

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9 VAC 5-80-490 C, E, and F.

VI. Permit Shield & Inapplicable Requirements

Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Applicability
40 CFR 64	Compliance Assurance Monitoring	Does not use air pollution control equipment to destroy pollutants
40 CFR 61	NESHAPS	Source category not listed
40 CFR 63	MACTs	Not a major HAPS source
9 VAC 5 Chapter 80, Article 7 & & 9 VAC 5 Chapter 60, Article 3	Major HAPS NSR Permitting	Not a major HAPS source
40 CFR 68	Prevention of Accidental Chemical Releases	Any chemicals on site are below threshold levels.

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by the administrator pursuant to §114 of the federal Clean Air Act, (ii) the Board pursuant to §10.1-1314 or §10.1-1315 of the Virginia Air Pollution Control Law or (iii) the Department pursuant to §10.1-1307.3 of the Virginia Air Pollution Control Law.
(9 VAC 5-80-500)

VII. General Conditions

A. Federal Enforceability

All terms and conditions in this permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those that have been designated as only state-enforceable.
(9 VAC 5-80-490 N)

B. Permit Expiration

This permit has a fixed term. Unless a timely and complete renewal application consistent, with 9 VAC 5-80-430, has been submitted, to the Department, by the owner, the right of the facility to operate shall be terminated upon permit expiration.

1. The owner shall submit an application for renewal at least six months but no earlier than eighteen months prior to the date of permit expiration.

2. If an applicant submits a timely and complete application for an initial permit or renewal under this section, the failure of the source to have a permit or the operation of the source without a permit shall not be a violation of Article 3, Part II of 9 VAC 5 Chapter 80, until the Board takes final action on the application under 9 VAC 5-80-510.

3. No source shall operate after the time that it is required to submit a timely and complete application under subsections C and D of 9 VAC 5-80-430 for a renewal permit, except in compliance with a permit issued under Article 3, Part II of 9 VAC 5 Chapter 80.

4. If an applicant submits a timely and complete application under section 9 VAC 5-80-430 for a permit renewal, but the Board fails to issue or deny the renewal permit before the end of the term of the previous permit, (i) the previous permit shall not expire until the renewal permit has been issued or denied, and (ii) all the terms and conditions of the previous permit, including any permit shield granted pursuant to 9 VAC 5-80-500, shall remain in effect from the date the application is determined to be complete until the renewal permit is issued or denied.

5. The protection under subsections F 1 and F 5 (ii) of section 9 VAC 5-80-430 shall cease to apply if, subsequent to the completeness determination made pursuant to section 9 VAC 5-80-430 D, the applicant fails to submit, by the deadline specified in writing by the Board, any additional information identified as being needed to process the application.
(9 VAC 5-80-430 B, C, and F, 9 VAC 5-80-490 D, and 9 VAC 5-80-530 B)

C. Recordkeeping and Reporting

1. All records of monitoring information maintained to demonstrate compliance with the terms and conditions of this permit shall contain, where applicable, the following:

   a. The date, place as defined in the permit, and time of sampling or measurements.

   b. The date(s) analyses were performed.

   c. The company or entity that performed the analyses.

   d. The analytical techniques or methods used.

   e. The results of such analyses.

   f. The operating conditions existing at the time of sampling or measurement.

   (9 VAC 5-80-490 F)

2. Records of all monitoring data and support information shall be retained for at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
(9 VAC 5-80-490 F)

3. The permittee shall submit the results of monitoring contained in any applicable requirement to DEQ no later than March 1 and September 1 of each calendar year. This report must be signed by a responsible official, consistent with 9 VAC 5-80-430 G, and shall include:

   a. The time period included in the report. The time period to be addressed are January 1 to June 30 and July 1 to December 31.

   b. All deviations from permit requirements. For purposes of this permit, deviations include, but are not limited to:

      (1) Exceedance of emissions limitations or operational restrictions;

      (2) Excursions from control device operating parameter requirements, as documented by continuous emission monitoring, periodic monitoring, or compliance assurance monitoring which indicates an exceedance of emission limitations or operational restrictions; or,

      (3) Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit.

   c. If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that "no deviations from permit requirements occurred during this semi-annual reporting period."

   (9 VAC 5-80-490 F)

D. Annual Compliance Certification

Exclusive of any reporting required to assure compliance with the terms and conditions of this permit or as part of a schedule of compliance contained in this permit, the permittee shall submit to EPA and DEQ no later than **March 1** each calendar year a certification of compliance with all terms and conditions of this permit including emission limitation standards or work practices. The compliance certification shall comply with such additional requirements that may be specified pursuant to §114(a)(3) and §504(b) of the federal Clean Air Act. This certification shall be signed by a responsible official, consistent with 9 VAC 5-80-430 G, and shall include:

1. The time period included in the certification. The time period to be addressed is January 1 to December 31.

2. A description of the means for assessing or monitoring the compliance of the source with its emissions limitations, standards, and work practices.

3. The identification of each term or condition of the permit that is the basis of the certification.

4. Consistent with subsection 9 VAC 5-80-490 E, the method or methods used for determining the compliance status of the source at the time of certification and over the certification period.

5. Whether compliance was continuous or intermittent, and if not continuous, documentation of each incident of non-compliance.

6. The status of compliance with the terms and conditions of this permit for the certification period.

7. Such other facts as the permit may require to determine the compliance status of the source.

One copy of the annual compliance certification shall be sent to EPA at the following address:

Clean Air Act Title V Compliance Certification (3AP00)
U. S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029.

(9 VAC 5-80-490 K)

E. Permit Deviation Reporting

The permittee shall notify the Director, Tidewater Regional Office within four daytime business hours, after discovery of any deviations from permit requirements which may cause excess emissions for more than one hour, including those attributable to upset conditions as may be defined in this permit. In addition, within 14 days of the discovery, the permittee shall provide a written statement explaining the problem, any corrective actions or preventative measures taken, and the estimated duration of the permit deviation. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. The occurrence should also be reported in the next semi-annual compliance monitoring report pursuant to General Condition VII.C.3. of this permit.
(9 VAC 5-80-490 F)

F. Failure/Malfunction Reporting

In the event that any affected facility or related air pollution control equipment fails or malfunctions in such a manner that may cause excess emissions for more than one hour, the owner shall, as soon as practicable but no later than four daytime business hours, notify the Director, Tidewater Regional Office by facsimile transmission, telephone, telegraph, or e-mail of such failure or malfunction and shall within two weeks provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. Owners subject to the requirements of 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the owner shall notify the Director, Tidewater Regional Office.

1. The emission units that have continuous monitors subject to 9 VAC 5-50-50 C are not subject to the two week written notification.

2. The emission units subject to the reporting and the procedure requirements of and the procedures of 9 VAC 5-50-50 C are listed below:
   CT 1-7.

3. Each owner required to install a continuous monitoring system subject to 9 VAC 5-50-410 shall submit a written report of excess emissions to Director, Tidewater Regional Office as required by Condition III.E.4. All reports shall be postmarked by the 30th day following the end of each reporting period and shall include the following information:

   a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurred during startups, shutdowns, and malfunctions of the source. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted;

c. Date and time identifying each period during which the continuous monitoring system was inoperative and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

4. All emission units not subject to 9 VAC 5-50-50 C must make written reports within two weeks of the malfunction occurrence.

(9 VAC 5-20-180 C, 9 VAC 5-50-50, and Condition 28 of NSR issued 10/05/2000)

G. Severability

The terms of this permit are severable. If any condition, requirement or portion of the permit is held invalid or inapplicable under any circumstance, such invalidity or inapplicability shall not affect or impair the remaining conditions, requirements, or portions of the permit.
(9 VAC 5-80-490 G.1)

H. Duty to Comply

The permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Air Act or the Virginia Air Pollution Control Law or both and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or, for denial of a permit renewal application.
(9 VAC 5-80-490 G.2)

I. Need to Halt or Reduce Activity not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
(9 VAC 5-80-490 G.3)

J. Permit Action for Cause

This permit may be modified, revoked, reopened, and reissued, or terminated for cause as specified in 9 VAC 5-80-490 L, 9 VAC 5-80-640 and 9 VAC 5-80-660. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
(9 VAC 5-80-490 G and L and Condition 1 of NSR permit issued 10/05/200)

K. Property Rights

The permit does not convey any property rights of any sort, or any exclusive privilege.
(9 VAC 5-80-490 G.5)

L. Duty to Submit Information

1. The permittee shall furnish to the Board, within a reasonable time, any information that the Board may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Board copies of records required to be kept by the permit and, for information claimed to be confidential, the permittee shall furnish such records to the Board along with a claim of confidentiality.
(9 VAC 5-80-490 G and L and Condition 33 of NSR permit issued 10/05/2000)

2. Any document (including reports) required in a permit condition to be submitted to the Board shall contain a certification by a responsible official that meets the requirements of 9 VAC 5-80-430 G.9 and 9 VAC 5-80-490 K.1.
(9 VAC 5-80-430 G.9 and 9 VAC 5-80-490 K.1)

M. Duty to Pay Permit Fees

The owner of any source for which a permit under 9 VAC 5-80-360 through 9 VAC 5-80-705 was issued shall pay permit fees consistent with the requirements of 9 VAC 5-80-310 et seq. The actual emissions covered by the permit program fees for the preceding year shall be calculated by the owner and submitted to the Department by **April 15** of each year. The calculations and final amount of emissions are subject to verification and final determination by the Department.
(9 VAC 5-80-490 H)

N. Fugitive Dust Emission Standards

During the operation of a stationary source or any other building, structure, facility, or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions may include, but are not limited to, the following:

1. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;

2. Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which may create airborne dust; the paving of roadways and the maintaining of them in a clean condition;

3. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty material. Adequate containment methods shall be employed during sandblasting or other similar operations;

4. Open equipment for conveying or transporting material likely to create objectionable air pollution when airborne shall be covered or treated in an equally effective manner at all times when in motion; and,

5. The prompt removal of spilled or tracked dirt or other materials from paved streets and of dried sediments resulting from soil erosion.

(9 VAC 5-40-20 E, 9 VAC 5-50-90 and 9 VAC 5-50-50)

O. Startup, Shutdown, and Malfunction

At all times, including periods of startup, shutdown, soot blowing, and malfunction, owners shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Board, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(9 VAC 5-40-20 E and 9 VAC 5-50-20 E)

P. Alternative Operating Scenarios

Contemporaneously with making a change between reasonably anticipated operating scenarios identified in this permit, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating. The permit shield described in 9 VAC 5-80-500 shall extend to all terms and conditions under each such operating scenario. The terms and conditions of each such alternative scenario shall meet all applicable requirements including the requirements of 9 VAC 5 Chapter 80, Article 3. (9 VAC 5-80-490 J)

Q. Inspection and Entry Requirements

The permittee shall allow DEQ, upon presentation of credentials and other documents as may be required by law, to perform the following:

1. Enter upon the premises where the source is located or emissions-related activity is conducted, or where records must be kept under the terms and conditions of the permit.

2. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of the permit.

3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit.

4. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(9 VAC 5-80-490 K.2 and Condition 27 of NSR permit issued 10/05/2000)

R. Reopening For Cause

The permit shall be reopened by the Board if additional federal requirements become applicable to a major source with a remaining permit term of three years or more. Such reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 9 VAC 5-80-430 F.

1. The permit shall be reopened if the Board or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

2. The permit shall be reopened if the administrator or the Board determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

3. The permit shall not be reopened by the Board if additional applicable state requirements become applicable to a major source prior to the expiration date established under 9 VAC 5-80-490 D.

(9 VAC 5-80-490 L)

S. Permit Availability

Within five days after receipt of the issued permit, the permittee shall maintain the permit on the premises for which the permit has been issued and shall make the permit immediately available to DEQ upon request.
(9 VAC 5-80-510 E and Condition 34 of NSR permit issued 10/05/2000)

T. Transfer of Permits

1. No person shall transfer a permit from one location to another, unless authorized under 9 VAC 5-80-130, or from one piece of equipment to another.

2. In the case of a transfer of ownership of a stationary source, the new owner shall comply with any current permit issued to the previous owner. The new owner shall notify the Board of the change in ownership within 30 days of the transfer and shall comply with the requirements of 9 VAC 5-80-560.

3. In the case of a name change of a stationary source, the owner shall comply with any current permit issued under the previous source name. The owner shall notify the Board of the change in source name within 30 days of the name change and shall comply with the requirements of 9 VAC 5-80-560.

(9 VAC 5-80-520 and Condition 32 of NSR permit issued 10/05/2000)

U. Malfunction as an Affirmative Defense

1. A malfunction constitutes an affirmative defense to an action brought for noncompliance with technology-based emission limitations if the requirements of paragraph 2 of this condition are met.

2. The affirmative defense of malfunction shall be demonstrated by the permittee through properly signed, contemporaneous operating logs, or other relevant evidence that show the following:

a. A malfunction occurred and the permittee can identify the cause or causes of the malfunction.

b. The permitted facility was at the time being properly operated.

c. During the period of the malfunction the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit.

d. The permittee notified the board of the malfunction within two working days following the time when the emission limitations were exceeded due to the malfunction. This notification shall include a description of the malfunction, any steps taken to mitigate emissions, and corrective actions taken. The notification may be delivered either orally or in writing. The notification may be delivered by electronic mail, facsimile transmission, telephone, or any other method that allows the permittee to comply with the deadline. This notification fulfills the requirements of 9 VAC 5-80-490 F 2 b to report promptly deviations from permit requirements. This notification does not release the permittee from the malfunction reporting requirement under 9 VAC 5-20-180 C.

3. In any enforcement proceeding, the permittee seeking to establish the occurrence of a malfunction shall have the burden of proof. The provisions of this section are in addition to any malfunction, emergency or upset provision contained in any requirement applicable to the source.

4. The provisions of this section are in addition to any malfunction, emergency or upset provision contained in any applicable requirement.

(9 VAC 5-80-650)

V. Permit Revocation or Termination for Cause

This permit may be modified, revoked, reopened, terminated, or reissued prior to its expiration for cause as specified in 9 VAC 5-80-410 L, 9 VAC 5-80-570, 9 VAC 5-80-580, 9 VAC 5-80-640, and 9 VAC 5-80-660. In addition the permit may be modified, revoked, reopened, terminated, or reissued prior to its expiration for cause for either of the following reasons. The owner knowingly makes material misstatements in the permit application or any amendments thereto, or if the permittee violates, fails, neglects or refuses to comply with the terms or conditions of the permit, any applicable requirements, or the applicable provisions of 9 VAC 5 Chapter 80, Article 3. The Board may suspend, under such conditions and for such period of time as the Board may prescribe any permit for any of the grounds for revocation or termination or for any other violations of these regulations. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
(9 VAC 5-80-490 G & L, 9 VAC 5-80-640, 9 VAC 5-80-660, and Condition 26 of NSR permit issued 10/05/2000)

W. Duty to Supplement or Correct Application

Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrections. An applicant shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit.
(9 VAC 5-80-430 E)

X. Stratospheric Ozone Protection

If the permittee handles or emits one or more Class I or II substances subject to a standard promulgated under or established by Title VI (Stratospheric Ozone Protection) of the federal Clean Air Act, the permittee shall comply with all applicable sections of 40 CFR Part 82, Subparts A to F.
(40 CFR Part 82, Subparts A-F)

Y. Accidental Release Prevention

If the permittee has more, or will have more than a threshold quantity of a regulated substance in a process, as determined by 40 CFR 68.115, the permittee shall comply with the requirements of 40 CFR Part 68.
(40 CFR Part 68)

Z. Changes to Permits for Emissions Trading

No permit revision shall be required under any federally approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.
(9 VAC 5-80-490 I)

AA. Emissions Trading

Where the trading of emissions increases and decreases within the permitted facility is to occur within the context of this permit and to the extent that the regulations provide for trading such increases and decreases without a case-by-case approval of each emissions trade:

1. All terms and conditions required under 9 VAC 5-80-490, except subsection N, shall be included to determine compliance.

2. The permit shield described in 9 VAC 5-80-500 shall extend to all terms and conditions that allow such increases and decreases in emissions.

3. The owner shall meet all applicable requirements including the requirements of 9 VAC 5-360 through 9 VAC 5-80-700.

(9 VAC 5-80-490 I)

May 2, 2003

Mr. Thomas A Larson
General Manager
Commonwealth Chesapeake Company, LLC
3415 White Oak Way
New Church, VA 23415-2948

Location: Accomack County
Registration No: 40898
AIRS No: 51-001-00030

Dear Mr. Larson:

Attached is an Acid Rain Operating Permit to operate an electrical peaker plant pursuant to 9 VAC 5 Chapter 80 of the Virginia Regulations for the Control and Abatement of Air Pollution.

The permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

In evaluating the application and arriving at a final decision to issue this permit, the Department deemed the application complete on July 30, 2001, and solicited written public comments by placing a newspaper advertisement in the Virginian Pilot newspaper on February 12, 2003. The thirty-day comment period (provided for in 9 VAC 5-80-670) expired on March 14, 2003. No comments were received.

This approval to operate does not relieve Commonwealth Chesapeake Company of the responsibility to comply with all other local, state, and federal permit regulations.

Issuance of this permit is a case decision. The Regulations, at 9 VAC 5-170-200, provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this permit is mailed or delivered to you. Please consult that and other relevant provisions for additional requirements for such requests.

Additionally, as provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal to court by filing a Notice of Appeal with:

Mr. Robert G. Burnley, Director
Department of Environmental Quality
P.O. Box 10009
Richmond, Virginia 23240-0009

In the event that you receive this permit by mail, three days are added to the period in which to file an appeal. Please refer to Rule 2A of the Supreme Court of Virginia for additional information including filing dates and the required content of the Notice of Appeal.

If you have any questions concerning this permit, please call Mr. Barry Halcrow at 757-518-2184.

Sincerely,

Francis L. Daniel

bwh/HW/CCC Acid Rain FOP.doc
Attachment: Permit
Statement of Legal and Factual Basis
Compliance Reporting Forms

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Air Enforcement Branch (3AP13), U.S. EPA, Region III

PHASE II ACID RAIN PERMIT

Issued to:	Commonwealth Chesapeake Power Station
Operated by:	Commonwealth Chesapeake Company, LLC
ORIS code:	55381
Effective:	January 1, 2000 through December 31, 2004

AIRS ID No. 51-001-00030
Registration Number: 40898
Location: Accomack County

Acid Rain Permit Contents

1. Statement of Basis.

2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.

3. The Phase II Permit Application and Compliance Plan submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application and compliance plan.

Permit Approval

Approved on: December 27, 2000

____

Director, Department of Environmental Quality

Permit consists of four pages plus attached Application, and Compliance Plan.

1. **Statement of Basis.**

Statutory and Regulatory Authorities: In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Interim Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register June 10, 1997, Volume 62, Number 111, Rules and Regulations, Pages 31516-31520 and effective July 10, 1997, and Title 40, Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality issues this permit pursuant to Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (9 VAC 5 Chapter 80, Article 3 - Acid Rain Operating Permits).

2. **SO_2 Allowance Allocations and NO_x Requirements for each affected unit:**

Unit 1. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 2. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 3. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 allowances under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 4. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 5. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 6. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

Unit 7. 43.3 MWe/hr oil fired simple cycle gas turbine at ISO conditions	*SO_2 Allowances Under 40 CFR Part 73 (tons)	2000 None	2001 None	2002 None	2003 None	2004 None
	NO_x limit	N/A. Not a coal fired unit subject to 40 CFR 76 for NO_x.				

* SO_2 allowances may be acquired from other sources in addition to those allocated by U.S. EPA. No revision to this permit is necessary in order for the owners and operators of this unit to hold additional allowances recorded in accordance with 40 CFR Part 73. The owners and operators of this unit remain obligated to hold sufficient allowances to account for SO_2 emissions from this unit in accordance with 40 CFR 72.9 (c)(1).

3. **Phase II Permit Application and Compliance Plan: Attached (3 pages)**

COMMONWEALTH OF VIRGINIA
Department of Environmental Quality
Tidewater Regional Office

STATEMENT OF LEGAL AND FACTUAL BASIS

Commonwealth Chesapeake Company, LLC
3415 White Oak Way, New Church, Virginia
Permit No. TRO-40898

In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, Pages 62961-62967 and effective November 30, 2001, and Title 40, the Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality issues this permit pursuant to 9 VAC 5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Acid Rain Operating Permits).

Engineer/Permit Contact:________________________________ Date:____________

Air Permit Manager:________________________________ Date:____________

Regional Director:______________________________ Date:____________

Attachment A: NSR of October 5, 2000

FACILITY INFORMATION

Permittee
Commonwealth Chesapeake Company, LLC
3415 White Oak Way
New Church, VA 23425-2948

Responsible Official
Thomas A. Larson
General Manager, Commonwealth Chesapeake Company, LLC
US EPA AAR ID No.: 2110

Facility Operator
TECO Power Services Virginia Operations Company

Facility
Commonwealth Chesapeake Power station
3415 White Oak Way
New Church, VA 23415-2948

Contact Person
Dan Runde
Manager, Commonwealth Chesapeake Power Station
Phone Number: (757) 824-3340

AIRS ID No. 51-001-00030

ORIS Code ID: 055381

NATS Facility Identification Number: 055381

SOURCE DESCRIPTION

SIC Code: 4911. Commonwealth Chesapeake Power Station functions as a peaker plant with seven GE LM6000 simple cycle combustion turbines to generate electricity.

The facility is a major source of NOx, CO, and SO2. This source is located in an attainment area for all pollutants, and is a PSD source. The facility was previously permitted under a PSD permit issued on October 5, 2000, and Acid Rain Phase II permit issued on December 27, 2000.

COMPLIANCE STATUS

The facility was in compliance with NSR permit and Acid Rain Phase II permit during its last inspection conducted on July 29, 2002.

Acid Rain Operating permit expiration: December 31, 2004, was used to make the Acid Rain Operating permit coincide with the same expiration and renewal date of the Phase II Acid Rain permit, incorporated by reference, during the transition from Phase II Acid Rain permit to Acid Rain Operating permits in Virginia.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Combustion Turbines							
CT-1 thru 7	CT 1-7	GE LM6000. CT 1 thru 3, 2000. CT 4 thru 7, 2001.	Each 43.3 megawatts at ISO conditions	GE water injection on each CT, 2000 and 2001.	WI 1-7	NOx	NSR Permit of 10/05/2000, and Acid Rain Permit of 12/27/2000
Distillate Oil Storage Tanks							
T-1, 2, & 3	T 1-3	Above ground fixed roof tanks, 2000 & 2001	Each at 2.2 million gal	N/a	N/a	N/a	NSR Permit of 10/05/2000.
T-4 & 5	T 4 & 5	Above ground fixed roof tanks, 2001	Each at 200 K gal	N/a	N/a	N/a	NSR Permit of 10/05/2000.

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

EMISSIONS INVENTORY

Actual Emissions

	2001 Criteria Pollutant Emission in Tons/Year				
Emission Unit	VOC	CO	SO_2	PM_{10}	NO_x
CT 1-3	0.3	13.3	23.4	6.6	84.3
CT 4-7	0.4	10.5	11.2	3.2	35.5
Total	0.7	23.8	34.6	9.8	119.8

EMISSION UNIT APPLICABLE REQUIREMENTS: NSR permit 10/05/2000

Limitations (per permit condition number)

1. The permittee shall meet all the applicable requirements of 40 CFR 60, Subpart GG Standards of Performance for Stationary Gas Turbines; and, 40 CFR Part 60, Subpart Kb [60.116b, paragraphs (a) and (b)] - Standards of Performance for Volatile Organic Liquid Storage Vessels.
(9 VAC 5-50-410)

2. Particulate matter emissions from each combustion turbine shall be controlled by the use of distillate oil, a clean burning fuel. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1800)

5. Sulfur dioxide and sulfuric acid mist emissions from each combustion turbine shall be controlled by the use of distillate oil with sulfur not to exceed 0.05% by weight.
(9 VAC 5-80-1800)

6. Nitrogen oxide emissions from each combustion turbine shall be controlled by water injection except during startup and shutdown when the use of water injection would interfere with turbine operations. The rate of water injection shall be at least that established during emissions tests as being sufficient to meet the emissions standards set forth in this permit.
(9 VAC 5-80-1800)

7. Carbon monoxide and volatile organic compound emissions from each combustion turbine shall be controlled by the use of good combustion operating practices.
(9 VAC 5-80-1800)

9. Combustion turbines CT-1, 2, 3, 4, 5, 6, and 7 (combined) shall not use more than 42.0 million gallons of distillate oil each year, calculated as the sum of each consecutive 12 month period.
(9 VAC 5-80-10, 9 VAC 5-50-50)

10. Combustion turbines 1-3 (combined) shall not operate more than 6,000 hours per year, and combustion turbines 4-7 (combined) shall not operate more than 8,000 hours per year, which means that the seven turbines can be operated simultaneously for up to 2000 hours per year. The number of operating hours for each combustion turbine shall be calculated as the sum of each consecutive 12 month period.
(9 VAC 5-80-10 H)

11 Except during startup and shutdown, each combustion turbine shall not operate at less than 70% of capacity.
(9 VAC 5-170-160)

12 The permittee is authorized to store distillate oil in storage tanks with Unit Reference Nos. T-1 through T-5. A change in the materials stored may require a permit to modify and operate.
(9 VAC 5-80-10)

13. The sulfur content and fuel-bound nitrogen content of the distillate oil to be burned in the combustion turbines shall not each exceed 0.05 percent by weight per shipment.
(9 VAC 5-80-1800, 9 VAC 5-50-20)

20. Emissions from the operation of the combustion turbines CT 1, 2, and 3 shall not exceed the limits as specified below:

	(each at 100% of capacity) lb/hr	(combined total) tons/yr
Particulate Matter	10.3	30.9
PM-10	10.3	30.9
Sulfur Dioxide	23.9	65.1
Nitrogen Oxides (as NO_2) (42 ppmvd* for FBN ≤ 0.015%)	85.1	243.6**
Nitrogen Oxides (as NO_2) (42 + 400 FBN) ppmvd* for 0.015% < FBN ≤ 0.05%	125.6	243.6**
Carbon Monoxide	30.0	90.0
Volatile Organic Compounds	5.6	16.8
Sulfuric Acid Mist	2.7	7.4

(Yearly is calculated as the sum of each consecutive 12 month period.)
*(one hour average at 15% oxygen, adjusted to ISO standard ambient conditions)
**(includes all operating hours per year–normal operations with the water injection system and startup, shutdown, or any malfunctions when the water injection system is not used)
FBN - Fuel Bound Nitrogen, percent by weight.

(9 VAC 5-50-260)

21. Emissions from the operation of the combustion turbines CT 4, 5, 6, and 7 shall not exceed the limits as specified below:

	(each at 100% of capacity) lb/hr	(combined total) tons/yr
Particulate Matter	10.3	41.2
PM-10	10.3	41.2
Sulfur Dioxide	23.9	86.8
Nitrogen Oxides (as NO_2)	(42 ppmvd* for FBN ≤ 0.015%) 85.1	322.4**
Nitrogen Oxides (as NO_2)	(42 + 400 FBN) ppmvd* for 0.015% < FBN ≤ 0.05% 125.6	476.0**
Carbon Monoxide	30.0	120.0
Volatile Organic Compounds	5.6	22.4
Sulfuric Acid Mist	2.7	9.9

(Yearly is calculated as the sum of each consecutive 12 month period.)
*(one hour average at 15% oxygen, adjusted to ISO standard ambient conditions)
**(includes all operating hours per year--normal operations with the water injection system and startup, shutdown, or any malfunctions when the water injection system is not used)
FBN - Fuel Bound Nitrogen, percent by weight.
(9 VAC 5-50-260)

22. Emissions from the operation of the fuel oil storage tanks T 1-5 (combined) shall not exceed the limits as specified below:

Volatile Organic Compounds	1.8 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits and emission factors supplied by the permittee. Exceedances of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition numbers 2 and 9.
(9 VAC 5-50-260)

23. Visible emissions from each combustion turbine exhaust stack shall not exceed ten (10) percent opacity as determined by EPA Method 9 (Reference 40 CFR 60, Appendix A). This condition applies at all times except during start-up, shut-down or malfunction.
(9 VAC 5-50-260)

29. In order to minimize the duration and frequency of excess emissions due to malfunctions of process equipment or air pollution control equipment, the permittee shall:
    a. Develop a maintenance schedule of all scheduled and non-scheduled maintenance and,
    b. Maintain an inventory of spare parts that are needed to minimize durations of air pollution control equipment breakdowns.

    (9 VAC 5-50-20 E, 9 VAC 5-170-160)

30. The permittee shall have available written operating procedures for the related air pollution control equipment. Operators shall be trained in the proper operation of all such equipment and shall be familiar with the written operating procedures. These procedures shall be based on the manufacturer's recommendations, at minimum. The permittee shall maintain records of training provided including names of trainees, date of training and nature of training.
    (9 VAC 5-170-160)

35. The emissions from the operation of the combustion turbines CT 1 thru 7 shall not exceed the limits as specified below:
    (each at 100% of capacity) (combined total)

	lb/hr	tons/yr
Hazardous Air Pollutants (as VOC)		
Formaldehyde	0.1	0.8
Hazardous Air Pollutants (as PM-10)		
Lead	0.006	0.04
Arsenic	0.005	0.03
Beryllium	0.0001	0.0009
Cadmium	0.002	0.01
Chromium	0.005	0.03
Manganese	0.4	2.3
Mercury	0.0005	0.004
Selenium	0.01	0.07

These emissions are derived from the estimated overall emission contribution from operating limits and emission factors supplied by the permittee. Exceedances of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition numbers 2 and 9.
(Yearly is calculated as the sum of each consecutive 12-month period.)
(9 VAC 5-50-180)

Monitoring

13. The monitoring requirements of this NSR permit condition have been modified to clarify when and how the %S and nitrogen fuel oil content monitoring will be conducted.
    Scenario #1 for sulfur and nitrogen content of fuel oil: The permittee shall obtain a fuel certification from the fuel supplier with each shipment of distillate oil delivered to each turbine fuel storage tank. Each fuel supplier certification shall include the following:
    a. The name of the fuel supplier;
    b. The date on which the distillate oil was received;
    c. The volume of distillate oil delivered in the shipment;
    d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications for numbers 1 or 2 fuel oil;
    e. The sulfur content of the distillate oil and indicate which ASTM method was used to determine the sulfur content: ASTM D 2880-71, 78, or 96, ASTM D-1552, ASTM D-129, or other approved method,
    f. The nitrogen content of the distillate oil and indicate which ASTM method was used to determine the nitrogen content: ASTM D-3228, ASTM D-5291, or other approved method.

    Scenario #2 for sulfur and nitrogen content of fuel oil: If the permittee does not obtain a fuel certification from the fuel supplier with each shipment of distillate oil delivered to the turbine fuel storage tank(s) under Scenario #1, the permittee shall sample and analyze the fuel from the tank(s) after each filling process has been completed to determine:
    a The distillate oil complies with the American Society for Testing and Materials specifications for numbers 1 or 2 fuel oil;
    b. The sulfur content of the distillate oil by using ASTM D 2880-71, 78, or 96, ASTM D-1552, ASTM D-129, or other approved method,
    c. The nitrogen content of the distillate oil by using ASTM D-3228, ASTM D-5291, or other approved method.

    (9 VAC 5-80-1800 and 9 VAC 5-50-20)
17. The continuous monitoring systems shall be installed and operated to monitor and record the fuel consumption and ratio of water injected to fuel being fired in each combustion turbine. These monitoring systems shall be operated at all times that water is being injected into the combustion turbines and shall be accurate to within ± 5.0 percent. The systems shall be maintained and calibrated in accordance with manufacturer's specifications. As a minimum, calibration shall be done prior to the performance test and at least annually thereafter.
    (9 VAC 5-50-20, 9 VAC 5-50-40)

    Additional Title V monitoring requirement:

    The permittee shall perform monthly visual observations on each turbine stack exhaust during daylight hours of normal operations for visible emissions. If visible emissions are noted from the stack, a visible emissions evaluation (VEE) shall be immediately conducted on the stack for at least six minutes in accordance with Method 9 (40 CFR 60, Appendix A). If the VEE opacity average exceeds five (5) percent, the VEE shall continue for one hour from initiation on the turbine stack to determine compliance with the opacity limit. The permittee shall record the details of the visual observations, VEE, and any maintenance actions to reduce opacity.

Recordkeeping

13, 25 & 36. The permittee shall maintain records of all emission data and operating parameters for the seven combustion turbines necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Tidewater Regional Office. These records shall include, but are not limited to:

a. The total operating hours per year for each combustion turbine with combined operating hours for CT 1-3 and CT 4-7, calculated as the sum of each consecutive 12 month period;
b. All the fuel oil analysis reports for sulfur and nitrogen content in accordance with condition 13;
c. Oil shipments purchased, indicating the name of the supplier, date of purchase, type and volume of fuel per each shipment;
d. Annual amount of distillate oil consumed by all turbines, calculated as the sum of each consecutive 12 month period;
e. Monthly and annual NOx and SO2 emission calculations. Monthly and annual emissions calculations for all other pollutants listed in Conditions 20, 21, 22, and 35 based on the usage of DEQ approved emission factors;
f. Listing of DEQ approved emission factors for pollutants listed in Condition 20, 21, 22; and 35;
g. Records of products stored in tanks T 1-5, dimensions and storage capacity of each tank;
h. Semi-annual excess emissions reports.

These records shall be available on site for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

Additional T-5 recordkeeping:
Turbine stack visual observations and VEEs.

29. In order to minimize the duration and frequency of excess emissions due to malfunctions of process equipment or air pollution control equipment, the permittee shall:
    a. Maintain records of all scheduled and non-scheduled maintenance. These records shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request,

    (9 VAC 5-50-20 E, 9 VAC 5-170-160)

30. The permittee shall have available written operating procedures for the related air pollution control equipment. The permittee shall maintain records of training provided including names of trainees, date of training and nature of training.
(9 VAC 5-170-160)

Testing

15. After the initial performance tests, performance tests shall be conducted on one combustion turbine each calendar year. A different turbine shall be selected each year such that each turbine selected shall be tested about every seven years for nitrogen oxides while operating at 70% and 100% of capacity by using Method 20 (40 CFR Part 60, Appendix A) to determine compliance with NO_x limits specified in condition 20 or 21. The tests shall be performed anytime during each calendar year following the initial performance test year. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Tidewater Regional Office.
(9 VAC 5-50-30 G)

16. Concurrently with the annual performance tests for each turbine being tested, a Visible Emission Evaluation (VEE) in accordance with 40 CFR, Part 60, Appendix A, Method 9, shall also be conducted on each combustion turbine stack while operating at 70% and 100% of capacity. The test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield 6 minute averages.
(9 VAC 5-50-20, 9 VAC 5-50-30)

The Department and EPA has authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.
If additional testing to demonstrate compliance is conducted in addition to the monitoring specified in this permit, the permittee shall use the following methods or other approved methods in accordance with procedures approved by the DEQ as follows:

Pollutant	Test Method
VOC	EPA Methods 18, 25, or 25A and 19
NO_x	EPA Method 20
SO_2	EPA Methods 6, or 6C and 19
CO	EPA Method 10 and 19
PM/PM-10	EPA Methods 5/201
Visible Emission	EPA Method 9

Reporting

15. For the annual test on one of the combustion turbines, the permittee shall submit a test protocol, required by Condition III.D.1, at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Tidewater Regional Office within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 G)

16. For the annual VEE on one of the combustion turbines, required by Condition III.D.2, one copy of the test results shall be submitted to the Director, Tidewater Regional Office within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-20, 9 VAC 5-50-30)

16 For annual VEE on one of the combustion turbines, should conditions prevent concurrent opacity observations, the Director, Tidewater Regional Office shall be notified in writing, within 7 days, and visible emissions testing to be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests and annual tests.
(9 VAC 5-50-20, 9 VAC 5-50-30)

18. Semi-annual reports of excess emissions shall be submitted to the Director, Tidewater Regional Office in accordance with 40 CFR Part 60, Section 7(c). The time periods to be addressed are January 1 to June 30 and July 1 to December 31. The reports shall be postmarked by January 31 and July 31 of each calendar year. The reporting cycle shall begin with the first report being submitted at the end of the time period in which the initial performance tests as specified in condition 14 have been conducted. In addition to the information required by 40 CFR Part 60, Section 7(c), each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions. For the purpose of this report, periods of excess emissions are defined as follows:
    a. Any one hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the average water- to-fuel ratio determined to demonstrate compliance with the nitrogen oxide PPMvd limits specified in condition 20 or 21during the most recent compliance test.
    b. Any period during which the sulfur content of the distillate oil being fired in the combustion turbines exceeds 0.05 percent by weight.
    c. Any period during which the nitrogen content of the distillate oil being fired in the gas turbines exceeds 0.05 percent by weight.

    (9 VAC 5-170-160 and 9 VAC 5-50-20)

Streamlined Requirements

The following conditions in the NSR permit of 10/05/2000 were not included in the Title V Acid Rain permit for the following reasons:
Condition 8: All of the test ports were installed during construction as was shown when initial testing on each turbine was conducted and completed.
Condition 14: All initial testing for NOx emissions from each turbine at start-up to show compliance with the permit had been accomplished in 2000 for CT 1-3 and 2001 for CT 4-7.
Condition 16: All initial testing for opacity from each turbine at start-up to show compliance with the permit had been accomplished in 2000 for CT 1-3 and 2001 for CT 4-7.
Condition 18: CMS for each turbine was installed prior to initial testing for each turbine to show compliance with the permit had been accomplished in 2000 for CT 1-3 and 2001 for CT 4-7.

Condition 24: Notifications for installation, start-up, and proposed initial testing date for each turbine had been accomplished in 2000 for CT 1-3 and 2001 for CT 4-7.
Condition 31: Invalidation because of non-construct is not needed as all units were constructed within permit time lines.
Condition 1: Incorporated into Title V Acid Rain boilerplate language of Condition VII.J.
Condition 2: Incorporated into Title V Acid Rain boilerplate language of Condition II.
Condition 26: Incorporated into Title V Acid Rain boilerplate language of Condition VII.V.
Condition 27: Incorporated into Title V Acid Rain boilerplate language of Condition VII.Q.
Condition 28: Incorporated into Title V Acid Rain boilerplate language of Condition VII.F.
Condition 32: Incorporated into Title V Acid Rain boilerplate language of Condition VII.T.
Condition 33: Incorporated into Title V Acid Rain boilerplate language of Condition VII.L.
Condition 34. Incorporated into Title V Acid Rain boilerplate language of Condition VII.S.

NSPS: 40 CFR 60, Subpart Kb, Para 60.116.b) for recordkeeping of tank dimensions, capacity, and products stored were included in Condition III.C.7.

ACID RAIN Phase II:
The Acid Rain Phase II permit of 10/27/2000 was incorporated by reference into Condition IV of this permit and made Appendix A.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 70 and 9 VAC 5-80-110, that apply to all Federal operating permit sources. These include requirements for submitting semi-annual monitoring reports and an annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions, including those caused by upsets, within one business day.

Comments on General Conditions

B. Permit Expiration

This condition refers to the Board taking action on a permit application. The Board is the State Air Pollution Control Board. The authority to take action on permit application(s) has been delegated to the Regions as allowed by ••2.1-20.01:2 and ••10.1-1185 of the *Code of Virginia,* and the "Department of Environmental Quality Agency Policy Statement NO. 3-2001".

This general conditions cites the entire Article that follow:
B.2. Article 3 (9 VAC 5-80-510 et seq.), Part II of 9 VAC 5 Chapter 80. Federal Permits for Stationary Sources
B.3. Article 3 (9 VAC 5-80-430 C & D et seq.), Part II of 9 VAC 5 Chapter 80. Federal Permits for Stationary Sources

This general condition cites the sections that follow:

B.	9 VAC 5-80-430. "Application"
B.2.	9 VAC 5-80-510. "Action on Permit Applications"
B.3.	9 VAC 5-80-430. "Application"
B.4.	9 VAC 5-80-430. "Application"
B.4.	9 VAC 5-80-500. "Permit Shield"
B.5.	9 VAC 5-80-430. "Application"

F. Failure/Malfunction Reporting

Section 9 VAC 5-20-180 requires malfunction and excesses emissions reporting within 4 hours. Section 9 VAC 5-80-650 also requires malfunction reporting; however, reporting is required within 2 days. Section 9 VAC 5-20-180 is from the general regulations. All affected facilities are subject to this section including Title 5 Acid Rain facilities. Section 9 VAC 5-80-650 is from the Acid Rain regulations. Title 5 Acid Rain facilities are subject to both Sections. A facility may make a single report that meets the requirements of 9 VAC 5-20-180 and 9 VAC 5-80-650. The report must be made within 4 day time business hours of the malfunction.

In order for emission units to be relieved from the requirement to make a written report in 14 days the emission units must have continuous monitors and the continuous monitors must meet the requirements of 9 VAC 5-50-410 or 9 VAC 5-40-41.
This general condition cites the sections that follow:

F.	9 VAC 5-50-50.	Notification, Records and Reporting
F.1.	9 VAC 5-50-50.	Notification, Records and Reporting
F.2.	9 VAC 5-50-50.	Notification, Records and Reporting

This general condition contains a citation from the Code of Federal Regulations as follows:
F.3.a. 40 CFR 60.13 (h). Monitoring Requirements.

U. Failure/Malfunction Reporting

The regulations contain two reporting requirements for malfunctions that coincide. The reporting requirements are listed in section 9 VAC 5-80-650 and 9 VAC 5-20-180. The malfunction requirements are listed in General Condition U and General Condition F. For further explanation see the comments on general condition F.

This general condition cites the sections that follow:

U.2.d. 9 VAC 5-80-490. Permit Content
U.2.d. 9 VAC 5-20-180. Facility and Control Equipment Maintenance or Malfunction

FUTURE APPLICABLE REQUIREMENTS
NOx SIP Call Trading Program.

INAPPLICABLE REQUIREMENTS

Citation	Title of Citation	Description of Applicability
40 CFR 64	Compliance Assurance Monitoring	Does not use air pollution control equipment to destroy pollutants
40 CFR 61	NESHAPS	Source category not listed
40 CFR 63	MACTs	Not a major HAPS source
9 VAC 5 Chapter 80, Article 7 & 9 VAC 5 Chapter 60, Article 3	Major HAPS NSR Permitting	Not a major HAPS source
40 CFR 68	Prevention of Accidental Chemical Releases	Any chemicals on site are below threshold levels.

INSIGNIFICANT EMISSION UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

Emission Unit No.	Emission Unit Description	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
FP-1	Diesel engine for fire pump		300 HP/hr
LO 1-7	CT lube oil tanks	VOC	4000 gal each
FPT-1	Fire pump diesel fuel tank	VOC	500 gal
Fugitive-1 (fuel oil)	Fugitives from unloading, processing and handling of distillate fuel oil	VOC	N/A
Fugitive–2 (fuel oil)	Fugitives from small distillate oil storage tanks	VOC	Each less than 500 gal
Fugitive –3 (Oil/water separator)	Fugitives from oil/water separator	VOC	N/A

Insignificant emission units include the following:
The citation criteria for insignificant activities are as follows:

9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

CONFIDENTIAL INFORMATION

None identified.

PUBLIC PARTICIPATION

Draft permit placed on public notice in the Virginian Pilot from February 12, 2003, to March 14, 2003.
Public comments: None
EPA comments: None
Proposed permit to EPA: March 15, 2003.
EPA comments: None

Table A. Summary of Feasible BACT Control Hierarchies for CCC oil fired turbines

Pollutant	Control Technology	Range of Control (%)	Control Level for BACT Analysis	Emissions Limit (Per CT)
PM/PM_{10}	Low-ash Fuel and Good Combustion (Baseline)	N/A	N/A	10% Opacity
SO_2/H_2SO_4	Distillate Fuel Oil (Baseline)	0.05 – 0.5 %S	0.05 % S	0.05 %S
CO	Oxidation Catalyst	70 – 90	90	3.0 lb/hr
	Good Combustion (Baseline)	N/A	N/A	30 lb/hr
NO_x	SCD + WI + HTSCR	70 – 90s	97.6[1]	10 ppmvd
	SCD + WI	70 – 90	90	42 ppmvd
	No Controls (Baseline)	N/A	N/A	417 ppmvd

SCD = standard combustor design
WI = wet injection
HTSCR = high temperature selective catalytic reduction
[1] Assumes constant removal efficiency: does not account for emissions during start up and shut down or from increased emissions resulting from catalyst degradation or contamination.

Table B. Summary of Selected BACT Control Hierarchies for CCC oil fired turbines

Pollutant	Control Technology	Range of Control (%)	Control Level for BACT Analysis	Emissions Limit (Per CT)
PM/PM_{10}	Low-ash Fuel and Good Combustion (Baseline)	N/A	N/A	10% Opacity
SO_2/H_2SO_4	Distillate Fuel Oil (Baseline)	0.05 – 0.5 %S	0.05 % S	0.05 %S
CO	Good Combustion (Baseline)	N/A	N/A	30 lb/hr
NO_x	SCD + WI FBN ≤ 0.05%	70 – 90	90	42 ppmvd* FBN ≤ 0.015% (42 + 400 FBN) ppmvd* for 0.015% < FBN ≤ 0.05%

SCD = standard combustor design
WI = wet injection
FBN = Fixed bound nitrogen
*one hour average at 15% oxygen, adjusted to ISO standard ambient conditions

Table C-1. Summary of NO_x BACT Cost Analysis[1]

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Rates tpy	Total Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Environmental Impact (Y/N)
SCD + WI +HTSCR	77.3	77.3	3,123.7[2]	18,067,149	4,535,000	1,452	12,354	134,262	N	N
	[10 ppmvd at 15% O_2, 48°F CT inlet air temperature]									
SCD + WI	324.8	324.8	2,876.2	4,562,603	1,477,321	514	514	126,464	N	N
	[42 ppmvd at 15% O_2, 48°F CT inlet air temperature]									
Base Case	3,201.0	3,201.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	[417 ppmvd at 15% O_2, 48°F CT inlet air temperature]									

[1] Base Case: Four GE LM6000 CTs, 100-percent load, 2,000 hr/yr oil-fired.
No controls, NO_x exhaust concentration of 417 ppmv for oil firing.

SCD = standard combustor design
WI = water injection
HTSCR = high temperature selective catalytic reduction

Sources: GE, 1999.
ECT, 2000.
Siemens-Westinghouse, 2000

2 Does not account for higher emissions during start up and shut down and resulting from catalyst degradation and contamination.

Table C-2. Summary of CO BACT Cost Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Rates tpy	Total Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Energy Impacts Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Environmental Impact (Y/N)
Oxidation Catalyst	21.0	21.0	189.0	4,515,771	1,050,638	5,559	4,445	N	N
Base Case	210.0	210.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Base Case: Seven GE LM6000 CTs, 100-percent load, 2,000 hr/yr oil-fired.
CO emission rate of 30 lb/hr for oil firing.

Sources: GE, 1999.
ECT, 2000.

BACT for NO_2:

NOx average cost for HTSCR control was reasonable at $ 1,452 per ton; however, the incremental cost at $ 12,354 per ton was judged too costly for BACT.
Besides the large incremental cost, HTSCR system for oil fired simple cycle turbines is still in the design stage. The one permitted turbine facility that tried operating HTSCR system for oil fired turbines in Puerto Rico failed. EPA, Region II removed the SCR system in the revised permit issued in 2000—leaving control to water injection. Tentative technology, high cost, and ammonia emissions do not make HTSCR a BACT selection for the CCC peaker plant project.
BACT selected as the use of water injection for NOx control.

BACT for CO:

CO average cost for oxidation catalyst control was over $ 5,000 per ton—is judged too costly for BACT.
BACT selected as good combustion practices for CO control.

Attachment 5
Dispersion Modeling Protocol

BLACK & VEATCH

11401 Lamar Avenue
Overland Park, Kansas 66211 USA

Tel: (913) 458-2000

Black & Veatch Corporation

Stock Island
Combustion Turbine No. 4

B&V Project 136839.0040
B&V File 32.0210
June 4, 2004

Al Linero
Florida Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Subject: Stock Island Combustion Turbine Unit 4 Project Class II and Class I Air Dispersion Modeling Protocols

The Florida Municipal Power Agency (FMPA) and Keys Energy Services (KEYS) are implementing the installation of a Nominal Net 47.6 MW General Electric (GE) LM6000 PC SPRINT combustion turbine operating solely on low-sulfur (0.05 percent) No. 2 distillate fuel oil in simply cycle mode (Project) at the KEYS Stock Island site in Key West, FL.

Since the proposed Project will be built at an existing major source, the major modification thresholds, or significant emission levels (SELs), will apply to the project. As such, the Project will be considered a PSD major modification source by the Florida Department of Environmental Protection (FDEP). It is anticipated that the proposed Project will be major for the following pollutants: NO_x, SO_2, and PM/PM_{10}, and sulfuric acid mist; thereby requiring Prevention of Significant Deterioration (PSD) review for those pollutants. As part of that review, an air dispersion modeling demonstration must be performed to ensure that the proposed Project will comply with the appropriate ambient air quality thresholds in the surrounding areas.

Prior to such demonstration, the attached air dispersion modeling protocols have been developed for your review in an effort to obtain concurrence with the proposed modeling methodologies. We would like to schedule a meeting with you to discuss the project. I will be contacting you in the near future to schedule a meeting. If you have any questions or comments, please feel free to contact me at 913-458-2126.

Regards,

BLACK & VEATCH

Bob Holmes

Bob Holmes
Air Quality Specialist

Enclosure

cc:

B. O'Neal – B&V
Jim Hay – FMPA
Susan Schumann – FMPA
Eddie Garcia – KEYS
Diane Tremor – Rose, Sundstrom & Bentley
File

STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT

CLASS II AND CLASS I AIR DISPERSION MODELING PROTOCOLS

PREPARED BY
BLACK & VEATCH

MAY 2004

ATTACHMENT 1

STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT ISC MODELING PROTOCOL

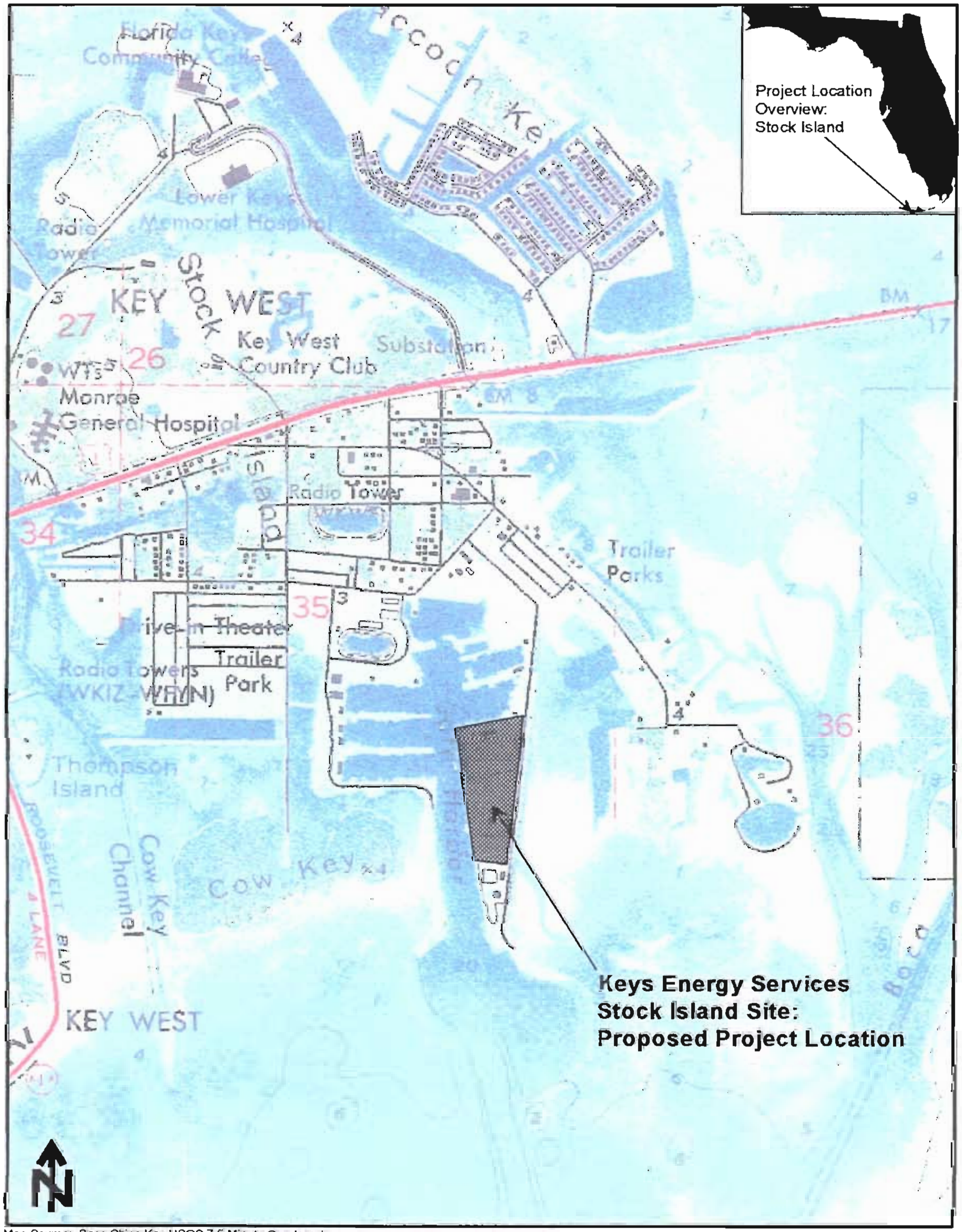
PREPARED BY
BLACK & VEATCH

MAY 2004

Air Quality Modeling Assumptions and Methodology

Modeling Scenario:	As a major modification to an existing PSD major source, the air quality impact analysis (AQIA) will be performed for Unit 4, a nominally rated 47.6 MW (net) simple cycle combustion turbine to be installed at the Keys Energy Services Stock Island site in Key West, Florida. The location of the proposed project is illustrated in the attached Figure.
Air Dispersion Model:	ISCST3 (Latest version)
Model Options:	EPA Default and Flat terrain.
GEP & Downwash:	EPA's BPIP program will be used to determine GEP stack height and direction specific building downwash parameters for the Unit 4 stack. Structures associated with the existing site, as well as the proposed additions will be included in the BPIP analysis.
Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 100 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Dispersion Coefficients:	Rural: Based on visual inspection of a 7.5 minute USGS topographic map of the site using the Auer method.
Meteorological Data:	Refined level modeling sequential meteorological data will consist of surface data from the Key West International Airport and upper air data from Tampa, FL for the years 1987-1991. The files will be obtained from the Support Center for Regulatory Air Models website and processed with the USEPA meteorological processor PCRammet.
Pollutants to be Modeled:	The only pollutants that are currently expected to be modeled are PM_{10}, NO_x, and SO_2.
Source Modeling Parameters:	Worst-case hourly emission rates and operating parameters will be used for short-term modeling impacts. These data will be enveloped across 50, 75 and 100 percent load cases at ambient temperatures of 41, 78, and 95°F from representative combustion turbine performance and emissions data. Potential to emit calculations and operating

	parameters for annual modeling impacts will be based on annual average data.
Modeled impacts:	It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. If the model predicted impacts exceed the SILs, additional agency consultation will be initiated regarding increment and cumulative air quality impact analyses.
Class I Analysis:	For analysis of the Everglades National Park Class I area, which lies beyond 50 km from the proposed modification, the CALPUFF model will be used. The CALPUFF modeling protocol is discussed in Attachment 2 of this submittal.
Toxics:	No toxic modeling analysis is required.



Map Source: Boca Chica Key USGS 7.5-Minute Quadrangle

Stock Island Combustion Turbine Unit 4
Proposed Project Location

ATTACHMENT 2

STOCK ISLAND UNIT 4 COMBUSTION TURBINE PROJECT
CALPUFF MODELING PROTOCOL

PREPARED BY
BLACK & VEATCH

MAY 2004

TABLE OF CONTENTS

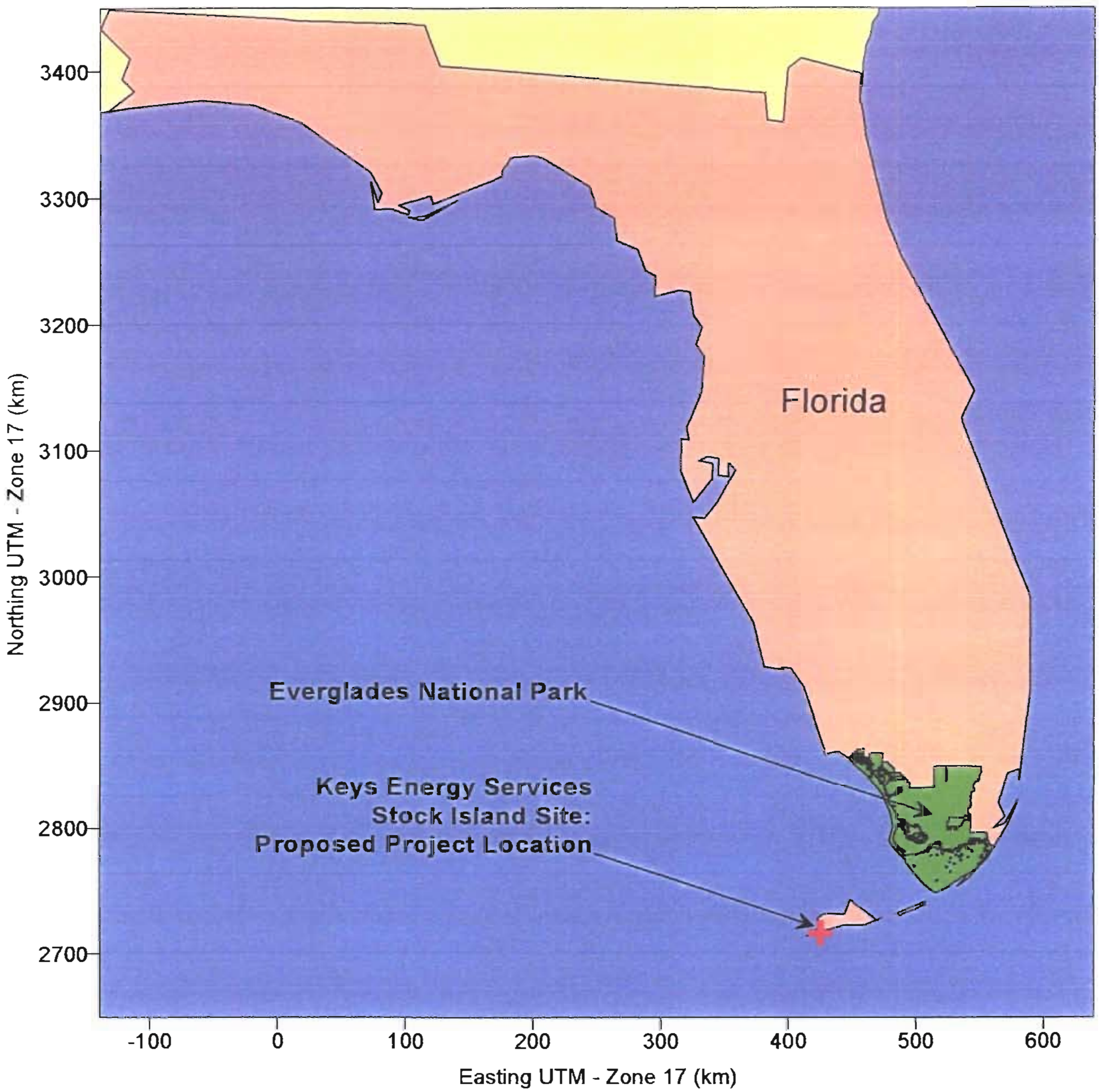
LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

As part of the air impact evaluation for the proposed modification to the KEYS Stock Island site, analyses of the proposed project's effect on the Everglades National Park (ENP) will be performed. The ENP is a Prevention of Significant Deterioration (PSD) Class I area located in southern Florida approximately 90 km northeast of the proposed project site. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) will be evaluated and compared to the recommended thresholds. Figure 1-1 presents the location of the proposed project site with respect to the ENP.

The methodology of the refined CALPUFF analysis will closely follow those procedures recommended in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II report dated December 1998, the Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG) report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at ENP.



Proposed Project Location
with respect to
Everglades National Park

Figure 1-1

2.0 Model Selection and Inputs

2.1 Model Selection

The California Puff (CALPUFF, Version 5.711, Level 030625) air modeling system will be used to model the proposed project and assess the AQRVs at ENP. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model, a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET will be input to CALPUFF to assess pollutant specific impacts.

2.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 2-1 will be used for the modeling analyses.

2.3 Building Wake Effects

The CALPUFF analysis will include the facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures will be processed with the Building Profile Input Program (BPIP), Version 95086, and included in the CALPUFF model input.

2.4 Receptor Locations

The CALPUFF analysis will use an array of discrete receptors for ENP, which were created and distributed by the NPS for standardized use in Class I analyses. Terrain throughout the ENP is included in the same NPS- provided receptor file.

Table 2-1 CALPUFF Model Settings	
Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional plume rise, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	<u>Regional Haze:</u> Highest predicted 24-hour change as processed by CALPOST. <u>Deposition:</u> Highest predicted annual total sulfur and nitrogen values in deposition units. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Levels (SELs).
Background Values	Monthly Ammonia: 0.5 ppb; Monthly background ozone will be based on a review of the available monitoring stations' values averaged for each month. Additionally, hourly background ozone values from several reporting stations may be assessed for inclusion into the CALPUFF modeling.

2.5 Meteorological Data Processing

The California Puff meteorological and geophysical data preprocessor (CALMET, Version 5.53, Level 030709) will be used to develop the gridded parameter fields required for the refined AQRV modeling analyses. The following sections discuss the data to be used and processed in the CALMET model.

2.5.1 CALMET Settings

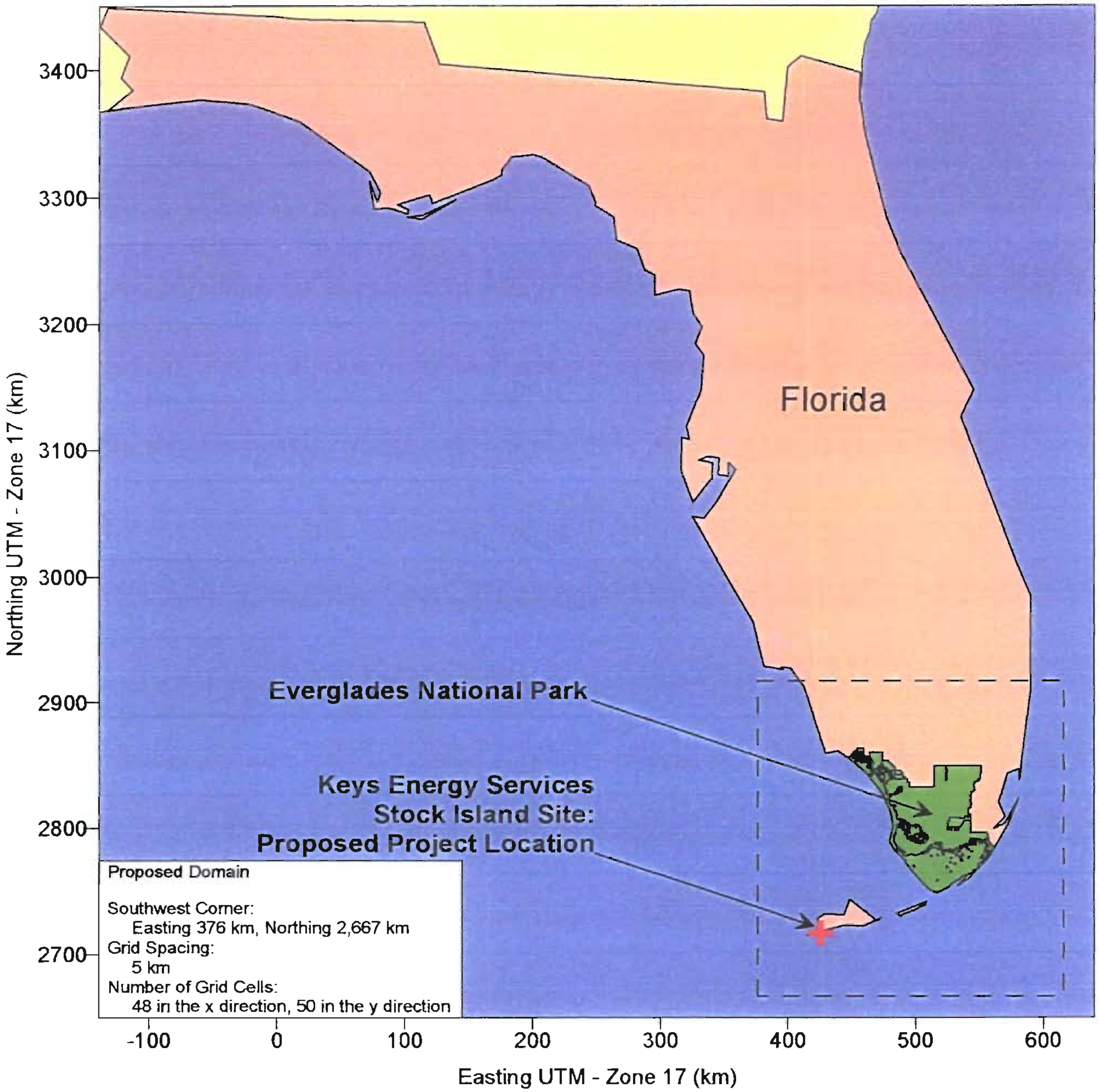
The CALMET settings, including horizontal and vertical grid coverage and resolution of prognostic mesoscale meteorological data, will be chosen to adequately characterize the area within the CALMET domain.

2.5.2 Modeling Domain

The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed project to the receptors at the ENP with at least a 50-km buffer zone in each direction. The modeling analysis will be performed in the UTM coordinate system. A rectangular modeling domain extending 240 km in the east-west (x) direction and 250 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is the origin and is located at 376 km Easting and 2,667 km Northing (based on UTM Zone 17, North American Datum (NAD) 1983 coordinates). The grid resolution for the domain will be 5 km. A grid spacing of 5 km yields 48 grid cells in the x-direction and 50 grid cells in the y-direction. Figure 2-1 illustrates the size and location of the modeling domain.

2.5.3 Mesoscale Model Data

Pennsylvania State University in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory have developed mesoscale meteorological data sets of prognostic wind fields, or "guess" fields, for the United States. The hourly meteorological variables used to create these data sets (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and are used to populate the modeling domain with meteorological data. The analysis will use 1990 MM4, 1992 MM5, and 1996 MM5 mesoscale meteorological data sets to initialize the CALMET wind fields for each modeled year. The three years of MM data will be obtained from a NPS database provided to Black & Veatch. The extraction program accompanying the data will be used to obtain the



Proposed CALPUFF Modeling Domain

Figure 2-1

appropriate MM data points to cover the modeling domain. The 1990 MM4 and 1992 MM5 data have a horizontal spacing, or resolution, of 80 km. The 1996 MM5 data has a resolution of 36 km. The meteorological observations contained with the MM data sets are assumed to be of sufficient density, both temporally and spatially, to make the need for discrete meteorological station observation unnecessary. Thus, CALMET will be run with the No Observations mode developed in the latest version available from the model developer, EarthTech.

2.5.4 Geophysical Data Processing

Terrain elevations for each grid cell of the modeling domain will be obtained from1-degree Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data will be extracted for the modeling domain grid using the CALMET preprocessor program TERREL. Land-use data, based on annual averaged values, will also be obtained from the USGS. Land-use values for the domain grid will be extracted with the preprocessor programs CTGCOMP and CTGPROC. Other parameters processed for the modeling domain include surface roughness, surface albedo, Bowen ratio, soil heat flux, and leaf index field. Once preprocessed, all of the land-use parameters will be combined with the terrain information in a processor called MAKEGEO. This processor will produce one GEO.DAT file for input to CALMET.

2.6 Project Emissions

The maximum pound per hour emission rates at 100% load and the average annual temperature will be used for the pollutants modeled with CALPUFF. Those pollutants include NO_x, SO_2, and PM_{10}.

3.0 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the ENP, including regional haze, deposition, and Class I SILs.

3.1 Regional Haze Analysis

A regional haze analysis will be performed for the ENP for ammonium sulfates, ammonium nitrates, and particulate matter by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations.

3.1.1 Visibility

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the ENP lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}(Mm^{-1}) = 3912 / vr(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

3.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the ENP. The background visual range, or constituents thereof, for the ENP will be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each relative humidity will be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98) where appropriate. Table 3-1 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-1 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to

Table 3-1 Outline of IWAQM Refined Modeling Analyses Recommendations *	
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition 3. Define background values for ozone and ammonia for area
Processing	Use highest predicted 24-hr SO_4, PM_{10} and NO_3 values; compute a day-average relative humidity factor (f(RH)) for the worst day for each predicted species, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.
* *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).	

post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze will be calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. Based on recent correspondence with staff of the NPS, the relative humidity will be capped at 95 percent. A supplementary analysis will be performed with the relative humidity capped at 98 percent for informational purposes only. Method 7, which eliminates hours during which visibility limiting weather events occur, may be explored as necessary. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM_{10} impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:

   $(NH_4)_2SO_4$ (μg/m3) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4

   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375

   Convert the NO_3 impact to NH_4NO_3 by the following formula:

   NH_4NO_3 (μg/m3) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3

   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
3. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

   b_{exts} = 3 x NH_4NO_3 x f(RH) + 3 x $(NH_4)_2SO_4$ x f(RH) + 1 x PM_{10}
4. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:

   b_{extb} = 3.912 / Visual range (km)
5. Compute the change in extinction coefficients:

in terms of deciviews:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

in terms of percent change of visibility:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the proposed project's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2 Deposition Analyses

Deposition analyses will be performed for ENP for both total sulfur and total nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 2.0 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results will be compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS).

3.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) onto to the ENP will be calculated for NO_x, SO_2, and PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Should the model predicted impacts onto the ENP exceed the Class I SILs, an appropriately derived inventory of PSD increment consuming sources will be developed through FDEP and modeled with the CALPUFF modeling system for comparison to the Class I Increment values.

APPLication Forms

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: The Utility Board of the City of Key West dba Keys Energy Services
2. Site Name: Stock Island Power Plant
3. Facility Identification Number: 0870003
4. Facility Location...
   Street Address or Other Locator: 6900 Front Street Extended
   City: Stock Island County: Monroe Zip Code: 33401
5. Relocatable Facility?
   ☐ Yes ☒ No
6. Existing Title V Permitted Facility?
   ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Edward Garcia – Environmental Safety Officer
2. Application Contact Mailing Address...
   Organization/Firm: The Utility Board of the City of Key West dba Keys Energy Services
   Street Address: 1001 James Street
   City: Key West State: FL Zip Code: 33040-6100
3. Application Contact Telephone Numbers...
   Telephone: (305) 295-1134 ext. Fax: (305) 295-1070
4. Application Contact Email Address: Edward.Garcia@Keysenergy.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	10-20-04
2. Project Number(s):	0870003-007-AC
3. PSD Number (if applicable):	PSD-FL-348
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

[X] Air construction permit.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
	Combustion Turbine Unit 4 – GE LM6000 PC-Sprint Simple Cycle Combustion Turbine	AC1A	$7,500

Application Processing Fee

Check one: [X] Attached - Amount: $ 7,500 [ ] Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : Daniel Cassel – Director of Generation
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: The Utility Board of the City of Key West dba Keys Energy Services Street Address: 1001 James Street City: Key West State: FL Zip Code: 33041-6100
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (305) 295-1142 ext. Fax: (305) 295-1145
4.	Owner/Authorized Representative Email Address: Dan.Cassel@KeysEnergy.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Daniel Cassel 10/14/04 Signature Date

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : Daniel Cassel – Director of Generation
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: The Utility Board of the City of Key West dba Keys Energy Services Street Address: 1001 James Street City: Key West State: FL Zip Code: 33041-6100
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (305) 295-1142 ext. Fax: (305) 295-1145
4.	Owner/Authorized Representative Email Address: Dan.Cassel@KeysEnergy.com
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Daniel Cassel 10/14/04 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* ____________________ ____________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: Stanley A. Armbruster, P.E. Registration Number: 30562
2.	Professional Engineer Mailing Address... Organization/Firm: Black & Veatch Street Address: 11401 Lamar Avenue City: Overland Park State: KS Zip Code: 66211
3.	Professional Engineer Telephone Numbers... Telephone: (913) 458-2763 ext. Fax: (913) 458-2934
4.	Professional Engineer Email Address: ArmbrusterSA@bv.com
5.	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.

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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.

Stanley A. Armbruster
Signature

10/13/04
Date

(seal)

STANLEY A. ARMBRUSTER LICENSE 30562 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: Stanley A. Armbruster, P.E. Registration Number: 30562
2.	Professional Engineer Mailing Address... Organization/Firm: Black & Veatch Street Address: 11401 Lamar Avenue City: Overland Park State: KS Zip Code: 66211
3.	Professional Engineer Telephone Numbers... Telephone: (913) 458-2763 ext. Fax: (913) 458-2934
4.	Professional Engineer Email Address: ArmbrusterSA@bv.com
5.	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.

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal 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.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal 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.

Stanley A. Armbruster

Signature

10/13/04

Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 425.65 North (km) 2716.67		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: Edward Garcia – Environmental Safety Officer
2. Facility Contact Mailing Address... Organization/Firm: The Utility Board of the City of Key West dba Keys Energy Services Street Address: 1001 James Street City: Key West State: FL Zip Code: 33041-6100
3. Facility Contact Telephone Numbers: Telephone: (305) 295-1134 ext. Fax: (305) 295-1070
4. Facility Contact Email Address: Edward.Garcia@Keysenergy.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	N
NOX	A	N
PM	A	N
PM10	A	N
SO2	A	N
VOC	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. A [ ] Previously Submitted, Date:_______
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. B [ ] Previously Submitted, Date:_______
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [x] Attached, Document ID: Attach. C [ ] Previously Submitted, Date:_______

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: [ ] Attached, Document ID:_________ [x] Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: [x] Attached, Document ID: Attach. D
3.	Rule Applicability Analysis: [x] Attached, Document ID: Attach. E
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): [x] Attached, Document ID: Attach. F [ ] Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): [ ] Attached, Document ID:_________ [x] Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): [ ] Attached, Document ID:_________ [x] Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): [x] Attached, Document ID: Attach. G [ ] Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): [x] Attached, Document ID: Attach. H [ ] Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): [x] Attached, Document ID: Attach. I [ ] Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:_________ [x] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:________ ☐ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:__________ ☐ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

[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.

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. Description of Emissions Unit Addressed in this Section: Combustion Turbine Unit 4 – GE LM6000 PC-Sprint Simple Cycle Combustion Turbine.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	[x] Yes [ ] No

9. Package Unit:
Manufacturer: GE   Model Number: LM6000 PC-Sprint

10. Generator Nameplate Rating: 47.6 MW (approximate)

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Water injection will be used for NOx control
2. Control Device or Method Code(s): 028

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 13.567 million gallons per year fuel oil	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: 462.0 million Btu/hr (HHV)	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: 24 hours/day 52 weeks/year	 7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment: The maximum annual fuel oil use rate of 13.567 million gallons per year given in Field 1 is intended to be an enforceable limit for this unit. This fuel use rate is equivalent to the unit operating at full load firing 4,422 hours per year, at an ambient temperature of 78 F. The unit will be operated between 50 and 100 percent of full load. Because the requested annual fuel use limit will effectively limit emissions, a limit on operating hours is not needed. The maximum heat input rate shown in Field 3 is with operation at 100% load at the site minimum ambient temperature of 41°F. Note that the heat input rate is a function of ambient temperature. As discussed in FDEP Guidance Document DARM-OGG-07, higher CT inlet temperatures will result in a lower heat input rate (MMBtu/hr) and vice versa. Variations of heat input (capacity) are to be expected due to the range of ambient temperatures and humidities encountered at the site. When they become available, the CT operating curves (capacity vs. inlet air temperature) will be provided to the Department. It is requested that the permit for this unit include Conditions 1 and 2 of DARM-OGG-07. We request inclusion of the standard permitting note that the heat input rates are provided for informational purposes only and are not intended to be enforceable limits.	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Combustion Turbine No. 4	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

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

5. Discharge Type Code: V	6. Stack Height: 60 feet	7. Exit Diameter: 10 feet
8. Exit Temperature: 837°F	9. Actual Volumetric Flow Rate: 566,400 acfm	10. Water Vapor: 11%

11. Maximum Dry Standard Flow Rate: 227,000 dscfm	12. Nonstack Emission Point Height: 60 feet
13. Emission Point UTM Coordinates... Zone: East (km): 425.651 North (km): 2716.682	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment: Emission point information given in Fields 8 through 11 are based on operation at 100% load and an ambient temperature of 78°F. This information will vary depending on ambient temperature and load.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): No. 2 fuel oil used in the combustion turbine		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 3.34	5. Maximum Annual Rate: 13,567	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash:	9. Million Btu per SCC Unit: 138 (HHV)
10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate give in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 41°F. The maximum annual fuel oil use rate of 13.567 million gallons per year given in Field 5 is intended to be an enforceable limit for this unit. This fuel use rate is equivalent to the unit operating at full load firing 4,422 hours per year, at an ambient temperature of 78 F. Because this requested annual fuel use limit will effectively limit emissions, a limit on operating hours is not needed.		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
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:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
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:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
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:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOX	**028**		**EL**
PM			
PM10			
SO2			**WP**
VOC			
SAM			**WP**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.5 lb/hour 33.6 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly CO emission rate is 16.5 lb/hour. The maximum annual CO emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load and the average ambient temperature at the site for 4,422 hours per year. Annual emissions = 15.2 lb/hr x 4,422 hours/year x 1 ton/2,000 lb = 33.6 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a CO emission rate of 15 ppmv, dry at 15% O_2.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: 75.9 lb/hour 154.1 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly NO_x emission rate is 75.9 lb/hour.
The maximum annual NO_x emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load and the average ambient temperature at the site for 4,422 hours per year.
Annual emissions = 69.7 lb/hr x 4,422 hours/year x 1 ton/2,000 lbs = 154.1 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on a NO_x emission rate of 42 ppmv, dry at 15% O_2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0075 x (14.4/Y) + F in percent by volume at 15% oxygen and on a dry basis	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference. See Attachment M for a more detailed discussion of compliance with Subpart GG, AS REVISED JULY 8, 2004.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42 ppm by volume at 15% oxygen and on a dry basis	4. Equivalent Allowable Emissions: 75.9 lb/hour 154.1 tons/year
5. Method of Compliance: CEMS.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent annual allowable emissions rate is based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation at 100% load at the average ambient temperature at the site of 78°F for 4,422 hours per year.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25 lb/hour 109.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 25 lb/hr Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential PM emissions are estimated to be 25 lb/hour at all operating conditions. Because estimated hourly PM emissions do not decrease with partial load operation and no limits on hours of operation are proposed, the maximum annual PM emissions are based on operation for 8,760 hours per year. Annual emissions = 25 lb/hr x 8,760 hours/year x 1 ton/2,000 lbs = 109.5 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a PM emission rate (front and back half catch) of 25 lb/hour.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25 lb/hour 109.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 25 lb/hr Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential PM_{10} emissions are estimated to be 25 lb/hour at all operating conditions. Because estimated hourly PM_{10} emissions do not decrease with partial load operation and no limits on hours of operation are proposed, the maximum annual PM_{10} emissions are based on operation for 8,760 hours per year. Annual emissions = 25 lb/hr x 8,760 hours/year x 1 ton/2,000 lbs = 109.5 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a PM_{10} emission rate (front and back half catch) of 25 lb/hour.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 23.55 lb/hour 47.8 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data using low sulfur fuel oil (0.05% sulfur).
The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly SO_2 emission rate is 23.55 lb/hour.
The maximum annual SO_2 emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load and the average ambient temperature at the site for 4,422 hours per year.
Annual emissions = 21.63 lb/hr x 4,422 hours/year x 1 ton/2,000 lbs = 47.8 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on using low sulfur fuel oil (0.05% sulfur) and conservatively assume all sulfur in the fuel is converted to SO_2 and there is no oxidation of SO_2 to SO_3.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.8% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 377 lb/hour 765 tons/year
5. Method of Compliance: Fuel testing and monitoring will be conducted in accordance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions are from 40 CFR 60, Subpart GG and Rule 62-204.800(8)(b).39 - 40 CFR 60, Subpart GG Stationary Gas Turbines, adopted by reference. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation at 100% load at the average ambient temperature at the site of 78°F for 4,422 hours per year.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 23.55 lb/hour 47.8 tons/year
5. Method of Compliance: Fuel testing and monitoring will be conducted in accordance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation at 100% load at the average ambient temperature at the site of 78°F for 4,422 hours per year.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.0 lb/hour 10.2 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly VOC emission rate is 5.0 lb/hour. The maximum annual VOC emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load and the average ambient temperature at the site for 4,422 hours per year. Annual emissions = 4.6 lb/hr x 4,422 hours/year x 1 ton/2,000 lbs = 10.2 tons/year	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on a VOC emission rate of 8.0 ppmv, dry at 15% O_2.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 7.21 lb/hour 14.6 tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: Vendor Data	7. Emissions Method Code: 5

8. Calculation of Emissions:
Potential emissions are based on vendor data.
The maximum hourly potential emissions are based on operation at conditions resulting in the maximum hourly rate. These conditions are at 100% load and an ambient temperature of 41°F. The maximum hourly sulfuric acid mist emission rate is 7.21 lb/hour.
The maximum annual sulfuric acid mist emissions are based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation of the unit at 100% load and the average ambient temperature at the site for 4,422 hours per year.
Annual emissions = 6.62 lb/hr x 4,422 hours/year x 1 ton/2,000 lbs = 14.6 tons/year

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Potential emissions shown in Fields 3 and 8 are based on use of low sulfur fuel oil (0.05% sulfur) and an SO_2 oxidation rate of 20% conversion of SO_2 to SO_3 and an assumed 100% conversion of SO_3 to H_2SO_4.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur by weight in the fuel	4. Equivalent Allowable Emissions: 7.21 lb/hour 14.6 tons/year
5. Method of Compliance: Fuel testing and monitoring.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are based on 20% oxidation of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 and are given for informational purposes only and do not represent limits. The equivalent allowable hourly emissions rate is based on operation at 100% load and an ambient temperature of 41°F and the equivalent allowable annual emissions rate is based on firing 13.567 million gallons per year of fuel oil, which is equivalent to operation at 100% load at the average ambient temperature at the site of 78°F for 4,422 hours per year.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined; Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: CO2 or O2	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined; Model Number: To be determined	Serial Number: To be determined
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be 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:	

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:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. B [ ] Previously Submitted, Date ________
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. J [ ] Previously Submitted, Date ________
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. K [ ] Previously Submitted, Date ________
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. L [ ] Previously Submitted, Date ________
   [ ] Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [x] Attached, Document ID: Attach. M [ ] Previously Submitted, Date ________
   [ ] Not Applicable
6. Compliance Demonstration Reports/Records
   [ ] Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________

   [ ] Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________

   [ ] To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________

   [x] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   [ ] Attached, Document ID: ________ [x] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: Attach. N [ ] Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: Attach. O [ ] Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [x] Attached, Document ID: Attach. P [ ] Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements [ ] Attached, Document ID: ____________	
2. Compliance Assurance Monitoring [ ] Attached, Document ID: ____________ [ ] Not Applicable	
3. Alternative Methods of Operation [ ] Attached, Document ID: ____________ [ ] Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID: ____________ [ ] Not Applicable	
5. Acid Rain Part Application [ ] Certificate of Representation (EPA Form No. 7610-1) [ ] Copy Attached, Document ID:_ [ ] Acid Rain Part (Form No. 62-210.900(1)(a)) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) [ ] Attached, Document ID:____________ [ ] Previously Submitted, Date:_________ [ ] Not Applicable	

Additional Requirements Comment

Attachment Q includes a discussion on the requested means of compliance with 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004.

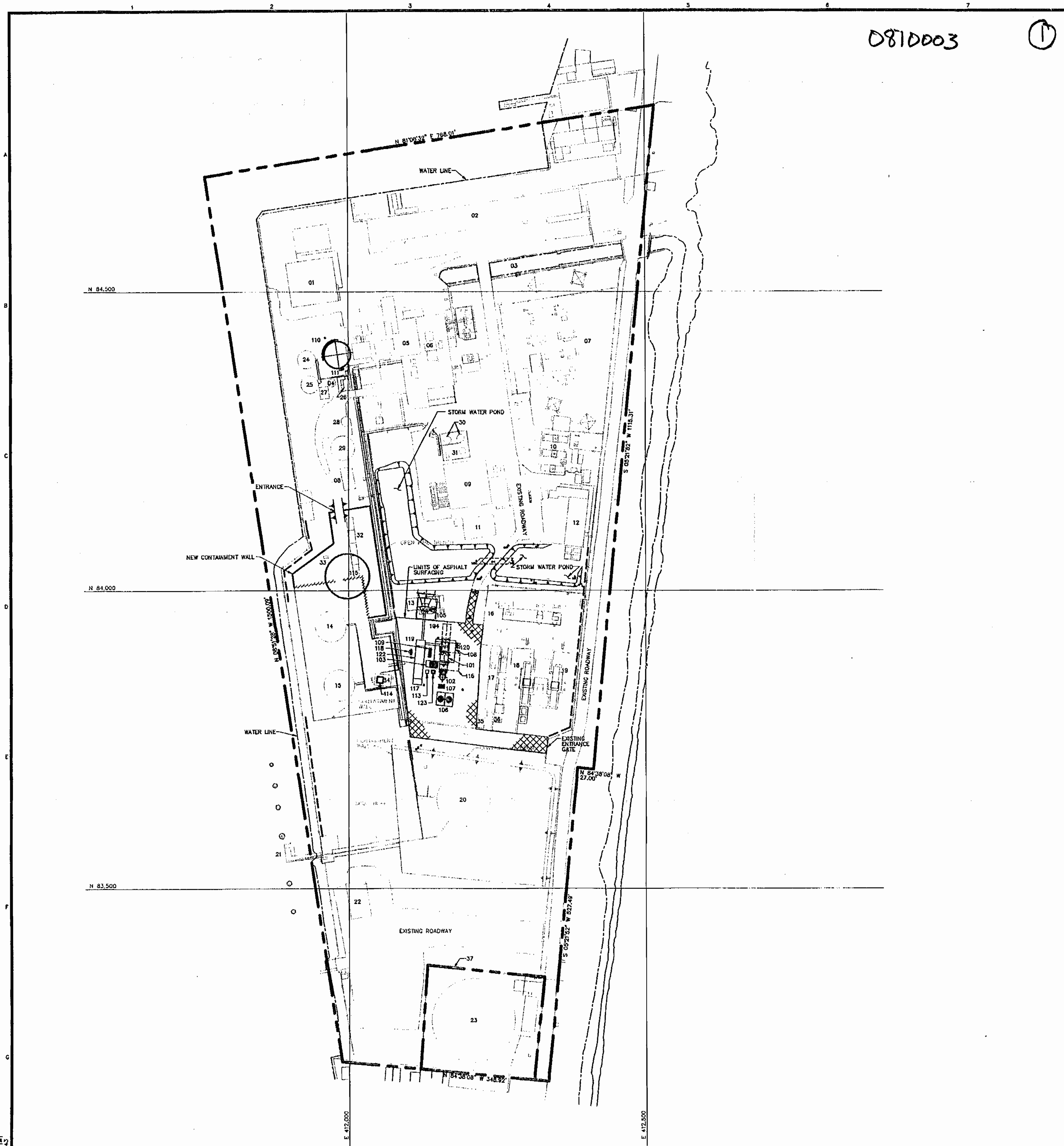
Attachment A

Facility Plot Plan

BEST AVAILABLE COPY

0810003

①



EXISTING FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
01	WAREHOUSE	–	–	–	
02	WAREHOUSE	–	–	–	
03	CIRCULATING WATER DISCHARGE FLUME	–	–	–	
04	RETIRED STEAM UNIT STACK	–	–	–	
05	RETIRED STEAM UNIT	–	–	–	
06	SYNCHRONOUS CONDENSER	–	–	–	
07	STOCK ISLAND SUBSTATION	–	–	–	
08	FIRE PUMP HOUSE	–	–	–	
09	MEDIUM SPEED DIESEL GENERATOR BUILDING	–	–	–	
10	HIGH SPEED DIESELS	–	–	–	
11	VEHICLE MAINTENANCE LIFT	–	–	–	
12	MAINTENANCE GARAGE	–	–	–	
13	STORAGE AREA	–	–	–	TO BE RELOCATED
14	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	–	–	–	
15	DIESEL FUEL TANK (500,000 GALLONS, 32' HIGH)	–	–	–	
16	SWITCHYARD	–	–	–	
17	COMBUSTION TURBINE GENERATOR #1	–	–	–	
18	COMBUSTION TURBINE GENERATOR #2	–	–	–	
19	COMBUSTION TURBINE GENERATOR #3	–	–	–	
20	DIESEL FUEL TANK (1.9 MILLION GALLONS, 40' HIGH)	–	–	–	
21	FUEL LOADING DOCK	–	–	–	
22	TWO-STORY OFFICE BUILDING	–	–	–	
23	FKAA WATER TANK	–	–	–	
24	DEMINERALIZED WATER TANK (189,000 GALLONS, 32' HIGH)	–	–	–	
25	DEMINERALIZED WATER TANK (189,000 GALLONS, 32' HIGH)	–	–	–	
26	CEMS BUILDING FOR RETIRED STEAM UNIT	–	–	–	
27	CINGULAR CEL TOWER CONTROL BUILDING	–	–	–	
28	ABANDONED TANK STORAGE SHED	–	–	–	
29	SERVICE/FIRE WATER TANK (300,000 GALLONS, 40' HIGH)	–	–	–	
30	FUEL OIL DAY TANKS	–	–	–	
31	LUBE OIL STORAGE TANK	–	–	–	
32	STORAGE SHEDS	–	–	–	TO BE RELOCATED
33	FIRE HYDRANT	–	–	–	TO BE RELOCATED
34	FUEL OIL FORWARDING BUILDING	–	–	–	
35	STORAGE BUILDING	–	–	–	
36	WATER INJECTION SKID	–	–	–	
37	FLORIDA KEYS AQUADUCT AUTHORITY PROPERTY LINE	–	–	–	

NEW FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
101	COMBUSTION TURBINE/GENERATOR	–	–	–	
102	COMBUSTION TURBINE EXHAUST STACK	–	–	–	
103	COMBUSTION TURBINE AUXILIARY SKID	–	–	–	
104	COMBUSTION TURBINE GENERATOR ROTOR REMOVAL	–	–	–	
105	COMBUSTION TURBINE GENERATOR STEPUP TRANSFORMER	–	–	–	
106	COMBUSTION TURBINE COOLING WATER SKID	–	–	–	
107	COMBUSTION TURBINE LUBE OIL COOLING WATER PUMP	–	–	–	
108	AIR INLET FILTER SYSTEM	–	–	–	
109	COMBUSTION TURBINE WATER INJECTION PUMP SKID	–	–	–	
110	DEMINERALIZED WATER STORAGE TANK (350,000 GALLONS, 32' HIGH)	–	–	–	
111	DEMINERALIZED WATER PUMP SKID	–	–	–	
112	NOT USED	–	–	–	
113	FUEL OIL PUMPS/FILTER	–	–	–	
114	FUEL OIL FORWARDING SKID	–	–	–	
115	DIESEL FUEL OIL TANK (1 MILLION GALLONS, 32' HIGH)	–	–	–	
116	TURBINE REMOVAL/MAINTENANCE AREA	–	–	–	
117	CEMS ENCLOSURE	–	–	–	
118	UNIT AUX TRANSFORMER	–	–	–	
119	GENERATOR BREAKER	–	–	–	
120	CO2 FIRE PROTECTION BOTTLE RACK	–	–	–	
121	NOT USED	–	–	–	
122	CTG POWER AND CONTROL MODULE	–	–	–	
123	SPRINT SYSTEM SKID	–	–	–	
124	NOT USED	–	–	–	
125	NOT USED	–	–	–	

GENERAL LEGEND

- PROPERTY BOUNDARY
- EXISTING FENCE
- EXISTING OVERHEAD TRANSMISSION LINES
- WATER LINE
- NEW FENCE
- EXISTING CONTAINMENT WALL TO BE DEMOLISHED
- ASPHALT SURFACING
- GRAVEL SURFACING

NOTES

1. THIS SPECIAL PURPOSE SURVEY WAS PERFORMED TO ESTABLISH SITE CONTROL MONUMENTS WITH AERIAL TARGETING FOR USE IN PHOTOGRAMMETRIC MAPPING OF THE SITE. THE BOUNDARY LINES WITH BEARINGS AND LENGTHS DEPICTED HEREON WERE PLOTTED FROM INFORMATION PROVIDED BY THE CLIENT. THE BOUNDARY LOCATION IS APPROXIMATE, AS GRAPHICALLY SCALED FROM DRAWINGS PROVIDED BY THE CLIENT, AND SHOULD NOT BE RELIED UPON FOR BOUNDARY SURVEY DETERMINATION.
2. VERTICAL CONTROL IS BASED ON THE NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD 88). ELEVATIONS ARE EXPRESSED IN FEET, AND DECIMALS THEREOF.
3. HORIZONTAL CONTROL DATA IS BASED ON FLORIDA STATE PLANE COORDINATE SYSTEM (EAST ZONE), NORTH AMERICAN DATUM OF 1983 (NAD 83) WITH THE 1999 ADJUSTMENT. COORDINATE VALUES ARE EXPRESSED AS "GRID COORDINATES" AND ARE IN FEET, AND DECIMALS THEREOF. FOR CONVERSION FROM GRID TO GROUND VALUES USE A SITE SCALE FACTOR OF 1.00000943.

PRELIMINARY
NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
B	08/03/04	ISSUED FOR CLIENT REVIEW	MRR	DAJ		MRR	
A	07/20/04	ISSUED FOR IN-HOUSE REVIEW	MRR	DAJ		MRR	

N

60' 30' 0 60' 120'
SCALE: 1"=60'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER DAJ DRAWN MRR
CHECKED DATE

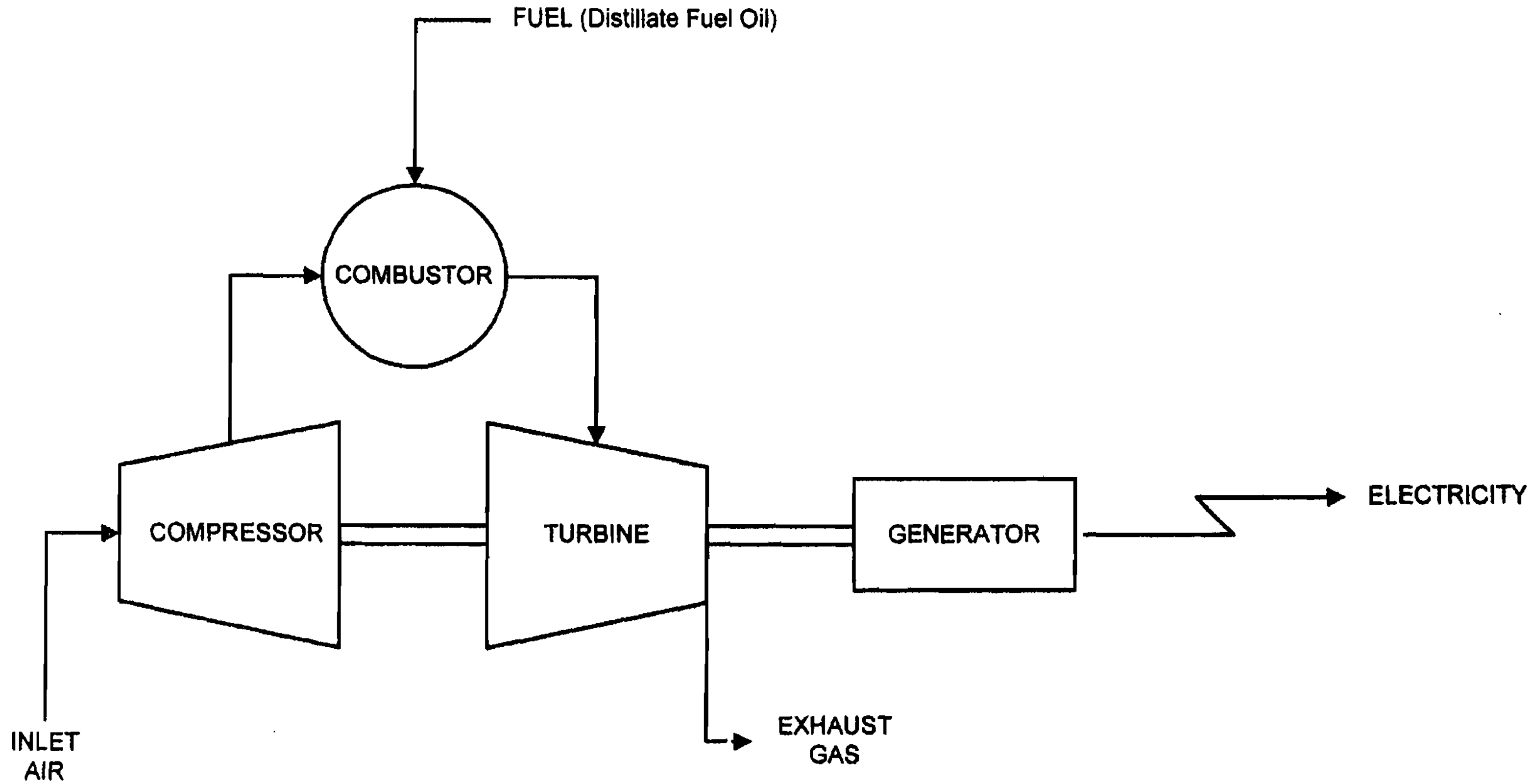
STOCK ISLAND
COMBUSTION TURBINE UNIT 4
SITE ARRANGEMENT

PROJECT / DRAWING NUMBER: 136839-DS-S1001
REV: B
CODE
AREA

Attachment B

Process Flow Diagrams

Keys Energy Services
Stock Island Power Plant
Combustion Turbine Unit 4



Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment C

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

Reasonable precautions to control unconfined emissions of particulate matter as listed in Rule 62-296.320(4), FAC will be employed as appropriate. These precautions include receiving delivery of fuel oil by barge rather than trucks, except during emergency situations, and using paved roads for the fuel trucks which deliver vehicle fuel. Additionally, watering will be used as needed to prevent emissions from unpaved areas.

Attachment D

Description of Proposed Construction or Modification

Description of Proposed Construction or Modification

The construction consists of installation of a GE LM 6000 PC-Sprint simple cycle combustion turbine and support facilities. New major support facilities for the Project will include an additional water storage tank and a fuel oil storage tank. A more detailed description of the proposed construction can be found in the application technical support document accompanying this application.

Attachment E

Rule Applicability Analysis

Rule Applicability Analysis

Rule Applicability Analysis for the Entire Facility

State: Rule 62-4.070 – Standards for Issuing or Denying Permits.

State: Rule 62-210.300 – Permits Required.

State: Rule 62-212.300 – General Preconstruction Review Requirements.

State: Rule 62-212.400 – Prevention of Significant Deterioration.

Rule Applicability Analysis for the GE LM6000 Simple Cycle Combustion Turbine

The following rules are applicable to Combustion Turbine Unit 4:

Federal: 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines

Federal: 40 CFR Part 60 Subpart A – General Provisions.

Federal: 40 CFR Part 72 – Permits Regulation (Acid Rain)

Federal: 40 CFR Part 75 – Continuous Emissions Monitoring

State: Rule 62-204.800(8)(b).39 – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines adopted by reference.

State: Rule 62-204.800(8)(d) – General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions.

State: Rule 62-212.400 – Prevention of Significant Deterioration applies to NO_x, SO_2, PM, PM_{10} and sulfuric acid mist. See the technical support document accompanying this application for a more detailed discussion of PSD applicability.

State: Rule 62-212.300 – General Preconstruction Review Requirements. Applies to CO, VOC and HAP emissions.

State: Rule 62-297.310 – General Compliance Test Requirements.

Rule Applicability Analysis for the One Million Gallon No. 2 Fuel Oil Storage Tank

Federal: 40 CFR Part 60 Subpart Kb, AS REVISED OCTOBER 15, 2003 – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23,

1984. Because the vapor pressure of No. 2 fuel oil is less than 3.5 kPa, this storage tank is not subject to 40 CFR Part 60 Subpart Kb.

State: Rule 62-212.300 – General Preconstruction Review Requirements. Per 62-210(3), F.A.C., this emissions unit is exempt from the permitting requirements of Chapter 62-212, F.A.C. because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1., F.A.C.

Attachment F

List of Exempt Emission Units

List of Exempt Emission Units

The new one million gallon fuel oil storage tank is exempt from the requirement to obtain an air construction permit. The unit is exempt in accordance with Rule 62-210.300(3)(b)1., F.A.C.

Attachment G

Ambient Impact Analysis

Ambient Impact Analysis

The ambient impact analysis is included as Section 4.0 of the technical support document included with this application.

Attachment H

Air Quality Impact Since 1977

Air Quality Impact Since 1977

A discussion of the Air Quality Impact since 1977 is included in Section 5 of the technical support document included with this application.

Attachment I

Additional Impact Analyses

Additional Impact Analyses

Additional Impact Analyses are included in Section 5 of the technical support document included with this application.

Attachment J

Fuel Analysis or Specification

Fuel Analysis or Specification

Fuel is specified as No. 2 fuel oil containing no more than 0.05 percent sulfur. Attached is a typical No. 2 fuel oil analysis for the Stock Island facility.

M O T I V A   E N T E R P R I S E S   L L C

NORCO REFINING

C E R T I F I C A T E   O F   A N A L Y S I S

Customer : LOW SULFUR DIESEL TO
Product : Low Sulfur
Product Code : 00429

Ship : PHILLY TRIP #70331
Cust Order No: N/A
Shipping Order No : N/A
Shipping date : 6-JAN-2004

Component/Property	Units	REQUIREMENTS Min	REQUIREMENTS Max	ANALYSIS Results	ANALYSIS Method
Color, ASTM				0.5	D-1500-00
Haze		<=2		1	D-4176-03
Sulfur	pct weight			0.032 %	D4294
Corr,Cu, 122F		<=1		1	D-0130
API Grav. 60F	API	Report		32.0	D-1298
Flash Pt, PMCC	deg F	130	999	165	D-56
90%	deg F	540	640	612	D-0086
CP	deg F		690	648	D-0086
Cloud Point	deg F	-20	15	7	D-2500
Pour Point	deg F	-20	0	-5	D-97
Visc,Kin, 104F	cs	2.0	3.6	3.0	D-445
Cetane Index		42.0		43.6	D-8976-00
Micro Carbon Residue	pct weight	<=0.35		0.0000	D-189
BS&W Sed + Water	pct vol	<=0.05		0.00	D-1796
Ash	pct weight	<=0.01		0.00	D-482
Stability Dupont			7	1	O-DUPT-03

The reference number is 1221356.
Where a result is flagged as '<', the value given is the minimum detectable limit for that component.
Source 1 (1221356)- 44763.07 barrels, 100 pct

Contact Faye Labiche at (504) 465-6742 with questions concerning COA.

Approved: P. M. CLOUATRE   Page 1 of 1   6-JAN-2004 14:14

Attachment K

Detailed Description of Control Equipment

Detailed Description of Control Equipment

Water Injection: A control technology used to limit NO_x emissions. The thermal NO_x contribution to total NO_x emissions is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine.

Attachment L

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

Procedures for startup and shutdown will be completed in accordance with manufacturers' operating procedures and/or plant operating procedures.

Attachment M

Operation and Maintenance Plan

Operation and Maintenance Plan

The emission units will be operated and maintained in accordance with manufacturer's recommendations, operations and maintenance experience, and technical guidance taking into account protection of equipment, safety of personnel and other factors as deemed necessary to maintain compliance with the permitted limits.

Attachment N

Control Technology Review and Analysis

Control Technology Review and Analysis

The control technology review and analysis is included as Attachment 4 of the application support document included with this application.

Attachment O

Good Engineering Practice Stack Height Analysis

Good Engineering Practice Stack Height Analysis

A good engineering practice stack height analysis is included in Section 4.2.3 of the application support document included with this application.

Attachment P

Description of Stack Sampling Facilities

Description of Stack Sampling Facilities

Combustion Turbine Unit 4 will be equipped with stack sampling facilities appropriate for performing required stack testing. A detailed description of stack sampling facilities is not available at this time. When available, if requested by the Department, the stack sampling facilities description will be supplied to the Department.

Attachment Q

Compliance with NSPS Subpart GG, AS REVISED JULY 8, 2004

Compliance with NSPS Subpart GG, AS REVISED JULY 8, 2004

For Stock Island Combustion Turbine Unit 4, compliance with the New Source Performance Standard (NSPS) for Stationary Gas Turbines, 40 CFR 60 Subpart GG, AS REVISED JULY 8, 2004, will be achieved in accordance with the following:

§60.332 Standard for nitrogen oxides. Combustion Turbine Unit 4 is subject to the NOx emission standard equation given in 40 CFR 60.332(a)(1). As allowed per 40 CFR 60.332(a)(3), an allowance for fuel-bound nitrogen will not be applied and the F-value in the emission standard equation will be zero. By accepting a F-value of 0, the requirements of 40 CFR 60.332(a)(4) do not apply.

§60.333 Standard for sulfur dioxide. Combustion Turbine Unit 4 will comply with the fuel sulfur standard given in 40 CFR 60.333(b).

§60.334 Monitoring of Operations. As allowed per 40 CFR 60.334(d), the owner/operator will use a NOx CEMS installed, certified, operated, maintained, and quality-assured as described in 40 CFR 60.334(b) to monitor NOx emissions. Because a NOx CEMS will be used to monitor NOx emissions, continuous water to fuel ratio monitoring included in 40 CFR 60.334(a) is not required.

The fuel oil sulfur content will be monitored in accordance with 40 CFR 60.334(h)(1). The frequency of determining the sulfur content of the fuel oil will be in accordance with 40 CFR 60.334(i)(1). Because an allowance for fuel bound nitrogen is not being claimed, fuel oil nitrogen content monitoring given in 40 CFR 60.334(h)(2) is not applicable.

Excess emissions and monitor downtime will be reported in accordance with 40 CFR 60.334(j). NOx excess emissions will be determined in accordance with 40 CFR 60.334(j)(1)(iii). Sulfur dioxide excess emissions will be determined in accordance with 60.334(j)(2)(ii).

§60.335 Test Methods and Procedures. The performance tests required in 40 CFR 60.8, will be conducted using the test methods given in 40 CFR 60.335(a). Compliance with the applicable nitrogen oxides emission limitation in 40 CFR 60.332(a) and the test requirements of 40 CFR 60.8 will be determined using the requirements of 40 CFR 60.335(b)(7). Fuel sampling and analysis during the performance test will be conducted in accordance with 40 CFR 60.335(b)(10).

Attachment R

Air Dispersion Modeling Files (CD)