TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Municipal Power Agency
Treasure Coast Energy Center

300-Megawatt Combined Cycle Power Plant

St. Lucie County

DEP File No. 1110121-001-AC
PSD-FL-353, PA 05-48

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

October 28, 2005

I. APPLICATION INFORMATION

A. APPLICANT NAME AND ADDRESS

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative: Roger A. Fontes, General Manager and CEO

B. PROCESSING SCHEDULE

April 14, 2005: Received Site Certification Application (SCA) including PSD application

June 6, 2005: Sufficiency determination issued by DEP Siting Coordination Office (SCO) – found insufficient.

July 29, 2005: Received Response to SCO sufficiency questions

August 29, 2005: SCO issues determination finding SCA/PSD Application sufficient

October 28, 2005: Intent to Issue PSD Permit distributed

C. FACILITY LOCATION

Treasure Coast Energy Center (TCED) will be located in St. Lucie County, southwest of the City of Fort Pierce, East of Highway 95, on Selvitz Road. The site is 180 km from the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area, Everglades National Park. The Chassahowitzka Class I area is 260 km to the Northwest. The UTM coordinates for this site are 561.51 km East and 3028.99 km North. The locations of Fort Pierce and TCEC are shown in Figures 1 and 2.

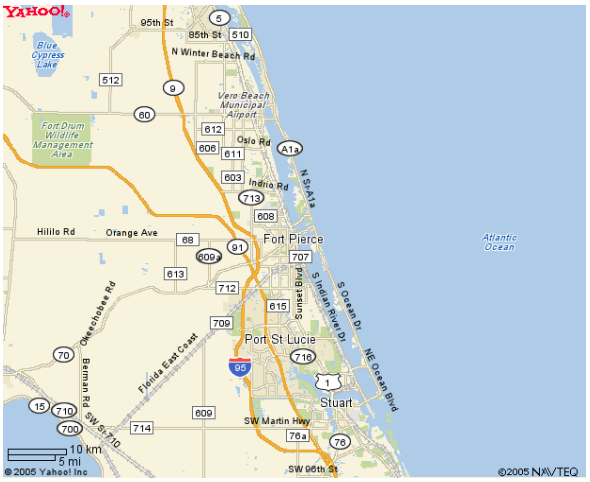

Figure 1. Location of Fort Pierce

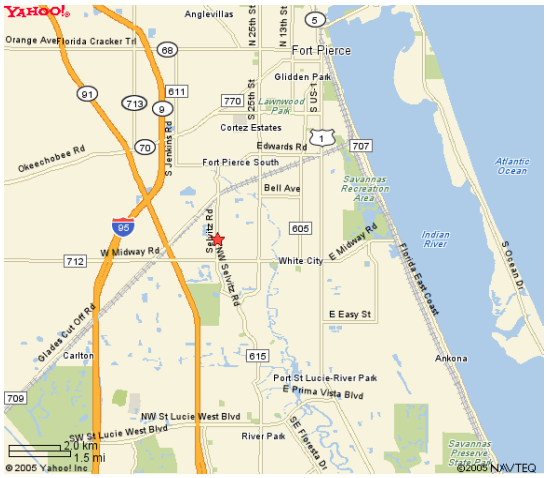

Fig. 2. Location, Treasure Coast Energy Center

D. STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

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

E. REGULATORY CATEGORIES

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

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. 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 designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 Prevention of Significant Deterioration (PSD) Major Facility Categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a major source of air pollution with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration of Air Quality.

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the unit will be subject to Subpart KKKK, and may no longer be subject to Subparts GG. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a major source of HAPs, therefore Unit 1 is not subject to the provisions of 40 CFR Part 63, Subpart YYYY (CT MACT).

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

II. PROPOSED PROJECT SUMMARY

A. PROJECT DESCRIPTION

The applicant proposes to construct a "one-on-one" (1x1) F-Class combined cycle unit (Unit 1) and associated auxiliary equipment. Unit one will consist of one General Electric PG7241 FA combustion turbine generator(CT), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG) for an overall nominal rating of 300 MW. The key components of the GE MS 7001 FA (a predecessor of the PG 7241 FA) are identified in Figure 3. An exterior view is also shown. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

Auxiliary equipment includes the following: a 990,000 gallon fuel oil storage tank; a diesel engine driven fire pump with an associated 500 gallon fuel oil storage tank, a safe shutdown generator with an associated 1,000 gallon fuel oil storage tank, a mechanical draft cooling tower equipped with drift eliminators, and a 170-foot exhaust stack.

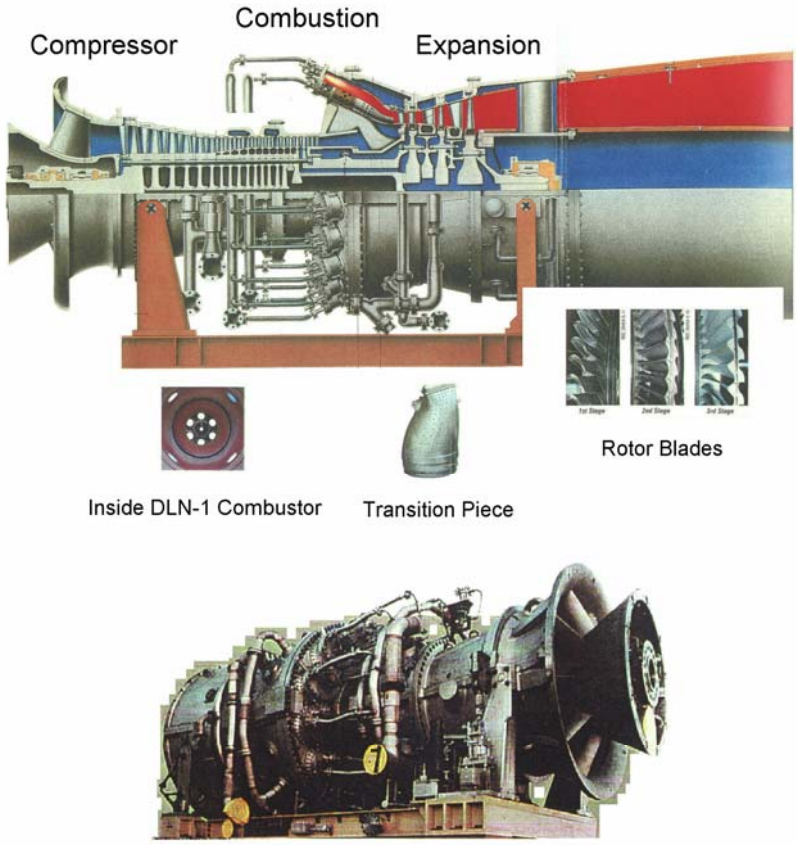

Figure 3 - Internal and External Views of Early GE 7FA

Additional project details, as proposed, are described below.

- Fuel: TCEC will use natural gas as the primary fuel for up to 8760 hours per year, and ultra-low sulfur (ULS) fuel oil (0.0015% Sulfur) as a backup fuel. The applicant requests operation with ULS fuel oil up to 500 hours per year.
- Generating Capacity: The combustion turbine has a nominal generating capacity of 170 MW. The duct-fired HRSG provides steam to the steam turbine electrical generator, which has a nominal capacity of 130 MW. The total nominal generating capacity of the 1 x 1 combined cycle unit is 300 MW.

- Controls: CO and PM/PM_{10} 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 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: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determination. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The heat recovery steam generator has a combined cycle stack (HRSG stack) that is 170 feet tall with an exit diameter of 18 feet. The following table summarizes the exhaust characteristics at 100 % load and with duct burners on.

Table 1. Exhaust Characteristics of Unit 1 at 100% Load and 26° F

Fuel	Total Heat Input CT + DB (HHV)*	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Exit Temp., °F	Stack Flow ACFM
Gas	2400 mmBtu/hour	26° F	1082° F	167 ° F	1,036,793
ULS F.O.	2597 mmBtu/hour	26° F	1060° F	252° F	1,239,934

*Duct burners account for 523 mmBtu/hour on gas and 553 mmBtu/hour on oil of the total heat input.

B. PROCESS DESCRIPTION

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

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

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (^oF). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine - section at temperatures of approximately 2500 ^oF. 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 1000 ^oF and high excess oxygen and is available for additional energy recovery.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the TCEC project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The key components of a combined cycle unit (without duct firing) are shown in the figure below. The steam is then fed to a separate steam turbine, which also drives an electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent. This equates to a little over 50% on a higher heating value (HHV) basis.

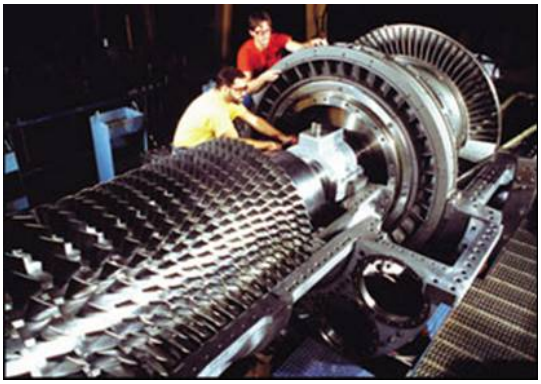

Figure 4 – Internal View - GE 7FA.

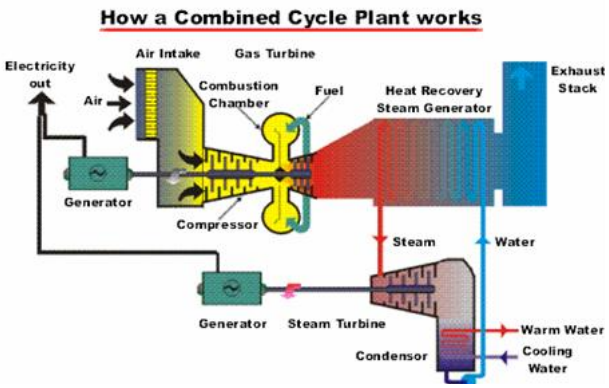

Figure 5. Components Combined Cycle Unit

The applicant has requested the following additional modes of 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 is typically practiced 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 unlimited use of duct burning for the unit while firing either gas or oil in the combustion turbine.

Other possibilities (not requested by FMPA) include power augmentation and peaking. Power augmentation is accomplished by returning a portion of the steam from the HRSG to the combustion turbine to increase mass flow and power output. Peaking is simply running the unit for limited time at heat input values greater than the design rating.

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

C. POTENTIAL EMISSIONS

The project will result in emissions of nitrogen oxides, sulfur dioxides, carbon monoxide, particulate matter, sulfuric acid mist (SAM), volatile organic compounds, lead (Pb), and mercury. The following table summarizes the applicant's estimates of the annual emissions in tons per year from the proposed project. Included in these estimates are emissions from the

duct burners, diesel engine fire pump, safe shutdown generator, the fuel oil storage tank for VOCs, and the cooling tower for PM/PM_{10}.

Table 2. Applicant's Estimated Potential Annual Emissions

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
NO_x	90.0	40	Yes
SO_2	56.5	40	Yes
CO	228.7	100	Yes
PM	175.9	25	Yes
PM_{10}	171.3	15	Yes
VOC	23.3	40	No
SAM	22.4	7	Yes
Mercury	0.001	0.1	No
Lead	0.007	0.6	No

III. RULE APPLICABILITY

A. 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 F.A.C.

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

B. 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.

C. 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 major facilities and modifications 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 as proposed are required for NO_X, SO_2, CO, PM/PM_{10}, and SAM. (Refer to Table 2.)

In addition to a determination of BACT, PSD review also requires an Air Quality Analysis for each pollutant exceeding the SER. The Air Quality Analysis consists 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.

IV. DRAFT DETERMINATION – BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A. 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.[1]

B. NO_X BACT DETERMINATION

1. Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine 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 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, also know as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The changes in NO_X production as flame temperatures vary due to increasing/decreasing equivalence ratios can be seen in figure 6 below.

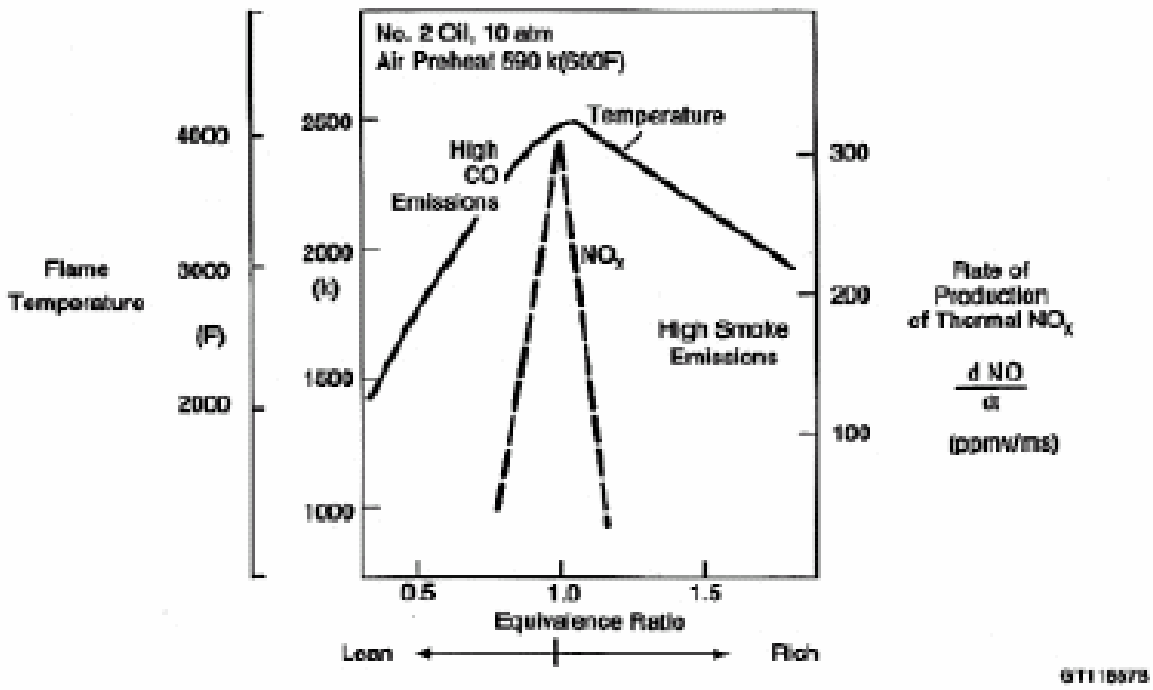

Figure 6 – NO_X Production Rate Variation With Temperature Change[2]

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 most 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.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 7, which is from a General Electric discussion on these principles.

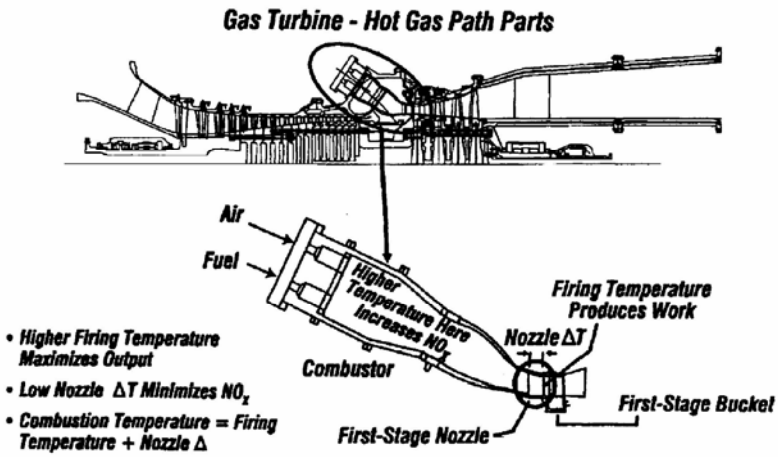

Figure 7 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

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 a the GE 7FA combustion turbine.[3]

2. Descriptions of Available NO_X Controls

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. 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 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 90% 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 8.

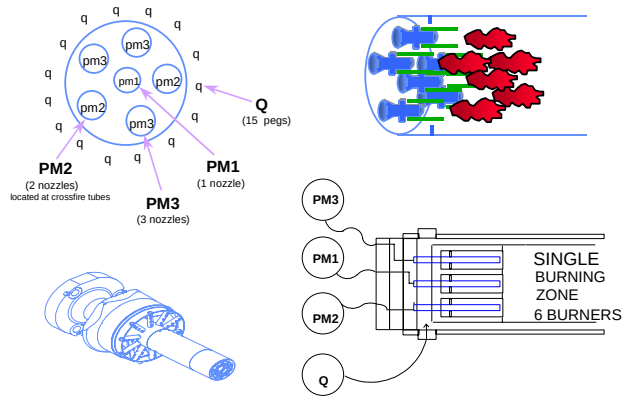

Figure 8 – DLN-2.6 Fuel Nozzle Arrangement

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. Design NO_X, CO, and VOC emission characteristics of the DLN-2.6 combustor while firing natural gas are given in the graph on the left side of Figure 9 for a unit tuned to meet a 9 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen). The graph on the right hand side is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility.

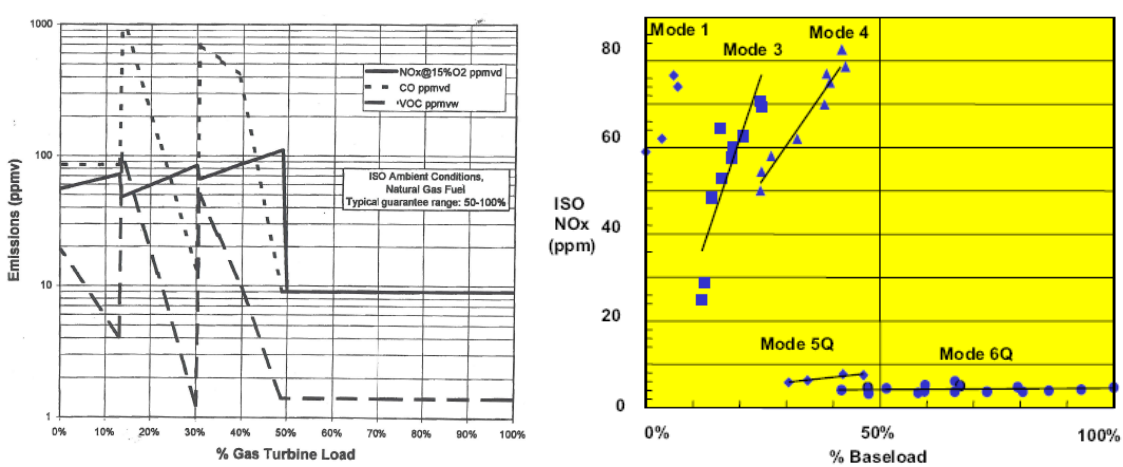

Figure 9 – Emissions Characteristics for DLN-2.6

The combustor emits NO_X at concentrations of 9 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. This suggests the need to minimize operation at low load conditions. The data plot suggests that there is at least a possibility of turndown to less than 50% of full load without excessive emissions.

Note also that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane. Actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[4] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd.

Table 3 – City of Tallahassee Purdom Power Plant (Station Unit 8) Test Results

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
Limit	12	25

* Not Determined

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[5] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd.

Table 4 – Tampa Electric Polk Power Station Emission Test Results

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

The test results at the Tallahassee and TECO projects confirm NO_X, CO, and VOC emissions less than the emission characteristics published by GE in Figure 9 above. Consistent with the discussion in the previous section, conversations with plant operators indicate that the Low NO_X characteristics extend to operations somewhat less than 50

percent of full load.[6] It is not certain whether low emissions under such operation is guaranteed by GE.

An important consideration in the effort to achieve low NO_X by combustion technology is that power and efficiency are sacrificed. This limitation is seen in Figure 10 from an EPRI report.[7] Developments such as single crystal blading, aircraft compressor design, and 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 10.

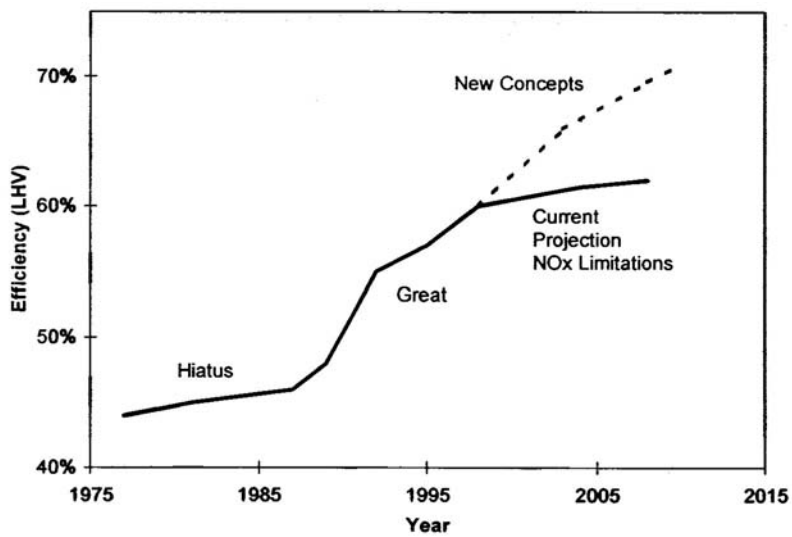

Figure 10 – Efficiency Increases in Combustion Turbines

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 for TCEC. 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 7). 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 than 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).[8] 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.[9] 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™.[10] 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.[11] By now, at least 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.[12] 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 FMPA TCEC 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 according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 ^oF), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. 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 available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) 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.

There are several examples of <u>conventional</u> SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas, 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require <u>conventional</u> SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

Figure 11 (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 12 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.

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).

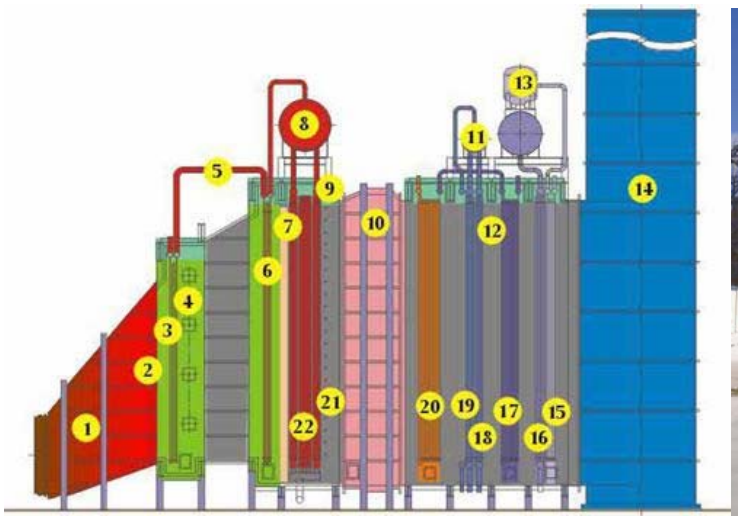

Figure 11 – Key HRSG Components (10 is SCR) Figure 12 – PGN Hines Block I

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.[13] The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 5. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[14]

% 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 a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is 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.[15] None were installed at large facilities.

$SCONO_X$™ technology (at 2.0 ppmvd) has 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. $SCONO_X$™ 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 a natural gas reforming unit.

Table 6 contains averaged cost values for $SCONO_X$™ and SCR developed by the California Air Resources Board for their Legislature.[16] 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 6. Cost Comparison between SCR and $SCONO_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X$™	SCR/CO	$SCONO_X$™
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 $SCONO_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the $SCONO_X$™ 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 FMPA for the proposed 300 MW project claim even greater annual cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that $SCONO_X$™ is not cost-effective for the present project.

3. Applicant's NO_X BACT Proposal

The applicant determined that BACT for proposed Unit 1 NO_X control, is the use of SCR in conjunction with Dry Low NO_X burners while firing natural gas, and SCR with water injection while firing ultra low sulfur fuel oil. Fuel oil use will be limited to 500 hours per year or less.

The applicant proposed the following BACT limits for NO_X:

- Gas Firing: 2.0 ppmvd @ 15% O_2
- Oil Firing: 8.0 ppmvd @ 15% O_2

Note: No averaging times are specified in the application.

4. Department's Draft NO_X BACT Determinations

Table 7 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 FMPA's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of fuel oil use represent 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 New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 7. Recent NO_X Standards for F-Class Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2, 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
Towantic Energy , CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
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
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DBs
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DBs
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
PGN Hines IV, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs

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

C. CO BACT DETERMINATION

1. CO Formation and Control Options

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most combustion turbines incorporate good combustion practices based on high temperature, sufficient time, turbulence, and excess air to minimize emissions of CO. 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.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO. Continuous data from these units verify the ability of the 7FA to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data recorded at TECO Bayside for 4 GE7FA units is shown in Table 8 below.

Table 8. CO CEMS Data – TECO Bayside Unit 1.

Turbine	Quarter	CO Max 24-hr Block (ppmvd)	CO Min 24-hr Block (ppmvd)	CO Quarterly Average (ppmvd)
1A	3rd Quarter 2003	4.3	0.3	0.83
1B		1.7	0	1
1C		2.1	0	0.8
1A	4th Quarter 2003	2.2	0	0.76
1B		1.9	0	1.14
1C		1.2	0	0.74

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE 7FA. 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.[17] 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.

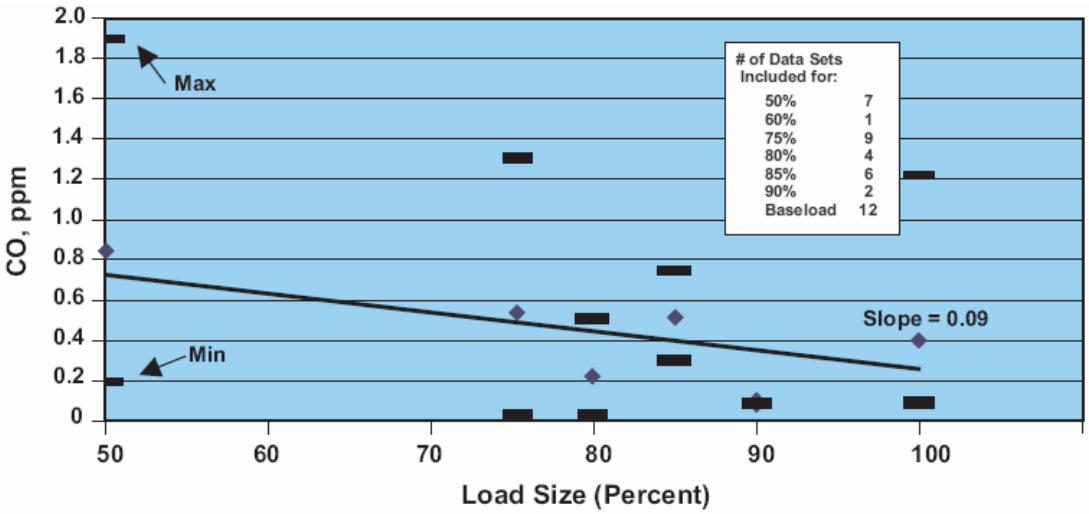

Figure 13. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

2. Duct Burner and Fuel Oil Considerations

The proposed unit includes a HRSG equipped with supplemental duct firing. Turbine exhaust gas (TEG) is reheated with a gas-fired duct burner prior to entering the heater. Key HRSG components are shown in Figure 11. 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, 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 14 and 15 are of an individual burner and a HRSG under construction showing horizontal duct burner elements and flow baffles. The hot TEG serves as combustion air for gas introduced into the burner array. The ignition temperature for CO is between 1,100 and 1,200 ^{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 control because of destruction by the duct burner.[18] 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. 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.

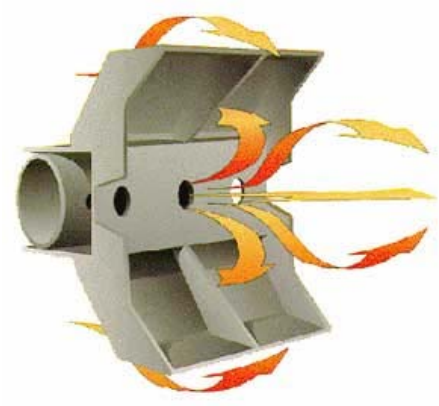

Figure 14 – Individual Burner **Figure 15 – Duct Burner and HRSG (Coen)**

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[19] and the Southern/KUA/OUC/FMPA project at OUC Stanton. The units are GE7FA combustion turbines (CT) of the same type that will be installed at the TCEC. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 9. CO and VOC Emissions while Duct Firing – 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
OUC Stanton Unit 25 (CT)	0.5	0.04
OUC Stanton Unit 26 (CT)	0.5	0.49
OUC Stanton Unit 25 (CT & DB)	1.6	0.2
OUC Stanton Unit 26 (CT & DB)	1.6	0.26

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in Table 10 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. The Department concludes that the low CO and VOC emissions while burning fuel oil are characteristics of the GE 7FA combustion turbines such as FMPA proposes to install at the TCEC.

Measured CO and VOC emissions were also low during a test of a GE 7FA combined cycle unit (permitted in 1999) while firing fuel oil and using a gas-fired duct burner. The results are given in the Table 11. FMPA does not propose fuel oil firing while using gas-fired duct burners. However this case is relevant because it combines the two modes for which FMPA requests additional emissions considerations. Even this special case indicates a reasonable expectation of low CO emissions.

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

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[20]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%)[21]	1.2	
Purdom Unit 8 (100%)	1.3	
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[22]	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%)[23]	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

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

KUA 3/Mode[24]	NO_X	CO	VOC	NH_3
CT & DB & FO	15	1.4	0.1	1.5

3. Low Load Considerations

The full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, the Department and most other regulatory agencies typically disallow operation at less than 50% load in most of the permits they issue for combustion turbines. In some cases the prohibition applies even at greater loads based on the features of the combustors.

FMPA personnel indicated that the proposed unit will often be operated at less than full load and that a higher CO BACT limit would be warranted. Figure 16 is a data plot from a GE publication showing how CO actually varies with respect to load. The data suggest that there is some turndown capability while emitting 7 or less ppmvd CO. This value is equal to approximately 5 to 6 ppmvd @15% O_2. The similar plot in Figure 9 suggested that NO_X emissions can also be maintained at low loads between 30 and 50% for both Modes 5Q (5 nozzles in operation) and 6Q (6 nozzles in operation), but not for Mode 4.

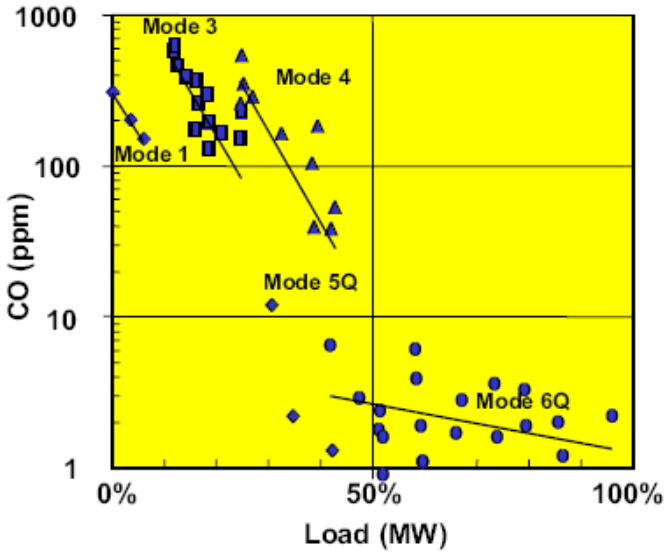

Figure 16 – Emissions Characteristics for DLN-2.6

The unit would need to operate in Mode 6Q which means that all six fuel nozzles and quaternary pegs are in operation. There is some suggestion that low CO can be maintained while operating in Mode 5Q, which is like 6Q, but without using the center nozzle. The manner by which the unit is ramped up through Modes 1, 2, 4, 5Q and 6Q and then backed down to low load cannot be inferred by this diagram. Flame stability of DLN conditions at low load is complex, and will not be addressed here.

The Department obtained data from operations at JEA Brandy Branch.[25] They are summarized in the following table. For reference 65 MW represents roughly 38% of full load. According to the utility, GE offers the software to tune and operate under the described conditions. A utility representative said that the unit operated in Mode 6Q during the tests.[26]

Table 12. CO Emissions during Low Load Operation at JEA Brandy Branch Unit 1

Test/Run	Load (MW)	Load (% full load)	CO (ppm)	CO (ppm) @15%O_2)
1/1	65	38	9.6	8.5
1/1	65	38	9.0	8.0
1/3	65	38	9.2	8.1
2/1	65	38	12.2	10.7
2/2	65	38	12.2	10.7
2/3	65	38	11.9	10.5
3/1	65	38	12.3	10.9
3/2	65	38	11.9	10.5
3/3	65	38	12.1	10.6

4. Applicant's CO BACT Proposal

The applicant has proposed BACT for CO as the use of good combustion controls while firing natural gas or ULS in accordance with the defined operating hours for each fuel. FMPA concluded that oxidation catalyst for the removal of CO is not cost effective. In the response dated July 28 to the Department's Notice of Insufficiency, FMPA requested the BACT limit for CO be set at 8.0 ppmvd while firing natural gas and 12.0 ppmvd while firing fuel oil based on 24-hr block averaging times.

Table 13 below contains the emissions guarantees for CO submitted to the Department by FMPA for the TCEC project. The values are "uncorrected". For reference the value of 5 ppmvd equates to approximately 4.1 ppmvd @15% O_2. Similar corrections apply to the other values cited.

Table 13. CO Guarantee Information Submitted by FMPA

Fuel	CO Guarantee (ppmvd)	Load Range (%)	Ambient Range (^oF)
Natural Gas	5.0	50 - 100	35 - 85
Natural Gas	5.0	60 - 100	>85 - 100
Natural Gas	9.0	50 - <60	>85 - 100
Natural Gas	9.0	50 - 100	26 - <35
Fuel Oil	8.0	75 - 100	26 - 100
Fuel Oil	20.0	50 - <75	26 - 100

The guaranteed value for CO emissions is 5 ppmvd (4.1 ppmvd @15% O_2) while burning natural gas at loads between 60 and 100 percent. A higher limit of 9 ppmvd is guaranteed for very low temperature conditions that are infrequent at the proposed site. The same value is proposed when the ambient temperature is greater than 85 ºF.

The Department has no data to support the need for the greater value at higher temperatures. Actually at such temperatures, the inlet air will be subjected to evaporative cooling and operation will simulate normal temperature ranges. Also, if the unit is operated at a higher heat input rate to try to recover some of the lost power at high ambient temperature, the firing temperature will increase and CO will probably decrease.

A limit of 8 ppmvd is guaranteed while burning fuel oil. However, according to Table 10 above, CO emissions while burning fuel oil are actually very low, even at 50 percent of full load. There does not appear to be a solid basis for the relatively high 20 ppmvd guaranteed value between 50 and 75 percent of full load.

5. Department's Draft CO BACT Determinations

Table 14 includes some recent BACT determinations for CO (and VOC and PM) in Florida and other states. FMPA's proposal is included for comparison. Most of the projects cited required oxidation catalyst. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

Table 14. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	**CO - ppmvd (@15% O_2)**	**PM - lb/mmBtu (or gr/dscf or lb/hr)**
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	0.01
Duke Morro, CA	2.0 (Ox-Cat)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL	4.1 – NG (DB off, AnnualTest) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FMPA TCEC, FL	8.0 NG (24-hr block) 12.0 FO (24-hr block)	38.0 lb/hr – NG (front + back ½) 52 lb/hr – FO (front + back ½)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
PGN Hines IV, FL	8.0 - NG 12.0 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - 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

With oxidation catalyst a GE 7FA will likely achieve CO values much less than 2 ppmvd @15% O_2. The actual performance would likely be as good or better than the GT-24 example given in Table 5. That unit had CO characteristics ranging from ~0 to 0.8 ppmvd @15% O_2 at 50% or more of full load. Although the GE 7FA will be guaranteed to achieve 5 ppmvd (4.1 ppmvd @15% O_2), the data suggest typical emissions without oxidation catalyst that are approximately equal to the emission limit of 2 ppmvd @15% O_2 given above as "Top" control.

If the unit fired only natural gas and did not experience the other operating modes, it would be straightforward to conclude that the cost of oxidation catalyst would not be justified because the cost to reduce "permitted emissions" from 5 to 2 ppmvd @15% O_2 would not be cost-effective. This is in agreement with the conclusion in the GE paper cited in the discussion leading to Figure 13 above.

Notwithstanding the guarantees given in Table 13, the data available to the Department suggests that CO emissions from the GE 7FA are also inherently low for the duct firing and fuel oil use modes. They are also inherently low to loads equal to 50%. At loads less than 50%, they can be maintained close to 10 ppmvd @15% O_2 while operating the unit with natural gas and in the 5Q or 6Q DLN modes. Some consideration can be given for the time that the unit will actually operate in those modes, in the same manner as consideration is given to increased CO emissions from limited power augmentation at other projects.

BACT for CO is determined to be the 5.0 ppmvd (4.1 ppmvd @ 15% O_2) for natural gas firing and the 8.0 ppmvd (7.6 ppmvd @ 15% O_2) for fuel oil firing. A continuous limit of 8.0 ppmvd @15% O_2 on a 24-hour basis will be implemented for both gas and oil firing, with or without the duct burner in operation.

An annualized limit of 6 ppmvd @15% O_2 will also be included in recognition of the preponderance of the time when the unit will be operated in the normal natural gas mode and the reality that most modes are characterized by inherently low emissions.

The limited time during which the unit will be operated at low load can be accommodated within this limit based on the data presented above. If extensive operation at loads less than 50% is foreseen, then the situation described in the GE paper would revert to the case where oxidation catalyst is indicated. In that case, CO emissions of 10 ppmvd or greater could be controlled to 2 ppmvd or less by oxidation catalyst.

The Department's BACT determination is the same as that issued for the FPL Turkey Pt. Project. The impacts of the modes (beyond the simple case of natural gas use at 50-100% load) are about equal for the two projects. In contrast to permits for other facilities in Florida and other states, it will not be necessary to prohibit low load operation because the behavior of emissions at lower loads is no longer unknown. Emissions limits can still be met with some operation between 40 and 50 % load.

For reference, FMPA estimated the cost of CO removal by oxidation catalyst to be approximately $3,400 per ton. While the Department does not necessarily agree with this estimation, oxidation catalyst would not be cost-effective for this unit given that the Department's BACT determination is implemented.

In summary, the Department will set the following BACT limits:

- Gas Firing: 8.0 ppmvd @ 15% O_2 (24-hr average)
  Without DB: 4.1 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  With DB: 7.6 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  Low Load: (included in 24-hr limit)
- Oil Firing: 8.0 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr average)
- All Modes: 6.0 ppmvd @ 15% O_2 (12-month average)

D. 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 to the market.

For this project, the applicant has proposed as BACT, for SO_2 and SAM, the use of pipeline natural gas and limited use (500 hrs or less) of ultra low sulfur diesel fuel oil with less than 0.0015 percent sulfur by weight as BACT. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8 percent by weight.

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

1. 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 fuel oil are efficiently combusted in gas turbines and will be the only fuels fired in the proposed unit. 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 ULS fuel oil to be combusted contains a minimal amount of ash and will be used for less than 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

2. Other PM/PM_{10} Considerations

<u>Ammonia Slip and Ammonium Salts Formation</u>: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. Because PM/PM_{10} emissions can be increased due to the formation of these ammonium salts prior to exiting the stack, it is important to limit ammonia emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of ammonia slip can also be an indication of a degrading catalyst. The Department proposes an ammonia limit of 5 ppmvd @ 15% O_2.

Cooling Tower PM Emissions: Small amounts of water entrained in the air passing through a wet cooling tower can be carried out of the tower and are known as "drift" droplets. Because the droplets contain impurities from the cooling water, the particulate matter constituent of the drift droplets may be classified as an emission[27]. The amount of particulates that may be emitted are based on the solids loading in the re-circulating water.

The applicant's proposal includes an 8-cell, 111,130 gallon per minute (gpm) mechanical draft cooling tower with drift eliminators with a design drift rate of 0.0005% of design water flow. FMPA estimates annual PM and PM_{10} emissions from the cooling tower to be 6.48 TPY and 1.87 TPY respectively.

3. Applicant's PM/PM_{10} Proposal

The applicant determined that BACT for proposed Unit 1 PM/PM_{10} is good combustion controls and the use of good natural gas, ultra low sulfur fuel oil.

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

The following conditions are established as the draft BACT standards.

- The gas turbine 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 turbine 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 tower shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

The Department notes that the described measures minimize emissions and formation of fine particulate matter classified as $PM_{2.5}$. The described strategy directly reduces PM emissions as well as formation of ammoniated particulate matter. Finally the NO_X and SO_2 control minimizes emissions of precursors known to contribute to formation of $PM_{2.5}$ in the environment.

F. BACT Considerations for Auxiliary Equipment

Safe Shutdown Generator: The safe shutdown generator (an approximately 765 hp diesel engine) will be used when the transmission connection to the plant is lost. The generator will be operated to provide power to the plant in a safe shutdown condition when needed, and for periodic testing throughout the year to ensure operability.

Diesel Engine Fire Pump: The diesel engine fire pump (an approximately 300 hp diesel engine) falls under the categorical emission unit exemption for fire and safety equipment (Rule 62-210.300(3)(a)22, F.A.C.) Like the safe shutdown generator, the fire pump will be operated only during emergency situations and for periodic testing throughout the year.

Use of ultra low sulfur fuel oil and limited operation (200 hours or less) ensure that emissions from both the safe shutdown generator and the diesel engine fire pump will be minimal. However, projected potential emissions from both units are included in the project potential to emit calculations and the ambient air quality impact analysis.

G. Summary of Department Draft BACT Determination

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

Table 15. Draft BACT Determination – Treasure Coast Energy Center Unit 1

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
		CT, Low Load	NA	NA	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10} [c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			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		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 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 24-hr 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 the 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 ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

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

V. NEW SOURCE PERFORMANCE STANDARDS

A. 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) ≤ 109 ppmvd @ 15% O_2 (corrected for heat rate of 9,355 Btu/KW-h LHV at peak load, evaporative cooler on) and;
- NO_X (oil) ≤ 101 ppmvd @ 15% O_2 (corrected for a heat rate of 10,120 Btu/KW-h LHV at peak load, evaporative cooler on); and
- SO2 emissions are limited to < 0.015 percent by volume at 15% O2 on a dry basis (150 ppmvd) or by the use of a fuel with a sulfur content of no more than 0.8% by weight (8000 ppmw).

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (gas) ≤ 0.39 lb/megawatt-hour. This is approximately equal to 11 ppmvd @15% O_2 for this turbine.
- NOX (oil) ≤ 1.2 lb/megawatt-hour. This is approximately equal to 33.5 ppmvd @15% O_2 for this turbine.
- SO2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% (500 ppmw) by weight.

The final rule will be applicable to TCEC Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

The Department considers the draft BACT standards more stringent than the existing or the proposed 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.

B. DUCT BURNERS

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 554 MMBtu per hour (HHV). 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)

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.1 lb/MW-hr for NO_X. This will insure that the NSPS NO_X emission limit 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.

VI. PERIODS OF EXCESS EMISSIONS

A. 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.

B. 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 four hours of excess emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting between 8 and 48 hours.
- For cold startup to combined cycle operation, up to six 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 generally 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.

DLN Tuning: Dry Low NOX combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NOX and CO emissions, and extends the life of the unit components. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Excess emissions of NOX, CO, and opacity are allowed during DLN tuning sessions provided the proper notification is provided to the Compliance Authority. Notification two weeks prior to tuning will be required.

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.

VII. AIR QUALITY IMPACT ANALYSIS

A. INTRODUCTION

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2 and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, 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.

B. MAJOR STATIONARY SOURCES IN ST. LUCIE COUNTY

The current largest stationary sources of air pollution in St. Lucie County are listed below. The information is from annual operating reports submitted to the Department.

Table 16. MAJOR SOURCES OF NO_X IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	***313***
Florida Gas Transmission (FGT)	FGT Station 20	261
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***91***
Tropicana Products	Tropicana Products	45
Fort Pierce Utilities Authority	HD King Power Plant	30

Table 17. MAJOR SOURCES OF SO_2 IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	**226**
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***58***
Dickerson Florida, In	Dickerson/Asphalt Plant #14	10

Table 18. MAJOR SOURCES OF PM/PM_{10} IN ST. LUCIE COUNTIES (2003)

Owner/Company	Site Name	Tons per year
Calpine	***Blue Heron Energy Center (proposed)***	**264**
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***176***
Tropicana Products	Tropicana Products	22
Cargill Juice North America	Ft. Pierce	9

Table 19. MAJOR SOURCES OF CO IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Florida Municipal Power Agency	***Treasure Coast Energy Center (proposed)***	***234***
Tropicana Products	Tropicana Products	169
Cargill Juice North America	Ft. Pierce	160
Calpine	***Blue Heron Energy Center (proposed)***	**156**
Florida Gas Transmission (FGT)	FGT Station 20	111

C. Air Quality and Monitoring in St. Lucie County

The Southeast District in West Palm Beach operates four monitors at one site in St. Lucie County measuring PM_{10}, $PM_{2.5}$, ozone, and NO_2. The monitoring site is shown in the figure below.

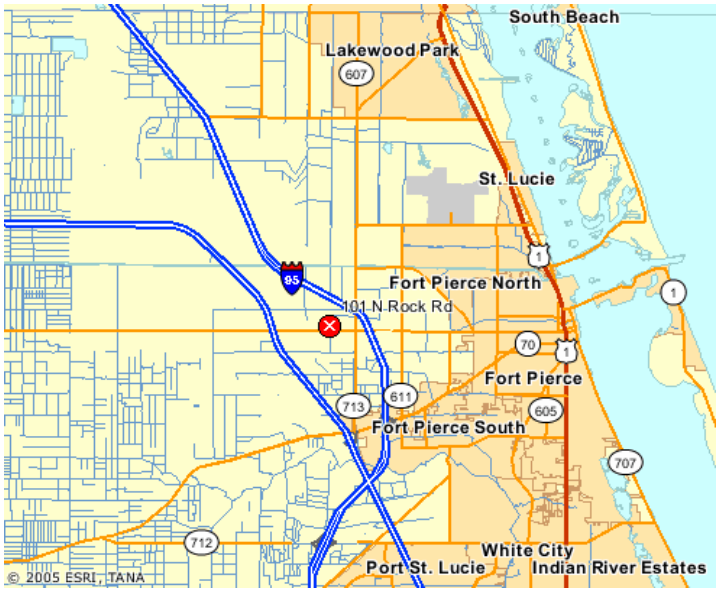

Figure 17. St. Lucie Monitoring Site

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

Table 20. Ambient Air Quality Nearest to Project Site (2003)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ft. Pierce	24-hour	65	43		150 [a]	ug/m^3
		Annual			17	50 [b]	ug/m^3
SO_2	Riveria Beach	3-hour	4	3		500 [a]	ppb
		24-hour	2	2		100[a]	ppb
		Annual			1	20 [b]	ppb
NO_2	Ft. Pierce	Annual			9	53 [b]	ppb
CO	West Palm Beach	1-hour	5	4		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Ft. Pierce	1-hour	0.081	0.076		0.12 [C]	ppm
		8-hour	0.071	0.071		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

St. Lucie County/The Southeast District does not monitor for Sulfur Dioxide or Carbon Monoxide. Therefore the data for these pollutants are not representative of air quality near the proposed plant site. However, measurements at sites throughout the state that are in the vicinity of larger SO_2 and CO sources than the proposed plant are also in attainment with the respect to the SO_2 and CO NAAQS. Therefore it is reasonable to conclude that SO_2 and CO concentrations near the project site are also in attainment of the SO_2 and CO 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 (NOX 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.

D. AIR QUALITY IMPACT ANALYSIS

1. 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 Chassahowitzka National Wildlife Refuge -CNWR) and PSD Class II Areas (everywhere except the Class I areas).

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 in the area (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. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 21. Maximum Projected Air Quality Impacts from Treasure Coast Energy Center Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Baseline Concentrations (ug/m3)	Ambient Air Standards (ug/m3)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	NO
	24-Hour	1	5	~5	260	NO
	3-Hour	3	25	~10	1300	NO
PM_{10}	Annual	0.2	1	~17	50	NO
	24-Hour	4.2	5	~65	150	NO
CO	8-Hour	17	500	~2300	10,000	NO
	1-Hour	27	2000	~5750	40,000	NO
NO_2	Annual	0.1	1	~17	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 180 km to the south-southwest west of the project site. The CWNR is located about 260 km to the northwest 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 SO_2, PM_{10}, and NO_2 are less than the applicable SILs for the Class I areas. Therefore no further detailed modeling efforts are required.

Table 22. Maximum Air Quality Impacts from the Treasure Coast Energy Center 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	0.003	0.2	NO
	24-hour	0.05	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.0005	0.1	NO
	24-hour	0.01	0.2	NO
	3-hour	0.03	1	NO

The Maximum Air Quality Impacts for comparison to the PSD Class I SILs at CWNR are less than the impacts at ENP.

2. 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 23. Maximum Air Quality Impacts vs. 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	~65	NO
NO_2	Annual	0.1	14	~17	NO
SO_2	24-hour	1	13	~5	NO
CO	8-hour	17	575	~2300	NO

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:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

3. Models and Meteorological Data Used in the Air Quality Analysis

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

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/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 West Palm Beach. 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 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 and CWNR beyond 50 km from the proposed project. Meteorological data used in this model was from the National Weather Service West Palm Beach as with the ISCST3 model.

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.

E. ADDITIONAL IMPACTS ANALYSIS

1. 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.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I areas. 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 less than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the maximum predicted deposition rates were located in the ENP. The impacts of the deposition rates of sulfur and nitrogen, 0.00051 and 0.00097 kg/ha/yr respectively, 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.

The National Park Service and Fish and Wildlife Service do not anticipate any significant impacts with regards to AQRV's in the ENP and CWNR from the proposed project.

2. Impact on Visibility and Regional Haze

The applicant submitted a regional haze analysis for the ENP and CWNR. The analysis included modeling from the CALPUFF model. The CALPUFF model predicts modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

The National Park Service and Fish and Wildlife Service do not anticipate any significant visibility impacts in the ENP and CWNR from the proposed project.

3. 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 286 additional workers will be needed over the 11-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the project will require 16 new permanent employees, which will cause no significant impact on the local area.

4. Growth-Related Air Quality Impacts since 1977

According to the applicant, St. Lucie County is the 3rd fastest growing county in Florida. Residential growth in the area of the proposed project, St. Lucie County, has nearly tripled from 1977 to 2005. The county has continued to be in attainment with all National Ambient Air Quality Standards.

5. Endangered Species Considerations

The purpose of the Endangered Species Act (ESA) is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[28] 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. Sections 2.3 and 4.4 of the Site Certification Application include a characterization of the existing environment, and an ecological impacts assessment including wildlife and threatened and endangered species. The applicant concludes that the project will not have an adverse effect on endangered species.

According to the U. S. Fish and Wildlife Service (F&WS) website 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

Threatened and endangered animal species observed within a five mile radius of the TCEC site include several bird species such as the bald eagle, the Florida sandhill crane, and the snail kite. The Sherman's fox squirrel and eastern indigo snake have also been observed within this area. According to the application, there are no federal or Florida listed threatened or endangered species known to occur on the site or in close proximity. There is one bald eagle nest, however northwest of the site, of which the exact location is not known. The bald eagle is protected in accordance with the Endangered Species Act, Bald and Golden Eagle Protection Act, and the guidance document entitled *Habitat Management Guidelines for the Bald Eagle in the Southeast Region*, issued by the U.S. Fish and Wildlife Service. FMPA has committed to consulting the U.S. Fish and Wildlife Service on how to best avoid disturbing the nest during site development and operation.

Figure 18. Nesting Eagle in South Florida

Figure 19. Eagle Pair in SW Florida

FMPA has already contacted both the U.S. Fish and Wildlife Service and the Florida Fish and Wildlife Conservation Commission by letter requesting review of the proposed project.[29, 30]

VIII. 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.

Cindy Mulkey is the project review engineer and is responsible for preparing the draft permit conditions. She may be contacted at cindy.mulkey@dep.state.fl.us and 850-921-8968. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the Section Adminstrator. He reviewed, contributed to and affixed his seal on this Techncial Evaluation and Preliminary Determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

REFERENCES

[1] Manual. EPA, Office of Air Quality Planning and Standards, "DRAFT New Source Review Workshop Manual", October 1990.

[2] Technical Report GE Power Systems GER 3568G. Davis, L. B., and S.H. Black, General Electric. "Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines." 2000.

[3] Technical Report GE 3695E. Badeer, G. H., General Electric. "GE Aeroderivative Gas Turbines – Design and Operating Features." 2000.

[4] Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station." September 2000.

[5] Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station." September 2000.

[6] Telecom. Heron, T., FDEP and Gianazza, N. B., JEA. Additional Hours of Operation at JEA Kennedy Station. January 22, 2001.

[7] Paper. Cohn, A. and Scheibel, J., EPRI. Current Gas Turbine Developments and Future Projects. October 1997.

[8] News Release. Calpine. Power Systems Mfg., LLC's Low Emissions Combustion System Achieves 5 ppm NO_X Commercial Certification at the Oyster Creek Power Plant in Freeport, Texas. May 5, 2003.

[9] Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

[10] News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

[11] News Release. Catalytica. Catalytica Energy Systems XONON Cool Combustion System Demonstrating NO_X Emissions Well Below its 3 ppm Guarantee in Commercial Gas Turbine Applications. February 17, 2004.

[12] Statement. EPA and Research Triangle Institute. ETV Joint Verification Statement. XONON™ Cool Combustion. December, 2000.

[13] Letter. KenKnight, J., EPA Region 10 to Fiksdal, A., Washington Energy Facility Site Evaluation Council. BP Cherry Pt. Cogeneration Project. December 4, 2003.

[14] Letters. Cusson, Thomas P., Massachusetts DEP to Maggiani, R., ANP Blackstone. Emissions Testing Results, ANP Blackstone Units 1 and 2.

[15] White Paper. Emerachem. NO_X Abatement Technology for Stationary Gas Turbine Power Plants – An Overview of Selective Catalytic Reduction (SCR) and Catalytic Absorption ($SCONO_X$™) Emission Control Systems. September 19, 2002.

[16] Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

[17] Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.

[18] White Paper. Rollins, W.S. et al. New Combined Cycle Technology for Achieving Ultra-Low Emissions. Coen Website. www.coen.com/i%5Fhtml/white%5Fnewcombcycle.html Accessed April 5, 2004.

[19] Letter. Waters, G.D., Gulf Power to Halpin, M.P., FDEP. Lansing Unit Units 4 & 5 Test Results. May 6, 2001.

[20] Report Attachment. "Initial Compliance Demonstration for Air Emissions Permit Limits on Units 8A and 8B. Combustion Turbine in Simple Cycle Mode – Distillate Oil." GE Energy and Environmental Research Corporation. Attachment prepared January 9, 2002.

[21] Letter Attachment. McGarrab, R., City of Tallahassee to Koerner, J., Florida DEP. Permit Revision Request. February 28, 2002.

[22] Fax Attachment. Norse, D., JEA to Heron, T., Florida DEP. Results of Testing, JEA Kennedy KCT 7. Tests conducted December 2001.

[23] Electronic Mail. Mulkey, C., DEP to Linero, A., DEP. Summary Table of Emission Tests (Oil Firing) at Reliant Osceola, Constellation Oleander, and KUA Unit 3 Projects. May 12, 2004.

[24] Electronic Mail. Mulkey, C., DEP to Linero, A., DEP. Emission Summary. Combustion Turbine (Oil Fired) with Duct Burner (Gas Fired). Kissimmee Electric Authority. Intercession City. Conducted by Air Consulting and Engineering on January 10, 2002. May 13, 2004.

[25] Letter. Chansler, J.M., JEA to Koerner, J.F., FDEP. Brandy Branch Generating Station Units 2 and 3. Unit 1 Test Results. August 24, 2005.

[26] Telecom. Mulkey, C., FDEP and Gianazza, N. B., JEA. Low Load Operation at JEA Brandy Branch Station. October 18, 2005

[27] Paper. Reisman, J. and G. Frisbie, Calculating Realistic PM10 Emissions from Cooling Towers, Air and Waste Management Association 94th Annual Conference and Exhibition, June 2001.

[28] Pamphlet. ESA Basics. ESA Basics – Over 25 Years of Protecting Endangered Species. U.S. Fish and Wildlife Service. Arlinton, VA. October 2002.

[29] Letter. Soltys, J.M., Black & Veatch Corporation to Slack, J., U.S. Fish and Wildlife Service. Treasure Coast Energy Center Project Review, March 9, 2005.

[30] Letter. Soltys, J.M., Black & Veatch Corporation to Collins, C., Florida Fish and Wildlife Conservation Commission. Treasure Coast Energy Center Project Review, March 9, 2005.