TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company (FP&L)
West County Energy Center Unit 3

One Nominal 1,250-Megawatt Combined Cycle Unit

Palm Beach County

DEP File No. 0990646-002-AC (PSD-FL-396)

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

April 25, 2008

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company (FP&L)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

Processing Schedule

- December 6, 2007: Received Prevention of Significant Deterioration (PSD) application
- December 21, 2007: Received supplemental information from FP&L
- January 21, 2008: Issued request for additional information (RAI)
- February 13, 2008: Held informational meeting in Royal Palm Beach
- March 14, 2008: Received responses from FP&L to RAI (application complete)
- April 25, 2008: Preliminary determination issued

Facility Description and Location

FP&L is presently constructing the West County Energy Center (WCEC) at 20505 State Road (SR) 80, Loxahatchee, Palm Beach County. The location with respect to other FP&L facilities in Florida is shown in Figure 1. The WCEC site is bounded by SR 80 (also known as Southern Boulevard) on the south, FP&L electrical transmission lines on the west, a major electrical substation on the northwest corner, as well as mining lands immediately north and east.

Figure 1. Location of FP&L WCEC

Figure 2. Aerial View, Rendition from Northeast

The Arthur R. Marshall (ARM) Loxahatchee National Wildlife Refuge (NWR) operated by the U.S. Fish and Wildlife Service (USFWS) is located immediately south of Southern Boulevard. The northwest corner of the refuge is visible in the upper left hand side of Figure 2, which is a rendition of the future plant on the proposed site looking from the northeast.

The southernmost corner of the J.W. Corbett Wildlife Management Area, operated by the Florida Fish and Wildlife Management Commission, is located approximately 4 miles north of the site.

With respect to Figure 3 below, the Town of Loxahatchee Groves is located approximately 4 miles east of the site. The Villages of Wellington and Royal Palm Beach are also located several miles generally east of the site. Other areas such as The Acreage, Deer Run and Indian Trails are populated and unincorporated communities east of and near to the site.

The Cities of Belle Glade and Pahokee are adjacent to Lake Okeechobee which is located about 20 miles west to northwest of the WCEC.

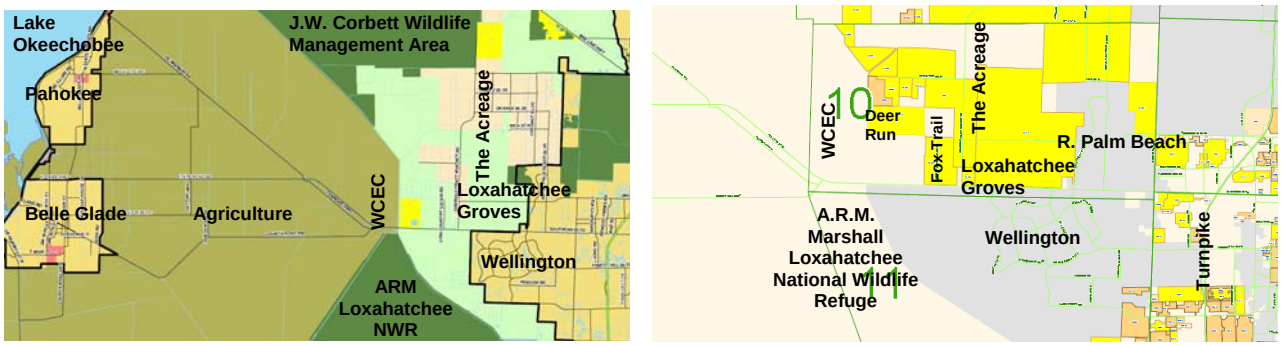

Figure 3. Municipalities, Communities and Wildlife Areas nearest to the FP&L WCEC

The site is located approximately 107 kilometers (km) north of the PSD Class I Everglades National Park. The UTM coordinates of the site are Zone 17; 562.19 km East; 2953.04 km North.

Regulatory Categories

40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). The facility under construction is subject to certain NSPS. Unit 3 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also applies to duct burners (DB) that are incorporated into combined cycle projects. Two additional emergency generators are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines. Two additional process heaters are subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

40 CFR Part 63 – National Emission Standards for Hazardous Air Pollutants (NESHAP). The facility under construction is a major source of hazardous air pollutants (HAP). The new unit is potentially subject to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbine electrical-generator (CTG) such as planned for this project.

Title IV, Clean Air Act, Acid Rain Provisions. The facility will operate units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits. 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 (TPY) or because it is a Major Source of HAP. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

Prevention of Significant Deterioration (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. The facility is classified as a "fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 TPY. Potential emissions of at least one regulated pollutant exceed 100 TPY, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 Florida Administrative Code (F.A.C.). Units 1 and 2 were permitted previously under PSD permit (PSD-FL-354).

Siting. The two units already under construction were originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. An application is under review to modify the certification to reflect the capacity of the third unit.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a third "three-on-one" combined cycle unit (Unit 3) where two such units (Units 1 and 2) are presently under construction. Combined cycle Unit 3 will consist of: three nominal 250 megawatt (MW) "G" Class combustion turbine-electrical generators (CTG) evaporative inlet cooling systems; three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors and a nominal 428 mmBtu/hour (lower heating value – LHV) gas-fired DB; three 149 foot exhaust stacks; one 26-cell mechanical draft cooling tower; and a common nominal 500 MW steam-electrical generator.

Additional ancillary equipment will include: two 2250 KW emergency generators and two natural gas fired fuel heaters. Following are additional project characteristics.

- Fuels: Each CTG will fire natural gas as the primary fuel and *ultra low sulfur diesel* (0.0015% Sulfur) fuel oil (ULSD FO) as a restricted alternate fuel. The applicant requests 500 hours per year per CTG (or equivalent) for oil firing. The ULSD FO will be stored in the tanks under construction for Units 1 and 2.
- Generating Capacity: Each of the three CTG has a nominal generating capacity of 250 MW. Each of the three HRSG provides steam to the single steam turbine-electrical generator (STG), which has a nominal capacity of 500 MW. The nominal capacity of Unit 3 will be 1,250 MW.
- Controls: CO, $PM/PM_{10}/PM_{2.5}$ and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ULSD FO. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and wet injection (WI) for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: Each CTG is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain best available control technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

- Stack Parameters: Each HRSG has a combined cycle stack that is at least 149 feet tall with a nominal diameter of 23 feet. The following table summarizes the exhaust characteristics of each of the three CTG/HRSG sets, exclusive of the DB:

Table 1. Exhaust Characteristics of the CTG comprising Unit 3 at 100% Load and 59 °F

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp., °F	Exhaust Temp., °F	Flow Rate ACFM
Gas	2333 mmBtu/hour	59 °F	195 °F	1,330,197
Oil	2117 mmBtu/hour	59 °F	293 °F	1,553,502

Project Description

A CTG is an internal combustion engine that operates with rotary rather than reciprocating motion and that is coupled to an electrical generator. A longitudinal section diagram of an M501G (rotor inside of casing) from a Mitsubishi Heavy Industries (MHI) brochure is shown in the left hand side of the figures below. The photograph on the right hand side of the figure is of the rotor being lowered into the shell (not visible) of an M501G. The compressor rotating blades are in the foreground and the 4-stage expansion section is in the background.

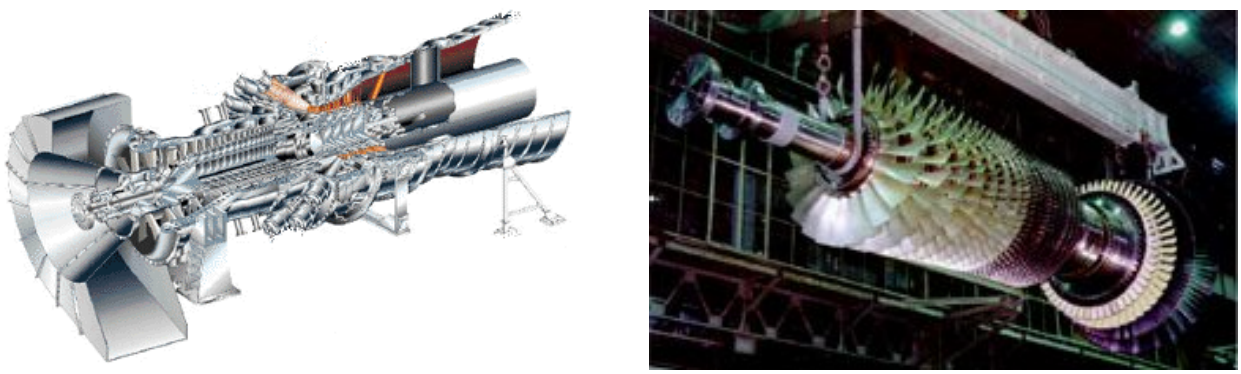

Figure 4. Longitudinal View of M501G, Photograph of Rotor (Source: MHI Website)

Ambient air is drawn into the 17-stage compressor of the M501G where it is compressed to a pressure ratio greater than 19 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate steam-cooled, can-annular, DLN combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is greater than 2,700 ºF.

The hot combustion gases routed through the steam-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. 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 (TEG) is discharged at a temperature of approximately 1200 ºF and contains more than 10% oxygen (O_2). The TEG is available for additional energy recovery and can also support further combustion.

Each CTG/HRSG set will operate in combined cycle mode as depicted in Figure 5. The TEG from each CTG will raise additional steam in each HRSG. The steam from the three HRSG will, in-turn, drive a single, separate STG producing additional electrical power.

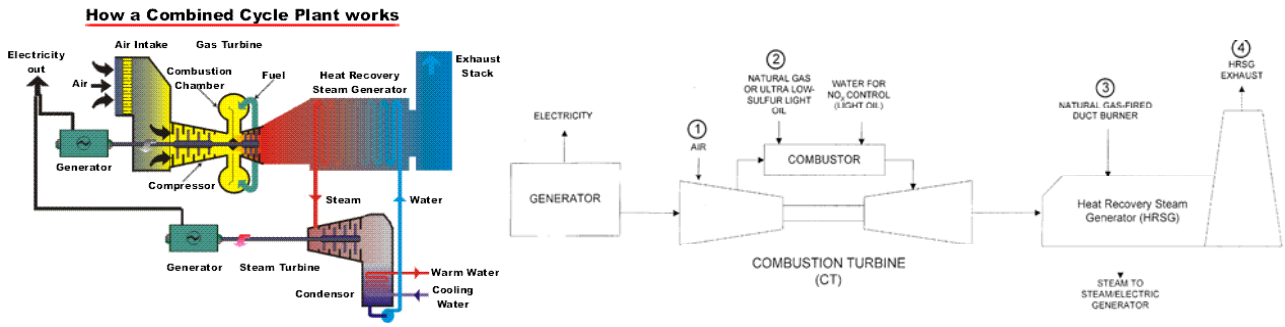

Figure 5. Natural Gas Fueled Combined Cycle Unit with DB and Backup ULSD FO

In combined cycle mode, the thermal efficiency of the G-Class CTG is approximately 58 percent (%) on the basis of LHV and about 53% based on the higher heating value (HHV).

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the CTG compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the CTG with a boost in electrical power production. The emissions performance remains within the normal profile of the CTG for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired DB can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2880 hours of duct burning per year for each HRSG.

Further process details are provided in the Draft BACT determination, Section 4.0 below.

3. RULE APPLICABILITY

State Regulations

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

Table 2. Key Applicable State Regulations

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

Federal Regulations

This project is also subject to the following federal provisions regarding air quality as established by the U.S. Environmental Protection Agency (EPA) in the CFR.

Table 3. Key Applicable Federal Regulations

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
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

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's PSD program, as described 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.

The WCEC is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant. [Rule 62-210.200(185)(a)1., F.A.C.]

Because it has been established that the WCEC is a Major Stationary Source, PSD will apply to each pollutant for which there will be a net emissions increase greater than its respective significant emission rate (SER). The SER means a rate of pollutant emissions that would equal or exceed the values described in Rule 62-210.200(185)(a)1., F.A.C.

Potential Emissions

The following table is a summary of the estimated annual emissions from the WCEC Unit 3 project compared with the respective PSD SER. Emissions from Units 1 and 2 are included for information purposes.

Table 4. Projected Annual Emissions from WCEC Unit 3 Versus PSD SER Thresholds

Pollutant	Units 1 & 2 TPY	Unit 3 TPY	PSD SER TPY	PSD Review Required?	WCEC Total TPY
CO	1,038	521	100	Yes	1,559
Pb (lead)	0.055	0.022	0.6	No	0.067
NO_X	713	359	40	Yes	1,072
$PM/PM_{10}/PM_{2.5}$	501/277/277	250/139/139	25/15/*	Yes	751/416/416
SO_2	399	199	40	Yes	598
SAM	81	40	7	Yes	121
VOC	165	82	40	Yes	247

* $PM_{2.5}$ emissions are conservatively estimated to equal PM_{10}. There is not yet a SER for $PM_{2.5}$.

For each pollutant with a net emission increase from Unit 3 exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) as defined in Paragraph 62-210.200(39), F.A.C. to minimize emissions and conduct an ambient air quality analysis as applicable.

The required ambient 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 (NAAQS) and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRV); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

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

4.1 BACT Determination Procedure

BACT is defined in Paragraph 62-210.200 (39), FAC as follows:

(a) 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:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; 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.*

(b) 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.

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

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), F.A.C., the applicant must at a minimum provide certain information in the application including:

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

According to Rule 62-212.400(10), F.A.C., the Department is required to conduct a control technology review and shall not issue any permit unless it determines that:

(a) The owner or operator of a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.

(b) The owner or operator of a new major stationary source shall apply best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts.

(c) The owner or operator of a major modification shall apply best available control technology for each PSD pollutant which would result in a significant net emissions increase at the source. (This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.)

(d) The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C.

4.2 NO_X BACT Determination

NO_X Formation

NO_X forms in the CTG combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO_X. Thermal NO_X forms in the high temperature area of the CTG combustor as seen on the left hand side of Figure 6.

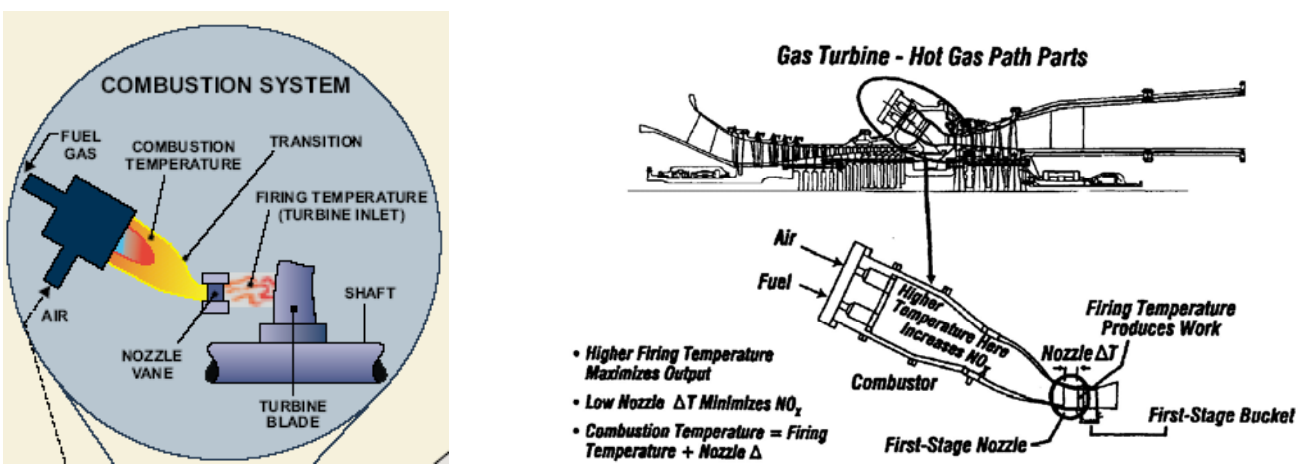

Figure 6. Relation between Combustion and Firing Temperatures and NO_X Formation

Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 6, which is from a GE discussion on these principles.

In all but the most recent CTG combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle.

Uncontrolled emissions can range from about 100 to over 600 parts per million by volume, dry, corrected to 15% O_2 (ppmvd @15% O_2) depending upon design. The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 from the CTG chosen for this project.

Descriptions of Available NO_X Controls

Diluent Injection: WI. Injection of either water or steam as a diluent 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 CTG.

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

CO and VOC emissions are relatively low for most CTG. However, WI may increase emissions (water more than steam) of both of these pollutants.

Combustion Controls: 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. These principles are incorporated into the M501G DLN combustor shown on the left hand side of Figure 7. There is a central diffusion pilot nozzle that provides stability but ultimately limits the ability of the combustor to achieve the lowest possible NO_X emissions without further control.

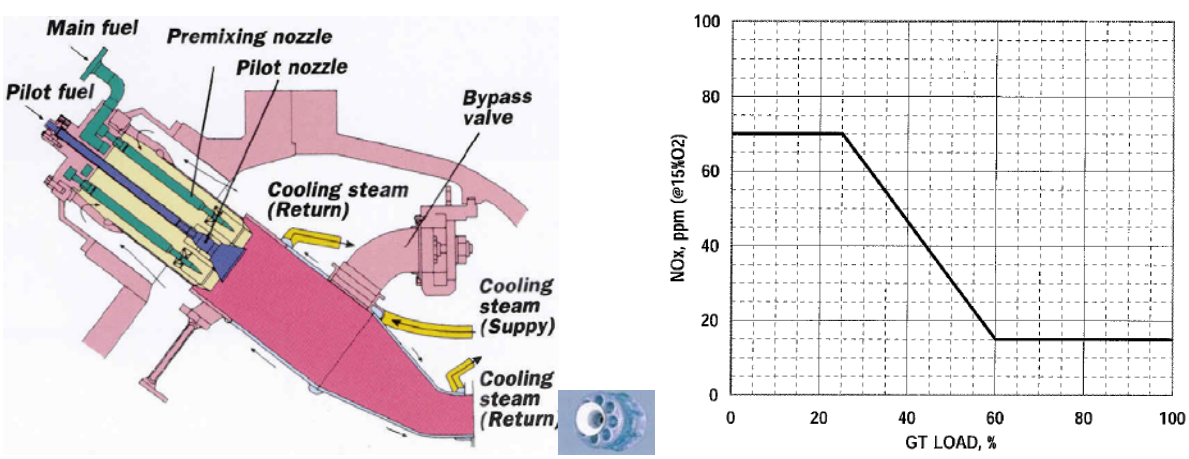

Figure 7. M501G DLN Combustor, Nozzle Block and NO_X versus Load Specification

The graph on the right hand side in Figure 7 contains the NO_X specifications for new Mitsubishi M501G1 CTG.[1] The combustor emits NO_X at concentrations less than 15 ppmvd at loads between 60 and 100 percent of capacity. The firing temperature within the 60-100% load range is between roughly 2500 and 2750 °F. The low NO_X values are an excellent achievement considering the high firing temperature.

The difference between combustion temperature and firing temperature into the first stage is minimized by steam cooling of the transition piece and first stage nozzle. Thus a lower combustion temperature (and lower NO_X) can be achieved by steam cooling compared with air cooling for a given firing temperature (equal work). Alternatively, a higher firing temperature (more work, greater efficiency) can be achieved by steam cooling compared with air cooling for a given combustion temperature (equal NO_X).

It is believed that the combustor for the M501G can actually achieve low NO_X emissions (< 20 ppm) at lower load than suggested by the diagram. The tendency to increase NO_X concentrations is mitigated by decreasing firing temperature.

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.[2] 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 known 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 CTG equipped with XONON™.[3] 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.[4] 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.[5] 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 FP&L West County Energy Center 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 CTG. SCR reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas in the presence of a catalyst. NH_3 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 NH_3 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 °F), 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.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the NH_3 injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

Figure 9 is a photograph of the PEF Hines Power Block I. The external lines to the NH_3 injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive NH_3 use can increase emissions of CO, NH_3 (slip) and $PM_{10}/PM_{2.5}$ when sulfur-bearing fuels are used.

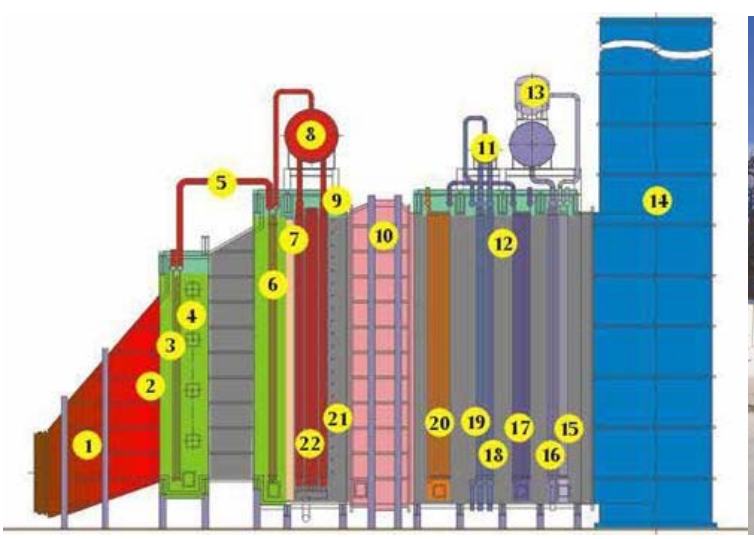

Figure 8 – Key HRSG Components (10 is SCR)

Figure 9 – PEF Hines Block I

The performance of SCR on a M501G combined cycle unit with DB at the Sithe Mystic Station (Massachusetts) is depicted in the following figure. The unit has a NO_X limit of 2 ppmvd @15% O_2.[6]

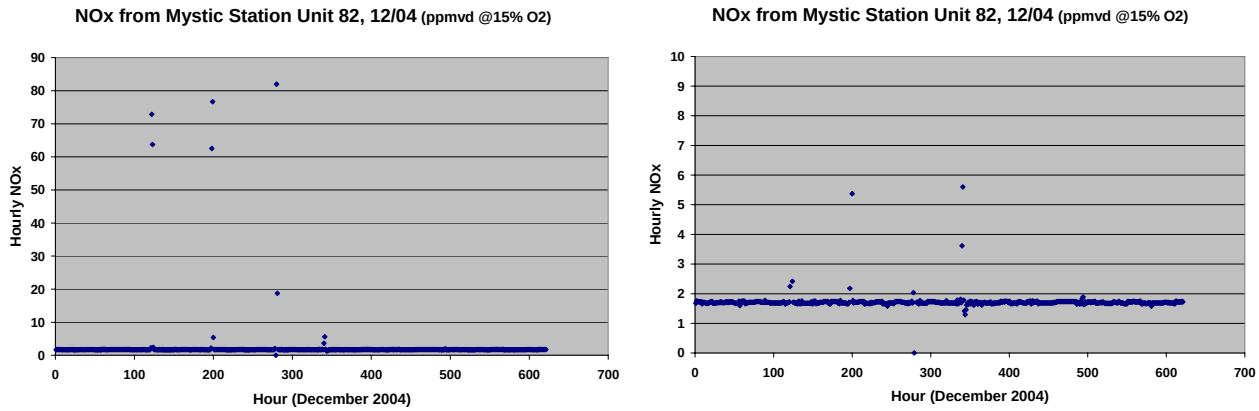

Figure 10. Hourly NO_X Data from Sithe Mystic Station, Massachusetts. December 2004

Unit 82 operated 620 hours during the month of December 2004, typically at CTG electrical generation rates between 170 and 250 MW. The data on the left comprise all reported hours of operation including thirteen measurements related to startups and shutdowns. The same data on the right, in greater resolution, clearly show that, with the exception of the startup and shutdown values, the unit consistently achieved less than 2 ppmvd NO_X @15% O_2.

Since 1999, SCR has been specified for all combined cycle projects in Florida that required a BACT determination. All of the projects rely on DLN or wet injection for basic NO_X control in addition to the add-on SCR systems.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle CTG 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 of 95 to 99%.

<u>EMx (formerly SCONO$_X$)</u> This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large CTG 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.

EMx systems were installed at seven sites ranging in capacity from 5 to 43 MW.[7] None was installed at a large facility.

EMx technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. EMx has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. EMx systems also oxidize emissions of CO and VOC for additional emission reductions. EMx can match the performance of SCR without NH_3 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 5 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for EMx developed by the California Air Resources Board for their Legislature.[8] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion CTG and one STG meeting BACT requirements.

Table 5. Cost Comparison between SCR and EMx 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 EMx multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the EMx system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Initially, the key argument in favor of EMx was its ability to achieve low NO_X emissions without NH_3 emissions. In response, SCR suppliers offered systems that include an NH_3 destruction catalyst.[9] Even if the NH_3 catalyst adds 50% to the SCR/CO costs given above, it does not appear that EMx would be competitive.

Estimates provided by FP&L for the proposed 1,250 MW Unit 3 project also indicate a large cost difference between SCR and EMx. While the Department does not accept or reject either set of figures, it appears that EMx is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant proposes a BACT NO_X limit of 2.0 ppmvd @15% O_2 for Unit 3 whether or not the DB are in use. This value is equal to the Department's final BACT determination issued for Units 1 and 2 in early 2007. FP&L proposes to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FP&L proposed a BACT NO_X emission limit of 8 ppmvd @15% O_2 by a combination of wet injection and SCR while burning backup ULSD FO.

Department's Draft NO_X BACT Determinations

Table 6 includes the known determinations for M501G units. All used SCR.

Table 6. NO_X Standards for M501G Combined Cycle Units with DB

Project Location	Capacity (MW)	NO_X Limit and Fuel (ppmvd @ 15% O_2)	Comments
FP&L WCEC Unit 3	**1,250**	**2.0/8.0-NG/FO (24-hr)**	**Draft BACT, Startup ~2011**
FP&L WCEC Units 1&2	2,500	2.0/8.0–NG&DB/FO (24-hr)	BACT, Startup ~2009
Port Westward, OR	415	2.5 – NG & DB (3-hr)	BACT, Startup ~ 2007
Covert Generating, MI	1,200	2.5 – NG & DB (24-hr)	BACT, Startup 2004
Sithe Mystic, MA	1,600	2 – NG & DB (1-hr)	LAER, Startup 2003
Sithe Fore River, MA	800	2/6 – NG & DB/FO (1-hr)	LAER, Startup 2003
Wolf Hollow, TX	730	9 – NG (DB?)	BACT, Startup 2003

Notes: NG = Natural Gas DB = Duct Burner FO = Fuel Oil

Based on this table, the "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average for G-Class units. The data from the Sithe Mystic project provides reasonable assurance that a level of 2.0 ppmvd @15% O_2 can be consistently achieved.

The Department will set limits of 2.0 and 8.0 ppmvd @15% O_2 while firing natural gas (with or without use of DB) and for the limited firing of ULSD FO, respectively. Averaging times will be 24 hours.

The Department does not consider a 1-hour averaging time to be necessary to insure continuous low NO_X levels. This provides relief from some of the small risks of occasionally exceeding the very low BACT NO_X limits during an hour while not exceeding it when averaged over a day.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5. Average NO_X emissions during the tests from the four CTG that comprise Unit 5 ranged from 1.36 to 1.70 ppmvd @15% O_2 while firing natural gas (whether or not the DB were used) even though their limit is 2.0 ppmvd @15% O_2 on a 24-hour basis.

The Department accepts FP&L's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of ULSD FO use to 500 hours as BACT for this project. The limit of 2.0 ppmvd @15% O_2 represents a further reduction of 87% compared with the recently promulgated New Source Performance Standard at 40 CFR 60, Subpart KKKK.

4.3 CO and VOC BACT Determination

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from CTG due to incomplete fuel combustion. Most CTG incorporate good combustion to minimize emissions of CO and VOC. The primary control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst.

The figure below contains CO specifications for the M501G while firing natural gas and FO, including the guarantee values that apply between 60 and 100%.[10]

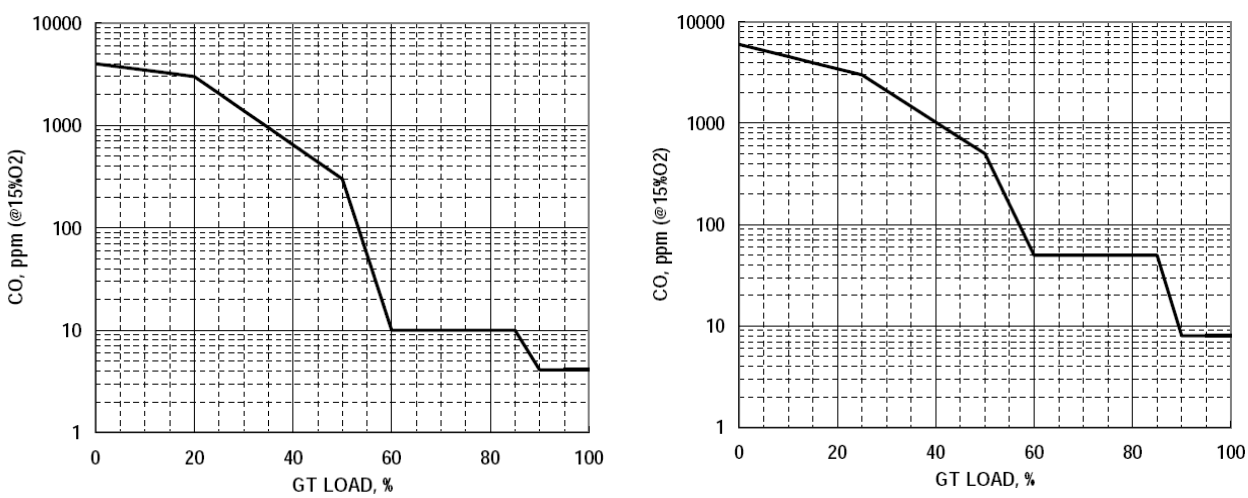

Figure 11. Expected CO versus Load while burning Gas or FO in a M501G

Generally the performance data on the left hand side indicate that the combustor performs very well on natural gas within the range of 60 to 100% of full load. At 60% of full load the flame and firing temperatures are great enough to destroy almost all CO. The graph on the right shows the characteristics while firing FO.

Typically, VOC concentrations are an order of magnitude less than CO concentrations. Therefore, while burning natural gas, VOC emissions will likely be less than 1 ppm while operating between 60 and 100% of full load. Similarly, VOC emissions less than 5 ppm and as low as 1 ppm are expected while firing FO.

DB and FO Considerations

The presence of a DB (refer to Figure 8, Component 4) complicates the evaluation somewhat. Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,200 ^{o}F) and high excess air (> 12% O_2). In the design shown in Figure 8, some of the heat is used by a high pressure superheater (Component 3). The gas-fired DB (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6). Figure 12 shows an individual burner and an array comprising a DB. The hot TEG serves as combustion air for gas introduced into the burner array.

Figure 12 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 ^{o}F. VOC such as ethane and propane ignite at temperatures less than 900 ^{o}F. All of the necessary conditions are present to minimize further CO and VOC concentration increases when corrected to 15% oxygen.

CO emissions while firing FO should be very low, again, based on the high combustion temperature and the relatively high temperature and excess air in the TEG.

FP&L's CO and VOC BACT Proposal

FP&L has proposed BACT for CO, VOC and $PM/PM_{10}/PM_{2.5}$ as the use of good combustion controls while firing natural gas or ULSD FO in accordance with the defined operating hours for each fuel. FP&L proposes the emissions limits given in Table 7 as BACT for CO and VOC to account for all of the scenarios discussed above.

FP&L obtained high load (90-100%) guarantees from Mitsubishi of 4.1 and 8.0 ppmvd CO @15% O_2 for natural gas and FO firing, respectively. The guaranteed CO emission at medium load is 10 ppmvd CO @15% O_2 while firing natural gas. Per Figure 11, expected medium load emissions are 50 ppmvd CO @15% O_2 while firing FO.

Table 7. FP&L BACT Proposal for CO, VOC Emissions - WCEC Unit 3 (ppmvd@15% O_2)

Modes	CO	VOC
Natural Gas	4.1	1.2
Natural Gas & DB	7.6	1.6
ULSD FO	8.0	6.0
All Modes	8.0 (24 hours)	
All Modes	6.0 (12 months)	

Department's Draft CO and VOC BACT Determinations

The known CO and VOC (as well as PM, NH_3 and visible emissions) determinations for projects based on the M501G technology are presented in Table 8. FP&L's proposal for the WCEC Unit 3 project is included in the table for comparison.

Table 8. CO, VOC, PM Standards for M501G Combined Cycle Units with DB

Project Location	CO – ppmvd @15% O_2	VOC – ppmv (@15% O_2)	PM – lb/mmBtu or lb/hr NH_3 – ppmvd @15% O_2
FP&L WCEC Unit 3	**4.1/8–NG/FO (DB off, 100%, test) 7.6 – NG (DB on, 100%, test) 8.0 – All Modes, 24 hours 6.0 – All Modes, 12 months**	**1.2 – NG (DB off) 1.5 – NG (DB on) 6 – FO (DB off)**	**10% Opacity (NH_3 = 5 ppmvd)**
FP&L WCEC Units 1&2	4.1/8–NG/FO (DB off, 100%, test) 7.6 – NG (DB on, 100%, test) 8.0 – All Modes, 24 hours 6.0 – All Modes, 12 months	1.2 – NG (DB off) 1.5 – NG (DB on) 6 – FO (DB off)	10% Opacity (NH_3 = 5 ppmvd)
Sithe Mystic, MA	2.0 – NG & DB (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) (NH_3 = 2.0 ppmvd)
Sithe Fore River, MA	2/7–NG & DB/FO (1-hr, Ox-Cat)	1.0 (DB off) 1.7 (DB on)	0.011 (32.5 lb/hr) (NG+DB) 0.05 (140 lb/hr) (FO+DB) (NH_3 = 2.0 ppmvd)
Covert Generating, MI	5 (Ox-Cat, per MHI Paper)[11] According to Permit:[12] 33.7 lb/hr (NG+DB, 24-hr)	7.7 lb/hr (NG+DB)	33.8 lb/hr (NG+DB) (NH_3 = 10 ppmvd)
Wolf Hollow, TX	33.8 (NG+DB, 24-hr)	NI	PM = NI (NH_3 = 10 ppmvd)
Port Westward, OR	4.9 (NG+DB, 3-hr, Ox-Cat)	7.7 lb (NG+DB)	(NH_3 = 8 ppmvd)

Notes: NI = No Information NG = CT on Natural Gas DB = Duct Burner FO = Fuel Oil

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.

It is clear from Figure 11 that CO emissions from the M501G are very low at high load for the normal natural gas mode and the FO mode even without oxidation catalyst. FP&L estimates greater CO concentrations while using the DB burners than when operating the CTG at full load.

The Department reviewed compliance test data for the recently commissioned 1,100 MW FP&L Turkey Point Unit 5 that was subject to the identical limits proposed for the WCEC Unit 3. Average CO emissions during the tests from the four CTG that comprise Turkey Point Unit 5 ranged from 0.26 to 0.94 ppmvd @15% O_2 while firing natural gas (whether or not ULSD FO or the DB were used) even though the applicable limits are 4.1 to 8.0 ppmvd @15% O_2 on a 24-hour basis.

On a given day, each CTG/supplementary-fired HRSG can operate within the full spectrum of loads (60-100%) and fuels. FP&L and the Department have agreed that a continuous 24-hour emissions limit to cover all the modes of operation will be 8.0 ppmvd @15% O_2. This and the full load proposals are consistent with recent determinations for FP&L Turkey Point, FMPA Treasure Coast and OUC Stanton Unit B combined cycle projects.

Similarly an annual 12-month limit of 6 ppmvd will apply that takes into consideration the preponderance of natural gas operation at 4.1 ppmvd @15% O_2.

While FP&L has requested to use 500 hours per year of ULSD FO, they will rarely use it. For example Martin Combined Cycle Units 3 and 4 were permitted to fire both natural gas and FO, but were never even commissioned to fire FO.

With respect to the dual-fuel units, FP&L advised: *"Our historical practice has been that we run on oil for limited hours each month for reliability purposes (to ensure that the systems operate properly), and from time to time, we burn oil when gas service is interrupted or other factors require us to use back-up fuel. Martin Unit 8 (2005), Fort Myers Units 3A and 3B (since 2003), Fort Lauderdale Units 4 & 5 (since 1996) and Putnam (since 1996) collectively averaged less than 100 hours of oil burning per year per unit."*[13]

The Department agrees that FP&L's description is a reasonable expectation for the proposed West County Power Plant. Given the low FO use and restrictive daily and annual CO <u>stack</u> emission concentrations, there is little benefit in installing oxidation catalyst.

For reference, FP&L submitted respective cost-effectiveness estimates of $8,700 and $87,164 per ton of CO and VOC removed when using oxidation catalyst. The Department does not necessarily accept or reject the cost estimates but agrees that oxidation catalyst is not cost effective for this project.

FP&L successfully obtained the lowest guarantees for "G" technology units specified to-date prior to consideration of additional control by catalyst. FP&L can install an oxidation catalyst at a future date to meet the low CO emission limits if circumstances such as very high natural gas prices cause greater operation at low load conditions characteristic of higher CO concentrations.

The Department concurs with the VOC BACT proposal while burning natural gas of 1.2 and 1.5 ppmvd @15% O_2 with the DB off and on, respectively. The Department also concurs with the VOC BACT proposal of 6.0 ppmvd @15% O_2 while burning ULSD FO. VOC emissions while burning ULSD FO will typically be less than 1 ppmvd @15% O_2 for high load and less than 5 ppmvd @15% O_2 for medium load, respectively, during the brief periods of ULSD FO.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde (CH_2O) emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the CH_2O limit of Part 63, Subpart YYYY - NESHAP for Stationary Combustion Turbines.

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

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

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

For this project the applicant has proposed as BACT the use of ULSD FO (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to CTG is 0.8% by weight.

FP&L estimated 199 tons per year of SO_2 and 40 tons per year of sulfuric acid mist (SAM) per this combined cycle unit. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 standard cubic foot (SCF) than to 2 gr/100 SCF. The Department accepts FP&L's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

4.5 Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} $PM_{2.5}$ Formation and Control Options

PM, PM_{10} and $PM_{2.5}$ will be emitted from the CTG and DB due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ULSD FO will be efficiently combusted at high temperature in the CTG and DB 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 ULSD FO to be combusted contains a minimal amount of ash and will be limited to less than 500 hours per year making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical.

Other $PM/PM_{10}/PM_{2.5}$ Considerations

NH_3 Slip and Ammonium Salts Formation: 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. These constituents form the fine PM that comprises $PM_{2.5}$. $PM_{10}/PM_{2.5}$ emissions can be increased due to the formation of these ammonium salts prior to exiting the stack or in the environment and contribute to regional haze. The BACT process limits the nitrate and sulfate formation potential of the CTG and DB exhaust. It is important to limit NH_3 emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of NH_3 slip can also be an indication of a degrading catalyst.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 26-cell mechanical draft cooling tower for Unit 3 with the following nominal specifications: a circulating water flow rate of 304,000 gallons per minute (gpm); design hot/cold water temperatures of 92 °F/76 °F; a design air flow rate of 1,360,000 actual cubic feet per minute (acfm) per cell; a liquid-to-gas air flow ratio of 1.13; and drift eliminators with a drift rate of no more than 0.0005 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water.

FP&L estimates maximum annual PM and PM_{10} emissions from the cooling tower of 117 and 5 TPY respectively.

Applicant's $PM/PM_{10}/PM_{2.5}$ Proposal

FP&L proposes $PM/PM_{10}/PM_{2.5}$ BACT as an opacity limit of 10% in conjunction with the use of inherently clean fuels. FP&L proposes PM control from the cooling tower to be accomplished by a 0.0005% drift rate design limitation.

Department's Draft $PM/PM_{10}/PM_{2.5}$ BACT Determinations

The following conditions are established as the draft BACT standards.

- The CTG 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 DB are limited to firing only natural gas meeting this specification. The CTG may fire ULSD FO 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.
- NH_3 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%.

4.6 New Source Performance Standards Applicable to CTG and DB

Stationary CTG are subject to the recent federal NSPS in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTG including the DB located in the HRSG. The limits are:

- NO_X (gas) ≤ 15 ppm @ 15% O_2 or 0. 43 lb/MWh (4-hr average);
- NO_X (oil) ≤ 42 ppm @ 15% O_2 or 1.3 lb/MWh (30 operating day average); and
- SO_2 ≤ 0.90 lb/MWh or ≤ 0.060 lb SO_2/MMBtu

Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring by demonstrating sulfur content of no more than 0.05% by weight FO or 20 gr/100 SCF of natural gas. The Department's BACT determinations are significantly more stringent than the requirements of 40 CFR 60, Subpart KKKK. The short term nature of the NO_X limit under Subpart KKKK will necessitate an additional 4-hour limitation in the permit. Subpart KKKK also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

4.7 Department Draft BACT Determinations for CTG and DB

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

Table 9. Draft BACT Determination

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	CTG	8.0	42.0	8.0, 24-hr 6, 12-month [h]
	Gas	CTG & DB	7.6	52.5	
		CTG Normal	4.1	23.2	
NO_X [b]	Oil	CTG	8.0	82.4	8.0, 24-hr
	Gas	CTG & DB	2.0	24.2	2.0, 24-hr and 15, 4-hr [h]
		CTG Normal	2.0	20.0	
PM/PM_{10} [c]	Oil/Gas	All Modes	2 gr S/100SCF of gas, 0.0015% sulfur FO		
			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 FO		
VOC [e]	Oil	CTG	6.0	19.6	NA
	Gas	CTG & DB	1.5	5.4	
		CTG Normal	1.2	4.1	
NH_3 [f]	Oil/Gas	CTG, All Modes	5	NA	NA

a. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, FO, and basic DB mode. The stacks test limits apply only at high load (90-100% of the CTG capacity).

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 KKKK 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 nitrogen dioxide (NO_2).

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each CTG represents (BACT) for $PM/PM_{10}/PM_{2.5}$ 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 CTG and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane. The limits apply only at high load (90-100% of the CTG capacity). Compliance with the CO CEMS based limits at lower loads shall be deemed as compliance with the VOC limit.

f. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

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

h. The 4-hr, 15 ppmvd NO_X limitation is from Subpart KKKK and is in addition to the 2.0 ppmvd NO_X BACT limits.

4.8 National Emission Standards for Hazardous Air Pollutants Applicable to CTG

The WCEC will be a new major source of HAP. As such, the proposed new CTG would be subject to 40 CFR 63, Subpart YYYY, which became final on March 5, 2004.[14] According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new CTG would be subject to an emissions standard for CH_2O of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2).

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[15] EPA has stayed the applicability of YYYY to units such as those proposed for the WCEC project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

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

4.9 BACT Determinations for Emergency Generators

Two standby emergency generators are included for Unit 3. These will be used when electricity is not available to the site, such as during hurricanes. Following are the specifications of the proposed emergency generators:

- Model is Caterpillar 3516BTA;
- Usage of 500 hours per year;
- 16 cylinders;
- Displacement of 4.3125 liters per cylinder;
- Engine rated at 3,200 Brake Horse Power (BHP); and
- Generator rated at 2,250 kW.

On July 11, 2006 EPA issued Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ICE).[16] The values applicable to generators sets in the size category of the emergency generators proposed by FP&L are given in the following table.

Table 10. Emission standards for 2007–2010 model year engines >2,237 kW (3,000 HP) and with a displacement of <10 liters per cylinder in grams/BHP-hr.

CO	Hydrocarbons	NO_X	PM
8.5	1.0	6.9	0.4

The Department accepts the values given for emergency ICE as BACT in conjunction with use of ULSD FO. Use of ULSD FO will result in substantially less PM than indicated above and will also minimize PM_{10}, and $PM_{2.5}$ emissions and precursors.

As emergency generators, these units will be subject to the notification requirements of 40 CFR 63, Subpart ZZZZ – NESHAP for Reciprocating Internal Combustors Engines.

4.10 BACT Determinations for Natural Gas Heaters

Two natural gas heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation.

FP&L described the specifications for the gas heaters are as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 10 MMBtu/hr heat input.

Table 11. Proposed Emissions from Natural Gas-fired Fuel Heaters

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	0.095 lb/mmBtu	0.08 lb/mmBtu	0.005 lb/mmBtu	0.002 lb/mmBtu

The Department accepts the proposed emission values given for the natural gas-fired fuel heaters as BACT. According to an interpretive memorandum by EPA in response to a Department inquiry, gas heaters in the subject size category are subject to 40 CFR 60, Subpart Dc.

Natural gas heaters were subject to 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters. Subpart DDDDD was vacated on July 30, 2007 by the U.S. Court of Appeals for the District of Columbia Circuit.

5. PERIODS OF EXCESS EMISSIONS

5.1 Excess Emissions Prohibited

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

5.2 Alternate Standards and Excess Emissions Allowed

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

During a cold startup of the STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. The gradual warming of the HRSG and STG components is accomplished by operating the CTG for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project.

In general, the sequences of startup/shutdown are managed by the automated control system. STG/HRSG startups occur as little as once during a ten-year period.

Based on information from FP&L regarding startup and shutdown, the Department establishes the following conditions for excess emissions for the CTG/HRSG system.

Excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, excess emissions NO_X and CO resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

- *STG/HRSG System Cold Startup*: For cold startup of the STG/HRSG, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.
- *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.
- *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.
- *Fuel Switching*: For fuel switching, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.
- For startup, NH_3 injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

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

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The proposed project, West County Energy Center (WCEC) Unit 3, will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC

and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. VOC and NO_X are ozone precursors and any net increase of 100 tons per year of either pollutant requires an ambient air impact analysis including the gathering of preconstruction ambient air quality data.

Although the proposed project is for Unit 3 at the West County Energy Center site, the Department required that the applicant provide an ambient air quality impact analysis for all three units, Units 1, 2 and 3, since Units 1 and 2 are currently under construction. All results, conclusions and analyses detailed below are for Units 1, 2 and 3 combined.

6.2 Major Stationary Sources in Palm Beach County

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

Table 12. Major Sources of NO_X in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	3,077
Palm Beach County SWA	Resource Recovery Facility	1,156
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**1,072**
New Hope Power Partnership	Okeelanta Cogeneration Plant	822
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	641
U.S. Sugar Corp.	Bryant Mill	361
United Technologies Corp.	Pratt & Whitney Aircraft	358
Osceola Farms	Osceola Farms	321

Table 13. Largest Sources of SO_2 in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	5,238
Florida Power & Light	**WCEC – Units 1, 2 and 3**	598
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	477
Palm Beach County SWA	Resource Recovery Facility	254
New Hope Power Partnership	Okeelanta Cogeneration Plant	166
Osceola Farms	Osceola Farms	106

Table 14. Largest Sources of PM_{10} in Palm Beach County (2006)

Owner	Site Name	Tons per year
Florida Power & Light	Riviera Power Plant	460
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**416**
US Sugar Corporation	Bryant Sugar Mill	290
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	278
Osceola Farms	Osceola Farms	234
Palm Beach County SWA	Resource Recovery Facility	79

Table 15. Largest Sources of CO in Palm Beach County (2006)

Owner	Site Name	Tons per year
U.S. Sugar Corp.	Bryant Mill	13,402
Osceola Farms	Osceola Farms	7,093
New Hope Power Partnership	Okeelanta Cogeneration Plant	1,753
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**1,559**
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	1,030
Palm Beach County SWA	Resource Recovery Facility	636
Florida Power & Light	Riviera Power Plant	593

Table 16. Largest Sources of VOC in Palm Beach County (2006)

Owner	Site Name	Tons per year
US Sugar Corporation	Bryant Sugar Mill	789
Osceola Farms	Osceola Farms	537
Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	426
Florida Power & Light	**WCEC – Units 1, 2 and 3**	**247**
New Hope Power Partnership	Okeelanta Cogeneration Plant	62
George Weston Bakeries, Inc.	Arnold and Thomas Bakery	60

6.3 Air Quality and Monitoring in the Palm Beach County

The Palm Beach County Health Department operates eleven monitors at seven sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, NO_2 and SO_2. The 2007 monitoring network is shown in the figure below.

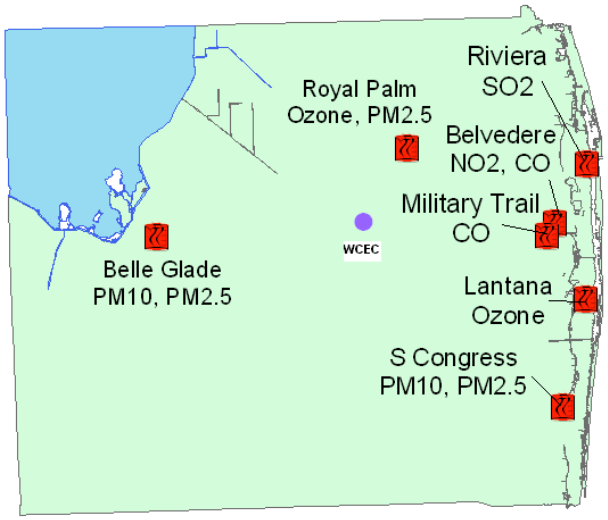

Figure 13. Palm Beach County Health Department Ambient Air Monitoring Network

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

Table 17. Ambient Air Quality in Palm Beach County Nearest to Project Site (2007)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Belle Glade	24-hour	60	37		150 [a]	$\mu g/m^3$
		Annual			17	50[b]	$\mu g/m^3$
$PM_{2.5}$	Royal Palm Beach	24-hour	57	38		35[c]	$\mu g/m^3$
		Annual			7[g]	15[d]	$\mu g/m^3$
		98th Percentile	18.6				$\mu g/m^3$
SO_2	Riviera Beach	3-hour	4	4		500[e]	ppb
		24-hour	2	2		100[e]	ppb
		Annual			1	20[b]	ppb
NO_2	Palm Beach	Annual			8	53[b]	ppb
CO	West Palm Beach Military Trail	1-hour	3	2		35[e]	ppm
		8-hour	1	1		9[e]	ppm
Ozone	Royal Palm Beach	1-hour	0.079	0.078		0.12[a]	ppm
		8-hour	0.069	0.068		0.08[f]	ppm

a. Not to be exceeded on more than an average of one day per year over a three-year period
b. Arithmetic mean
c. Three year average of the 98th percentile of 24-hour concentrations
d. Three year average of the weighted annual mean
e. Not to be exceeded more than once per year
f. Three year average of the 4th highest daily max
g. mean does not satisfy summary criteria for 2007

On March 12, 2008 the U.S. Environmental Protection Agency announced that it will reduce the 8-hour ozone standard listed above from 85 parts per billion (ppb) to 75 ppb. Upon redesignation and classification, possibly in 2009, the areas shown in the following figure will no longer be in attainment with the applicable ozone AAQS. Palm Beach County will remain in attainment with the new ozone standard.

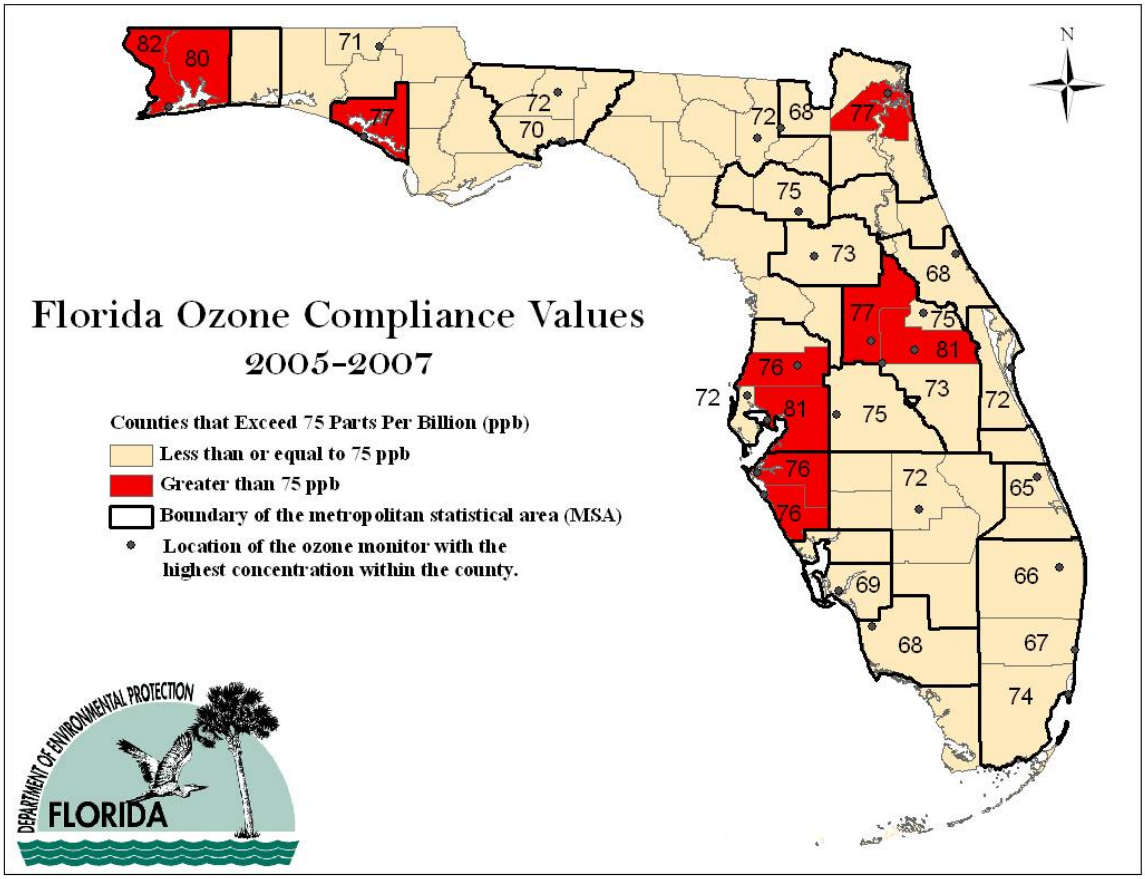

Figure 14. Map indicating Areas Registering an ozone Value Greater than 75 ppb.

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, at least at the monitoring locations. One exception is ozone because it is formed from precursors that are clearly available (NO_X and VOC) from local industrial and transportation emissions. The tendency to form ozone is accentuated by hot ambient temperature, solar insolation, high pressure, and relatively low wind speed. Such conditions when combined with cyclical drought or Everglades fires have the greatest potential to cause ozone exceedances.

Although low CO concentrations are recorded at the single monitor located on Military Trail, it is likely that CO concentrations will occasionally be greater in the area of sugar cane farming and milling due to fires and inefficient combustion of moist bagasse.

6.4 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SIL) 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 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 SIL for the PSD Class I Everglades National Park (ENP) and the PSD Class II Area (everywhere except the ENP). Further, the Class II area includes the Loxahatchee National Wildlife Refuge.

For the Class II analysis, a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 5 kilometers from the facility. From 5 to 7 kilometers, Cartesian receptors with a spacing of 500 meters were used and from 7 to 10 kilometers, a spacing of 1000 meters was used.

Receptors within the grid described above may be eliminated if they fall on property that is inaccessible to the public. Modeling impacts are only measured in areas of “ambient air” or where the public has access. For this proposed project, Palm Beach Aggregates leases a public restricted property in the vicinity of the WCEC site. Within this property, Palm Beach Aggregates, along with three additional minor sources of pollutants, are in operation. Therefore, the receptors on this restricted property were eliminated for the analysis.

For the Class I analysis, 901 discrete receptors located at the ENP were used. These receptors represent a subset of receptors provided by the National Park Service (NPS).

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project’s impacts compared to the AAQS and 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 greater than the applicable SIL for the Class II area (i.e. all areas except ENP) except for SO_2 on a 3-hour basis and CO. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 18. Maximum Predicted Air Quality Impacts from FPL West County Energy Center for Comparison to the PSD Class II SIL

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	2007 Baseline Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
SO_2	Annual	1.3	1	~3	60	YES
	24-Hour	9.8	5	~5	260	YES
	3-Hour	16	25	~10	1300	NO
PM_{10}	Annual	1.6	1	~17	50	YES
	24-Hour	14	5	~60	150	YES
CO	8-Hour	50	500	~1150	10,000	NO
	1-Hour	74	2000	~3450	40,000	NO
NO_2	Annual	1.6	1	~15	100	YES

It is clear that maximum predicted impacts from the project are much less than the respective AAQS. SO_2 on a 3-hr basis and CO 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 102 km to the south 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 equal to or less than the applicable SIL for the Class I area. Therefore, no further detailed modeling efforts are required for these pollutants.

Table 19. Maximum Predicted Air Quality Impacts from the FPL West County Energy Center for Comparison to the PSD Class I SIL at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area ($\mu g/m^3$)	Class I Significant Impact Level ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.004	0.2	NO
	24-hour	0.3	0.3	NO
NO_2	Annual	0.006	0.1	NO
SO_2	Annual	0.007	0.1	NO
	24-hour	0.1	0.2	NO
	3-hour	0.5	1	NO

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 used 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 except for PM_{10} on a 24-hour basis. Therefore, no pre-construction monitoring is required for those pollutants except for PM_{10} on a 24-hour basis.

Table 20. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Baseline Concentrations ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	14	10	~60	YES
NO_2	Annual	1.6	14	~15	NO
SO_2	24-hour	10	13	~5	NO
CO	8-hour	50	575	~1150	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC and NO_x emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_x emissions from the project to be 247 and 1,072 tons per year respectively. Therefore, preconstruction monitoring for ozone is required.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for SO_2 on a 24-hour and annual basis, PM_{10} and NO_2 in the Class II area;
- A Preconstruction Monitoring analysis for 24-Hour PM_{10} and ozone;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

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.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at Palm Beach International (PBI) Airport and Florida International University in Miami respectively. The 5-year period of meteorological data was from 2001 through 2005. The surface weather station was selected for use in this study because the modeling results were more conservative with regards to comparing surface parameters at PBI and the project site. The Miami station was selected for use in the study because it is the most representative with regards to this region.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 2001, 2002 and 2003.

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.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted SO_2 on a 24-hour and annual basis, PM_{10} and NO_2 PSD Class II area impacts from this project and all other increment-consuming sources in the vicinity of the West County Energy Center are shown in the following table.

Table 21. PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	24	30	NO
	Annual	4	17	NO
SO_2	24-hour	29	91	NO
	Annual	5	20	NO
NO_2	Annual	8	25	NO

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Table 22. Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2004- 2006 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	27	42	69	NO	150
	Annual	7	20	27	NO	50
SO_2	24-hour	36	8	44	NO	260
	Annual	13	3	16	NO	60
NO_2	Annual	43	21	64	NO	100

Ozone

Ozone is an area-wide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation). According to the applicant, in 2005, Palm Beach County had total emissions of NO_X and VOC from stationary and mobile sources of 55,000 and 54,600 TPY respectively.

The West County Energy Center will add 247 and 1,072 TPY of VOC and NO_X respectively. The proposed facility will have very low emissions per unit of energy produced, but will still contribute appreciably to regional NO_X loading. VOC emissions will add less than 1% of regional VOC emissions.

In the near future, many existing power plants and other industries that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). A number of the plants included in the CAIR and BART process are located in the Tri-County Area (Miami-Dade, Broward, and Palm Beach Counties).

To conclusively prove whether or not the 1,072 tons of NO_X and 247 tons of VOC will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. The uncertainty in any regional ozone model would be greater than the contribution from this project.

Preconstruction Monitoring Analysis for 24-hour PM_{10} and Ozone

The applicant provided a monitoring analysis for ozone and PM_{10} for the area of Palm Beach County closest to the project site. There is an ozone monitoring site 8 miles to the east of the project site and a PM_{10} monitor 17 miles to the west of the project site. Both of which are close

to the proposed project and are representative of the air quality in the vicinity of the project. Therefore, placing preconstruction monitors at the project site is not needed, nor required to obtain background air quality concentrations.

The air quality in the vicinity of the project is detailed in above sections. The county is in attainment for both ozone and PM_{10}. PM_{10} modeling also shows that the proposed project will not contribute to a violation of the standard.

6.5 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from the natural gas and ultralow sulfur diesel fuel oil that is fired in 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 and wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. Annual SO_2 levels of 8 $\mu g/m^3$ can lead to adverse impacts. SO_2 impacts from the West County Energy Center will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, guinea pigs have respiratory stress when exposed to levels of 96 $\mu g/m^3$ of nitrogen oxides on an annual basis. Long-term NO_2 levels predicted from the West County Energy Center will be well below this level and therefore, will not contribute to adverse impacts on wildlife, such as guinea pigs.

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

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.0059 and 0.0036 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

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

Impact on Visibility:

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

Despite FPL's initial BACT proposals to minimize SO_2, NO_X, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 6 days in three years. Because of the limitation in fuel oil use, the probability that the meteorology on a given day which lead to visibility impairment will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years. Visibility impairment while firing natural gas is less than when firing fuel oil.

The NPS was provided the opportunity to comment regarding the aforementioned AQRV analysis, including visibility, for this project. After their review, the NPS stated that "we are not concerned about the level of impacts on resources at the Everglades National Park." The Department did not receive comments from the U.S. Fish and Wildlife Service regarding the Class I or Class II impacts from this project.

Growth-Related Impacts Due to the Proposed Project:

According to the applicant, there will be short-term increases in the labor force to construct the project. According to the applicant, about 350 additional workers will be needed over the 24-month construction period. Operation of the new facility will require 10-15 permanent employees.

The project is a response to state-wide and regional electrical demand growth and is one of several projects identified by FPL for its service area within its annual 10 year plans submitted to the Public Service Commission.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, population growth in the area of the proposed project, Palm Beach County, has increased 155% from 1977 to 2005. The number of residential households has also increased in the county, 113% from 1977 to 2005. Transportation in the county also grew in terms of vehicle miles traveled by 95 percent over the same time period. Between 1977 and 2000, the number of those employed in the county grew about 234%.

The applicant addressed industrial growth in Palm Beach County as well. According to the applicant, the manufacturing industry has seen a slight decrease in employment from 1977-2005, however, the agricultural industry saw about a 329% increase in employees (1977-2005). Existing Utility Facilities in Palm Beach County include the FPL Riviera Facility and Lake Worth Utility.

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

7. 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 BACT determinations, review of the air quality impact analysis, and the conditions specified in the draft permit.

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