TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Orlando Utilities Commission
Curtis H. Stanton Energy Center Unit B

300-Megawatt Natural Gas-Fueled Combined Cycle Unit

Orange County

DEP File No. 0950137-020-AC
PSD-FL-373A

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

March 25, 2008

I. APPLICATION INFORMATION

A. Applicant Name and Address

Orlando Utilities Commission (OUC)
500 South Orange Avenue
Post Office Box 3193
Orlando, Florida 32802

Authorized Representative: Denise Stalls, Vice President Environmental Affairs

B. Processing Schedule

December 26, 2006:	Department issued Prevention of Significant Deterioration (PSD) Permit PSD-FL-373 to construct an integrated coal gasification and combined cycle (IGCC) unit at the OUC Curtis H. Stanton Energy Center (Stanton Unit B).
November 13, 2007:	Southern Power and OUC mutually agreed to terminate the IGCC Project.
March 6, 2008:	Department received a complete PSD application to construct a natural gas-fueled combined cycle (NGCC) unit in lieu of the IGCC unit.
March 25, 2008:	The Intent to Issue PSD Permit was distributed.

C. Facility Location

The OUC Curtis H. Stanton Energy Center (the Stanton Plant) is located in Orange County, Southeast of Orlando and North of Highway 528 at 5100 South Alafaya Trail. The OUC Stanton Plant presently consists of two fossil fuel-fired steam electrical generating units and a combined cycle unit. Fossil fuel-fired steam electric generating Units 1 and 2 (468 MW each) began operation in 1987 and 1996 while Combined Cycle Unit A (640 MW) began operation in 2003.

The site is located 144 km southeast from the Chassahowitzka National Wildlife Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The UTM coordinates for this site are 483.6 km East and 3151.1 North. The location of the OUC Stanton Energy Center is shown in Figure 1.

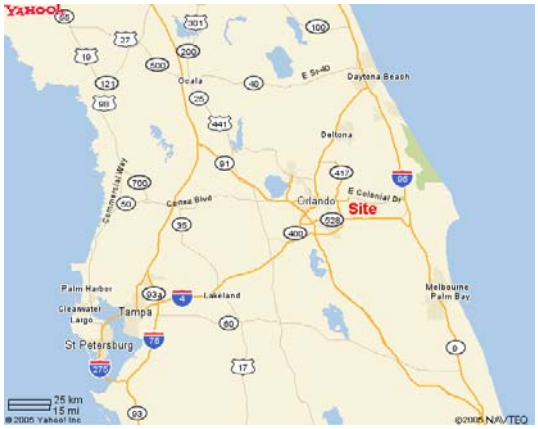


Figure 1. Project Location near Orlando. Figure 2. Aerial View of the Stanton Plant.

D. STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)

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

E. Regulatory Classifications

40 CFR 60, Subpart KKKK. The proposed project is subject to 40 Code of Federal Regulations (CFR) 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers duct burners that are incorporated into combined cycle projects.

40 CFR 60, Subpart Kb. A proposed 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.

40 CFR 63, Subpart YYYY. The existing facility is a major source of hazardous air pollutants (HAP). The new unit is potentially subject to 40 CFR63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines such as planned for this project.

Title IV, Clean Air Act, Acid Rain Provisions. The facility operates 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 plants 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 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 Florida Administrative Code (F.A.C.).

Siting. The facility was originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C. The certification was modified to include the IGCC project.

II. PROPOSED PROJECT SUMMARY

A. Project Description

Instead of the planned IGCC project, the applicant proposes to construct a "one-on-one" F-Class NGCC unit (Stanton Unit B) and associated auxiliary equipment. Unit B will consist of: one nominal 150 megawatts (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners; and a nominal 150 MW steam turbine generator (STG) for an overall nominal rating of 300 MW. 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.

According to OUC the project is a revision of the previously permitted IGCC. The NGCC version of the project will allow firing of natural gas as the primary fuel, with ultralow sulfur diesel (ULSD) fuel oil serving as a backup fuel, while removing the coal handling, gasification and synthetic gas cleanup components.

Auxiliary equipment includes the following: a nominal 1,000,000 gallon tank for the storage of ultralow sulfur diesel (ULSD) fuel oil; a six-cell mechanical draft cooling tower equipped with drift eliminators; and a 205-foot exhaust stack.

- Fuel: Stanton Unit B will use natural gas as the primary fuel for up to 8760 hours per year, and ULSD fuel oil (0.0015% Sulfur) as a backup fuel. The applicant requests operation with ULSD fuel oil up to 1000 hours per year.
- Generating Capacity: The combustion turbine has a nominal generating capacity of 150 MW. The duct-fired HRSG provides steam to the steam turbine electrical generator, which has a nominal capacity of 150 MW. The total nominal generating capacity of Stanton Unit B is 300 MW.
- Controls: CO and $PM/PM_{10}/PM_{2.5}$ will be minimized by the efficient combustion of natural gas and ULSD fuel oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ULSD fuel oil. NO_X emissions will be reduced with dry low-NO_X (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 Emissions Monitoring Systems (CEMS): The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same CEMS as well as CO CEMS 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: The heat recovery steam generator has a combined cycle stack (HRSG stack) that is 205 feet tall with a nominal exit diameter of 20 feet ($\pm$1 foot). The following table summarizes the exhaust characteristics at 100 % load and with duct burners on.

Table 1 lists the nominal characteristics of Stanton Unit B when referenced to 20 degrees Fahrenheit (°F). This temperature occurs very infrequently in Central Florida, but reflects the conditions of maximum air density and therefore greatest throughput, fuel consumption and combustion turbine (CT) power production.

Table 1. Exhaust Characteristics of Unit 1 at 100% Load and 20 °F

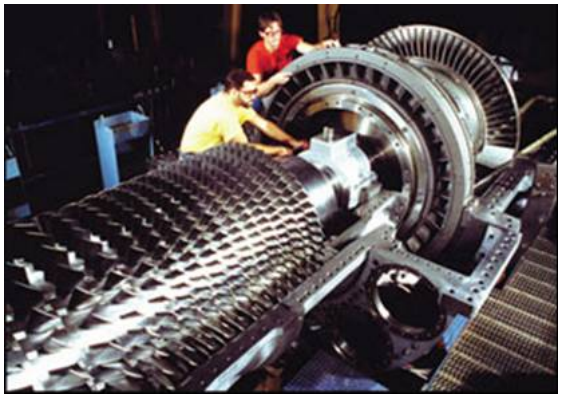
Fuel	Heat Input of CT (HHV)*	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Exit Temp., °F	Stack Flow ACFM
Gas	1925 mmBtu/hour	20° F	1,073° F	227 °F	1,031,061
ULSD F.O.	2100 mmBtu/hour	20° F	1,121° F	262 °F	1,239,934

* Duct burners are used at higher temperatures and account for an additional 450 mmBtu of heat input.

B. Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7241FA CTG (also called a 7FA) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. Figure 3 is a photograph from the GE website of a "7FA on the half-shell" with the compressor section in the foregrounds and the rotor (expansion) section in the rear.

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. A preassembled 7FA is shown in Figure 4 prior to coupling with the rest of the components.



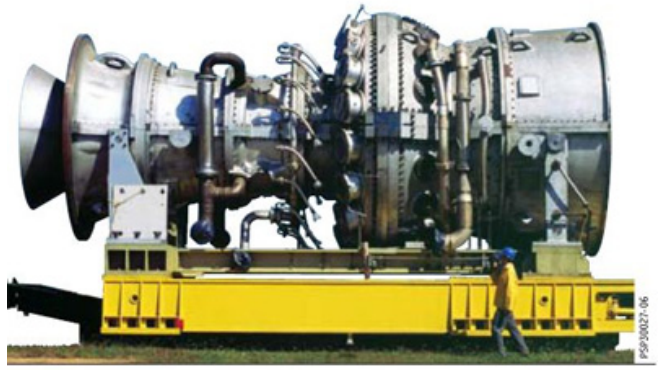


Figure 3. A GE 7FA on a half-shell. Figure 4. Preassembled GE 7FA ready for shipping.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). 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 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent (%) is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas contains more than 12% oxygen (O_2) at a temperature greater than 1000 °F 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 Stanton Unit B 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 exceeds 50% on a higher heating value (HHV) basis.

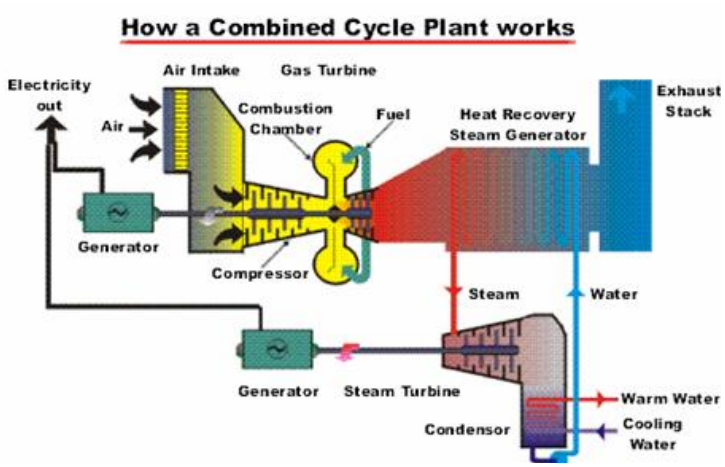


Figure 5. Components Combined Cycle Unit

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 greater than 60 °F.
- Duct firing: Gas-fired duct burners (DB) can be used in the HRSG to provide supplemental heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand that often occur at high ambient temperatures when the CTG cannot process the high air throughput rates possible at low temperatures.
- Power (steam) augmentation: Power augmentation (PA) is an infrequently used high power mode and is accomplished by returning a portion of the steam from the HRSG to the CTG to increase mass flow and power output.

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

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.

Table 2. Key Applicable State Regulations.

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.

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
Part 96	NO_X Budget Trading Program for State Implementation Plans

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 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 Stanton Plant 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.]

The Stanton Unit B project is a Major Modification of a Major Stationary Source if there will be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. 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. SER values relevant to the project are listed in Table 4 below.

D. Potential Emissions

For each pollutant with a net emission increase 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 impact analysis as applicable.

The project will result in emissions of NO_X, SO_2, CO, $PM/PM_{10}/PM_{2.5}$, SAM, VOC and very minor emissions of lead (Pb), mercury (Hg) and other hazardous air pollutants (HAP). Table 4 summarizes the applicant's estimates of the annual emissions of key PSD pollutants in TPY from the proposed project and indicates the pollutants subject to PSD and to a determination of BACT. Included in these estimates are emissions from the CTG, the DB, the ULSD fuel oil storage tank for VOC, and the cooling tower for PM/PM_{10}.

PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – 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.]

OUC's estimates of maximum potential annual emissions from the proposed NGCC project are summarized in the following table. The emissions from the former IGCC design are included for comparison.

Table 4. Estimated Potential Annual Emissions for IGCC, NGCC versions in TPY.

Pollutant	IGCC (TPY)	NGCC (TPY)	SER (TPY)	PSD Required?
NO_X	1006 (-19)*	80	40	Yes (NGCC)
CO	654	163	100	Yes
PM/PM_{10}	189/179	110/109	25/15	Yes
SO_2	162	55	40	Yes
SAM	22.4	8	7	Yes
VOC	129	19	40	No (NGCC)
Hg	0.01	0.003	0.1	No

* Decrease of 19 TPY after consideration of concurrent reductions from existing coal-fueled Units 1 and 2. The previously proposed reductions will not be enforceable under the NGCC project.

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

A. 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.

B. NO_X BACT Determination

NO_X Formation

NO_X forms in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. 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 gas turbine combustor as seen on the left hand side of Figure 6.

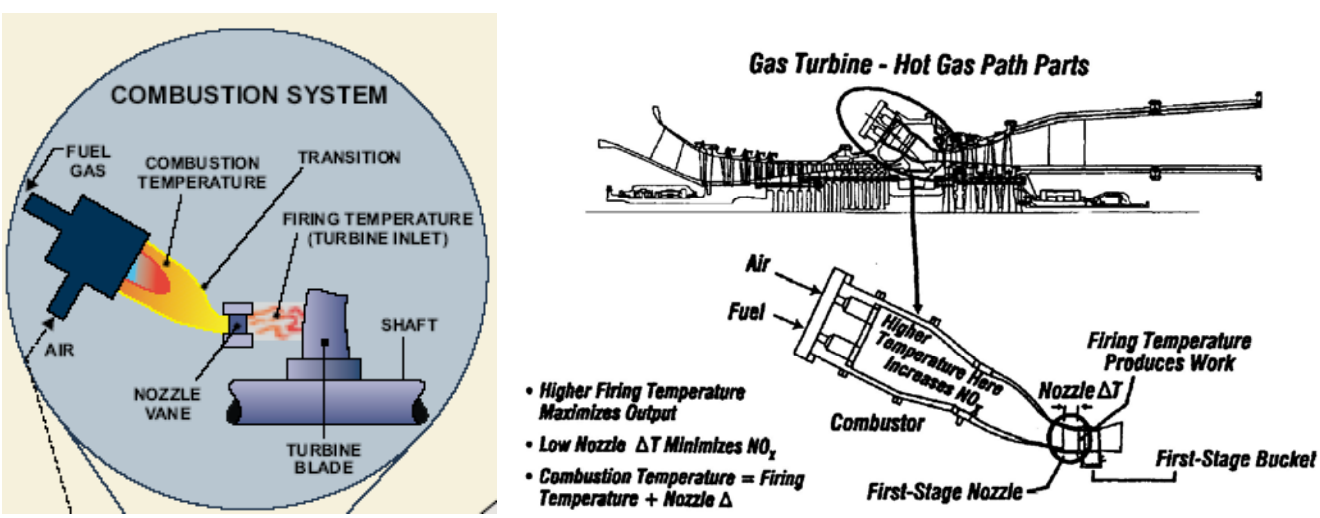


Figure 6. Relation between Combustion and Firing Temperatures and NO_X Formation

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

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

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

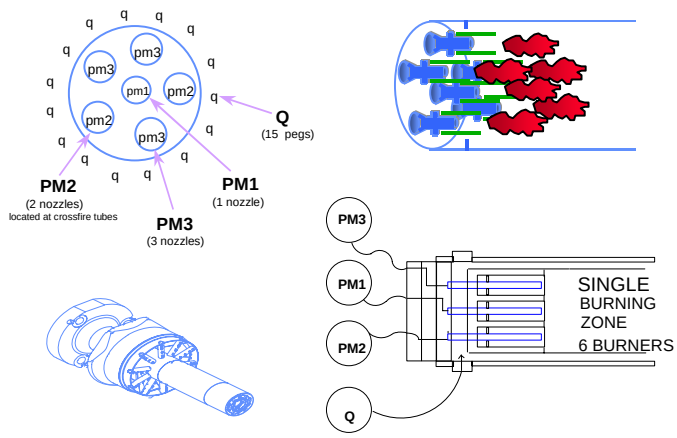
Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order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

CO and VOC 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 7.

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.

NO_X, CO, and VOC design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 8 for a unit tuned to meet a NO_X limit of 9 ppmvd @15% O_2. Based on the design characteristics, the combustor emits NO_X at concentrations of 9 ppmvd @15% O_2 at loads between 50 and 100 percent (%) of capacity, but concentrations as high as 100 ppmvd @15% O_2 may occur at less than 50% of capacity. This suggests the need to minimize operation at low load conditions.



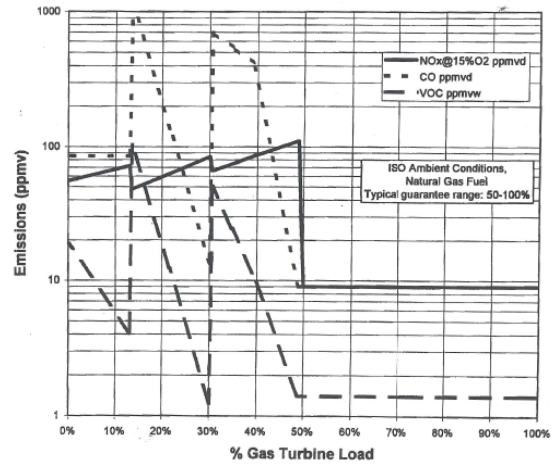
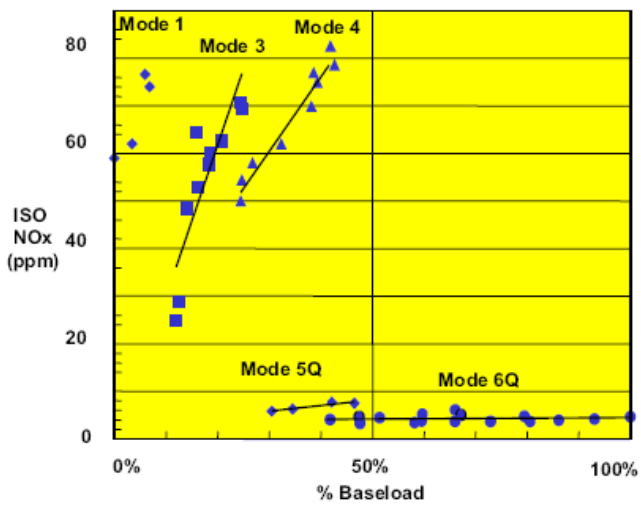


Figure 7. DLN-2.6 Fuel Nozzles. **Figure 8. Design Emissions Characteristics of DLN-2.6.**

The graphs in Figures 9 and 10 are from a GE publication and provide NO_X and CO data from actual installations or possibly test facilities. These graphs suggest that actual emissions using the DLN-2.6 technology are actually less than the design values shown in Figure 8. The data plots also suggest that there is a possibility of turndown to values somewhat less than 50% of full load without excessive emissions.



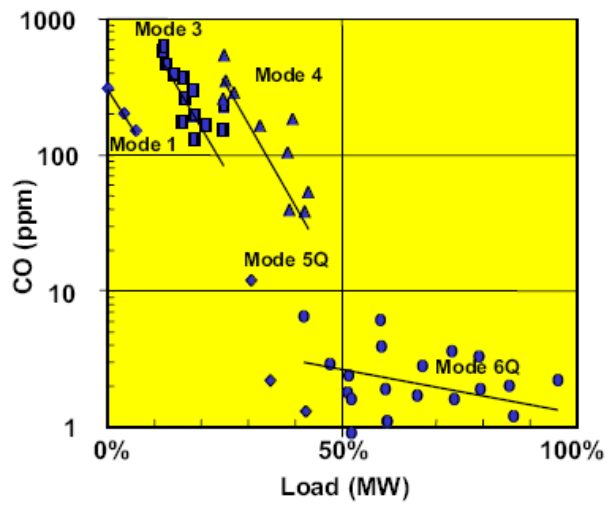


Figure 9. NO_X Emissions from DLN-2.6. **Figure 10. CO Emissions from DLN-2.6.**

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.[1]

Table 5 – City of Tallahassee Purdom Power Plant (Station Unit 8) Test Results

% of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	Not Provided
80	6.1	Not Provided
90	6.6	Not Provided
100	8.7	0.85
Limit	12	25

The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd @15% O_2 of NO_X while burning natural gas although the permit limit is 12 ppmvd @15% O_2.

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.[2] 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 6 – Tampa Electric Polk Power Station Emission Test Results

% 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 8 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 % of full load.[3] It is not certain whether low emissions under such operation are 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 11 below from an EPRI report.[4] 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 all turbine manufacturers to meet the challenges implicit in Figure 11.

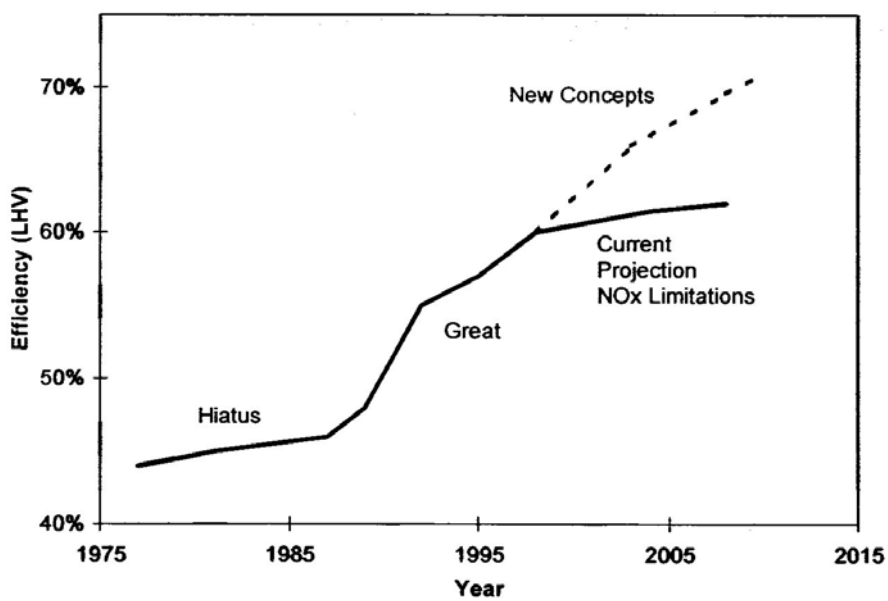


Figure 11 – Efficiency Increases in Combustion Turbines

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 Stanton Unit B.

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% compared with uncontrolled emissions.

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).[5] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE 7FA 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.[6] 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™.[7] 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.[8] 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.[9] 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 OUC Stanton Unit B 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 °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.

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 numerous conventional SCR systems operating in Florida.

Figure 12 (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 13 is a photograph of the existing OUC Stanton Unit A that includes two CTG. The external lines to the ammonia injection grid are visible.

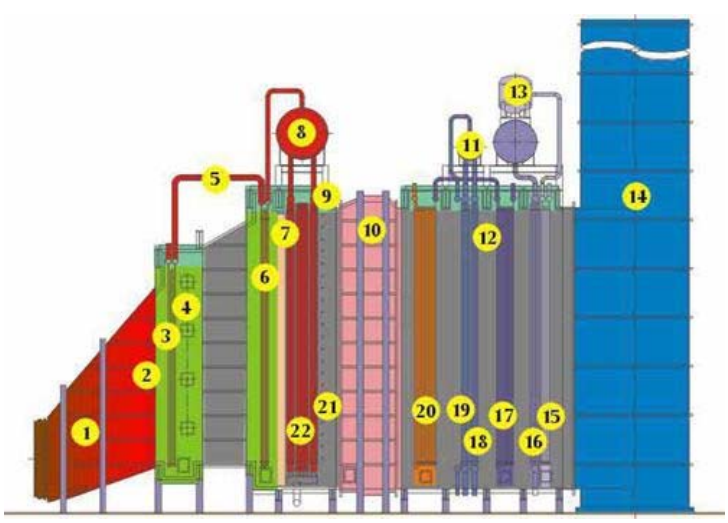


Figure 12 – Key HRSG Components (10 is SCR)

Figure 13 – OUC Stanton Unit A

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

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

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[10]

Table 7. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[11]

% 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

The units consist of two nominal 180 MW gas combustion turbine-electrical generators with an unfired HRSG, and with PA capability. It is noteworthy 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 water injection (WI) in a combined cycle unit or total control on the order of 95 to 99%.

EMx formerly $SCONO_X$. 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 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.

EMx systems were installed at seven sites ranging in capacity from 5 to 43 MW.[12] 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 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 8 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for $SCONO_X$™ (now EMx) developed by the California Air Resources Board for their Legislature.[13] The comparison is for a 500-MW combined-cycle power plant consisting of two CTG and one STG meeting BACT requirements.

Table 8. Cost Comparison between SCR and $SCONO_X$ (now 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

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.

While the Department does not accept or reject the values given in Table 8, it appears that EMx is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant proposed that the NO_X BACT for the Stanton Unit B (including the duct burners) is the use of SCR in conjunction with DLN technology on the CTG while firing natural gas, and SCR with WI while firing ultra low sulfur fuel oil. Fuel oil use will be limited to 1,000 hours per year or less.

The applicant proposed the following BACT limits for NO_X on a 24-hour basis:

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

Department's Draft NO_X BACT Determinations

Table 9 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 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 not the DB were used) even though their limit is 2.0 ppmvd @15% O_2 on a 24-hour basis.

The Department accepts OUC's proposal of 2.0 ppmvd @15% O_2 with an averaging period of 24-hrs, and minimization of fuel oil use to 1000 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.

Table 9. 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)	2 GE 7FA (cancelled)
Towantic Energy, CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3 GE 7FA & DB
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4 GE 7FA & DB
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2 ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4 GE 7FA &DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2 ABB GT-24
OUC Stanton B, FL	**300**	**2.0 – NG (24-hr) 8 – FO**	**1 GE 7FA & DB**
FMPA Treasure Coast, FL	300	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2 WH 501F
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DB
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DB

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

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 (Tables 5 and 6), 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 GE 7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone (Table 7) 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 10 below.

Table 10. 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* and *are* 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.[14] 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.

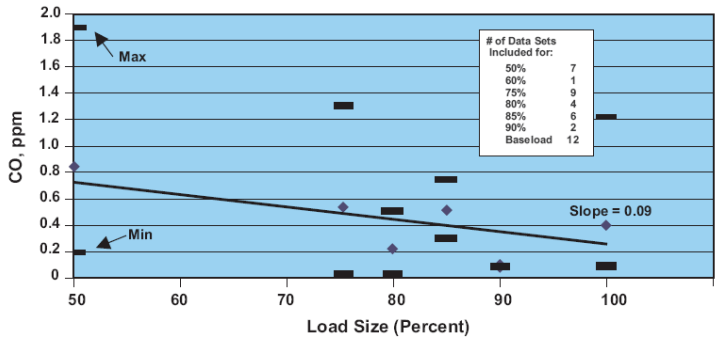


Figure 14. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Duct Burner (DB), Fuel Oil and Power Augmentation (PA) 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 12 in the previous section. TEG enters the HRSG at a relatively high temperature (1,100 to 1,200 °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 15 and 16 are of an individual burner and a HRSG under construction showing horizontal duct burner elements and flow baffles.

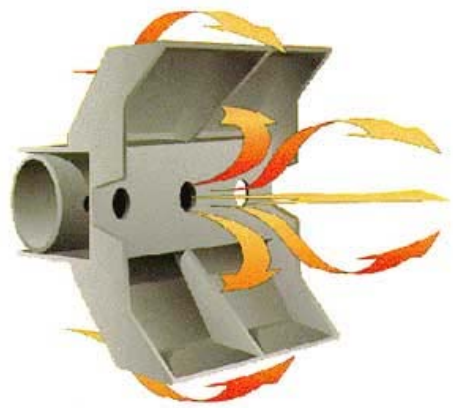


Figure 15 – Individual Burner

Figure 16 – Duct Burner and HRSG (Coen)

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 °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.

Following is a table with the results of CO and VOC testing completed on the two CTG that comprise the existing OUC Stanton Unit A. The two GE 7FA CTG are of the same type that will be installed for Stanton Unit B. Tests were conducted on each CTG while using duct burners (DB) and while practicing PA. CO emissions increase slightly when firing duct burners, but still remain very low. CO emissions were clearly greater when practicing PA.

Table 11. CO and VOC Emissions while Duct Firing – GE 7FA CTG. **(ppmvd@15% O_2)**

Unit (Modes)	CO	VOC
OUC Stanton A25 (CTG)	0.5	0.04
OUC Stanton A26 (CTG)	0.5	0.49
OUC Stanton A25 (CTG & DB)	1.6	0.2
OUC Stanton A26 (CTG & DB)	1.6	0.26
OUC Stanton A25 (CTG, DB & PA)	5.2	0.61
OUC Stanton A26 (CTG, DB & PA)	8.6	0.38

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in Table 12 below.

Table 12. CO and VOC Emissions while firing Fuel Oil - GE 7FA CTG. **(ppmvd @15% O_2)**

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[15]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[16]	2.1	1.1
Stanton A25 (100%)	1.0	1.1
Stanton A26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)[17]	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

Measured CO and VOC emissions were also low during a test of a GE 7FA combined cycle unit (permitted in 1999) at Kissimmee Utilities Authority (KUA) while firing fuel oil and using a gas-fired DB. The results are given in the Table 13. OUC does not propose fuel oil firing while using gas-fired DB, but the results are instructive because even this special case yields low CO, VOC, and NH_3 emissions.

Table 13. Emissions while firing Fuel Oil and Duct Firing - GE 7FA CTG. **(ppmvd @15% O_2)**

KUA 3/Mode[18]	NO_X	CO	VOC	NH_3
CTG & DB & FO	15	1.4	0.1	1.5

Low Load Considerations

Generally speaking, the full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, some regulatory agencies disallow operation at less than 50% load in many 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.

The data in Figure 10 above suggest that there is some turndown capability while achieving low CO emissions. To maintain very low CO, the unit would need to operate in Modes 5Q or 6Q which means that five or all six fuel nozzles and quaternary pegs are in operation. 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.[19] They are summarized in the following table. For reference, a 65 MW load represents roughly 38% of full simple cycle CTG 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.[20]

Table 14. 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

Applicant's CO BACT Proposal

OUC has proposed BACT for CO as the use of good combustion controls while firing natural gas or ULSD fuel oil in accordance with the defined operating hours for each fuel. OUC proposes the following emissions limits as BACT to account for all of the scenarios discussed above.

Table 15. OUC BACT Proposal for CO Emissions from Stanton Unit B. **(ppmvd@15% O_2)**

Modes	CO
CTG on Natural gas	4.1
CTG on Natural Gas & DB	7.6
CTG on Natural Gas & PA (with or without DB)	14.0
CTG on Fuel Oil	8.0
CTG all Modes	8.0 (24 hours)
CTG all Modes	6.0 (12 months)

Department's Draft CO BACT Determinations

Table 16 includes some recent BACT determinations for CO and PM in Florida and other states. OUC's proposal is included for comparison. Some 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.

It is clear from Tables 10, 11, 12 and 13 that CO emissions from the GE 7FA are inherently low for the normal CTG natural gas mode, the duct firing mode and the fuel oil mode even without oxidation catalyst. CO emissions were consistently less than 5 ppmvd @15% O_2. Emissions were also very low to loads equal to 50%.

Table 16. CO 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
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
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
OUC Stanton B, FL	**4.1 – NG (DB off, Annual Test)** **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**
FPL Turkey Pt., FL	4.1 – NG (DB off, Annual Test) 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 Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip

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

Under the much less frequent PA mode, emissions approach 10 ppmvd @15% O_2. Similarly while operating infrequently at loads less than 50%, CO emissions 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.

On a given day, the CTG/supplementary-fired HRSG can operate within the full spectrum of loads (40-100%), modes and fuels. The limited time during which the unit will be operated at low load can be accommodated within the limits proposed by OUC based on the data in Tables 15 presented above. While OUC has requested 1000 hours per year of ULSD fuel oil operation, they will rarely use fuel oil. Given the infrequent use of ULSD fuel oil and the fact that emissions are actually low when firing fuel oil, there would be little benefit in installing oxidation catalyst.

The Department concurs with the OUC proposal for BACT given in Table 15. BACT for CO is determined to be the 4.1 ppmvd @ 15% O_2 for natural gas firing and 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 BACT determination for CO is consistent with recent determinations for the FP&L West County (G-Class), FP&L Turkey Point Unit 5, Progress Energy Bartow Repowering and the FMPA Treasure Coast NGCC project.

OUC claimed that it is not cost-effective to install oxidation catalyst but did not actually submit a cost estimate to support the claim. The most recent estimate for a nearly identical project was submitted by one of the partners in the OUC Stanton Power Plant (the Florida Municipal Power Agency) for the 300 MW Treasure Coast Energy Center. That estimate was approximately $3,400 per ton removed.

A detailed cost assessment for this specific project would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. The cost has also been estimated by General Electric at approximately $8,000 per ton of CO removed within the previously cited report supporting the elimination of oxidation catalyst requirements for CO control on its units. While the Department does necessarily accept or reject the FMPA and GE estimates, the Department concurs that the oxidation catalyst is not cost-effective for the OUC Stanton Unit B project.

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 Stanton Unit B. Average CO emissions during the tests from the four CTG that comprise Unit 5 ranged from 0.26 to 0.94 ppmvd @15% O_2 while firing natural gas (whether ULSD fuel oil 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. The Department believes very low CO emissions will be achieved at Stanton Unit B without oxidation catalyst and without requiring the applicant to obtain even lower emission guarantees from the suppliers.

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 the use of ULSD fuel oil (0.0015% 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 specification of the natural gas is approximately equal to 0.006% (by weight).

OUC estimated 55 TPY of SO_2 and 8 TPY of SAM from Stanton Unit B. This equates to 412 and 40 TPY for SO_2 and SAM respectively from the two combined cycle units. 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 SCF than to 2 gr/100 SCF. The concentration of sulfur in the ULSD fuel oil has been reported at approximately half of the specification.

At such low sulfur concentrations, annual emissions of both pollutants will likely be less than the respective PSD thresholds of 40 and 7 TPY of SO_2 and SAM respectively. The Department accepts OUC's BACT proposal for SO_2 and SAM. This approach is consistent with other recently permitted projects.

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

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

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

Natural gas and ULSD will be efficiently combusted at high temperature in the CTG 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 fuel oil to be combusted contains a minimal amount of ash and will be limited to less than 1000 hours per year making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical.

<u>Other $PM/PM_{10}/PM_{2.5}$ Considerations</u>

<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. 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 exhaust. 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.

<u>Cooling Tower PM Emissions</u>: 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[21]. The amount of particulate matter that may be emitted is based on the solids loading in the re-circulating water.

The applicant's proposal includes a 6-cell, 56,000 gallons per minute (gpm) mechanical draft cooling tower with drift eliminators with a design drift rate of 0.0005% of design water flow. The height of each cell will be 50 feet (nominal) with an exit diameter of 33.5 feet (nominal). OUC estimates annual PM and PM_{10} emissions from the cooling tower to be 2.3 TPY and 0.94 TPY respectively.

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

The applicant determined that the $PM/PM_{10}/PM_{2.5}$ BACT for proposed Stanton Unit B is good combustion controls and the use of natural gas and ULSD fuel oil.

Department's Draft $PM/PM_{10}/PM_{2.5}$ 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 gr S/100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbine may fire ULSD fuel oil as a restricted alternate fuel (≤ 1,000 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 PM. The NO_X, SO_2 and NH_3 control strategies minimize emissions of precursors known to contribute to formation of $PM_{2.5}$ in the environment.

F. New Source Performance Standards Applicable to Gas Turbines and Duct Burners

Stationary gas turbines are subject to the recent federal New Source Performance Standards 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 fuel oil 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 limit in the permit. Subpart KKKK also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations.

G. Summary of Department Draft BACT Determination

Emissions from the gas turbine shall not exceed the values given in Table 17.

Table 17. Draft BACT Determination – Curtis H. Stanton Energy Center Unit 1

Pollutant	Fuel	Method of Operation	Initial and Annual Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	NA	NA	
		CTG & PA with or w/o DB	NA	NA	14.0, 24-hr
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	NA	NA	
$PM/PM_{10}/PM_{2.5}$ [c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			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	CTG, 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 PA 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 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 NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ 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 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 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the 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. 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 (NO_X, CO and Opacity)

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 GE 7FA CTG in lean premix mode is achieved by at least 50% of base load conditions. Startup when the HRSG or STG is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and STG 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 the CTG/HRSG system.

- Excess NO_X and CO 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 NO_X and CO emissions shall not exceed 1 hour in any 24-hour period.
- Excess NO_X and CO 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 NO_X and CO 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 NO_X and CO 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 NO_X and CO 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

DLN 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 NO_X 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 NO_X, 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

Under the rare circumstance that the STG is off line for some reason, it is possible that the CTG/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.

VI. 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. VOC and NO_X are ozone precursors and any net increase of 100 TPY would (in contrast to the present project) require an ambient impact analysis including the evaluation or collection of preconstruction ambient air quality data.

B. Major Stationary Sources in Orange County

The current largest stationary sources of air pollution in Orange County are listed below. The information is from annual operating reports submitted to the Department from 2006. The emissions of NO_X and SO_2 from Stanton Unit B will be minimal (< 1%) compared with emissions from the rest of the plant. The emissions will also be less than the year-to-year variation of present plant SO_2 and NO_X emissions.

Table 18. Largest Sources of SO_2 in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	8193
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**55**
Middlesex Asphalt LLC	Orange County Plant	13
Ranger Construction Industries	Ranger Construction–Winter Garden	10

Table 19. Largest Sources of PM_{10} in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	396
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**109**
Orlando Cogen Limited, L.P.	Orlando Cogen Limited, L.P.	31
Walt Disney World Company	Walt Disney World Resort	13

Table 20. Largest Sources of CO in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	716
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**163**
Florida Gas Transmission Co.	FGTC Station 18	71
Kinder Morgan Energy Partners	Central Florida Pipeline	49

Table 21. Largest Sources of NO_X in Orange County

Owner	Site Name	Tons per year
Orlando Utilities Commission	Stanton Energy Center (Existing)	8823
FL Gas Transmission Co.	FGTC Station 18	548
Walt Disney World Company	Walt Disney World Resort	236
Orlando Cogen Limited, L.P.	Orlando Cogen Limited, L.P.	198
Orlando Utilities Commission	**Stanton Unit B (Proposed)**	**80**

C. Air Quality and Monitoring in the Orange County

The Orange County Local Program operates twelve criteria pollutant monitors at five sites measuring PM_{10}, $PM_{2.5}$, ozone (O_3), CO, nitrogen dioxide (NO_2) and SO_2. The 2007 monitoring network is shown in the figure below.

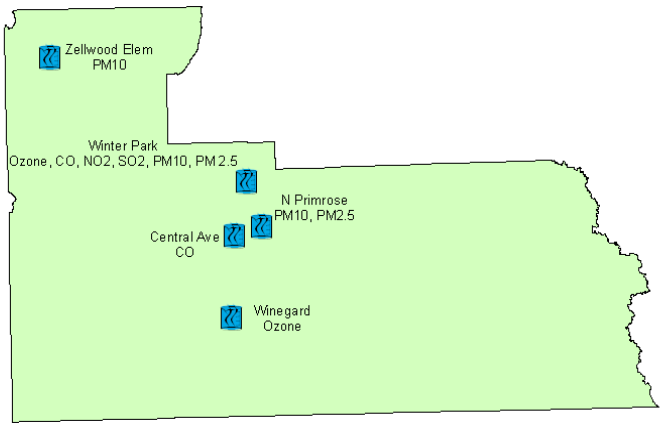


Figure 17. Orange County Ambient Air Monitoring Network

The results of monitoring conducted during 2006 are summarized in the following table. All of the stations were in attainment with the corresponding ambient air quality standards (AAQS).

Table 22. Ambient Air Quality in Orange County Nearest to Project Site (2006)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	N Primrose	24-hour	42	38		150 [a]	$\mu g/m^3$
		Annual			21	50 [b]	$\mu g/m^3$
$PM_{2.5}$	Winter Park	24-hour	36	29		35 [c]	$\mu g/m^3$
		Annual			11	15 [d]	$\mu g/m^3$
SO_2	Winter Park	3-hour	10	9		500 [e]	ppb
		24-hour	3	3		100 [e]	ppb
		Annual			1	20 [b]	ppb
NO_2	Winter Park	Annual			9	53 [b]	ppb
CO	Central Avenue	1-hour	3	2		35 [e]	ppm
		8-hour	2	2		9[e]	ppm
Ozone	Winegard	1-hour	0.102	0.089		0.12 [f]	ppm
		8-hour	0.083	0.082		0.08 [g]	ppm
		8-hour	2007 3-yr attainment		81	85	ppb

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. Not to be exceeded on more than an average of one day per year over a three-year period.
g. Three year average of the 4th highest daily maximum 8-hr average over each year

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 2010, the areas shown in the following figure (including Orange County) may no longer be in attainment with the applicable ozone AAQS.

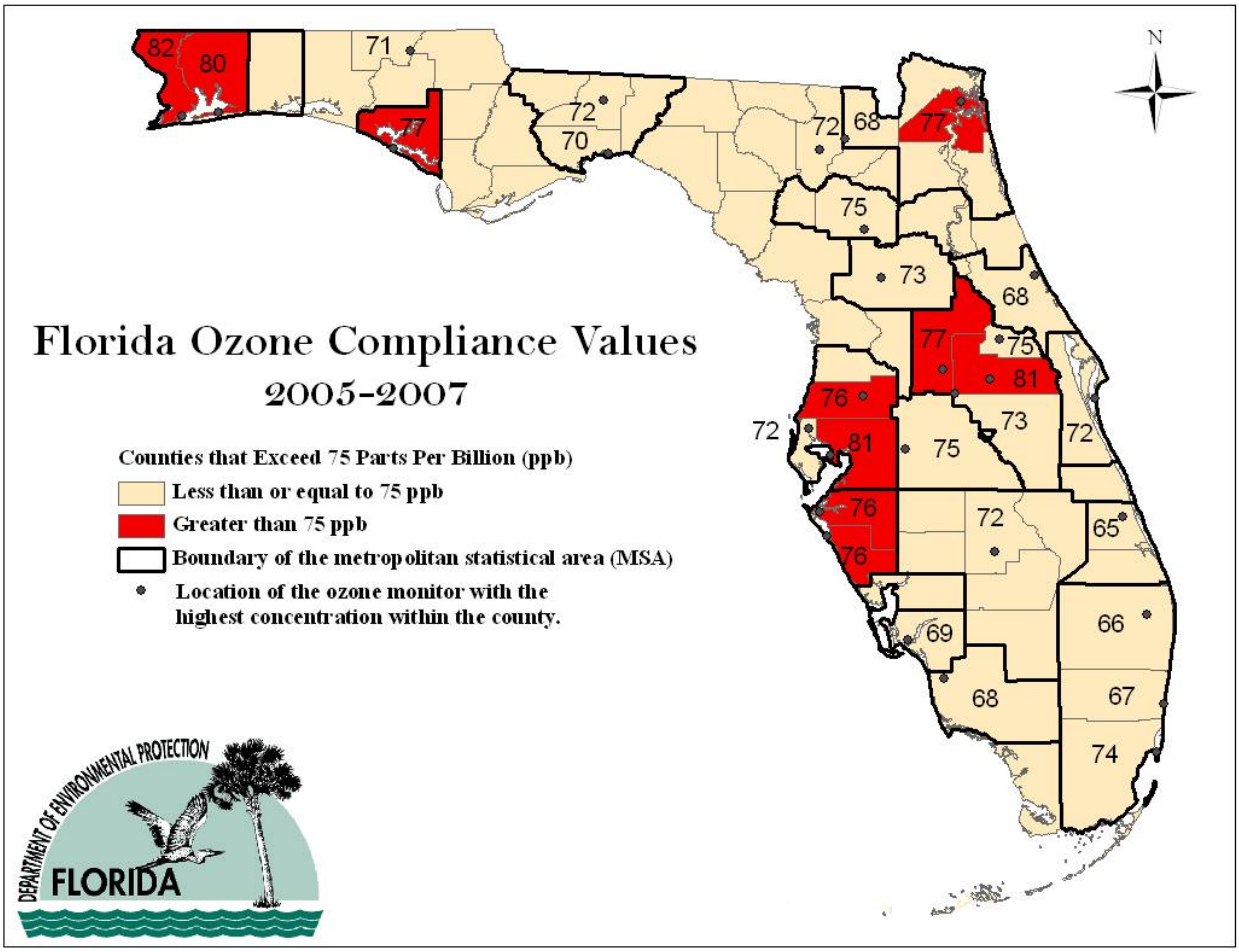


Figure 18. Map indicating Areas Registering an ozone Value Greater than 75 ppb.

Some of the recent trends in ambient air quality in Orange County are depicted in the following figures.[22]

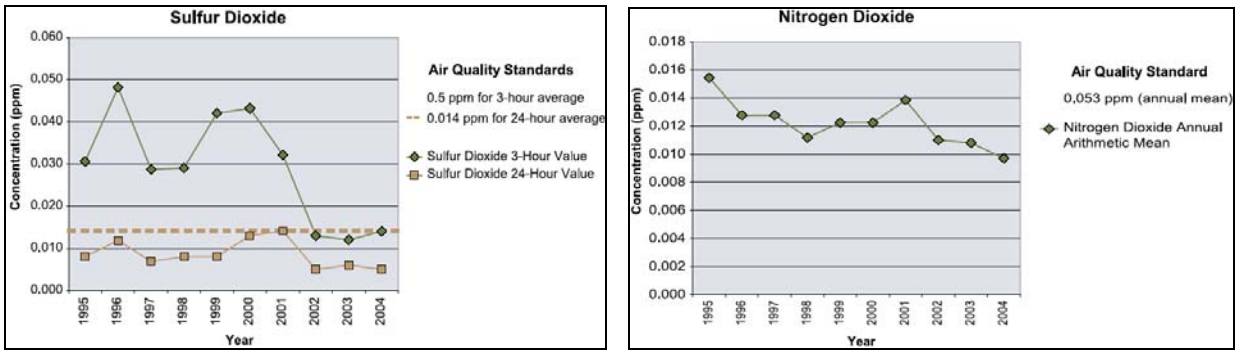


Figure 19. SO_2 and NO_2 Trends in Orange County Florida. 1995-2004.

A large reduction in maximum 3-hour and 24-hour SO_2 trends is clear. The main reason for the reduction is FPL's natural gas repowering project at the residual fuel oil-fired Sanford Power Plant. The benefits of the repowering between 2000 and 2002 overwhelmed the startup of coal-fueled Stanton Unit 2 (with a flue gas desulfurization scrubber) that occurred in 1997. The net reduction in combined SO_2 emissions from the two plants is on the order of 20,000 tons per year.

A similar trend is noticeable in NO_2, (NO_X indicator pollutant). This again suggests beneficial effects of the Sanford Power Plant repowering project and NO_X emissions reductions even with the Stanton Unit 2 project (that incorporated an SCR system).

A trend towards lower ozone is also seen in the following figure that is partially explained by the reduction in precursors (NO_X).

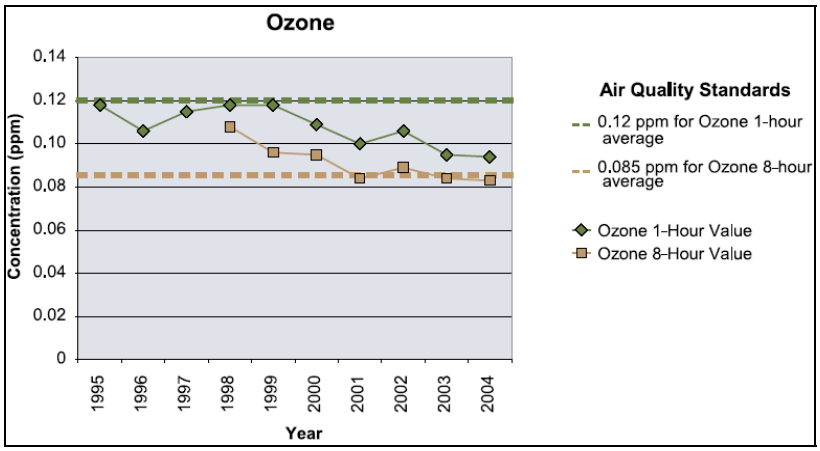


Figure 20. Ozone (O_3) Trends in Orange County Florida. 1995-2004.

Ozone trends also reflect VOC emissions, contributions from transportation emissions, the climatological cycles and the presence of meteorological conditions such as hot ambient temperature, solar insolation, high pressure, and relatively low wind speed that contribute to ozone formation and persistence. The 2007 value of 81 ppb (0.081 ppm) demonstrates a leveling of the trend towards progressively declining ozone values seen between 1998 and 2004. The large regional NO_X decreases expected due to the Clean Air Interstate Rule (CAIR) may yet help reestablish the downward trend in order to meet the new EPA standard of 75 ppb.

D. 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 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 SIL for the PSD Class I Chassahowitzka National Wildlife Refuge (CNWR) and the PSD Class II Area (everywhere except the Class I area).

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 3 kilometers. Beyond 3 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 6 kilometers from the facility. From 6 to 15 kilometers, Cartesian receptors with a spacing of 500 meters were used.

According to the application, 113 receptors, identified by the National Park Service, were used for the CNWR Class I analysis.

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 less than the applicable SIL 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 23. Maximum Projected Air Quality Impacts from OUC Stanton Unit B Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Baseline (2006) Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	No
	24-Hour	0.5	5	~8	260	No
	3-Hour	1.4	25	~26	1300	No
PM_{10}	Annual	0.1	1	~21	50	No
	24-Hour	1.5	5	~42	150	No
CO	8-Hour	5	500	~2300	10,000	No
	1-Hour	4	2000	~3450	40,000	No
NO_2	Annual	0.3	1	~17	100	No

It is clear 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 CNWR located about 144 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 SIL for the Class I area. Therefore, no further detailed modeling efforts are required.

Table 24. Maximum Air Quality Impacts from the OUC Stanton Unit B Project for comparison to the PSD Class I SIL at CNWR

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (µg/m^3)	Class I Significant Impact Level (µg/m^3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.03	0.3	No
NO_2	Annual	0.001	0.1	No
SO_2	Annual	0.0004	0.1	No
	24-hour	0.01	0.2	No
	3-hour	0.02	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 uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	1.5	10	~42	No
NO_2	Annual	0.2	14	~17	No
SO_2	24-hour	1	13	~8	No
CO	8-hour	5	575	~2300	No

Projects with VOC or NO_X emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including sophisticated modeling and gathering of preconstruction ambient air quality data. The proposed project predicts worst case emissions to be less than 100 tons per year for these ozone precursors and thus is not subject to an ambient impact analysis for ozone.

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

- 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 Orlando International Airport and Tampa/Ruskin respectively. The 5-year period of meteorological data was from 1999 through 2003. These airport stations were selected for use in the study because they are most representative of the project site.

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 EPA regulatory version of the California Puff (CALPUFF) dispersion modeling system was used to evaluate the pollutant emissions from the proposed project in the Class I CNWR beyond 50 km from the proposed project. The meteorological or (CALMET) dataset was processed using prognostic model data (MM4 and MM5) 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.

E. ADDITIONAL IMPACTS ANALYSIS

Impact on Soils, Vegetation, and Wildlife:

The NGCC version of Stanton B replaces the previously approved IGCC version. In terms of gross emissions, those from the NGCC project will be less than the previously planned IGCC unit. The impact of the NGCC project on soils, vegetation and wildlife will likely be less than the previously projected non-adverse impact of the IGCC unit.

In contrast to the NGCC project, the IGCC project included a cap on NO_X from the two coal-fueled units (Stanton Units 1 and 2) and a permanent reduction of approximately 1,000 TPY of NO_X that effectively offset the similar increase permitted for the IGCC project.

As a practical matter, it is likely that significant NO_X emission reductions will still be realized from Units 1 and 2 given the recent projects actually under construction to install improved low NO_X burners and overfire air (OFA) on the two units. Therefore, it may be fair to compare the 80 TPY increase from the NGCC with the previously projected NO_X emission level of 1006 TPY from the IGCC without the offsets from Units 1 and 2.

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 National Park Service.

The Department concludes that there will be minimal air impacts, if any, on flora, fauna and soils.

Impact on Visibility:

The applicant submitted a regional haze analysis for the CNWR. The analysis included modeling from the CALPUFF model. The National Park Service threshold for visibility percent change in extinction is 5%. The modeling results concluded that the new unit will not contribute to an adverse impact.

Minimization of acid rain and ozone precursors also minimizes fine particulate emissions, fine particulate formation in the environment and thus regional visibility effects.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, population growth in the area of the proposed project, Orange County, has doubled from 1980 to 2000. Housing units have also doubled in the same time period. The Orlando population as of 2003 was 1,755,000. Most of the growth has been tourism-dominated. This tourism-dominated growth has lead to an increase in mobile source activity in terms of vehicle miles traveled. However, increases in air pollution due to mobile sources have been counteracted by cleaner fuels and technological advances.

The beginning of the decade has shown that growth in the area has slowed. New power plants in the area have included good air pollution control equipment and the large existing residual oil fired plant has been repowered with natural gas.

VII. CONCLUSION

The Department has reasonable assurance that the proposed Stanton Unit B project will comply with the Department's regulations and has made a preliminary decision to issue a permit under the Rules for the Prevention of Significant Deterioration. The Department has reviewed and concurs with the applicant's BACT proposals.

Based on the ambient air quality review, the Department concludes that the project will neither cause nor contribute to a violation of ambient air quality standards or increments. Furthermore, there will not be significant impacts on soils, wildlife or vegetation.

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