TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power Corporation dba
Progress Energy Florida
P.L. Bartow Power Plant

1,475 Megawatt Power Plant Repowering Project
New Gas-fueled Combined Cycle Unit and Simple Cycle Unit
Shutdown of three Residual Oil-fueled Units

Pinellas County

DEP File No. 1030011-010-AC (PSD-FL-381)

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

December 13, 2006

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power Corporation dba
Progress Energy Florida
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Rufus Jackson

Processing Schedule

- July 31, 2006: Received PSD application
- August 30: Department's Request for Additional Information (RAI)
- October 3: Received Response to RAI
- October 26: Received Additional Information
- December 13: Intent to Issue, Draft PSD Permit, and Technical Evaluation Distributed

Facility Description and Location

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) proposes to construct a natural gas-fueled combined cycle unit and a simple cycle unit and to shut down the three residual oil-fueled units at the P.L. Bartow Power Plant on Weedon Island on the eastside of St. Petersburg, Pinellas County. The location with respect to other PEF facilities in Florida is shown in Figure 1. Also shown is the location of Weedon Island within Tampa Bay.

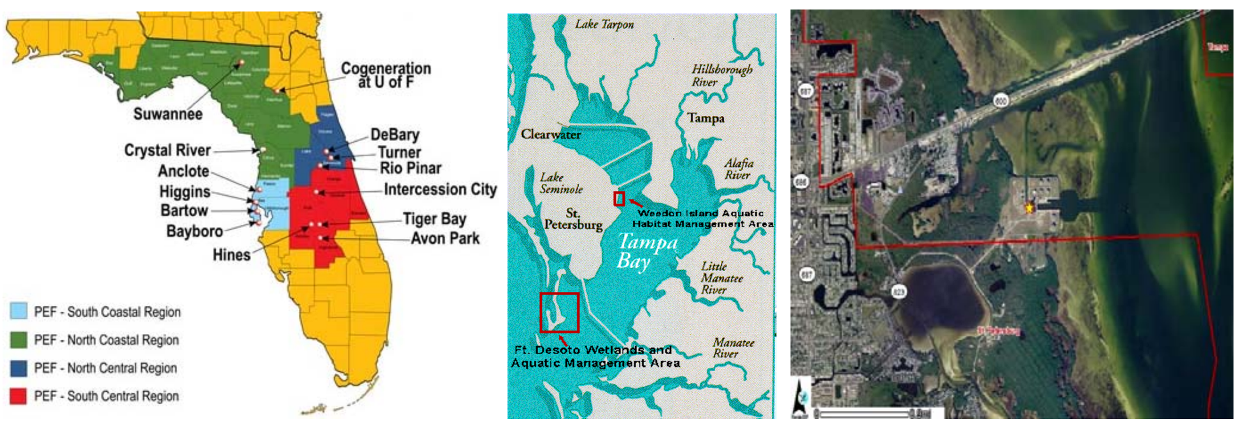


Figure 1. Bartow Power Plant in PEF System and Location of Weedon Island and Plant.

The plant is located approximately 83 km south of the PSD Class I Chassahowitzka Wilderness Area. The facility UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

Standard Industrial Classification Codes (SIC)

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

Regulatory Categories

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources: The proposed project is subject to 40CFR60, 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. Stationary combustion turbines subject to KKKK are exempt from 40 CFR 60, Subpart GG. Heat recovery steam generators and duct burners subject to KKKK are no longer subject to 40 CFR 60, Subparts Da, Db and Dc for duct burners.

Title I, Section 112, Clean Air Act, Hazardous Air Pollutants (HAP): The existing facility is a major source of HAPs. Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions. Because the CTs for this project will have the potential for an aggregate oil-firing total of 5,000 hours (>> 1,000 hours applicability threshold) during any calendar year, Subpart YYYY is applicable.

Title I, Part C, Clean Air Act, 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 F.A.C.

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 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}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Clean Air Interstate Rule (CAIR): The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting): The facility was <u>not</u> certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is <u>not</u> subject to Siting because there will be no net increase in <u>steam</u>-generated electrical power. [Design; Letter from Applicant to Siting Office dated December 19, 2005]

2. PROPOSED PROJECT

Project Description

The project is the construction of a gas-fueled combined cycle unit with a nominal rating of 1,280 megawatts (MW) at ISO conditions and a gas-fueled simple cycle unit combustion turbine-electrical generator with a nominal rating of 195 MW at ISO conditions.

The combined cycle unit will consist of: four Siemens SGT6-5000F combustion turbine-electrical generators (CTG) with a nominal rating of 215 MW at ISO conditions when practicing power (steam) augmentation; four supplementary-fired heat recovery steam generators (HRSG's) each equipped with a nominal higher heating value (HHV) 500 million Btu per hour (mmBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG).

Each CTG within the combined cycle unit will also be capable of operating in simple cycle by directing the exhaust to a bypass stack instead of to the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

The simple cycle CTG will exhaust through its own 120 foot stack. All CTGs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures. Each CTG will be capable of firing backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). Two 3.5 million gallon distillate fuel oil storage tanks are included.

A single auxiliary boiler with a nominal capacity of 85,000 pounds per hour (lb/hr) of steam and a heat input rating less than 100 mmBtu/hr will be included for the initial combined cycle unit startup and occasionally thereafter when steam is not available during a startup.

Five gas-fired fuel heaters each with nominal heat input ratings of 3 mmBtu/hr will be provided to maintain natural gas fuel for the CTGs at temperatures above the dew point. A nominal 300 hp diesel-fueled emergency fire pump is also included. Following is a listing of the new emissions units for the proposed project.

ID	Emissions Unit Description
009	Unit 4A – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
010	Unit 4B – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
011	Unit 4C – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
012	Unit 4D – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
013	Unit 5 – one 195 MW (ISO) gas turbine operating in simple cycle mode
014	One nominal 85,000 lb/hr (99 mmBtu/hr) auxiliary boiler
015	Five nominal 3 mmBtu/hr gas-fired process heaters
016	Two nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
017	One nominal 300 horsepower diesel-fueled emergency fire pump

* ISO indicates nominal rating at sea level, 59 degrees F and 60% relative humidity. The ratings shown for the CTGs associated with the combined cycle unit reflect gas firing and power (steam) augmentation.

Following are additional project characteristics.

- Primary Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and low sulfur distillate oil. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing.
- Add-on Controls: Selective catalytic reduction (SCR) systems will be installed on the CTGs used in the combined cycle unit to further reduce NO_X emissions during combined cycle operation. The extent of reduction below the permitted emission limit will depend on the company's NO_X strategy to comply with the Clean Air Interstate Rule (CAIR).

- Continuous Monitors: Each CTG stack equipped with continuous emission monitoring systems (CEMS) as required to monitor NO_X emissions in accordance with the acid rain provisions. Each HRSG stack will have a NO_X CEMS and a CO CEMS that will be 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.

The following figure includes a photograph from the Progress Energy website of the three existing residual oil-fueled units taken in a south/southwesterly direction. The other graphic is an artist rendition of the combined cycle unit in an east/northeasterly direction. The eight stacks associated with the combined cycle are clearly shown. Also shown are the stacks of the three existing units destined for shutdown.

Figure 2. P.L. Bartow Units 1, 2 and 3. Artist's Rendition of New Combined Cycle Unit

The shut down of the three units will be quite noticeable as they are presently fueled by 2.5% sulfur residual fuel oil. Also the existing units are subject to a 40% visible emissions standard and are allowed even greater opacity during soot blowing. By contrast, the new unit will use inherently clean fuels and will typically exhibit no visible emissions.

The project will also require, via separate permits, the upgrading about four miles of underground transmission lines and the construction of a 17-mile long underwater natural gas pipeline by Gulf Stream Natural Gas L.L.C.

PEF requests that two of the new CTGs be available for simple cycle service for a period of seven months prior to shut down of Units 1, 2 and 3. The other two CTGs associated with the combined cycle unit will be placed in service as part of the combined cycle unit is in service after Units 1, 2 and 3 shut down. The ramifications of the early startup of two CTGs in simple cycle are discussed below.

Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A longitudinal section diagram of a Siemens SGT6-5000F (compressor, combustor section and rotor inside of casing) is shown in the left hand side of the figures below. The photograph (Siemens 2005 PowerGen presentation) on the right hand side of the figure is of the compressor and rotor section within the bottom half shell. The compressor rotating blades are on the left hand side of each graphic and the 4-stage expansion section is towards the right.

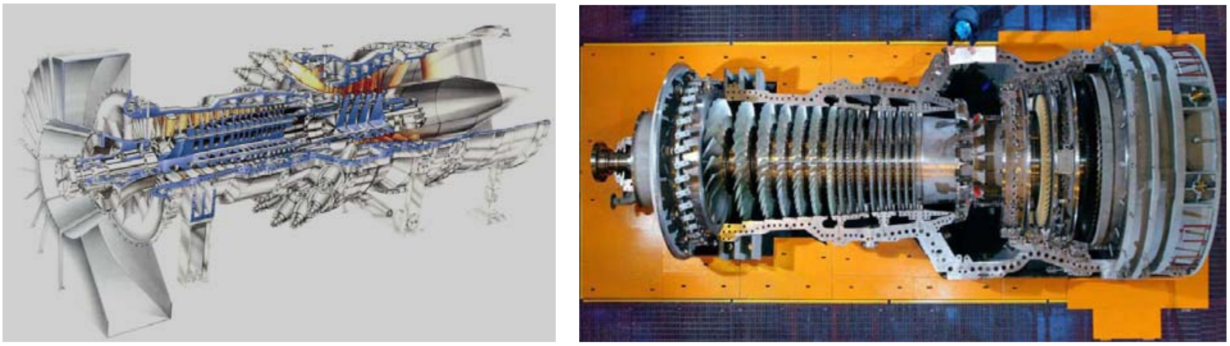


Figure 3. SGT6-5000F. Internal View and Overhead View of Compressor and Rotor.

Ambient air is drawn into the 16-stage compressor of the 5000F where it is compressed to a pressure ratio of approximately 17 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate air-cooled, can-annular, Dry Low NO_X (DLN) combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is on the order of 2,500 ºF.

The hot combustion gases routed through the air-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas (TEG) is discharged at a temperature of approximately 1100 ºF and high excess oxygen. The TEG is available for additional energy recovery.

A basic combined cycle unit with only one CTG, unfired HRSG and a steam turbine-electrical generator (STG) is depicted in Figure 4. The heat from the reheated TEG is used to raise steam in the HRSG. The steam from the HRSG, in-turn, drives the STG producing additional electrical power.

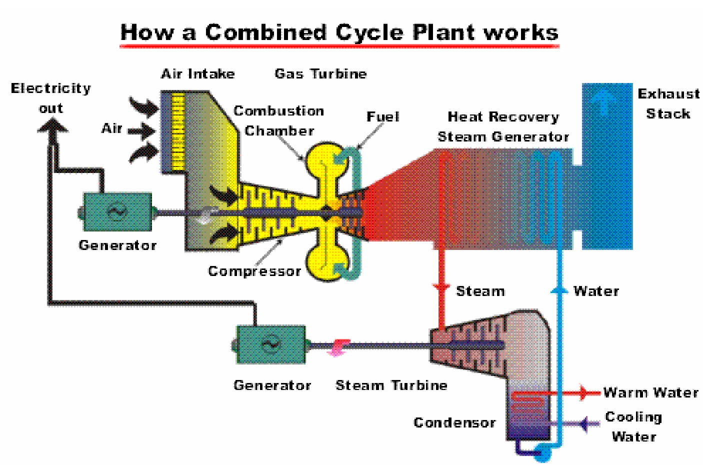


Figure 4. Combined Cycle Unit (Unfired HRSG)

The proposed project will have four CTGs and four HRSGs that will drive a single STG. The TEG will be reheated by natural gas fired in the duct burners located within each HRSG. Some of the steam will be returned to the CTGs to produce extra power by steam augmentation.

In simple cycle mode, the thermal efficiency of the Siemens SGT6-5000F is approximately 37 percent (%) on the basis of lower heating value (LHV) and 34% on the basis of higher heating value (HHV). In combined cycle mode, the thermal efficiencies are approximately 57% and 52% based on LHV and HHV respectively.

Additional features of the combined cycle unit include:

- Inlet Conditioning: Evaporative cooling 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 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. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2,434 hours of duct burning per year for each HRSG.
- Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PA causes greater uncontrolled CO emissions. The applicant requests 1,688 hours of PA for each CTG.
- Simple Cycle (SC) Mode: Bypass stacks have been included in the design allowing the CTGs associated with the combined cycle unit to operate in SC mode. This is a low probability scenario given the lower thermal efficiency. However it allows operation if there are STG, HRSG, or main condenser problems that would preclude operation in combined cycle mode.

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

3. RULE APPLICABILITY

<u>Federal Regulations</u>

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

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 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

State Regulations

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

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

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 PEF P.L. Bartow Power 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 Repowering 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: 100 tons per year (TPY) of carbon monoxide; 40 TPY of nitrogen oxides (NO_X), sulfur dioxide (SO_2), or volatile organic compounds (VOC); 25 TPY of particulate matter (PM); 15 TPY of PM smaller than 10 microns (PM_{10}); 7 TPY of sulfuric acid mist (SAM); or 0.6 TPY of lead (Pb). [Rule 62-210.200(185)(a)1., F.A.C.]

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. BACT determinations for this project are required for CO and VOC only for reasons described below.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

Estimates of Net Emissions Increases

The new combined cycle unit and new simple cycle unit will result in emissions of CO, NO_X, SO_2, PM/PM_{10}, SAM and VOC. The shut down of the three residual oil-fueled units will result in reductions of the same pollutants.

The following table is a summary of the emissions increases and decreases resulting from the proposed project to determine which pollutants will be emitted in excess of their respective SERs.

Table 1. Applicant's Summary of Net Emissions Increases and PSD Applicability for the P.L. Bartow Plant Repowering Project Permanent Scenario.

Pollutant	Baseline Emissions TPY	New Units Potential Emissions TPY	Net Emissions Increases (Decreases) TPY	PSD SER TPY	PSD?
SO_2	24,816	466	(24,350)	40	No
PM/PM_{10}	804/559	413/413	(391)/(146)	25/15	No
NO_X	4,043	3,191	(852)	40	No
CO	367	938	571	100	Yes
VOC	57	145	88	40	Yes
SAM	423	72	(351)	7	No
Lead	0.10	0.06	(0.04)	0.6	No
HAPs	No Estimate	23.1	< 23.1	NA	No

The baseline emissions are for Units 1, 2 and 3 that are destined for shut down. SO_2 and NO_X emissions were calculated using the continuous emissions monitoring systems (CEMS) required by the Acid Rain Program. These two pollutants account for 95% of the present PSD pollutant emissions. The rest of the emissions were calculated by annual emissions tests or by emission factors.

There will be decreases in all PSD pollutants except for CO and VOC. Given the high opacity limits at the existing units, the quality of fuel used and the frequency of soot blowing, the Department believes that baseline annual PM/PM_{10} emissions are greater than estimated and that reductions will be greater than estimated. The applicant's estimates of baseline PM/PM_{10} and CO are likely conservative and tend to make it more likely that PSD will apply than otherwise.

Although no baseline estimates of HAPs are provided, the switch from residual fuel oil to inherently clean fuels will reduce emissions of nickel (Ni, a HAP) and vanadium (V, not classified as a HAP) that tend to catalyze the oxidation of SO_2 to SAM.

According to the applicant's estimates, net emissions increases of CO and VOC will be greater than their respective SERs. Therefore, a PSD review and determinations of BACT are required for those pollutants.

The applicant has requested authorization to use two of the CTGs for a seven month period prior to the permanent shut down of Units 1, 2 and 3. During the period December 2008 through June 2009, those CTGs will be operated as simple cycle peaking units (intermittent duty with rapid startup to full load operation) prior to their incorporation into the combined cycle unit.

Because this initial phase will occur prior to the shut down of Units 1, 2 and 3 it is not possible to take "credit" for contemporaneous emissions reductions when calculating net emissions increases. Rather than making permanent and enforceable emissions reductions from Units 1, 2 and 3 the applicant will insure that emissions from the initial simple cycle phase will not exceed the respective significant emission rate (SER) for any PSD pollutant.

The following table is a summary of the emissions increases resulting from the operation of two CTGs in simple cycle mode.

Table 2. Applicant's Summary of Net Emissions Increases and PSD Applicability for the Operation of two CTGs in Simple Cycle Mode for Seven Months.

Pollutant	Emissions from Two Simple Cycle CTGs tons	PSD SER TPY	PSD?
SO_2	<< 39	40	No
PM/PM_{10}	< 24/14	25/15	No
NO_X	39	40	No
CO	< 99	100	No
VOC	<< 39	40	No
SAM	<< 6	7	No
Lead	<< 0.6	0.6	No

According to the equipment characteristics NO_X is the controlling pollutant with respect to PSD applicability. Over three times as much NO_X will be emitted compared with CO. During this temporary period of simple cycle peaking, the Department will limit NO_X emissions to 39 tons from both units (combined) with compliance demonstrated by CEMS. In addition, the total aggregate hours of operation will be limited to 1,100 hours during this period. By doing so, the Department will have reasonable assurance that emissions of all pollutants will be less than their respective SERs. The units will still be subject to the unit specific requirements of this permit and 40 CFR 60, Subpart KKKK-Standards of Performance for Stationary Combustion Turbines.

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

4.1 BACT Determination Procedure

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

(a) *An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:*

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*

3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

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

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

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

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

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

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

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

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

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

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

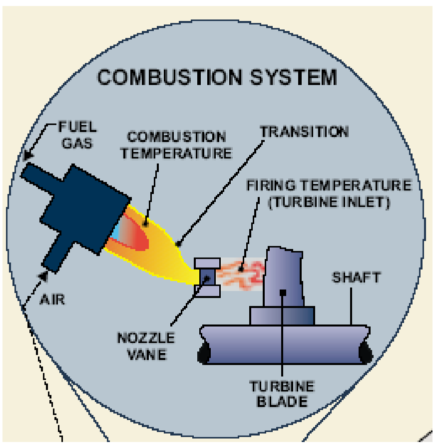
4.2 NO_X Emission Technology and Limits (non-BACT)

Although a BACT determination is not required for NO_X, it is nevertheless useful to discuss the technology to be employed for NO_X in order to gain a better understanding of the possibilities and limitations to CO and VOC control. Additionally, it is necessary to insure that the project will comply with the NO_X requirements given in 40 CFR 60, Subpart KKKK.

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 5. 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 5, which is from a GE discussion on these principles.



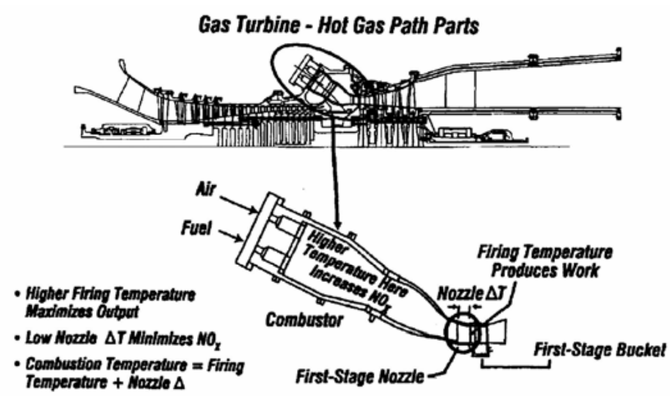


Figure 5. Relation between Combustion and Firing Temperatures and NO$_X$ Formation

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 range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the PEF 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.

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

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

The traditional DLN combustor for the Siemens/Westinghouse 501FC engine (the predecessor of the SGT6-5000F) was a partially premixed combustor, with a center-core pilot diffusion flame surrounded by eight lean premix nozzles where the fuel is injected at multiple ports inside the combustor and mixes with the combustion air in advance of the flame zone.

Figure 6 shows the combustor with the air bypass configuration (eliminated from some recent models).[1]

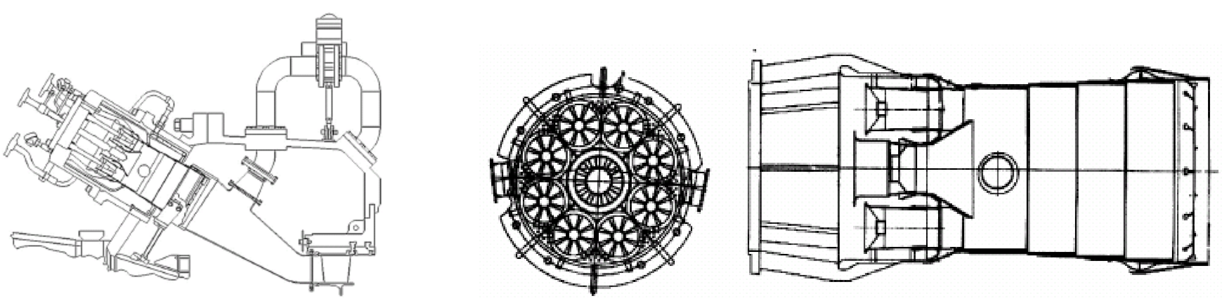


Figure 6. Siemens/Westinghouse 501FC DLN System and Combustion Basket.

In the combustor, natural gas is injected into three or four stages; pilot, A, B, and C (for certain configurations). The diffusion flame pilot injector provides stability for the premixed A, B, and C-stages. Because a diffusion flame has high NO_X emissions it is necessary to minimize the amount of flow through the pilot.

The majority of the fuel is injected upstream of the pilot through the main A and B stages. The main fuel is injected tangential to the flow direction through 8 fuel rockets each with 4 fuel injection holes. This fuel premixes with the air before reaching the combustion zone. During the C-stage, a small amount of fuel is injected in a zone called the “top hat” region before the flow enters the basket.

The C-stage provides additional premixing of the fuel and air and allows a reduction in the pilot fuel flow. Typically the DLN combustor is ignited on the pilot and A-stage. The B-stage is initiated at 30% load and the C-stage is initiated at 50% load.

According to Siemens, a DLN combustion system improvement reduced NO_X from >25 parts per million by volume (ppmv) down to <9 ppmv and was successfully demonstrated on a service unit in 2004.[2] The exact profile with respect to load for that installation is not known. Presumably values significantly greater than 9 ppmvd occur during the pilot, A-Stage, B-Stage and early C-Stage operational loads.

The exact features of the DLN (or possibly Ultralow NO_X - ULN) technology that will be incorporated into the proposed project are not yet known to the Department. However, the applicant has proposed to meet NO_X limits of 15 ppmvd for natural gas firing to meet the requirements of 40 CFR 60, Subpart KKKK for combined cycle units. It appears that this value can be accomplished with the described DLN technology.

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

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

Figure 7 below is a diagram of the typical Nooter Eriksen (NE). NE supplied the HRSGs for the PEF Hines Energy Complex Power Block 1 also shown in the figure.

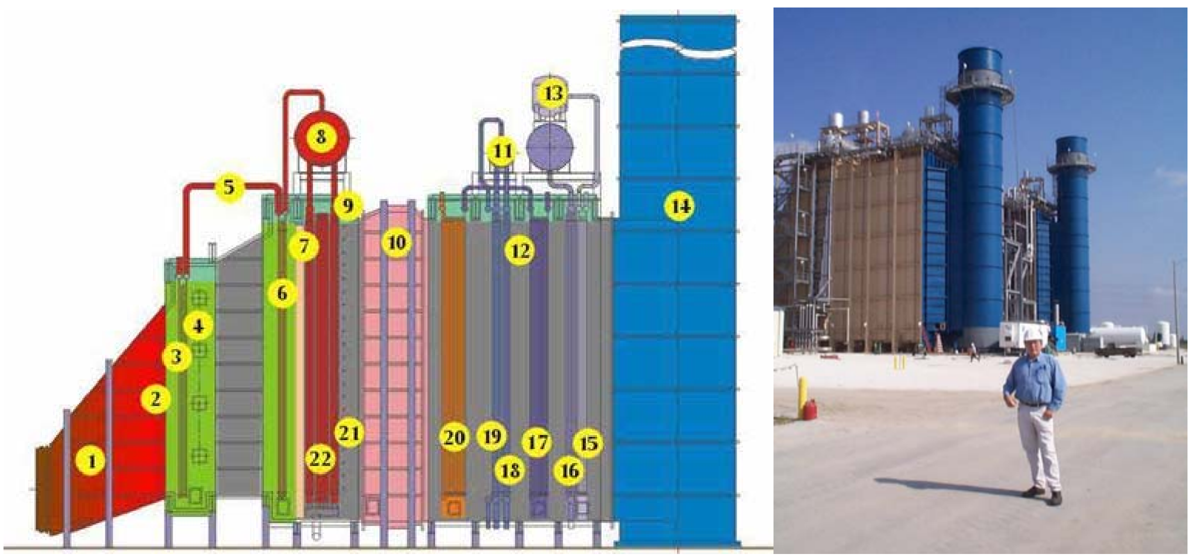


Figure 7. Key Nooter Eriksen HRSG Components (10 is SCR) and PEF Hines Block 1

Components 10 and 21 represent the SCR reactor and the ammonia injection grid. In this arrangement the SCR system lies between the high pressure evaporator (22) and the high-pressure economizer (20) where the temperature requirements for conventional SCR can be met.

The external lines to the ammonia injection grid are easily visible in the photograph. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

In the given design, the duct burner (4) lies between a "split" high pressure superheater (3 and 6). For future reference in discussion below, the CO catalyst in this design is Component 7.

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. SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order of 95 to 99%.

Although the combined cycle unit can likely comply with the requirements of Subpart KKKK, PEF will install an SCR system within each of the four HRSGs. When used, this will further insure compliance and will also provide flexibility in achieving PEF's overall company strategy pursuant to the Clean Air Interstate Rule (CAIR).

4.3 CO and VOC BACT Determination

CO and VOC Formation and Combustor Characteristics

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

The following table contains proposed CO and VOC emission estimates provided in the application for the SGT6-5000F CTGs that will be used for the project.

Table 3. Applicant's CO and VOC Estimates for SGT6-5000F CGTs (ppmvd @15% O_2)

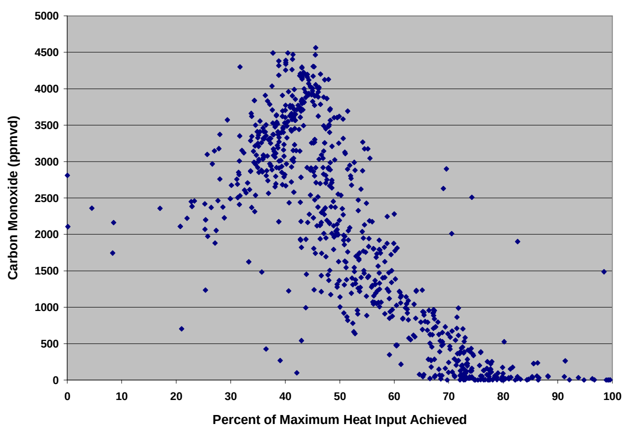
Load Range	Fuel/Mode	CO	VOC
70-100%	Gas	4	1
60-70%	Gas	10	4
100%	Gas/Duct Burner	9	2
70-100%CO	Fuel Oil	30	10

The projections while firing natural gas in the range of 70-100% of full load are consistent with the full load experience of the predecessor Siemens-Westinghouse 501F (SW 501F) CGTs installed at the PEF Hines Energy Complex. Hines CGTs 1A and 1B exhibited full load CO and VOC emissions during all compliance runs of less than 1.0 and less than 0.6 ppmvd for the two pollutants respectively.[3] CO and VOC emissions should be very low based on the high combustion temperature and the relatively high temperature and excess air in the turbine exhaust gas (TEG).

However, there is concern regarding the performance on natural gas at loads less than 70%. Based on the values in the above table, performance is projected to degrade somewhat by 60 to 70% load. Additionally, it is known that the applicant wants the ability to turn down the load to levels less than shown in the table. Therefore, it is important to have an understanding of performance at low load because of CTG startups and shut downs that may or may not involve HRSG or STG startups and shut downs. Fuel oil and duct burner performance are discussed further below.

The Department requested manufacturer's curves showing expected emissions with respect to CGT load as percent of full load.[4] In its response, the applicant advised that according to Siemens "they do not provide 'curves' for various loads".[5] In response to a request related to a separate project, PEF provided tabulated CO data covering startups, shut downs, fuel switches, tunings and malfunctions.[6] The data comprise experience from four SW501F CGTs that are (at least to the untrained eye) identical to the SGT6-5000F.

The Department entered the data into a spreadsheet and produced the following charts relating CO emissions to the described events.



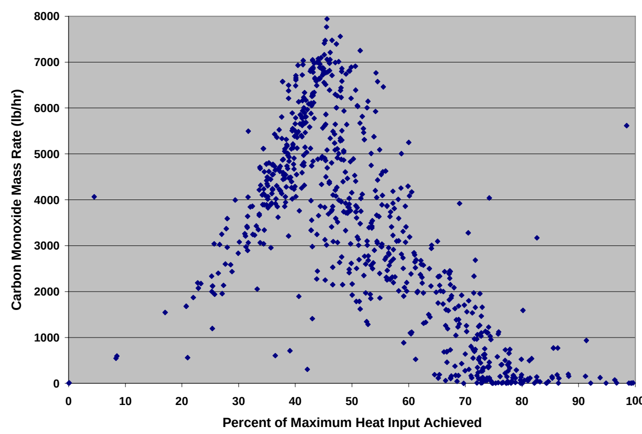


Figure 8. CO Emissions during Certain Low Load and Transient Conditions

The data indicate that CO emissions are very high at least during the transient periods related to the mentioned events. During a number of hours more than 2 tons of CO were emitted at concentrations of 8,000 ppmvd at roughly 50% of full load when the C-Stage is initiated.

The Department also focused on operation greater than 50% of full load to assess the likely performance of the units given that the data are indeed representative of such operation unassociated with transients. The results are shown in the graph on the following page. Again the data suggest the possibility of high CO emissions.

Siemens is at least aware of these issues. The Department obtained a recent paper presented by Siemens at the 2005 PowerGen Conference. In it Siemens described some possible improvements allowing faster startup times and also the manner by which they can achieve low CO emissions at partial loads on the SGT6-5000F CTG.[7] According to Siemens (with some minor paraphrasing):

"The original startup time from initiation to full power took approximately 30 minutes. The improved start time capability is as follows: 5 minutes from start initiation to minimum load, and then the GT is loaded at 30 MW/minute. This permits 150 MW within 10 minutes.

To achieve the improved start capability the following steps were taken:

1. *Implement static frequency converter (static start), whereby the CTG generator operates as a motor replaces the mechanical starter motor. This allows more efficient and faster rotor acceleration than the equivalently sized mechanical starting motor.*

2. *The turning gear (TG) speed was increased from 3 rpm to 120 rpm. The higher TG speed enables the generator rotor wedges to lock up and also helps the engine cool down faster, because the turbine parts are cooled faster and tip clearances are similar to the cold tip clearance."*

"Reduced low load CO emissions were achieved by operational modifications which include a second modulating circuit added to turbine cooling air supply. When load is reduced, the second modulating circuit is opened bypassing additional cooling air around the combustor. Bypassing air around the combustor increases combustor flame temperature and hence limits CO production. There are other measures which can be taken to reduce CO if necessary, including changes to valve scheduling to allow compressor air to be bypassed into the exhaust. With this equipment & operational changes, CO is kept to <10 ppm down to between 45% and 50% load. This CO reduction will reduce total CO mass emissions by 70% per startup-shutdown cycle."

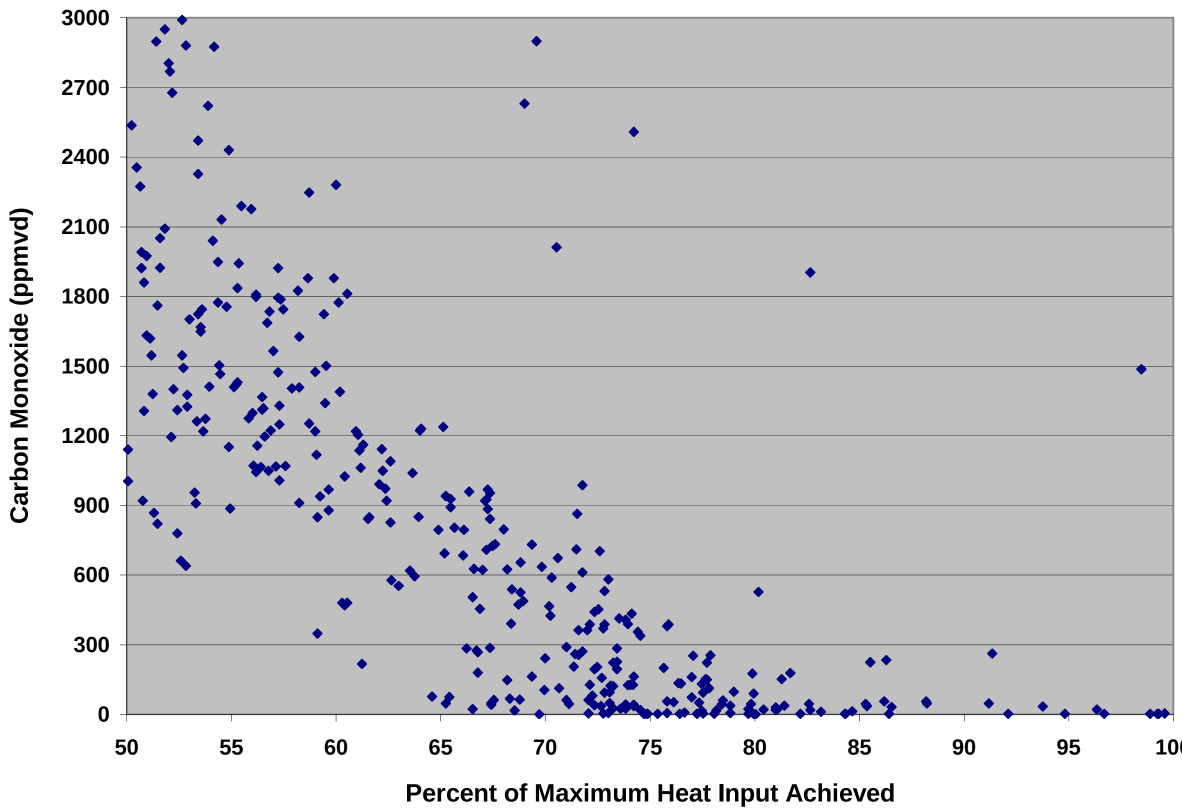


Figure 9. CO Emissions during Certain Medium Load Conditions

The following figures from the Siemens presentation compare original to improved startup characteristics. The graph on the left demonstrates the reduction of startup times which may be minimized to reduce CO emissions during these periods. The graph on the right suggests that the operating cycle can be improved to extend the "low CO" range to loads less than 50%.

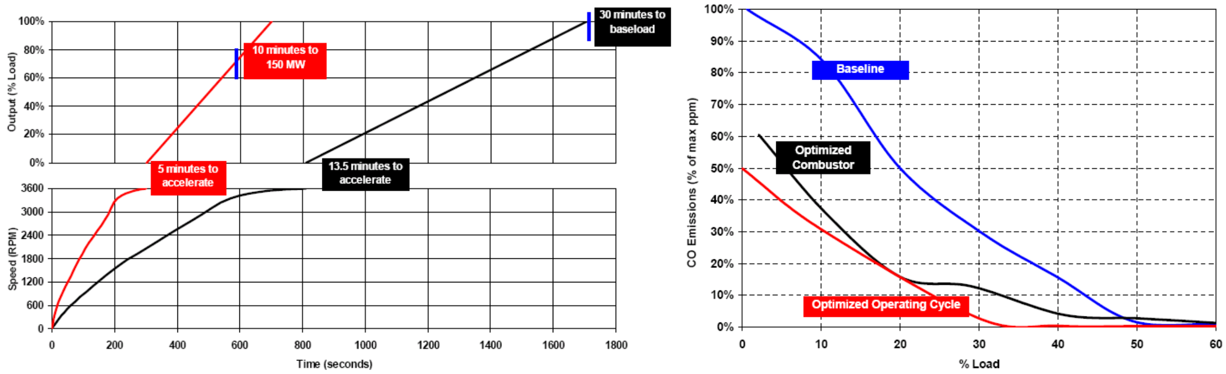


Figure 10. Improved Startup Times to High Load. Relative CO Emissions at Low Load.

The Department does not dispute that the emissions can be reduced to less than 10 ppmvd in the 45-50% load range as suggested by the Siemens paper. However, the applicant has not provided information regarding the measures to actually be incorporated to avoid very high CO emissions during startups, shutdowns and low load (whether or not the low load is associated with startups and shutdowns).

The options described by Siemens may be available for the project to help achieve BACT level CO and VOC emission limits and possibly avoid installation of oxidation catalyst.

<u>Low Load Considerations</u>

As previously discussed and shown in Figures 8 and 9, emissions from existing SW501F CGTs at PEF Hines Energy Complex during low load operation are extremely high when compared to operation above 70 % load. The data shown in the graphs include startups, shutdowns, fuel switches, tunings and malfunctions. Emissions during periods of startups, shutdowns, and fuel switches, as well as during "idling" at less than full load, as they relate to this project are discussed below.

Startup and Shutdown

Simple Cycle Operation:

Frequent startups and shutdowns are expected of the Unit 5 simple cycle gas turbine, as well as the two CTs designated to operate in simple cycle mode during the slated "interim" period. Note that the emission levels in the graph in Figure 8 represent hourly averages. The Siemens SGT6-5000F in SC mode can be at baseload (Figure 11) and achieve low emissions within 30 minutes of initiation of startup.

It can also be seen from Figure 8 that emissions ramp up and peak at about 40 to 50 % load. Therefore, total emissions for a "startup" cycle would include a period at the beginning of startup with very low emissions, a period during the middle of startup with very high emissions, and the remainder of startup and the rest of the hour with normal levels of mass emissions. The actual hourly emission rate would therefore likely be lower than that implied by the graphs. Additionally, with the Siemens operational enhancements for improved startup capability and part load CO emissions reduction described earlier, startup emissions should be significantly reduced.

The CTGs of the combined cycle unit will be equipped with bypass stacks to allow for SC operation during periods such as steam turbine or main condenser failures. This mode will be used only to ensure reliability of the units and would naturally be minimized by the facility because of the lower efficiency realized in SC operation. Additionally, SC operation of the CTGs for this unit would require cooling of the ducting between the CTG and the HRSG in order to remove one plate and to install another to divert turbine exhaust gas (TEG) to the bypass stack. Operation under this scenario is expected to be very limited therefore the number of startups using the bypass stacks will be very low.

Combined Cycle Operation

For a CC cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated. This can take several hours of low load operation. Following the slated "interim" period, Bartow Units 1 through 4 will primarily operate in continuous combined cycle mode. Although emissions from a CC startup will be significantly higher than that from a SC startup, it is expected that very few will actually occur. Typically cold startup of the steam turbine electrical generator (STG) occurs less than twice per year.

The above discussion focuses on unit startups. However, the same ideas can be applied to shutdowns which are generally of much shorter duration and account for significantly fewer overall emissions.

Operation Below Full Load Other Than Startup and Shutdown

During off-peak hours when demand for electricity is lowest, many CC units are often turned down to loads less than 100 % in order to conserve fuel and lower costs. Units 1 through 4 will be base loaded units and are normally expected to operate at, or near, 100 % load. However, these units will not be limited to full load operation, and even when operating at the lower loads they will be required to meet the CO emissions limits and demonstrate compliance by CEMS. According to Siemens, with the recent enhancements (if implemented), CO emissions of less than 10 ppm can be maintained at operation to between 45 and 50 % load.

Fuel Switching

The principal reason for increased emissions during fuel switching is generally the same as that for startup – low load operation. It is necessary to bring the CT to low load operation for a limited amount of time in order to switch from one fuel to the other. Each turbine will be limited to 1,000 hours of oil use as a back-up fuel. Fuel switching is expected to be infrequent, but will vary depending on fuel availability and cost.

<u>Fuel Oil Considerations</u>

Fuel oil firing is expected to be minimal but is actually requested for 1,000 hours per year per turbine. The annual potential to emit (PTE) CO emissions at 1,000 hours of operation at the requested BACT values is comparable to the annual PTE for the full time natural gas case, excluding power augmentation and duct burner operation.

The CO and VOC estimates given in Table 3 while firing fuel oil near full load are excessive and in contrast to the compliance tests conducted at the PEF Hines Energy Complex. Whereas limits of 30 ppmvd CO and 10 ppmvd VOC are requested for fuel oil firing for the Bartow units, the full load tests at Hines indicated emissions during all compliance runs less than 1.3 ppmvd and less than 0.4 ppmvd for the two pollutants respectively.[8] However, it is possible that CO emissions when firing fuel oil exhibit the same startup, shutdown and low load characteristics as discussed above.

Again, CO and VOC emissions while firing fuel oil near full load should be very low based on the high combustion temperature and the relatively high temperature and excess air in the TEG. It would appear that some of the possible design and operational remedies described by Siemens for the low load conditions while firing natural gas can also be employed for fuel oil firing.

<u>Duct Burner Considerations</u>

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,100 ^oF) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by the first part of the split high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering the second section (Component 6) of the split superheater.

The figure below shows an individual burner and an array comprising a duct burner. The hot TEG contains sufficient combustion air to burn the natural gas introduced into the burner array.

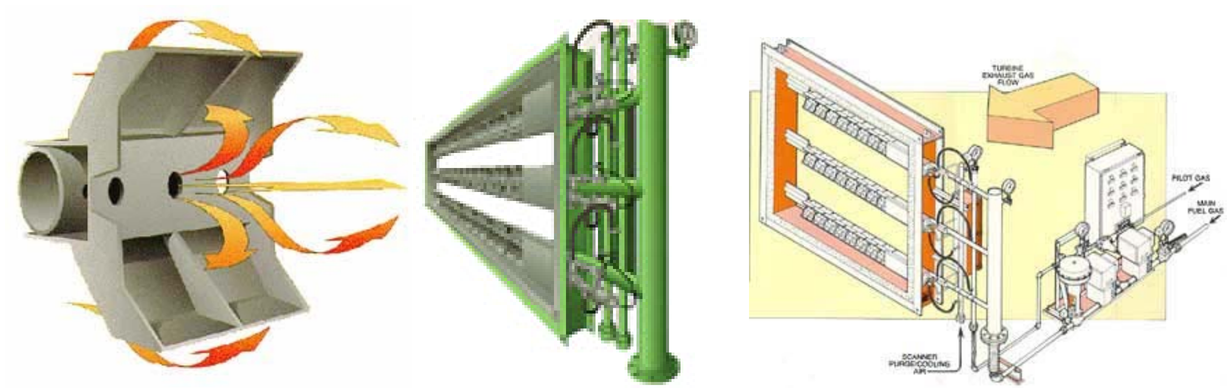


Figure 11 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 ^oF. VOC such as ethane and propane ignite at temperatures less than 900 ^oF. All of the necessary conditions (oxygen, temperature, turbulence and time) are present to minimize CO and VOC concentration increases.

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[9] and OUC Stanton Unit A. The units are GE7FA combustion turbines (CT) that are the same-class competitor to the SGT6-5000F. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 4. CO and VOC Emissions while Duct Firing – GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CGT & DB)	1.21	0.15
Gulf Smith Unit 5 (CGT & DB)	1.26	0.31
OUC Stanton Unit 25 (CGT)	0.5	0.04
OUC Stanton Unit 26 (CGT)	0.5	0.49
OUC Stanton Unit 25 (CGT & DB)	1.6	0.2
OUC Stanton Unit 26 (CGT & DB)	1.6	0.26

Based on the full load CGT testing at PEF Hines Energy Complex and the fact that duct burners will be used at or near full load CGT operation, the Department would expect very low CO and VOC emissions at PEF Bartow when the duct burners are used.

Comparison of PEF's Initial CO and VOC BACT Proposal with Recent Projects

Following are some of the most recent BACT determinations by the Department for CO and VOC emissions from large CTGs. PEF's proposal is included in the table for comparison.

Table 5. Recent CO and VOC Standards for "F and G-Class" CTGs

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
PEF Bartow Application	4.0 – NG (baseload - 70%, CEMS) 10.0 – NG (70-60% load, CEMS) 9.0 – NG (DB on, CEMS) 30 – FO (baseload to 70%, CEMS)	1.0 – NG (baseload – 70%, Annual Test) 4 – NG (70-60% load, Annual Test) 2 – NG (DB on, Annual Test) 10 – FO (Annual Test)
FP&L Turkey Pt.	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – 24-hr NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.3 – NG (DB off, Annual Test) 1.9 – NG (DB on, Annual Test) 2.8 – FO (Annual Test)
FP&L W. County	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.2 – NG (DB off, Annual Test) 1.5 – NG (DB on, Annual Test) 6 – FO (Annual Test)

Table 5 (Cont). Recent CO and VOC Standards for "F and G-Class" CTGs.

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
FMPA Treasure Coast	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	Not PSD
PEF Hines 4	8.0 – NG (24-hr block) 12.0 – FO (24-hr block)	1.3 – NG (Annual Test) 3.0 – FO (Annual Test)

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

<u>Department's CO and VOC BACT Determination</u>

Based on data and information available to the Department as presented in the above discussion, the following conclusions can be drawn:

- PEF's proposed CO emission limit for normal operation (gas firing, 70-100 % load, DB off) of 4.0 ppmvd @ 15% O_2 is acceptable and consistent with similar unit experience at the PEF Hines Energy Complex. However, the proposed limits for less than 70 % load, duct burner operation, and fuel oil firing as listed in Table 3 are excessive and in contrast to compliance test results on similar units.
- There will be considerable use of duct burners (DB). The Department believes CO emissions under DB in terms of ppmvd @15% O_2 will be approximately equal to emissions under the normal mode. PEF still estimates greater CO concentrations while using the duct burners than when operating the combustion turbine at full load. The requested value of 9.0 ppmvd @15% O_2 for this mode of operation is slightly higher than other recent BACT determinations of 7.6.
- The CO proposal of 30 ppmvd @15% O_2 while firing fuel oil appears very high when compared to past experience on existing units and other recent proposals for new units. The expectation is that CO emissions during periods of fuel oil firing will be similar to emissions during gas firing.
- PEF's proposed VOC emissions limits are similarly high for periods of duct burner operation and fuel oil firing. The same discussions presented above apply, and actual emissions of VOCs are expected to be considerably lower than proposed during these modes of operation.

The applicant has determined that CO oxidation catalyst is not cost effective for this project. According to PEF, estimated capital cost per CT is $1,422,634 and total annualized cost per CT is $688,966 resulting in a cost effectiveness of $3,956 per ton of CO removed assuming an 80% reduction in CO emissions. The Department however, does not agree with all aspects of the applicant's determination and feels that CO catalyst would be cost effective if necessary to comply with all BACT limits.

For example, capital and replacement costs are slightly lower in an independent budgetary proposal obtained by the Department for a CO catalyst system on a GE 7FA unit, than those proposed by PEF. The Department's Engelhard catalyst performance guarantee includes a maximum pressure drop across the catalyst of 0.9 to 1.0 inches water gauge (WG). The applicant's proposed cost effectiveness analysis was based on a maximum pressure drop of 1.5 to 2.0 WG. Additionally, based on experience with existing units a minimum 5-year expected catalyst life is a better representation of real-life expectations than the 3-years assumed by PEF.

PEF updated the heat rate penalty to reflect a more recent natural gas cost as requested by the Department. A cost of $9.6/MMBtu was used for the new estimate. Although this may have been the instantaneous price at the time the estimate was updated, considering the recent overall trend in natural gas prices the amount chosen may be unnecessarily high. For the last week of November prices were in the $8.00/MMBtu range.

For a more long-term look, the recently published 2007 Annual Energy Outlook presents a midterm forecast and analysis of US energy supply, demand, and prices through 2030[10]. The projections are based on results from the *Energy Information Administration's* National Energy Modeling System. The following table is an excerpt from the DOE report showing natural gas price projections in the $5 and $6 per MMBtu range through 2025. Expansion of existing and construction of new liquefied natural gas (LNG) terminals is the main reason for the long term stability in the future.

Table 6. Energy Prices by Sector and Source (2005 Dollars per Million Btu)

Sector and Source	Reference Case					
	2004	**2005**	**2010**	**2015**	**2020**	**2025**
Electric Power						
Distillate Fuel Oil	9.52	11.38	11.71	9.26	9.84	10.25
Residual Fuel Oil	4.99	6.96	6.58	5.60	6.08	6.58
Natural Gas	**6.11**	**8.18**	**6.22**	**5.50**	**5.76**	**6.05**
Steam Coal	1.40	1.53	1.71	1.60	1.58	1.63

CO and VOC limits consistent with recent BACT determinations issued by the Department will be set for PEF Units 4 and 5. These limits should be readily met without the use of oxidation catalyst systems assuming fast startups and high load operation. Each HRSG stack will be equipped with a CO CEMS, and a reasonable continuous 24-hour emissions limit will be set to cover all modes of operation. This is consistent with recent determinations for FPL Turkey Point and FMPA Treasure Coast combined cycle projects. If additional measures are needed in the future to meet the CO emission limits due to extended low load operation by the CC unit 4 CTs, then oxidation catalyst will be a cost effective alternative control strategy.

Because full load is quickly reached, and operation will be limited to loads greater than 70 % during simple cycle operation, oxidation catalyst is not a consideration for the Unit 5 CT nor will it be required prior to the bypass stacks on Unit 4. Simple cycle operation of the Unit 4 CTs is expected to be minimal. Compliance determinations with the CO standards during simple cycle operation will be based on required stack tests.

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

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

Table 7. Draft BACT Determination

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

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

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

5. NEW SOURCE PERFORMANCE STANDARDS APPLICABLE TO GAS TURBINES AND DUCT BURNERS

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTs. Subpart KKKK also applies to emissions from any associated HRSG and duct burners.

- 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% (500 ppmw) by weight fuel oil or 20grains of sulfur per 100 standard cubic feet of natural gas.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS APPLICABLE TO GAS TURBINES

The Bartow Power Plant is an existing source of hazardous air pollutant emissions. As such, the proposed new combustion turbines will be subject to NESHAP Subpart YYYY- National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, which became final on March 5, 2004.[11]

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[12] EPA has stayed the applicability of YYYY to certain gas-fired units and proposed to permanently delete such units (as well as other classes) from the list of sources subject to the regulation.

For a stationary combustion turbine to qualify as a gas-fired unit under Subpart YYYY each stationary combustion turbine which is equipped both to fire gas and oil, must be located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

Because the CTs for this project will have the potential for an aggregate oil-firing total significantly greater than 1,000 hours (up to 5,000 hours) during any calendar year, initial compliance with the applicable YYYY standard must be determined upon startup. Applicability thereafter will be based upon actual aggregate fuel oil use during any calendar year.

Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

PEF proposes to meet the limit proposed in YYYY of 91 ppbvd. The Department believes the formaldehyde emission limit will be met given the BACT CO limits of 8.0 and 6 ppmvd @15% O_2 for daily and annual operation respectively. It is also expected that the units will easily demonstrate compliance with the formaldehyde limit during the initial and annual test requirements.

7. PERIODS OF EXCESS EMISSIONS

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.

Alternate Standards and Excess Emissions Allowed

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

Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

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

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases:

- For the very infrequent oil-to-gas and gas-to-oil fuel switching, excess emissions shall not exceed 2 hour in any 24-hour period.

- Steam turbine startups occur as little as once during a ten-year period. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 8 hours in any 24-hr period. A cold startup of the "steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown lasting at least 48 hours.
- CT/HRSG startups are infrequent but occur more often than steam turbine startups. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed 4 hours in any 24-hr period. A cold startup of a "gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one–hour period. Short startup is enhanced by the use of the auxiliary steam generators that assist in heating surfaces and provide high quality steam for transition piece and nozzle cooling.
- For startup of a CT for the purpose of operation in simple cycle mode, excess emissions shall not exceed 1 hour in any 24-hour period.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.
- Dry Low NO_X 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. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. 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. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions. The permit will require notification prior to any tuning session.

While CO and NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation.

8. BACT DETERMINATIONS FOR THE AUXILIARY BOILER

One gas-fired auxiliary boiler is required for the combined cycle unit system. The primary purpose of the auxiliary boiler is to assist in combined cycle startup by providing steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The specifications for the auxiliary boiler are as follows:

- Nebraska Boiler or equivalent;
- Usage of up to 1,000 hours per year;

- Maximum heat input rate of 99 mmBtu/hr heat input; and
- Steam capacity: 85,000 lb/hr.

A recent BACT determination was conducted for the Port Westward, Oregon project. An auxiliary boiler was required for startup of an M501G combined cycle unit. A 91 MMBtu auxiliary boiler was specified for that project.

The state of Oregon conducted a search of BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC) in early 2005. Approximately 20 RBLC determinations were reviewed by the State of Oregon for auxiliary boilers in the range of 10 to 100 MMBtu/hr that are used in support of combined cycle projects. Separate tables were developed for CO and VOC as well as NO_X, SO_2, and PM/PM_{10}.

The ranges from the Oregon survey are presented in the following table along with limits from other projects for which the auxiliary boiler limits are known. Emissions performance estimates provided by PEF for the auxiliary boiler are included for comparison. NSPS and NESHAP requirements that are applicable to the auxiliary boilers are also included.

Table 8. CO and VOC Standards – Auxiliary Boilers for Combined Cycle Units

Project Location	CO (lb/MMBtu)	VOC lb/MMBtu
RBLC Survey	0.016 – 0.15	0.004 – 0.018
Port Westward, OR	0.08	0.005
Sithe Mystic, MA	0.08	0.008
Sithe Fore River, MA	0.08 and 100 ppm @3% O_2	0.008/0.004 (NG/FO)
Covert Generating, MI		
Progress Bartow (Application)	**0.08**	**0.01**
NSPS Subpart Dc	Boilers between 10 and 100 mmBtu/hr - Record Keeping Required	
NESHAP Subpart DDDD	400 ppm@3% O_2	

Notes: NG = Natural Gas FO = Fuel Oil

The CO and VOC performance values submitted by PEF for this project are similar to the projects in the Oregon survey and the other combined cycle projects listed above. The auxiliary boiler for this project will be used for the same purpose as those in the other projects.

The Department will set a CO BACT limit of 0.08 lb/MMBtu and operation of no more than 1,000 hours per year for the auxiliary boiler. The Department believes this is at least as stringent as, and possibly more stringent than, the applicable NESHAP standard of 400 ppm @ 3% O_2. This value can be achieved by numerous suppliers by good combustion techniques without resorting to catalysts. In a recent BACT determination conducted by the Washington State Energy Facility Site Evaluation Council for a similar unit, cost effectiveness for CO oxidation catalyst was estimated to be \$16,227 per ton of CO. Emissions of VOC from the auxiliary boiler are estimated by PEF to be less than 0.5 TPY. A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC.

9. BACT DETERMINATIONS FOR NATURAL GAS-FIRED FUEL HEATERS

Five fuel heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperatures and prevent condensation. The fuel heaters will be fired with natural gas only.

PEF included, as an example, specifications for the gas heaters as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 3 MMBtu/hr heat input.

Table 9. PEF Emission Estimates from Each Natural Gas-fired Fuel Heater

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	100 lb/MMscf	84 lb/MMscf	5.5 lb/MMscf	1.9 lb/MMscf

Small gaseous fuel process heaters (≤ 10 MMBtu/hr) are not subject to Subpart DDDDD. Annual emissions from all 5 heaters of CO and VOC are estimated by PEF to be 5.3 and 0.35 tons per year respectively.

The BACT limit for the fuel heaters will be the same as the auxiliary boiler: 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC. Hours of operation are not limited.

10. BACT DETERMINATIONS FOR THE EMERGENCY FIRE PUMP ENGINE

Progress proposes a 300 HP Clarke/John Deere diesel emergency fire pump. Such engines are regulated under 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

The standards vary depending on the size of the engine. The standards for engines from model year 2007 are given in the following table that are applicable to the emergency engine proposed for this project:

Table 10. EPA Emergency Fire Pump Standards, grams/bhp-hr

Size (hp)	CO	NMHC+NO_X	PM
175 and greater	2.6	7.8	0.40

Notes: bhp = brake horse power NMHC non-methane hydrocarbons

The Department's BACT for this emergency fire pump is compliance with the NSPS standards and use of 0.05% sulfur fuel oil.

11. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: CO and VOC. CO is a criteria pollutant and has 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 VOC. VOC is an ozone precursor and any net increase of 100 tons per year requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

Major Stationary Sources in Pinellas County

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

Table 11. Largest Sources of NO_X in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	4210
Progress Energy	***Bartow Power Plant (proposed repowering)***	***3191***
Pinellas Board of Co Comm.	Pinellas Co Resource Recovery Facility	1447
Florida Power/Progress	Bayboro Power Plant	337
Florida Power/Progress	Higgins Plant	151

Table 12. Largest Sources of SO_2 in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	16,462
Progress Energy	***Bartow Power Plant (proposed repowering)***	***466***
Pinellas County	Pinellas County Resource Recovery Facility	39

Table 13. Largest Sources of PM in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	Bartow Power Plant (before repowering)	495
Progress Energy	***Bartow Power Plant (proposed repowering)***	***413***
Pinellas County	Pinellas County Resource Recovery Facility	33
Progress Energy	Bayboro Power Plant	4

Table 14. Largest Sources of CO in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***938***
Progress Energy	Bartow Power Plant **(**before repowering)	369
Pinellas County	Pinellas County Resource Recovery Facility	121
Progress Energy	Higgins Plant	39

Table 15. Largest Sources of VOC in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***145***
Cardinal Health	Cardinal Health PTS, LLC	110
Hydro Spa	Hydro Spa – Clearwater	60
Times Publishing Co.	St. Pete Times Printing Plant	58
Progress Energy	Bartow Power Plant **(**before repowering**)**	57
Lifoam Industries	Lifoam Industries	54

Air Quality and Monitoring in Pinellas County

Pinellas County Department of Environmental Management operates twenty-three monitors at fourteen sites measuring PM_{10}, $PM_{2.5,}$ ozone, CO, $NO_{2,}$ lead, toxics and SO_2. The 2006 monitoring network is shown in the figure below.

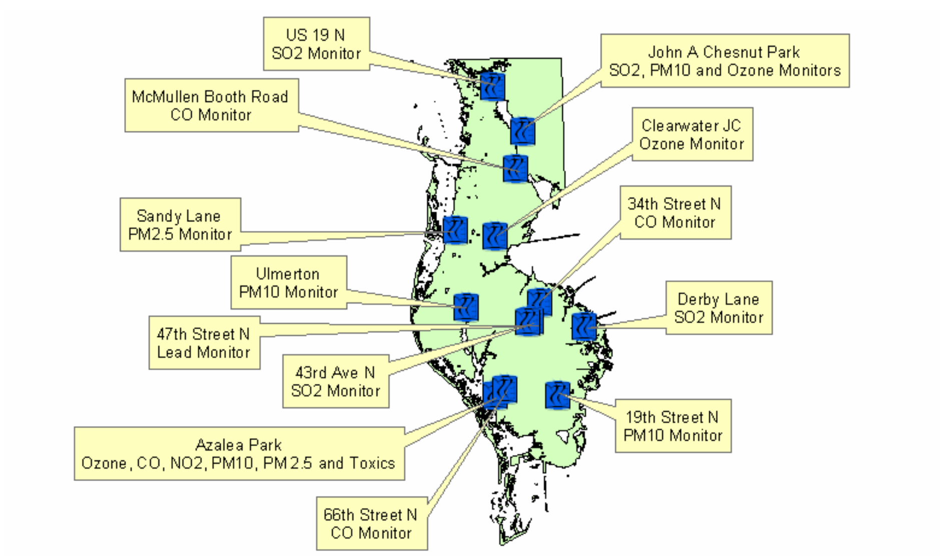


Figure 12. Pinellas County DEM Ambient Air Monitoring Network

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

Table 16. Ambient Air Quality in Pinellas County Nearest to Project Site (2005)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ulmerton	24-hour	44	40		150 [a]	ug/m^3
		Annual			21	50 [b]	ug/m^3
SO_2	Derby Lane	3-hour	75	59		500 [a]	ppb
		24-hour	32	24		100[a]	ppb
		Annual			3	20 [b]	ppb
NO_2	Azalea Park	Annual			8	53 [b]	ppb
CO	34th Street N	1-hour	3	3		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Clearwater JC	1-hour	.090	.088		0.12 [C]	ppm
		8-hour	.076	.074		0.08 [C]	ppm

* The Mean does not satisfy summary criteria due to missing data.
a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

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

Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for CO. A significant impact analysis is performed on this pollutant to determine if the proposed project can cause an increase in ground level concentrations greater than the SILs for CO. The applicant also performed a significant impact analysis for the Class II area for other PSD pollutants that will decrease as a result of the project or increase by values less than their respective significant emission Rates (SERS). The pollutants are SO_2, PM_{10} and NOX. The additional analysis was performed to ensure compliance with National Ambient Air Quality Standards.

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

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 4 kilometers from the facility. From 4 to 6 kilometers, Cartesian receptors with a spacing of 500 meters were used. From 6 to 10 kilometers, Cartesian receptors with a spacing of 1000 meters were used.

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

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) for Phase I (2 combustion turbines in simple cycle mode). The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) except for non-PSD SO_2, 24-hour PM_{10} and NOx for Phase 2 (4 combustion turbines in combined cycle mode, 1 simple cycle). These values are tabulated in the tables below and are compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 17. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase I

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	8	60	NO
	24-Hour	4.7	5	83	260	NO
	3-Hour	14	25	195	1300	NO
PM_{10}	Annual	0.1	1	21	50	NO
	24-Hour	3.5	5	44	150	NO
CO	8-Hour	17.9	500	2,300	10,000	NO
	1-Hour	39.7	2000	3,450	40,000	NO
NO_2	Annual	0.5	1	15	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 for Phase I. SO_2, PM_{10}, CO and NO_X are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

Table 18. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase II

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	2	1	8	60	YES
	24-Hour	29	5	83	260	YES
	3-Hour	80	25	195	1300	YES
PM_{10}	Annual	0.9	1	21	50	NO
	24-Hour	24	5	44	150	YES
CO	8-Hour	108	500	2,300	10,000	NO
	1-Hour	153	2000	3,450	40,000	NO
NO_2	Annual	5	1	15	100	YES

Maximum predicted impacts from the project for CO (PSD pollutant) are much less than the respective AAQS and the baseline concentrations in the area for Phase II. However, maximum predicted impacts from the project for SO_2, PM_{10} and NOx (non-PSD) are much greater than the SILs but still much lower than the respective AAQS in the area for Phase II. CO is also less than the respective significant impact levels that would otherwise require more detailed modeling efforts. Although SO_2, PM_{10} and NOx are not subject to PSD and the project will ultimately improve air quality in the County with regards to these pollutants, the applicant provided further, more detailed multi-source modeling to ensure compliance with PSD Increments and National and State Ambient Air Quality Standards.

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 CO was less than this de minimis level. Therefore, no pre-construction monitoring is required for CO.

Table 19. 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?
CO	8-hour	108	575	2,300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential net VOC emissions from the repowering project to be 88 tons per year. Therefore, preconstruction monitoring for ozone is not required.

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.

<u>Models and Meteorological Data Used in the Air Quality Analysis</u>

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 November 2005 and will officially replace the ISCST3 model December 2006. During this "transition" time period from November 2005 to December 2006, both the ISCST and AERMOD model may be used. This "transition" will allow applicants and the Department to assimilate AERMOD guidance and procedures.

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.

AERMET Meteorological data prepared by the Department and used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the Tampa International Airport and twice-daily upper air soundings from the National Weather Service at Ruskin. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWR beyond 50 km from the proposed project. Meteorological data used in this model was from 2001 through 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.

<u>Multi-source PSD Class II Increment Analysis</u>

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted Class II area impacts from this project and all other increment-consuming sources in the vicinity of the Bartow Power Plant are shown in the following table.

Table 20. PSD Class II Increment Analysis (not required, pollutants not subject to PSD)

Pollutant	Averaging Time	2nd Highest-High All Sources Max Predicted Impact (μg/m³)	Allowable Increment (μg/m³)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	24	30	NO
PM_{10}	Annual	0.3	17	NO
SO_2	24-hour	36	91	NO
SO_2	3-hour	93	`512	NO
SO_2	Annual	0	20	NO
NOx	Annual	3	25	NO

<u>AAQS Analysis</u>

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

Table 21. Ambient Air Quality Impacts (Background Highest of 2004-05)

Pollutant	Averaging Time	Major Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
PM_{10}	24-hour	27.4	80	107	NO	150
PM_{10}	Annual	2.2	29	32	NO	50
SO_2	24-hour	137	86	223	NO	260
SO_2	3-hour	464	267	731	NO	1300
SO_2	Annual	24	5	29	NO	60
NO_2	Annual	8	17	25	NO	100

Ozone

Ozone is an area-wide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

The Bartow Repowering Project will have net reductions of 852 TPY of NO_X. Less than 100 TPY of VOC will be added, which is an increase of less than 1% in the region. Although a minimal amount of VOC will be added, the reduction of NOx should have a positive result in reducing total ozone in the area.

In the near future, many existing power plants and other industries in Florida that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). These NOx reductions will also contribute to decreasing ozone formation.

Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Substantial net emissions reductions for sulfuric acid mist, SO_2, PM_{10} and NO_X will help ameliorate past air pollution effects on soils, vegetation and wildlife.

The maximum ground-level concentrations predicted to occur for CO as a result of the proposed project will be considerably less than the respective AAQS. According to the applicant, plant species most sensitive to CO showed cellular damage when exposed to 685,000 micrograms per cubic meter of CO. The applicant modeled CO impacts in the Chassahowitzka Class I area. The highest modeled impact from the proposed repowering was 3.44 micrograms per cubic meter of CO.

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. Clearly, with net reductions of sulfur and nitrogen, the deposition of pollutant from Bartow in the Class I area will be less than current levels.

Impact on Visibility:

There will be significant visibility improvements in the immediate vicinity because of the reduction of particulate emissions from the repowered plants and the very significant reductions in condensable and fine particulate precursors. The existing units are subject to opacity limitations of 40 percent under present normal operation whereas the replacement units will be subject to a 10% opacity standard.

Regional Haze in the Chassahowitzka National Wildlife Refuge will experience some improvement as well due to reduced emissions of ozone precursors and fine particulate precursors.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 300 additional workers will be needed over the 31-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the new facility will require no new permanent employees, which will cause no impact on the local area.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, there has been little growth in the area of the Bartow facility since 1977. However, according to the Census, the population of Pinellas County has increased from 728,531 in 1980 to 921,482 in 2000. In 2000, Pinellas County was the most densely populated county in Florida. Despite population growth, the air quality has remained fairly constant. The chart below shows the Air Quality Index, an index of daily air quality, for Pinellas County over twelve years. With the exception of a few years around 1990, the index has remained close to 300 "Good" days while experiencing no days in the "Unhealthy" categories despite a growth of approximately 80,000 people.

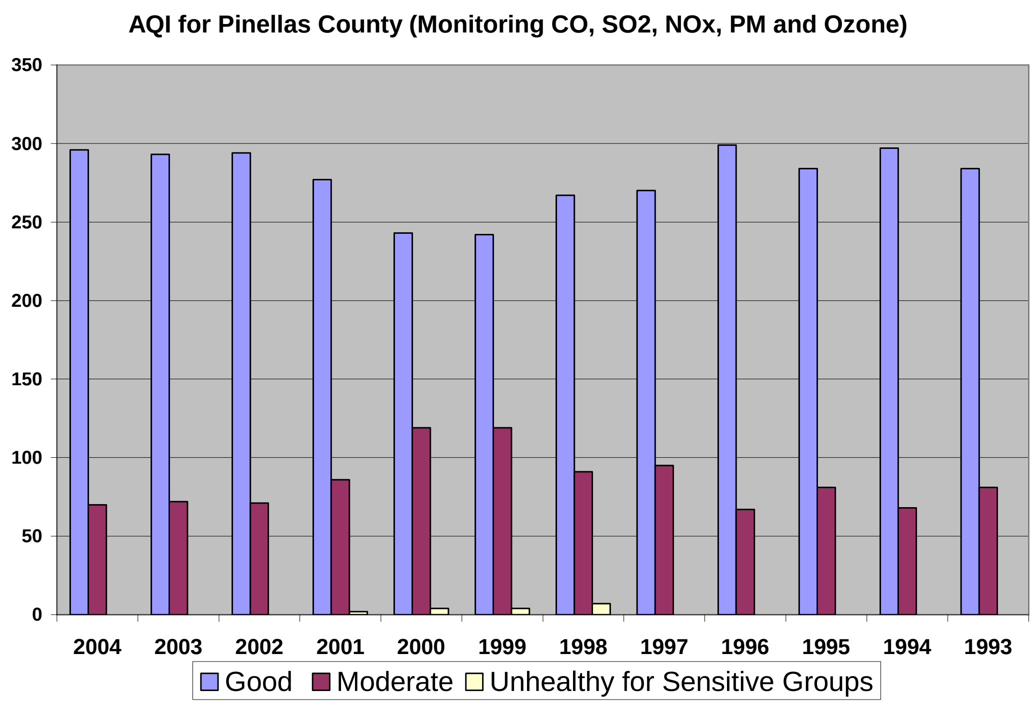


Figure 13. Pinellas County Air Quality Index History.

12. PRELIMINARY DETERMINATION

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

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Teresa Heron is responsible for reviewing the application, and preparing the draft permit. She may be contacted at teresa.heron@dep.state.fl.us and 850-921-9529. Alvaro Linero is the project engineer responsible for preparing the draft BACT determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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