TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company
FPL Turkey Point Fossil Plant

1,150-Megawatt Combined Cycle Power Project

Miami-Dade County

DEP File No. 025003-006-AC (PSD-FL-338)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section

May 28, 2004

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
9700 Southwest 334th Street
Homestead, Florida 33035

Authorized Representative:
H.O. Nunez, Plant General Manager

Processing Schedule

- Received Site Certification and PSD application on November 14, 2003;
- Additional information requested via Power Plant Siting Office on January 20, 2004;
- Received additional information on March 1, 2004;
- Siting Application Found Sufficient on April 7, 2004;
- Intent to Issue PSD Permit distributed May 28, 2004.

Facility Description and Location

The Florida Power and Light (FPL) Company operates the Turkey Point Fossil Plant, which is located south of Miami, east of Homestead and Florida City and adjacent to Biscayne Bay, in Miami-Dade County. The existing Turkey Point Fossil Plant consists of two fossil fuel-fired steam electrical generating units and five "Black Start" diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The location of the Turkey Point Fossil Plant is shown in Figures 1 and 2.

Figure 1. Location of Turkey Point

Figure 2. Turkey Point Fossil Plant

The Turkey Point Fossil Plant is located generally east of the Class I Everglades National Park and is approximately 20 kilometers northeast of the nearest boundary to the park. Biscayne National Park encompasses the general area to the east of the plant.

Regulatory Categories

Title III: The facility is a "Major Source" of hazardous air pollutants (HAPs). Based on the available information, the project is potentially subject to at least one National Emission Standard for Hazardous Air Pollutants (NESHAP) and the applicable Maximum Achievable Control Technology (MACT).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAPs. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "4-on-1" combined cycle unit (Unit 5) consisting of the following equipment and specifications: four 170 MW gas turbine-electrical generator sets; four gas-fired heat recovery steam generators (550 mmBtu/hour); four exhaust stacks between 130 and 150 feet in height; a common steam-electrical generator (470 MW); a 22-cell mechanical draft cooling tower; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment. Gas turbines are also called combustion turbines.

Gas Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric 7FA gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, and a supplementary gas-fired heat recovery steam generator (HRSG). Following are additional project characteristics.

- Fuels: Each gas turbine will fire natural gas as the primary fuel and *ultra low sulfur* (0.0015% Sulfur) distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.
- Generating Capacity: Each of the four gas turbines has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Each of the four heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4-on-1" combined cycle unit is 1150 MW.

- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of ultra low sulfur distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: Each gas turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at least 130 feet tall with a nominal diameter of 19 feet. The following summarizes the exhaust characteristics:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	1608 mmBtu/hour	59° F	202° F	1,023,872
Oil	1830 mmBtu/hour	59° F	295° F	1,224,407

Project Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressors of the GE 7FA combustion turbines proposed for this project. The air is compressed by a pressure ratio of about 15 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the turbine section at temperatures of approximately 2600 ^{o}F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1100 ^{o}F and high excess oxygen and is available for additional energy recovery.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator (HRSG). The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Figure 3 is a simplified diagram of combined cycle operation.

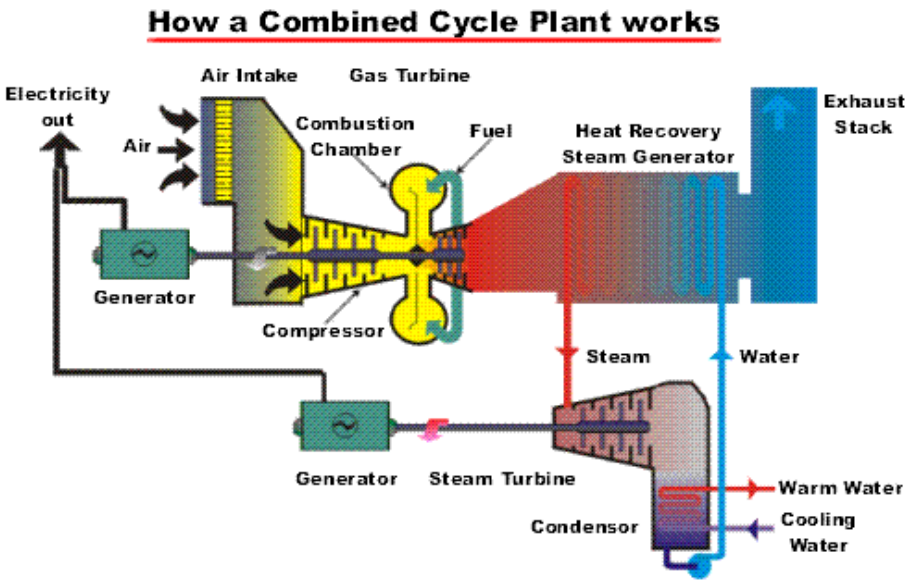

Figure 3. Key Components of a Combined Cycle Unit

The applicant has also requested the following modes of operation within the normal combined cycle operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging will be implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2880 hours of duct burning per year for each gas unit.
- High Power Modes (HPM): These include Power Augmentation (PA) and Peaking (PK). Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PK is based on greater fuel use and combustion turbine temperatures resulting in greater power production. PA and PK can cause greater uncontrolled NO_X emissions. PA causes greater uncontrolled CO emissions while PK theoretically causes less CO emissions. The applicant requests 400 hours of HPM for each unit and only when using the Duct Burners.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NO_X	312	40	Yes
PM/PM_{10}	420/229	15/25	Yes
SO_2	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Miami-Dade County Code of Ordinances

Chapter	Description
24 - II	Air Quality
24.41.1	Prohibitions against Air Pollution (Ringleman)
24.41.3	Sulfur Dioxide (Liquid Fuel Sulfur Dioxide Emissions)
24.41.6	Storage and Handling of Petroleum Products (Reid Vapor Pressure)

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for NO_X, CO, VOC, SO_2, SAM and PM/PM_{10}.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"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.

a. *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

b. *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, 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.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.

4.2 NO_X BACT Determination

Nitrogen Oxides Formation

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

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

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

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles.

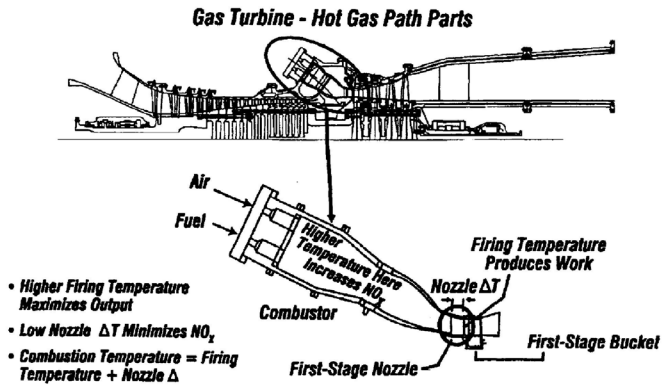

Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this FPL project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the FPL project. The proposed NO_X controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 105 ppmvd @15%O_2. This constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

<u>Descriptions of Available NO_X Controls</u>

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 5.

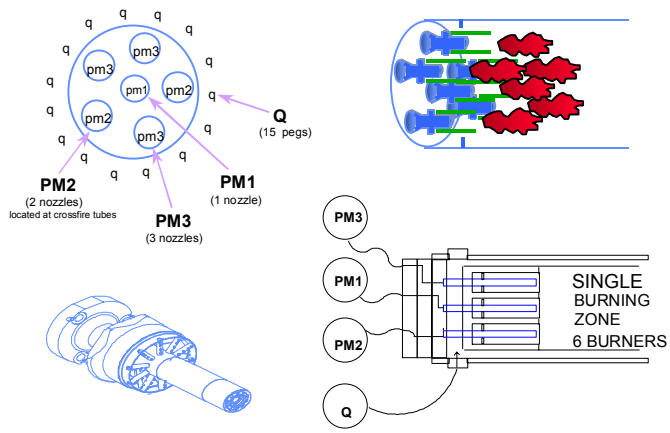

Figure 5 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

<u>Design</u> emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 6 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X. Actual emissions of CO and VOC are actually much less than suggested by the diagram. However the diagram also suggests the need to minimize operation at low load conditions.

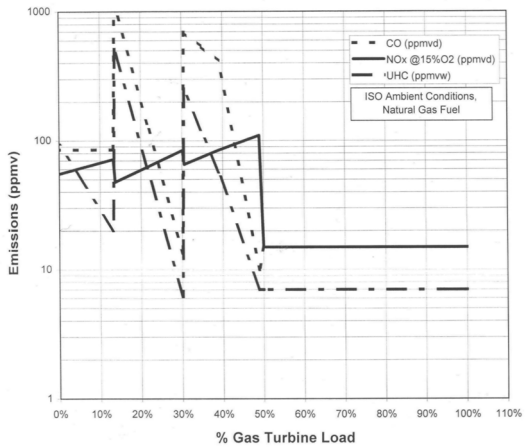

Figure 6 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

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

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.

Table 2. Test Results for GE 7FA Gas Turbine, TECO Polk Power (Simple Cycle) [i]

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

Following are the results for testing of the GE7FA combined cycle unit at the City of Tallahassee Purdom Plant.

Table 3. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station[ii]

Percent of Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

The test results at the TECO and Tallahassee projects confirm NO_X, CO, and VOC emissions substantially less than typical guarantees as discussed below.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 7 from an EPRI report.[iii] Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 7.

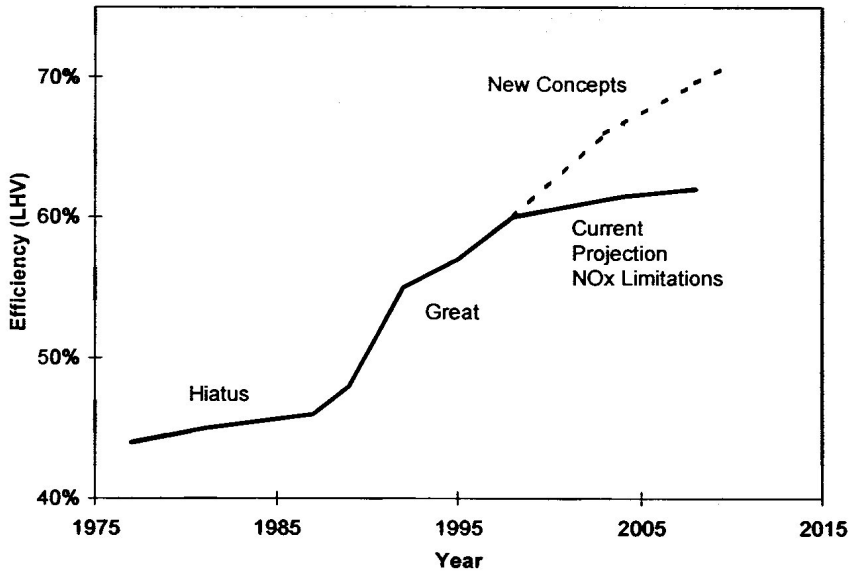

Figure 7 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by FPL. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater that 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).[iv] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_X emissions when firing fuel oil as discussed above.

Catalytic Combustion - XONON™

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

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[vi] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[vii] By now, five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[viii] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FPL Turkey Point project.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts

used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 ^{o}F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

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

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project complies with a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued to Competitive Power Ventures (CPV), Calpine, Progress Energy, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O_2 by SCR. Similarly permits were issued in 2003 to FPL for projects in Manatee and Martin County each with a limit of 2.5 ppmvd @15%O_2 by SCR.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 9 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

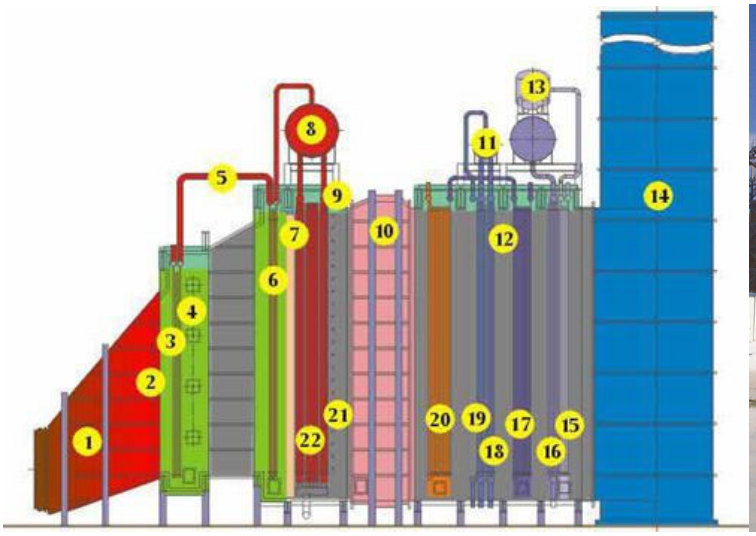

Figure 8 – Key HRSG Components (10 is SCR) **Figure 9 – PGN Hines Block I**

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[ix] The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 4. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[x]

% Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd	NH_3 ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 - 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_X emissions were achieved with minimal ammonia (NH_3) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO$_X$™

This technology is an NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[xi] Alstom Power was not successful in marketing the product at large facilities.

SCONO$_X$™ technology (at 2.0 ppmvd) was been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$™ can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from natural gas reforming unit.

Table 5 contains averaged cost values for $SCONO_X^{TM}$ and SCR developed by the California Air Resources Board for their Legislature.[xii] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 5. Cost Comparison between SCR and $SCONO_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X^{TM}$	SCR/CO	$SCONO_X^{TM}$
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with $SCONO_X^{TM}$ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the $SCONO_X^{TM}$ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by FPL for the proposed 1,150 MW project claim even greater cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that $SCONO_X^{TM}$ is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant originally proposed a BACT NO_X limit of 2.5 ppmvd @15% O_2. FPL proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FPL proposed a BACT NO_X emission limit of 10 ppmvd @15% O_2 while burning backup ultra low sulfur fuel oil by a combination of wet injection and SCR.

Since that time, FPL agreed to lower limits as follows:

a. Gas Firing: 2.0 ppmvd @ 15% O_2, 24-hour average

b. Oil Firing: 8.0 ppmvd @ 15% O_2, 24-hour average

Department's Draft NO_X BACT Determinations

Table 6 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average.

The Department agrees that FPL's proposal of 2.0 ppmvd @15% O_2 on a 24-hour basis and minimization of fuel oil use represents BACT for this project. The limits of 2.0 and 8.0 ppmvd @15% O_2 represent reductions of 98% and 92% for the gas and oil cases respectively when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 6. Recent NO_X Standards for "F-Class" Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 - FO	4x170 MW GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 - FO	4x170 MW GE 7FA & DBs
PGN Hines III, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
El Paso Manatee, FL	250	2.5 – NG (24-hr)	175 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs
Enron/Ft. Pierce, FL	~250	3.5 – NG (3-hr) 10 - FO	170 MW MHI 501F

Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation; FO = Fuel Oil; GE = General Electric; WH = Westinghouse; ABB = Asea Brown Bovari

4.3 CO and VOC BACT Determination

CO and VOC Formation and Control Options

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Similarly, VOC emissions less than 1 ppm have consistently been measured at new GE7FA units throughout the state. Again the results are roughly equal to those at ANP Blackstone.

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[xiii] The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation - thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

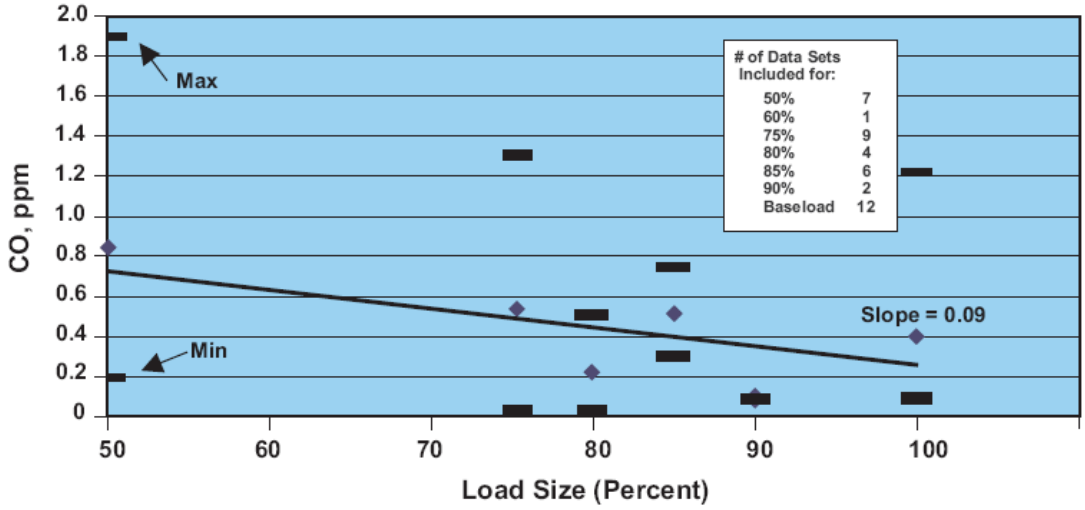

Figure 10. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Duct Burner, HPM, Low Load and Fuel Oil Considerations

The presence of a duct burner (refer to Figure 8, Component 4) and possibility of other high power modes (HPM) including power augmentation (PA) and peaking (PK) complicate the evaluation somewhat.

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (1,100 to 1,200 ^{o}F) and high excess air (> 12% O_2). In the design shown in Figure 8, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 11 and 12 are of an individual burner and an array comprising a duct burner. The hot TEG serves as combustion air for gas introduced into the burner array.

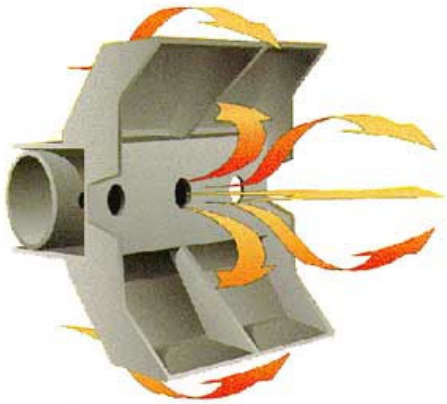

Figure 11 – Individual Burner (Coen)

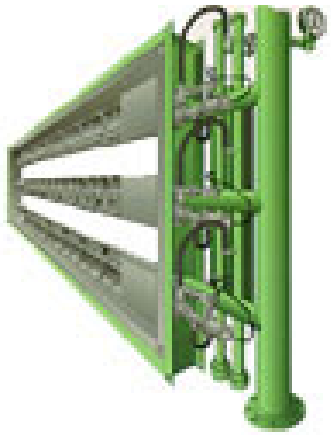

Figure 12 – Burner Array (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 ^{o}F. VOC such as ethane and propane ignite at temperatures less than 900 ^{o}F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Certain configurations (NovelEdge^{TM}) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC and CO control because of destruction by the duct burner.[xiv] Basically, the claim is that a "3 on 1" configuration (3 CT's & 1 HRSG) producing 750 MW can be replaced with a "2 on 1" configuration by adding very large Coen "Power Plus" DBs in a Nooter Eriksen HRSG and still produce 750 MW. Basically the capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided.

Following is a table with the results of CO and VOC testing recently completed at the Gulf Power Lansing Smith Plant.[xv] The units tested were GE7FA combustion turbines (CT) of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine while using duct burners (DB).

Table 7. CO and VOC Emissions - Gulf Power Plant Smith GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
Gulf Smith Unit 4 (CT & PA)	5.18	0.61
Gulf Smith Unit 5 (CT & PA)	8.61	0.38

As seen from Table 7, emissions of CO and VOC are very low when the DBs are used and without PA. The values under the DB mode are roughly the same as those for the normal operation mode (no DB or PA) in Tables 2 and 3 above.

The Gulf Smith units also provide an example of power augmentation (PA) with the duct burners (DB) off. Emissions when employing PA are clearly greater than the base case in Tables 2 and 3 and greater than the DB case.

Following is a table with results of CO and VOC emissions from GE 7FA units at Alabama Power's Plant Barry when operating simultaneously in DB and PA modes.[xvi]

Table 8. CO and VOC Emissions - Alabama Power Plant Barry GE 7FA Units (lb/mmBtu)

Unit (Modes)	CO	VOC
Barry Unit 7A (CT & DB & PA)	0.018 (< 9 ppmvd@15% O_2)	0.000 (< 1 ppmvd@15% O_2)
Barry Unit 7B (CT & DB & PA)	0.008 (< 4 ppmvd@15% O_2)	0.000 (< 1 ppmvd@15% O_2)

Comparison of the results from the Gulf Power and Alabama Power units suggests that the PA mode increases CO emissions whether or not the duct burners are used, while VOC emissions remain low.

Recently, the Department received additional information regarding tests conducted at the recently commissioned Southern/KUA/OUC/FMPA project located at the OUC Stanton Facility. The two units are equipped with ducts burners and practice power augmentation. Following are the results of those tests.[xvii]

Table 9. Emissions from Stanton A Combined Cycle GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	NO_X	CO	VOC	NH_3
Unit 25 (CT)	2.5	0.5	0.04	0.2
Unit 25 (CT & DB)	2.5	1.6	0.2	0.4
Unit 25 (CT & PA)	3.1	8.3	1.7	0.9
Unit 26 (CT)	3.1	0.5	0.49	0.1
Unit 26 (CT & DB)	3.2	1.6	0.26	0.5
Unit 26 (CT & PA)	2.7	6.7	0.8	0.9

The results from Stanton A add further credence to the hypotheses that CO and VOC emissions are low when using duct burners and are greatest when practicing power augmentation.

According to information from General Electric, CO emissions during PK will actually be less than during normal operation while NO_X emissions will increase. This is because of higher flame temperature in the combustors during PK compared with normal operation.[xviii] The projections regarding NO_X were confirmed recently at an FPL facility.[xix] Baseline NO_X emissions (DLN control only) increased from 7 to 9.6 ppmvd @ 15% O_2, while power production from the CT-electrical generator increased by 3 or 4 MW. No tests were reviewed by DEP to confirm the CO emissions reduction effect of PK.

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in the Table below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_X control is practiced on all such units when firing fuel oil.

Table 10. CO, VOC Test Results. GE 7FA Gas Turbines firing Fuel Oil. **(ppmvd @15% O_2)**

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[xx]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%)[xxi]	1.2	
Purdom Unit 8 (100%)	1.3	
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[xxii]	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)[xxiii]	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

The Department did not compare the manner in which water or steam is introduced into the CT during wet injection versus power (steam) augmentation to explain why the CO results from the two modes are different. The Department concludes that the low CO and VOC emissions while burning fuel oil constitute an empirical observation just as the high CO emissions during the PA mode also constitute an empirical observation.

One final observation is that CO and VOC emissions were low during a recent test of a GE 7FA combined cycle unit while firing fuel oil and using a gas-fired duct burner. The results are given in the following table.

Table 11. Emissions from GE 7FA CT - Fuel Oil & Gas-Fired Duct Burner (ppmvd @15% O_2)

KUA 3/Mode[xxiv]	NO_X	CO	VOC	NH_3
CT & DB & FO	15	1.4	0.1	1.5

FP&L does not propose fuel oil firing while using gas-fired duct burners, but the results are instructive because even this unusual case yields low CO, VOC, and even NH_3 emissions.

The Department provided the information from the research summarized above to GE and FP&L. As a result, FP&L was able to obtain a guarantee for the FO case of 8 ppmvd @15% O_2.

El Paso was required to install oxidation catalyst at permitted but deferred (or cancelled) combined cycle projects using GE7FA CTs in Broward, Palm Beach, and Manatee Counties. The purpose of the catalyst for those projects is to limit CO emissions during continuous PA as opposed to the infrequent power augmentation (< 400 for sum of PA and PK) planned by FPL for the Turkey Point Unit 5 project.

Another consideration is "low load" operation. Several operators in Florida installed, will install, or are considering installing oxidation catalyst because: the supplier could not guarantee low CO emissions at medium loads (50 to 70 percent); the units actually exhibited high emissions at such loads; or the units required very long warm-up periods under low load (< 50% and very high CO) conditions.

These include Lakeland McIntosh Unit 3, Seminole Payne Creek, Enron Fort Pierce (deferred), and Progress Energy Hines Power Block II. This is in contrast to the GE 7FA units that exhibit low CO emissions at 50 percent.

Determinations CO, VOC, and PM/PM_{10} Emission Limit Determination

The following table is a list of recent CO and VOC (and PM) determinations for project throughout the country. FPL's proposal is included for comparison.

Table 12. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO - ppmvd (@15% O_2)	VOC - ppmv (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	1.0	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	1.0 (DB off) 1.7 (DB on))	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	1.0 (DB off) 2.0 (DB on))	0.01
Duke Morro, CA	2.0 (Ox-Cat)	1.15 (DB off) 2.0 (DB on)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	1.4	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	1.0 (DB off) 1.64 (DB on))	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL **(applicant proposal)**	4.1 – NG (DB off) 7.6 – NG (DB on) 14.1 – NG (DB+PA) 8.0 – FO	1.3 – NG (DB off) 1.9 – NG (DB on) 2.2 – NG (DB+PA) 2.8 – (FO)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	3 – 7.5 lb/hr	0.011
Calpine OEC, PA	10 (1-hr)	1.8	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	1.2	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
PGN Hines III, FL	10 - NG (3.5 if Ox-Cat) 20 – FO (7 if Ox-Cat)	2 – NG 10 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	1.1 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/mmBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

Applicant's CO and VOC BACT Proposal

In response to comments by EPA and data provided by the Department, FPL obtained CO emission guarantees of 4.1 and 8.0 ppmvd @15% O_2 when firing natural gas and fuel oil respectively. These values represent the lowest guarantees yet without the need for oxidation catalyst. The applicant's revised BACT proposal is as follows:

Table 13. FPL Proposed BACT Emissions Limits for CO and VOC (@ 59 ^oF)

Modes	Hours (Max)	CO (ppmvd @15% O_2	VOC (ppmvd @15% O_2)
Gas Firing	8,760	4.1	1.3
Gas & DB	2,880	7.6	1.9
Gas & DB & HPM (PA/PK)	400	14.1/11	2.2
Fuel Oil Firing	500	8.0	2.8

Department's CO and VOC BACT Proposal

Based on the data available to the Department, FP&L's respective proposed CO emission limits for normal operation and fuel oil firing of 4.1 and 8.0 ppmvd @ 15% O_2 are acceptable. A detailed cost assessment would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. This cost has been estimated by General Electric at approximately $8,000 per ton. While the Department does not necessarily accept the GE estimate, oxidation catalyst would not be cost-effective.

There will be considerable use of duct burners (DB). Although the Department believes CO emissions under DB in terms of ppmvd @15% O_2 will be approximately equal to emissions under the normal mode, the requested value of 7.6 ppmvd @15% O_2 is acceptable. This provides for a margin of uncertainty because the manufacturer of the DB assumes that the burner does create some CO and adds to that generated in the CT. Requirement of oxidation catalyst could reduce that uncertainty, but would not be cost effective given the tonnage removed for the cost and the empirical observation that emissions will actually be low (~ 2 ppmvd @15% O_2).

The High Power Modes (HPM) of Power augmentation (PA) and peaking (PK) are low probability scenarios that will occur for only 400 hours per CT and only in conjunction with use of the duct burners. The requested values of 11 and 14.1 ppmvd @ 15% O_2 are acceptable for PK and PA respectively in conjunction with DB.

The Department will set a continuous 24-hr CO limit of 8.0 ppmvd to be comprised of all firing modes and durations with the exception of simultaneous DB & PA, which will be subject to a separate limit of 14.1 ppmvd @15% O_2. Stack testing will still be required to demonstrate compliance with the guaranteed values for the key normal, fuel oil and duct burner modes.

Similarly, the Department accepts FP&L's proposals for VOC emission limits. It is noted that total VOC emissions will be only 68 TPY combined from the four combustion turbines. The test data reviewed by the Department indicate that actual emissions are likely to be less than the PSD significant emission rate of 40 TPY. The BACT values provide a small margin of safety that assures compliance.

4.4 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

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

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the use of ultra low sulfur fuel oil (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). This will be the first project in the state required to use the cleanest fuel oil scheduled to be available by the time the new unit begins operation. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

The applicant estimated total emissions for the project at 193 tons per year of SO_2 and 19 tons per year of sulfuric acid mist. The Department accepts FP&L's BACT proposal for SO_2 and SAM.

4.5 Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ultra low sulfur fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.[xxv, xxvi]

Table 14. PM_{10} Emissions from GE 7FA Units (pounds per hour)

Fuel	Range	Average	Std. Deviation
Natural Gas - Front-half (filterable)	0 – 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM_{10} emission limits are included in Table 12. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_X, SO_2 and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. The NO_X control technology of SCR can increase PM/PM_{10} emissions from the stack due to formation of ammonium sulfates prior to exiting.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_X control technologies that rely on ammonia injection. A few permit limits are given in Table 12. Very low values ($\leq$ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH_3 emissions from the Stanton projected cited in Table 9 above ranged from 0.1 to 0.9 ppmvd @15% O_2 while firing natural gas. NH_3 and NO_X emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH_3 emissions were 1.5 ppmvd @15% O_2 when firing fuel oil. The Department proposes an ammonia limit of 5 ppmvd @15% O_2.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 22-cell mechanical draft cooling tower with the following specifications: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators with a drift rate of no more than 0.001 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water.

FPL estimates annual emissions of 201 tons of PM due to drift losses assuming total dissolved solids (TDS) of 30,000 mg/L. PM_{10} emissions were projected to be 10 TPY based on TDS of 4,000 mg/L.

For reference, PM emissions estimated from the Martin Unit 8 project were estimated to be substantially less than from the Turkey Point project because the cooling water contains less TDS. It is possible for FPL to reduce the drift rate to further minimize PM emissions. For

example, FPL Energy agreed to a drift rate limit of 0.0005% in conjunction with a TDS limit of 6,000 mg/L for the Tesla Project in Alameda County California.

The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM emissions from the cooling tower are expected to be on the order of 100 tons per year.

Applicant's PM/PM_{10} Proposal

FP&L proposes PM/PM_{10} BACT equal to 14.9 pounds per hour (lb/hr, front-half) when firing natural gas under all loads and modes of operation (DB, PK, PA). They propose a limit of 17.6 lb/hr (front-half) when firing fuel oil. They also propose an opacity limit of 10%. FPL proposes PM control from the cooling tower to be accomplished by a 0.001% drift rate design limitation.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

4.6 Summary of Department Draft BACT Determination

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 15. Draft BACT Determination – FPL Turkey Pt. Unit 5

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO_X [b]	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM_{10} [c]	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC [e]	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia [f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

5 NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_X (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

5.2 Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 495 MMBtu per hour (LHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NO_X ≤ 1.6 lb/MW-hr (gross)
- SO_2 ≤ 0.20 lb/MMBtu
- PM ≤ 0.03 lb/MMBtu

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.06 lb/MW-hr for NO_X. The specifications for the ultra low sulfur fuel oil and natural gas insure that the NSPS PM and SO_2 emission limits for the duct burners will easily be met. For example, if emissions from a duct burner alone exceeded its NSPS standards, then emissions from the duct burner and associated combustion turbine combined would exceed the BACT limits. An Appendix to the permit will summarize applicable federal requirements.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NSHAP Subpart YYYY, which became final on March 5, 2004.[xxvii] According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[xxviii] EPA has stayed the applicability of YYYY to units such as those proposed for the Turkey Point project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

Based on the same GE technical cited in the Section 4.3 above, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_X technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

7. PERIODS OF EXCESS EMISSIONS

7.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

7.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to three hours of excess emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting at least 24 hours.
- For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

Combined Cycle Operation with Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

8. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

The following table shows the Department's estimated annual emissions from the completed combined cycle unit, including the cooling tower based on the draft permit conditions.

Pollutant	CO	Pb	NO_X	PM	PM_{10}	SO_2	SAM	VOC
Emissions (TPY)	464	0.026	312	320	224	193	19	68

The following ambient impact analyses were conducted using the higher values for PM and CO based on the applicant's original proposed BACT or subsequent revisions.

9. AIR QUALITY IMPACT ANALYSIS

9.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

9.2 Major Stationary Sources in Miami-Dade County

The current largest stationary sources of air pollution in Miami-Dade County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 16. Major Sources of SO_2 in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
Florida Power &Light	***Turkey Pt. Plant (proposed project)***	***193***
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

Table 17. Major Sources of NO_X in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Pt. Plant (existing boilers)	6,263 (EPA)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	5,010
Titan Industries	Tarmac Pennsucco Cement	2,469
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	1,316
Homestead City Utilities	G.W. Ivey Power Plant	655
Florida Power & Light	Cutler Power Plant	547
Florida Power &Light	***Turkey Pt. Plant (proposed project)***	***312***

Table 18. Major Sources of CO in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	3,106
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	995
Florida Power & Light	Turkey Pt. Power Plant (existing)	865
Florida Power &Light	***Turkey Point Plant (proposed project)***	***464***

Table 19. Major Sources of PM in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Point Power Plant (existing)	734
Florida Power & Light	***Turkey Point Plant (proposed project)***	***419***
Titan Industries	Tarmac Pennsucco Cement	~ 325 (est.)
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	157

Table 20. Major Sources of VOC in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Nailite International	Nailite International	147
Fine Art Lamps	Fine Art Lamps	88
Waste Management	Medley Landfill and Recycling	80
Contender Boats Inc.	Contender Boats Site #1	78
DM Industries, Ltd.	DM Industries	76
GP Plastics Corp.	GP Plastics Corp. Miami Plant	76
Florida Power & Light	***Turkey Point Plant (proposed project)***	***68***
Florida Power & Light	Turkey Point Power Plant (existing)	64
Avanti Press, Inc.	Avanti Press, Inc.	64

Emissions from the proposed project are relatively low considering the high capacity (1,150 megawatts). For example the existing units emit 20 to 50 times as much SO_2 and NO_X despite their smaller capacity (total 880 MW).

For reference, an ongoing modernization project at Titan Industries, Tarmac Pennsucco Cement Plant will greatly reduce SO_2 emissions. A similar project at the CSR Rinker Miami Cement Plant already reduced SO_2 emissions by approximately 2,000 tons per year.

9.3 Pollutant Emissions in Miami-Dade County

Emission inventories have been prepared for each county in Florida for evaluation of regional haze. The following table is a listing of pollutant estimates from all kinds of sources in Miami-Dade County during 2002.[xxix] These include stationary sources, area sources, and on-road and non-road mobile sources. The category of area sources also includes fires.

Emissions from the proposed Turkey Point Unit 5 project are included. Emissions of ozone precursors (NO_X and VOC) from the proposed project will be minimal compared to total existing pollutant load. Thus the contribution to regional ozone formation will be very low.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO_2	NO_X	CO	PM_{10}	VOC	NH_3
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
Turkey Pt. Unit 5	193	320	450	229	68	~200

The contributions to regional particulate matter emissions will also be very low even if all SO_2, NO_X, and NH_3 are ultimately converted to PM.

9.4 Air Quality and Monitoring in the Miami-Dade County

The Miami-Dade County Department of Environmental Resource Management (DERM) operates fifteen monitors at eleven sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, SO_2 and NO_2. The 2002 monitoring network is shown in the figure below.

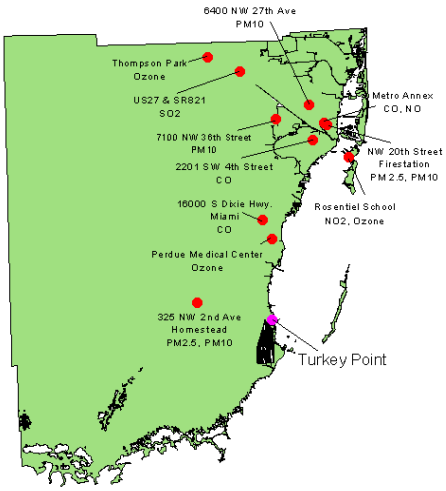

Figure 13. Miami-Dade DERM Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 22. Ambient Air Quality in Miami-Dade County Nearest to Project Site (2002)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Homestead	24-hour	38	31		150 [a]	ug/m^3
		Annual			19	50 [b]	ug/m^3
SO_2	US 27, SR 821	3-hour	5	5		500 [a]	ppb
		24-hour	4	4		100[a]	ppb
		Annual			2	20 [b]	ppb
NO_2	Rosenstiel, V. Key	Annual			6	53 [b]	ppb
CO	S. Dixie Highway	1-hour	3	3		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Perdue Medical	1-hour	0.091	0.086		0.12 [C]	ppm
		8-hour	0.070	0.064		0.08 [C]	ppm

a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

The data are reasonably representative of air quality near Turkey Point with the exception of SO_2. Since the existing Turkey Point fossil units constitute the largest source of SO_2, it is doubtful that the Station on US 27 and SR 821 adequately represents the Homestead area. However, measurements at sites throughout the state that are in the vicinity of larger SO_2 sources than the existing Turkey Point units are also in attainment with the respect to the SO_2 NAAQS. Therefore it is reasonable to conclude that SO_2 concentrations off of the Turkey Point site are also in attainment of the SO_2 NAAQS.

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels. The exception is ozone because it is formed from precursors that are clearly available (NO_X and VOC). The precursors are more available during drought years. The tendency to form ozone is accentuated by hot ambient temperature, high pressure, and relatively low wind speed.

9.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all facilities or projects (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 23. Maximum Projected Air Quality Impacts from FP&L Turkey Point Unit 5 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.1	1	~5	60	NO
	24-Hour	2	5	~10	260	NO
	3-Hour	8	25	~13	1300	NO
PM_{10}	Annual	0.2	1	~20	50	NO
	24-Hour	3.7	5	~40	150	NO
CO	8-Hour	30	500	~2300	10,000	NO
	1-Hour	73	2000	~3450	40,000	NO
NO_2	Annual	0.3	1	~11	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 21 km to the west of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from annual SO_2, annual PM_{10}, and NO_2 are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required for these pollutants.

Maximum predicted impacts from 24-Hour and 3-Hour SO_2, and 24-Hour PM_{10} are greater than the applicable SILs for the Class I area. Although the values are miniscule compared with the ambient air quality standards given in the previous table, additional modeling was required as discussed below.

Table 24. Maximum Air Quality Impacts from the FP&L Turkey Point Unit 5 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.04	0.2	NO
	24-hour	0.5	0.3	YES
NO_2	Annual	0.073	0.1	NO
SO_2	Annual	0.04	0.1	NO
	24-hour	0.4	0.2	YES
	3-hour	1.8	1	YES

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 25. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~40	NO
NO_2	Annual	0.3	14	~11	NO
SO_2	24-hour	2	13	~10	NO
CO	8-hour	30	575	~2300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant

estimated annual potential VOC emissions from the project to be 68 tons per year. Therefore, preconstruction monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-Hour and 3-Hour SO_2, and 24-Hour PM_{10} in the ENP Class I area;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Miami International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996. Meteorological surface data used were from Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami, West Palm Beach and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern part of the state.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Within 50 km of the source, the EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. Characteristics, parameters and data used in this model are detailed above.

For Visibility within 50 km, the EPA-approved VISCREEN model was used. VISCREEN calculates the potential impact of a plume of specified emissions for specific transport and dispersion conditions. Surface meteorological data used in this model was obtained from the National Weather Service station in Miami from 1987 to 1991.

Multi-source PSD Class I Increment Analysis

The maximum predicted 3 and 24-hour SO_2 and 24-hour PM_{10} PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table.

Table 26. PSD Class I Increment Analysis – ENP

Pollutant	Averaging Time	2nd-Highest-High Unit 5 Max Predicted Impact ($\mu g/m^3$)	2nd Highest-High All Sources Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
SO_2	24-hour	0.4	4.1	5	NO
SO_2	3-hour	1.8	17.5	25	NO
PM_{10}	24-hour	0.5	2.1	5	NO

The existing Turkey Point Units have much greater ground level effects than predicted for the proposed project. This is obvious because emissions from the existing units are approximately 9,000 tons of SO_2 per year, whereas Unit 5 will emit less than 200 tons per year. However these effects are not included because the sources were in operation before the PSD Program and the baseline date for increment consumption.

It is possible to "expand" increment by reducing emissions from existing sources. Examples of SO_2 increment expansion projects are the Rinker Cement Plant modernization that reduced SO_2 emissions by approximately 2,000 tons per year and the on-going Tarmac Cement modernization that will result in a similar reduction.

9.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

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

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. SO_2 levels of 200-400 $\mu g/m^3$ for a 6 hour period in the course of a week for 10 weeks can lead to adverse impacts. SO_2 impacts from the Turkey Point Expansion will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, deer mice numbers will decline when exposed to levels of 13-157 $\mu g\ SO_2/m^3$ continuously for 5 months. Annual and 24-hour SO_2 levels predicted from the Turkey Point Expansion will be well below these levels and therefore, will not contribute to adverse impacts on wildlife, such as deer mice.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are slightly greater than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.014 and 0.024 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_X limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

Impact on Visibility and Regional Haze:

Consultation with the National Park Service Air Quality experts resulted in commitments by the applicant to use ultra low sulfur fuel oil that is not yet available in the Southeast Florida market. Additionally, that consultation also resulted in a commitment to lower NO_X emissions to 2 ppmvd @15% O_2.

The applicant submitted a regional haze analysis for the ENP. The analysis included modeling from the CALPUFF model and VISCREEN model.

Despite the measures proposed, through the application of BACT, to minimize SO_2, NO_X, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 2 days in three years under atypical meteorological conditions for coastal Southeast Florida (temperature less than 35 degrees). Because of the limitation in fuel oil use, the probability that these two factors will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years.

The coherent plume modeling with VISCREEN performed by the NPS showed no adverse impacts on the ENP.
The NPS also did an analysis to determine impacts at Biscayne National Park (a Class II area). The NPS determined that there may be plume impacts when firing oil if winds are from the south. This was determined with a 2.5 ppm NO_X limit for BACT. The 2.0 limit should slightly decrease these impacts. As stated above, fuel-oil firing will be limited to 500 hours per year, thus further reducing the probability of visibility impairment.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 250 additional workers will be needed over the 24-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

The project is a response to state-wide electrical growth and the legal requirement that certain investor owned utilities in Florida maintain a 20 percent electrical reserve. This project is one of several projects identified by FP&L in its annual 10 year plans submitted to the Public Service Commission.

Overall the project will not cause additional growth in the given area, but is a response to projected state-wide electrical power demand growth. Although the project could have been located elsewhere in Southeast Florida, the exact location is the result of economic optimization and transmission constraints.

Effects on Gas Supply and on Emissions from other Power Plants in Southeast Florida:

The existing FP&L Turkey Point Fossil Units 1 and 2 are basically residual oil fired units with natural gas co-firing capability. There are similar units at Port Everglades and Riviera Beach. Emissions, particularly of PM, SO_2, and SAM, are much greater for the residual fuel oil portion of the fuel used at the three plants than the natural gas portion.

Because the Turkey Point plant is “at the end of the pipeline,” there is some concern regarding the gas supply and the possibility that natural gas usage by Turkey Point Unit 5 can decrease the availability of natural gas by the older units at Turkey Point, Port Everglades, and Riviera Beach.

According to the Annual Operating Reports received by the Department, the three plants used approximately 33 trillion BTUs of natural gas in 2002. The new Turkey Point Unit 5 will consume more than 60 trillion BTUs of natural gas.

For reference, in 1998, the natural gas transmission capacity to the state of Florida was approximately 1 billion standard cubic feet per day (bscfd). There have since been several expansions by Florida Gas Transmission Company. The Gulfstream Pipeline across the Gulf of Mexico was completed in 2002 and the estimated total transmission capacity to Florida is now closer to 3.5 bscfd.[xxx]

In response to a Department inquiry on gas availability to the three plants, FP&L responded that the Gulfstream Pipeline (cutting across the state) will supply all of the needs of the Martin Power Plant located further north. This will theoretically free up transportation capacity along the existing FGT network allowing for maintenance of present supplies and the additional future needs of Turkey Point Unit 5.

There are even more important developments that lend credence to the conclusion by FP&L that the Turkey Point project will not reduce gas availability for the existing units. At the present time, there are three proposed projects to construct liquefied natural gas (LNG) receiving and processing plants that will supply natural gas via pipelines to Southeast Florida. For example, on April 13, 2004 the Governor and Cabinet approved easements for two of the projects to cross state lands.[xxxi, xxxii]

The two projects are the Tractebel Calypso and AES Ocean Express. These will enter South Florida at points in Broward County. The projects will supply natural gas (often associated with crude oil production) that is presently flared, reinjected, or left in place at distant sources in Africa, the middle east, Trinidad Tobago, etc.[xxxiii] Following is a diagram showing the expected path of one of the projects.

Figure 14. Projected Path of the AES Ocean Express Pipeline (Source: Sun-Sentinel)

El Paso and FPL recently announced agreements for participation of an FPL subsidiary (FPL Group Resources) in the third Bahamas LNG project and pipeline called Seafarer. El Paso and FPL Group Resources announced an agreement for 800 dekatherms per day of capacity on this project. [xxxiv, xxxv] This project will enter Florida in the area of Riviera Beach.

The total capacity of the three projects will be approximately 2.5 bscfd. The gas need at Turkey Point Unit 5 will be less than 0.2 bscfd. The supply from just one (let alone three) projects is sufficient to overwhelm the needs of the any foreseeable projects in Southeast Florida without impacting usage by the existing units.

In conclusion, the Department accepts that natural gas use at FP&L Turkey Point Unit 5 will not cause increased emissions from the existing residual fuel oil and gas co-fired-fired units in Southeast Florida.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, Residential growth in the area of the proposed project, Miami-Dade County, has increased 47% from 1977 to 2000. The number of vehicle miles traveled has also increased in the county, 58% from 1977 to 2001. During this time period, the number of those employed in the county grew about 71%.

The applicant addressed industrial growth in Miami-Dade County as well. The manufacturing industry has seen a 184% employee increase from 1977-2000 but the agricultural industry saw about a 19% drop in employees (1977-1999). Existing Utility Facilities in Miami-Dade County include the existing FPL Turkey Point Facility, FPL Cutler and the City of Homestead Utility. Currently, other than the expansion at Turkey Point, there are no permits for additional utility growth in the county.

Although, the population and miles traveled in Miami-Dade has increased since 1977, according to the application, air emissions from mobile sources have decreased. Carbon Monoxide has decreased by 61%, VOC has decreased by 65% and Nitrogen Oxides has decreased by 29%. Improvements to automobiles and fuels have more than counteracted any increase in mobile sources in Miami-Dade County.

Despite the growth in Southeast Florida, air quality has improved as evidenced by the redesignation of the Tri-County (Broward, Miami-Dade, and Palm Beach) area to attainment status with respect to the ozone standard.

Endangered Species Considerations

The purpose of the ESA is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[xxxvi] Under the law, species may be listed as either "endangered" or "threatened".

Endangered means a species is in danger of extinction throughout all or a significant portion of its range. Threatened means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened.

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Chapter 2 of the Site Certification Application includes a characterization of the existing environment including vegetation, land use and ecology. Chapters 4 and 5 address the effects of construction and operation on ecological systems aquatic and terrestrial ecology. These sections are available at State and local environmental program offices.

According to the U. S. Fish and Wildlife Service (F&WS) website at there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004. The reader is referred to the following website: http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

For reference, the F&WS recently noticed the availability of an implementation schedule for the South Florida Multi-Species Recovery Plan designed to restore endangered or threatened animals and plants to the point where they are again secure, self sustaining components of their ecosystems.[xxxvii]

One endangered species of common interest is the American crocodile, the population of which numbers only about 1000 individuals. It lives within and near FP&L's property including the extensive cooling water canals visible in the following aerial photograph.

Figure 15. Cooling Canals at Turkey Pt.

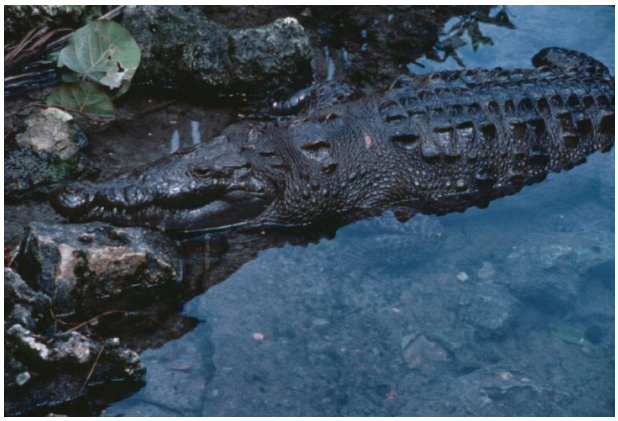

Fig. 16. Crocodile - Everglades National Park

According to FP&L's application, the precise project site is not part of the zone delineating the crocodile habitat, although parts of it can be used by the species. FP&L runs a crocodile management program and stated that it has increased the population of this species. FPL also stated in the application that any loss of potential habitat associated with the project will not jeopardize the continuing existence of the American crocodile or impact the designated habitat.

According to the application, other federally listed endangered species known to occur in Miami-Dade County including several kinds of turtles, the peregrine falcon, the Florida Panther, the manatee, and various plants such as spurges. There is also a State listing that is more extensive than the federal one.

Additional information is given in the separate Department Staff Report prepared in support of the preliminary Siting decision and available from the Department's Siting Office.

10. Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

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