TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT
Duke Energy Florida, Inc.
299 First Avenue North, FL-903
St. Petersburg, FL 33701-3308

Suwannee River Power Plant
ARMS Facility ID No. 1210003

PROJECT
Simple Cycle Combustion Turbine Project
Draft Permit No. PSD-FL-428
Project No. 1210003-008-AC

COUNTY
Suwannee County, Florida

PERMITTING AUTHORITY
Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

February 26, 2014

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

Duke Energy Florida, Inc. (DEF) operates the existing Suwannee River Power Plant which is located within the city of Live Oak in Suwannee County, Florida (see **Figure 1** and **Figure 2**). The facility can be accessed from River Road south of Route 90. The UTM coordinates are Zone 17, 290.466 kilometers (km) East, and 3362.521 km North. The facility is an electrical power generating plant with a Standard Industrial Classification Code (SIC) of No. 4911.

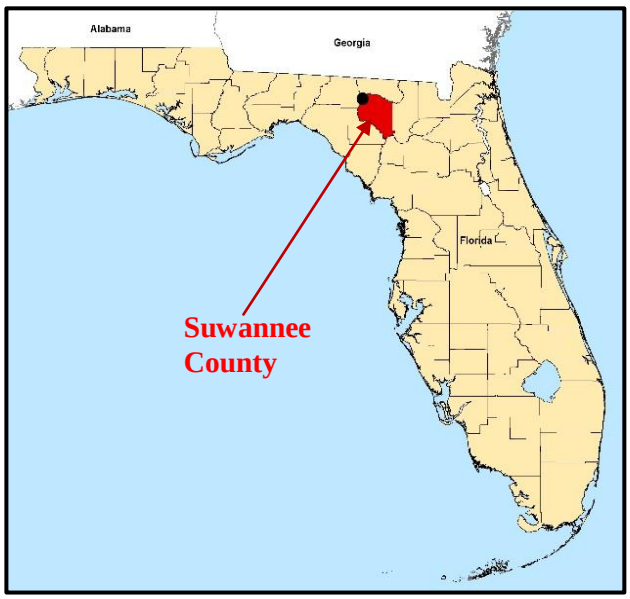


Figure 1. Location of Suwannee County.

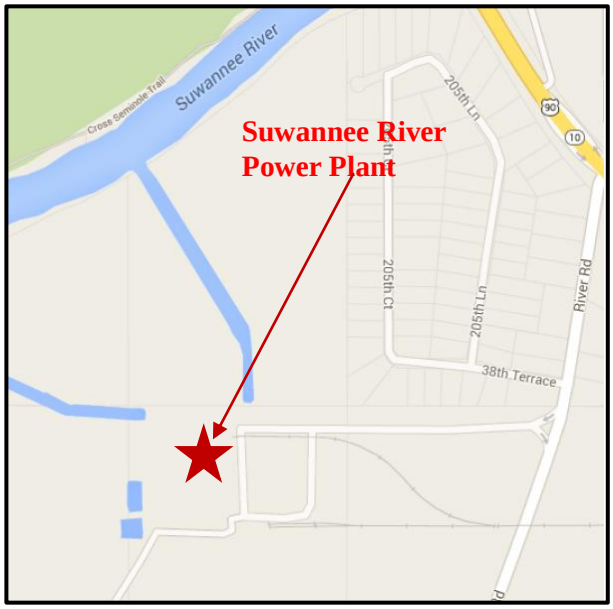


Figure 2. Location of the Suwannee River Plant.

The existing facility is a nominal 345 megawatt (MW) electrical generation facility comprised of three fossil fuel fired steam generators (Boiler Nos. 1, 2, and 3) and three combustion turbine peaking units (CTP Unit Nos. 1, 2, and 3). Boiler Nos. 1, 2, and 3 began operation in 1953, 1954, and 1956 respectively while CTP Units Nos. 1, 2 and 3 began operation in October 1980. The current CTP units generate 189 MW with the boilers contributing 156 MW. **Figure 3** presents a satellite view of the facility, while **Figure 4** shows a rendering of the peaker units that will be installed as a result of the current project along with the existing boiler units.

Figure 3. Satellite View of the Suwannee Plant.

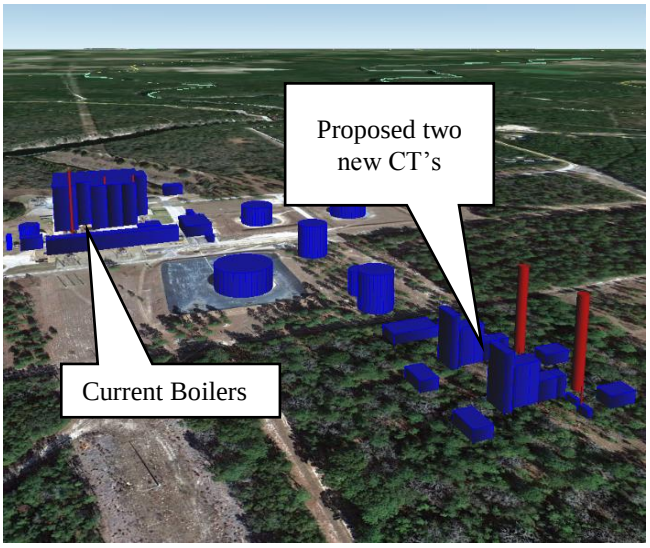


Figure 4. Suwannee Facility and Project.

In addition to units mentioned above, the Suwannee Plant has 18 storage tanks used for fuel oil, waste oil, and unleaded gasoline. Each boiler is permitted to fire natural gas, No. 2 fuel oil, No. 6 fuel oil, and used oil. The CTP units are permitted to fire natural gas and No. 2 fuel oil.

A summary of the regulated existing emission units at the Suwannee Plant is given in **Table 1** below. The emission unit that is involved in this project is highlighted in turquoise in the table.

TABLE 1 – REGULATED EMISSION UNITS AT THE SUWANNEE PLANT.

EU ID No.	Brief Description
001	Boiler No. 1
002	Boiler No. 2
003	Boiler No. 3 – **to be shutdown**
004	CTEG Peaking No. 1
005	CTEG Peaking No. 2
006	CTEG Peaking No. 3
007	Petroleum Product Storage -#2,6 oil, waste oil, unleaded gas
008	Unloading stations (3 No.2 , 9 No.6 high S & 4 No.6 low S)
009	Emergency Diesel Generator
010	Emergency Diesel Fire Pump Engine

1.2. Primary Regulatory Categories

1.2.1. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60) that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, Florida Administrative Code (F.A.C.). State regulations approved by EPA are given in 40 CFR 52, Subpart K – Florida; also known as the State Implementation Plan (SIP) for Florida. The following federal regulations apply to the Suwannee Plant and this project.

- The existing facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality and Rule 62-210.200 (Definitions), F.A.C.
- This project (as discussed below) **does** trigger a PSD review and a requirement to conduct Best Available Control Technology (BACT) determinations pursuant to Department Rule 62-212.400, F.A.C.
- The existing facility is a major source of hazardous air pollutants (HAP).
- The existing facility has units regulated under Clean Air Act, Title IV, Acid Rain provisions, Phase II.
- The existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The proposed project includes units subject to the Clean Air Interstate Rule (CAIR).
- The proposed project includes units subject to the NSPS of 40 CFR 60.
- The proposed project includes units subject to the NESHAP of 40 CFR 63.

1.2.2. State Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of

Environmental Protection (DEP) to establish air quality regulations as part of the F.A.C., which includes the applicable chapters contained in **Table 2**.

TABLE 2 – APPLICABLE RULES FROM THE F.A.C.

Chapter	Description
62-4	Permits
62-17	Electrical Power Plant Siting
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

1.3. Project Description

DEF proposes to construct two nominal 178 MW primarily natural gas-fueled General Electric (GE) 7FA.03 model simple cycle combustion turbines (CT) and ancillary equipment. Ultra-low sulfur distillate (ULSD) fuel oil will be used as a limited backup fuel in the CT. The ancillary equipment will include: two new natural gas-fired fuel gas heaters, a new emergency diesel fire pump, a new 2.5 million gallon double-wall fuel oil storage tank, as well as four new circuit breakers and miscellaneous natural gas piping components. Currently, DEF expects to use four circuit breakers but this may change as a final engineering design emerges.

Each CT will include the following major features:

- Dual fuel firing system using natural gas or ULSD fuel oil;
- Dry low NO_X combustion system for NO_X reduction when firing natural gas and water injection while firing ULSD fuel oil;
- Static inlet air filtration; and
- Mark VIe control system.

The fuel for these two CT will be natural gas (2 grains sulfur/100 scf - primary fuel) and ULSD fuel oil (0.0015% sulfur - limited backup fuel). Natural gas will be delivered to the site by the existing pipeline; however, new piping components will be installed to deliver the fuel to the specific area where the new CT will be located. ULSD fuel oil delivery will be by truck.

The project includes the permanent shutdown of fossil fuel steam Boiler No. 3. Once commercial operation of the CT peaking commences, the existing Boiler No. 3 shall be permanently shut down. During the initial startup and shakedown of the CT peaking units, the existing Boiler No. 3 may continue to operate. The new CT peaking units are expected to have an in-service date during February, 2016. Since the shutdown date of Boiler No. 3 falls within the contemporaneous period, defined as beginning five years prior to the date of construction and ending when the emissions increase from the project occurs, the project completed a netting analysis using the emission reductions from boiler No. 3 to offset emissions from the two new CT.

The project equipment is listed **Table 3** below

TABLE 3 – LIST OF NEW EMISSIONS UNITS FOR THE SUWANNEE PROJECT.

New EU ID No.	Description
011	Simple cycle combustion turbine-electrical generator (Unit P4)
012	Simple cycle combustion turbine-electrical generator (Unit P5)
013	2.5 million gallon ULSD fuel oil storage tank
014	Two 4.79 million British thermal units per hour (MMBtu/hr) natural gas heaters

015	160 horsepower (hp) Emergency diesel fire pump engine
016	New circuit breakers (emit Sulfur hexafluoride (SF_6) a greenhouse gas) Currently four circuit breakers are expected to be used.
017	Natural gas piping components (emits Methane (CH_4), a greenhouse gas)

1.4. Processing Schedule

- May 1, 2014: The Department received a PSD air construction permit application from DEF for the Suwannee peaking unit project. Application deemed complete on August 6, 2014.
- February 26, 2014: The Department issued the draft permit package.

2. PSD APPLICABILITY REVIEW

2.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal ambient air quality standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants. Commonly addressed PSD pollutants in the power industry include: carbon monoxide (CO), NO_X, particulate matter (PM), PM with a mean diameter of 10 microns or less (PM_{10}), PM with a mean diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC), lead (Pb), fluorides (F), sulfuric acid mist (SAM), and mercury (Hg). According to state and federal rules, six greenhouse gases (GHG), are also subject to PSD review.

Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), total reduce sulfur (TRS) including H_2S, reduced sulfur compounds (RSC) including H_2S, municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (dioxin/furan), MWC metals measured as PM; MWC acid gases measured as SO_2 and HCl, and MSW landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(174)(a)1, F.A.C., a stationary source is a "major stationary source" (major PSD source) if it emits or has the potential to emit (PTE):

- 250 tons per year (TPY) or more of any PSD pollutant; <u>or</u>
- 100 TPY or more of any PSD pollutant <u>and</u> the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input. This category applies to the Suwannee Plant before and after the proposed project. The Suwannee Plant is a major stationary source based on actual emissions of and potential to emit 100 TPY or more of several PSD pollutants.

For major stationary sources such as the Suwannee Plant, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(274), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200(204), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant". SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 TPY as applicable) for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER given in **Table 4**.

TABLE 4 – LIST OF SER BY PSD-POLLUTANT. [1, 3]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [2]	40
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
Ozone (NO_X) [2]	40	SAM	7
SO_2	40	Pb	0.6
Hg	0.1	GHGs	> 75,000 (CO_2e) and > 0 (mass) [3, 4]

1. Excluding fluoride and pollutants specific to the Pulp and Paper industry, MWCs, MSW landfills.
2. Ozone (O_3) is regulated by its precursors (VOC and NO_X). PSD for $PM_{2.5}$ can be triggered by its precursors (NO_X and SO_2).
3. Pursuant to 40 CFR 52.21(b)(23)(ii), pollutants with no SER listed at 40 CFR 52.21(b)(23)(i) have a SER of zero tons/year.
4. In making the CO_2e calculation, the values listed in 40 CFR 98, Subpart A, Table A-1 are used to weight emissions by their respective Global Warming Potential (GWP). For example, the current GWP factors for four of the GHGs are: CO_2 = 1; CH_4 = 25; N_2O = 298 and SF_6 = 22,800.

According to guidance[1] issued by the EPA in July 2014, a source that triggers PSD review for a traditional PSD pollutant (listed above) would also trigger PSD review for greenhouse gases (GHGs) if the source would emit or have the potential to emit 75,000 tons per year of GHGs on a carbon dioxide-equivalent basis. Under this framework, a source cannot become subject to PSD review solely on the basis of GHG emissions.

2.2. PSD Applicability for the Project

The project is located in Suwannee County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The Suwannee project will emit the following PSD-pollutants SO_2, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SAM, VOC, lead (Pb) and CO_2e (GHG).

Table 5 provides PSD applicability calculations from DEF based on the net emissions increases and decreases expected to result from the Suwannee project. In this project, the net emissions are calculated by taking the potential emissions of the new units minus the baseline actual emissions (BAE) for the unit being retired (Boiler No. 3). The BAE, is defined in Rule 62-210.200(28)(a) as:

"For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation."

TABLE 5 – NET PSD POLLUTANT EMISSION INCREASES DUE TO THE SUWANNEE PROJECT IN TONS PER YEAR (TPY).

Pollutant	Emissions Increase [1]	Baseline Emissions Boiler No. 3 [2]	Net Emissions Increases (Decreases) [3, 4]	SER	PSD Applies? (Yes, No)
NO_X	408.26	-648.72	(240.46)	40	No
PM	25.31	-12.79	12.52	25	**No**
PM_{10}	52.97	-24.09	28.88	15	**Yes**
$PM_{2.5}$	52.97	-17.04	35.93	10	**Yes**
CO	121.62	-171.36	(49.74)	100	No
SO_2	36.61		36.61 [5]	40	No
SAM	6.22		6.22 [5]	7	No
VOC	20.94		20.94 [5]	40	No

[1] U.S. Supreme Court opinion dated June 23, 2014. Link to Supreme Court Opinion EPA guidance dated July 24, 2014. Link to EPA Guidance

Pb	0.01		0.01 [5]	0.6	No
CO_2e [6]	912,889	-243,606	669,283	75,000 [7] 0 [8]	**Yes**

1. Combined emission increase from both CTs, operating 3,500 hours per CT on gas and 500 hours per CT on oil, and accounting for startup emissions (worst case scenario), emissions from gas heaters, fire pump, oil tank, breakers, and pipelines.
2. 2-year average of specific pollutant from the Boiler unit No. 3 during the previous 5 years of operation at the Suwannee Plant.
3. A number in parentheses represent a negative value for PSD applicability with regard to TPY increase for the specified pollutant and SER.
4. Total project increase minus a 2-year average from the existing boiler for each pollutant.
5. Assumes no reduction in emissions from shutdown unit (Boiler No. 3).
6. CO_2e emissions are the aggregate of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).
7. Greenhouse Gases (GHG) – CO_2e Basis.
8. Greenhouse Gases (GHG) – Mass Basis.

The baseline actual emissions were determined using continuous emissions monitoring system (CEMS) data, as well as stack test and emission factor-based calculations as reported to the FDEP in annual operating reports for the most recent five-year period. The Department reviewed the data and has reasonable assurance it is accurate.

As seen from **Table 5**, according to DEF, the Suwannee peaking unit project triggers a PSD preconstruction review for emissions of PM_{10}, $PM_{2.5}$ and GHG under Department and federal rules.

3. BACT DETERMINATIONS

3.1. Definitions and Requirements Related to BACT

"Best Available Control Technology" or "BACT" is defined in Rule 62-210.200(40), F.A.C. 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:

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

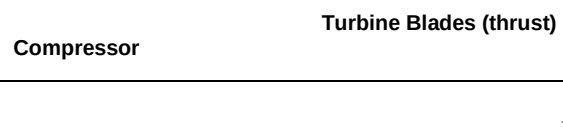
(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

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

3.2. Non-GHG Emission Limits and BACT Determinations for the Combustion Turbine Electrical generator (CTG)

3.2.1. How a Combustion Turbine-Electric Generator (CTG) Works

Refer to **Figure 5** for this discussion. Henceforth a CTG will be referred to as a CT. The CT shown in **Figure 5** is a more recent model of the GE CT proposed by DEF for the Suwannee peaker unit project.



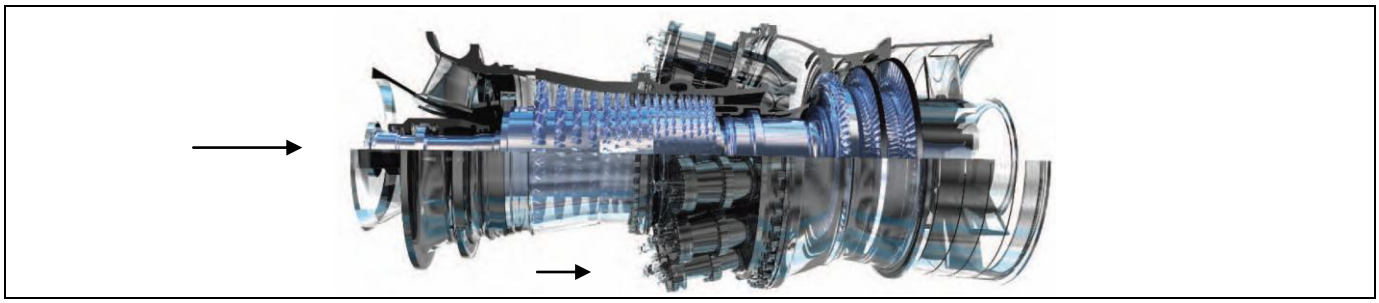


Figure 5. Parts and Internal View of a GE 7FA.05 Combustion Turbine-Electrical Generator.

A CT compresses air and mixes it with fuel. The fuel is burned and the hot air-fuel mixture is expanded through turbine blades, making them spin. The spinning turbine drives a generator which converts the spinning energy into electricity. In the Suwannee project, the units will operate in simple cycle mode, meaning that the hot turbine exhaust gases are directed through a stack without prior waste heat recovery and steam generation via a heat recover steam generator (HRSG) and steam turbine electrical generator (STEG).

3.2.2. CT Emission Standards (NO_X) – Not a BACT Determination

3.2.2.1. *NO_X Formation*

NO_X is formed during combustion as a result of the dissociation of molecular nitrogen (N_2) and oxygen (O_2) to their atomic forms and subsequent recombination into seven different oxides of nitrogen (especially NO and NO_2).

Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with flame temperature and linearly with residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also known as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relation of NO_X production with respect to flame and equivalence ratios (lean versus rich operation) is shown in **Figure 6**.

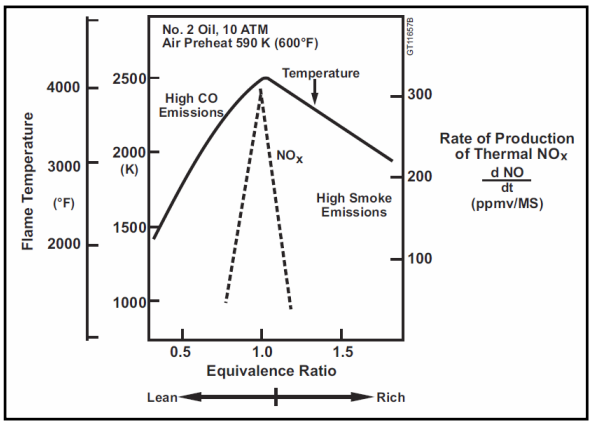


Figure 6. NO_X vs. Temperature, Equivalence Ratio[2].

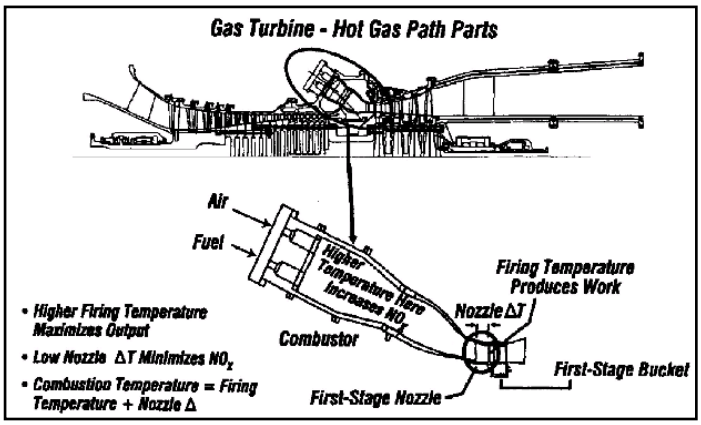


Figure 7. Hot Gas Path, NO_X Control.

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. The relationship between flame temperature, firing temperature, work output and NO_X formation is depicted in **Figure 7**, which is from a General Electric discussion on these principles.

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

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

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

Uncontrolled emissions from combustion turbines range from about 100 to 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 for large frame combustion turbines such as those under consideration for this project.[3]

3.2.2.2. *NO_X Controls*

The following discussion of NO_X controls and their associated performance in some cases uses GE F frame CT models as examples. Added on controls, such as selective catalytic reduction (SCR), are not discussed since this type of NO_X control would only be considered if the Suwannee peaker unit project had triggered PSD for NO_X.

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the CT. Emissions of CO and VOC are very low for large gas turbines when operated at higher loads. However steam or water injection may increase emissions of both of these pollutants.

Advanced dual-fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd @15% O_2 when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by means such as SCR.

Dry Low NO_X (DLN) Combustion. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of gaseous fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) within the combustion zones. This principle is incorporated into the General Electric DLN-2.6 can-annular combustor design depicted in **Figure 8** below.

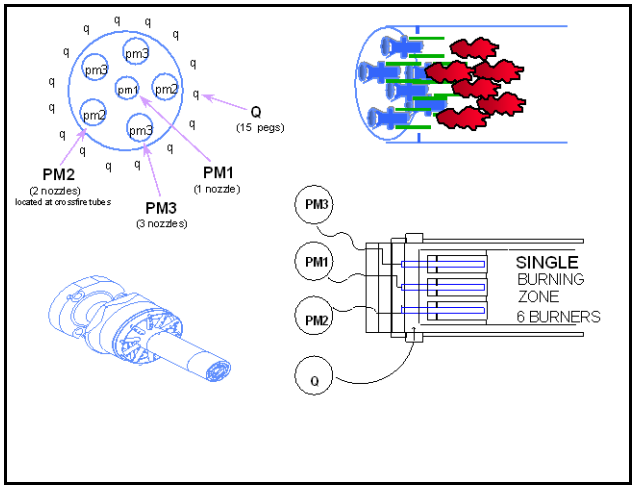


Figure 8. DLN-2.6 Fuel Nozzle Arrangement.

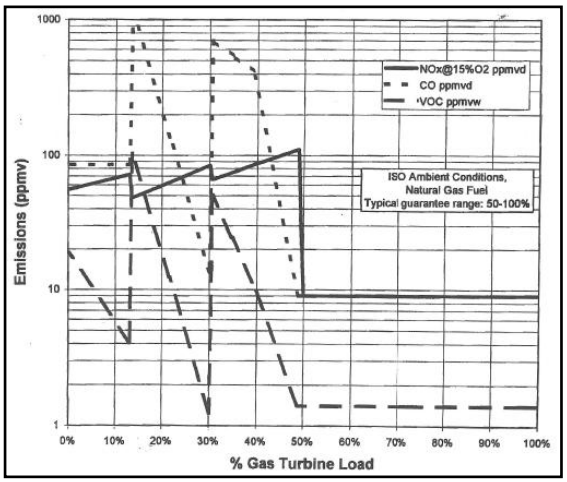


Figure 9. Design Characteristics for DLN-2.6.

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

Each combustor includes six nozzles within which gaseous fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability. Liquid fuel-based lean premix DLN combustion is generally not feasible for large combustion turbines.

Design NO_X, CO, and VOC emission characteristics (basis of guarantees) of the GE DLN-2.6 combustor for the GE 7FA.03 while firing natural gas are given in **Figure 9** above. The combustor design is such that NO_X concentrations can be tuned to achieve 9 ppmvd @15% O_2 at loads between 50 and 100 percent of capacity. However, *NO_X concentrations as high as 100 ppmvd may occur in the exhaust gas when the CT is at less than 50 percent of capacity*. This suggests the need to *minimize operation at low load conditions and during startup*. Units guaranteed to achieve 9 ppmvd @15% O_2 of NO_X were typically guaranteed to 9 ppmvd (uncorrected) of CO which equates to approximately 7.4 ppmvd CO @15% O_2. In the further discussion below use of the term ppmvd implies that the value is not corrected to 15% O_2.

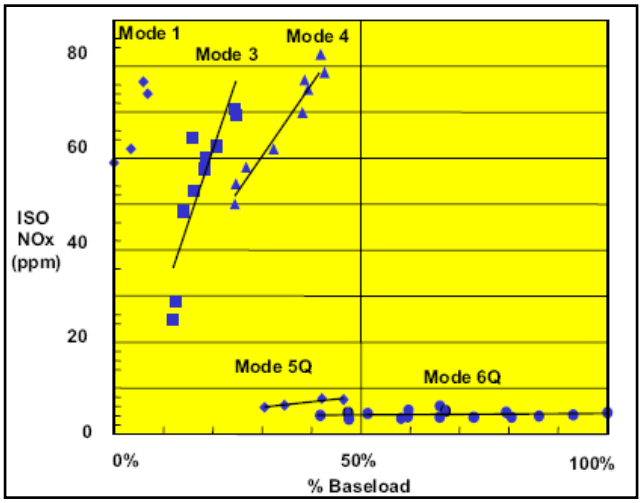


Figure 10. NO_X Performance of DLN-2.6 (GE 7FA.03).

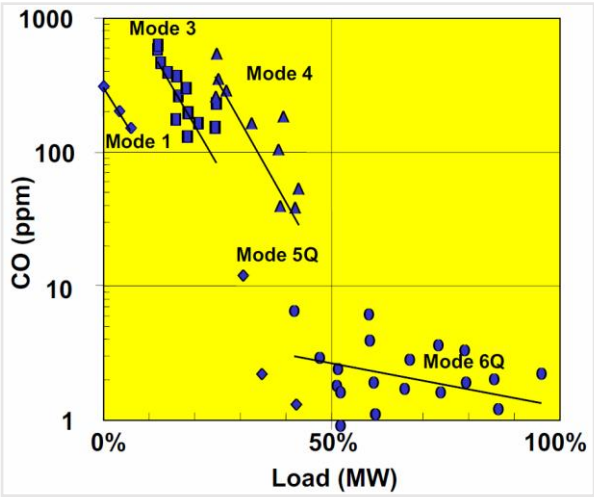


Figure 11. CO Performance of DLN-2.6.

Figure 10 above is from a GE publication and is a plot of NO_X data from actual GE 7FA.03 combustion turbines (or earlier models) or possibly a test facility. Actual NO_X emissions are less than the design values. The Department has reviewed numerous reports and low load operation data from GE 7FA.03 in Florida and confirms the accuracy of **Figure 10**. Also, actual emissions of CO at loads greater than 50% of full load have proven to be less than suggested by **Figure 9** above and more like the behavior shown in **Figure 11** above.

Table 6 below summarizes the results of the new and clean tests conducted on a dual-fuel GE 7FA.03 CT with DLN-2.6 combustors operating in simple cycle mode and burning natural gas at the existing Tampa Electric (TECO) Polk Power Station.[4] The test results over a range of loads confirm that NO_X, CO, and VOC emissions are, in practice, consistently less than the design (guarantee) values given in **Figure 9** above.

TABLE 6 - PERFORMANCE OF DLN-2.6 COMBUSTORS ON GE 7FA.03, TECO POLK POWER STATION (ppmvd).

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

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

Numerous simple cycle GE 7FA.03 units with DLN-2.6 technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd @15% O_2. This represents a reduction greater than 95%, assuming uncontrolled emissions are 200 ppmvd.

3.2.2.3. *Requirements of 40 CFR Parts 60 Subpart KKKK to the CT with Respect to NO_X*

The two proposed CT peaking units are subject to the requirements in 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. The citation is abbreviated as NSPS Subpart KKKK for the purposes of subsequent discussion. Link to NSPS Subpart KKKK. **Table 7** is a summary of the emission standards applicable to the Suwannee project CT. The table was excerpted from NSPS KKKK. The requirements applicable to the Suwannee project when firing natural gas and ULSD fuel oil are 15 and 42 ppmvd @ 15% O_2, respectively, on a 4-hour rolling average basis. A NO_X standard of 96 ppmvd @15% O_2 on a 4-hour rolling average basis is provided for CT operating at less than 75% of peak load.

TABLE 7 – NSPS SUBPART KKKK STANDARDS FOR NEW LARGE STATIONARY COMBUSTION TURBINES.

Combustion Turbine Type	Peak Load Heat Input, Power Output [1]	NO_X Standard [2]
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/hour	15 ppm @15% O_2 or 54 ng/J, useful output (0.43 lb/MW-hour)
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/hour	42 ppm @15% O_2 or 160 ng/J, useful output (1.3 lb/MW-hour)
Turbines located north of the Arctic Circle, **turbines operating at less than 75% of peak load**	> 30 MW output	96 ppm @15% O_2 or 590 ng/J, useful output (4.7 lb/MW-hour)

1. Heat input based on the higher heating value (HHV) or MW of useful output
2. ng/J means nanograms per joule

3.2.2.4. *DEF NO_X Emissions Standard Proposal*

DEF proposes NO_X limits for the Suwannee project when firing natural gas and ULSD fuel oil of 15.0 and 42.0 ppmvd, respectively, on a four-hour rolling average with compliance by CEMS. The limits will be reached using Dry-Low NO_x (DLN) and water injection technologies.

The applicant's proposed NO_X emission standards are acceptable to the Department and follow NSPS KKKK requirements. NOx emissions will also be limited by the Department accepting the combined 1,000 hours per year limitation proposed by DEF for ULSD fuel oil firing in the two CT.

3.2.3. CT Emission Standards (SO_2 and SAM) – Not a BACT Determination

3.2.3.1. *SO_2 Formation and Control*

SO_2 and formation in a CT is purely a function of the amount of sulfur in the fuel being combusted. SO2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for CT contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2 from CT. Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution. As described in **subsection 3.2.3.3**, the fuel sulfur limits proposed by DEF for the Suwannee project are well below the fuel sulfur requirements of NSPS Subpart KKKK.

3.2.3.2. *Requirements of 40 CFR Parts 60 Subpart KKKK to the CT with respect to SO_2*

The NSPS Subpart KKKK Limit for SO_2 is that you must not burn in the subject stationary CT any fuel which contains total potential sulfur emissions in excess of 26 nanograms SO_2/Joule (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement. Compliance with this

SO_2 limit can be demonstrated by the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content is 0.05% weight percent or less for oil and less than 20 gr/100 SCF for gas.

3.2.3.3. *DEF SO_2* and SAM *Emissions Standard Proposal*

For this project the applicant has proposed the use of ULSD fuel oil with a sulfur content of 0.0015% and clean natural gas with a sulfur content of 2.0 grains sulfur per 100 standard cubic foot (2.0 gr S/100 SCF) to control SO_2 and SAM emissions. Use of these fuels will more than meet the Subpart KKKK Limit for SO_2 of 0.060 lb SO_2/MMBtu heat input (see **subsection 3.2.3.2**). Compliance can be demonstrated by the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content is 0.05% weight percent or less for oil and less than 20 gr/100 SCF for gas.

The applicant's proposed sulfur fuel limits are acceptable to the Department and will insure that: PSD for SO_2 and SAM will not be triggered; the CT will comply with the SO_2 emission standards in NSPS Subpart KKKK; and the project will not cause or contribute to a violation of the AAQS for SO_2 or $PM_{2.5}$.

3.2.4. <u>CT Emission Standards (CO and VOC) – Not a BACT Determination</u>

3.2.4.1. *CO and VOC Formation and Combustor Characteristics*

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

Typically, VOC concentrations are an order of magnitude less than CO concentrations. Therefore, while burning natural gas, VOC emissions will likely be less than 1 ppm at high loads. CO and VOC emissions in the turbine exhaust gas while firing fuel oil in the CT should be very low based on the high combustion temperature and the relatively high temperature and excess air in the turbine exhaust gas.

3.2.4.2. *Requirements of 40 CFR Parts 60 Subpart KKKK to the CT with respect to CO and VOC*

NSPS Subpart KKKK does not include a CO or VOC emission standard for a CT.

3.2.4.3. *DEF CO and VOC Emissions Standards Proposal*

DEF used mass emission rates for CO PSD applicability calculations in their application of 17.37 pounds per hour and 41.9 lb/hr when firing natural gas and fuel oil, respectively (at 59 ºF). These mass emission rates equate to concentration based CO emission rates of 4.0 ppmvd @ 15% O_2 and 8.0 ppmvd @ 15% O_2 when firing natural gas and fuel oil, respectively.

DEF used mass emission rates for VOC PSD applicability calculations in their application of 3.5 lb/hr and 10.4 lb/hr (as methane) when firing natural gas and fuel oil, respectively. These mass emission rates equate to concentration based VOC emission rates of 1.4 ppmvd @ 15% O_2 and 3.5 ppmvd @15% O_2 when firing natural gas and fuel oil, respectively.

The above CO and VOC limits are acceptable to the Department. The Department has determined that an initial stack test is sufficient to demonstrate compliance with the CO and VOC mass and concentration emissions standards. Thereafter an annual stack test to demonstrate compliance with the CO concentration limit will suffice to provide reasonable assurance of compliance with all CO and VOC standards. These conclusions apply only to the DEF Suwannee peaker unit project and do not necessarily apply to projects that trigger PSD review including BACT determinations for CO and VOC.

3.2.5. <u>CT BACT Determination for Particulate Matter (PM_{10}/$PM_{2.5}$)</u>

Particulate matter (PM_{10}/$PM_{2.5}$) is directly emitted from combustion turbines due to incomplete combustion and the ash and sulfur present in the fuels. Such emissions are minimized by use of clean fuels, with low ash and sulfur content, and good combustion practices. Clean fuels are a necessity in combustion turbines in order to avoid

excessive maintenance due to damaged turbine blades and other components already exposed to very high temperatures and pressures.

3.2.5.1. *Applicant's $PM_{10}/PM_{2.5}$ BACT Proposal*

The applicant will use natural gas and ULSD fuel oil that are characterized by very low particulate formation potential. Natural gas is an inherently clean fuel, and contains no ash. ULSD fuel emits low amounts of ash and will be limited to minimal use (a combined 1,000 hours per year for both CT). Therefore, adding a control device to remove PM is unnecessary. In addition, the applicant will use ULSD fuel oil with a sulfur content of 0.0015% and clean natural gas with a sulfur content 2.0 gr S/100 SCF to minimize PM emissions.

DEF proposes as an emission standard a visible emissions (VE) standard of 10 percent opacity in conjunction with the use of inherently clean fuels. To verify compliance, annual VE tests using EPA Method 9, will be used.

3.2.5.2. *Department's $PM_{10}/PM_{2.5}$ BACT Determination*

The Department concurs with the applicant's proposal for VE and fuel sulfur limits as BACT for $PM/PM_{10}/PM_{2.5}$. Compliance will be shown by fuel sulfur monitoring or vendor certification and annual opacity testing for VE.

3.2.6. NESHAP Subpart YYYY Requirements

The emission limit for formaldehyde (CH_2O) of 91 parts per billion by volume dry (ppbvd) corrected to 15% O_2 in NESHAP Subpart YYYY for oil-fired Stationary Combustion Turbines shall apply to the DEF Suwannee peaker project if the facility cumulatively exceeds 1,000 oil-fired CT hours in any one year at the entire facility.

3.3. Non-GHG Emission Limits and BACT Determinations for 160 hp Emergency Fire Pump Engine

One emergency fire pump engine is included in this project. The following are the proposed specifications of the fire pump:

- Usage of 100 hours per year;
- Engine rated at 160 Horse Power (hp);
- Generator rated at 120 kilowatts (kW)
- Heat Input is 1.24 MMBtu/hour (higher heating value) from ULSD fuel oil.

The requirements of NSPS Subpart IIII and NESHAP Subpart ZZZZ apply to the fire pump engine. Also the fire pump engine meets the requirements of NESHAP Subpart ZZZZ by meeting the requirements of NSPS Subpart IIII. Those specifically applicable to the fire pump engine specified by DEF are summarized in **Table 8**.

TABLE 8 – NSPS SUBPART IIII STANDARDS FOR FIRE PUMP ENGINES.

Fire Pump Engine (100 ≤HP <175)	**CO** (g/kW-hr) [1]	**PM** (g/kW-hr)	**NMHC [2]+NO_X** (g/kW-hr)	**Diesel Fuel [3]** (sulfur)
2009 and later	5.0	0.30	4.0	15 ppm

1. g/kW-hr means grams per kilowatt-hour.
2. NMHC means Non-Methane Hydrocarbons.
3. Nonroad diesel specification from 40 CFR part 80, subpart I – Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel. Link to Non-Road Diesel Spec

The Department determines that the requirements listed in **Table 8** satisfy the requirements of BACT for $PM/PM_{10}/PM_{2.5}$ and provide acceptable limits for the other pollutants for the fire pump engine.

Compliance shall be shown by an initial and annual stack tests, or in lieu of stack tests, manufacturer engine certification. In the case of SO_2 emissions, compliance shall be shown by either fuel sulfur monitoring or vendor certification.

3.4. Standards for the ULSD Fuel Oil Storage Tanks (Not Subject to BACT)

The 2.5 million gallon ULSD fuel oil storage tank is not subject to 40 CFR 60, Subpart Kb - NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction,

Reconstruction, or Modification Commenced after July 23, 1984 because the tanks store a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). The Department believes that these storage tanks are not subject to NSPS Subpart Kb: Link to NSPS Subpart Kb.

3.5. Non-GHG BACT Determination for Natural Gas Heaters

Two natural gas heaters rated at 4.79 MMBtu/hour are required for the project. The purpose of these units is to heat natural gas above the dew point temperature and prevent condensation. The gas heaters are not subject to NSPS Subpart Dc as they do not meet the 10 MMBtu/hour heat input threshold.

The facility is currently considered a major source of hazardous air pollutants (HAPs), and therefore, the fuel heaters are subject to 40 CFR Part 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. If and when the facility becomes an area HAP source, Subpart DDDDD will no longer apply. 40 CFR Part 63 Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources would not apply because the subpart does not covers process heaters or units that fire only natural gas.

Emission limits in Subpart DDDDD are categorized according to fuel and process heater/boiler types. 40 CFR 63.7500 states that if a unit is designed to only burn gas 1 fuels, such as natural gas, it is not subject to emission limits set in Tables 1 and 2, or 11 through 13, or the operating limits in Table 4 of the subpart. However, as described in 40 CFR 63.7540 the units are subject to 5-year tune-up requirements as outlined in Table 3 of Subpart DDDDD.

According to applicant the heaters operate in two modes; standby mode where the heaters operate at 40% of capacity to heat the gas sink and dew point heating mode where the heater operates at full capacity during operation of the CT. Consequently, while the operational hours of the heaters will be 8,760 hours per year only 4,000 hours will be at full capacity. Accordingly, instead of an operational hour limit, the Department will set a $PM_{10}/PM_{2.5}$ BACT limit based on the use of clean burning natural gas with a sulfur content 2.0 gr S/100 SCF along with a natural gas usage limit. The combined natural gas usage in the heaters is limited to 56.8 million standard cubic feet of natural gas per year, which equates to each heater operating 5,904 hours per year at full load.

4. GHG BACT DETERMINATIONS

The process as defined by the EPA to determine a GHG BACT for the CT is described below in detail. The remaining GHG for other emission units are addressed in less detail since approximately 99% of the GHG emissions from the DEF Suwannee peaker project are attributable to the CT.

4.1. GHG BACT Analysis for CT

4.1.1. Step 1: Identify all Available Control Technologies

The applicant identified the following control technologies in their permit application for the proposed project:

- Carbon capture and storage (CCS)
- Clean fuels
- Energy efficiency

***Carbon Capture and Storage (CCS)*:** Carbon capture and storage (CCS) falls under the category of add- on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. CCS is an add-on pollution control technology that is available for large CO_2 emitting facilities including fossil fuel-fired power plants and industrial facilities with high purity CO_2 streams. As a result, CCS should be considered in Step 1 of the BACT analysis. CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage.

Deep saline formations, which are layers of porous rock, saturated with brine present a potential for geologic storage of CO_2. However, there is not as much experience with saline formations as there is acquired through resource recovery from oil and gas reservoirs and coal seams. There is ongoing research focused on storage in

organic rich shale, which is a thin horizontal layer of sedimentary rock with low vertical permeability and in basalt formations, which are geologic formations of solidified lava. Other possible options include liquid storage in deep ocean areas.

Clean Fuels: Clean fuels fall under the general category of lower polluting processes/practices. Natural gas is an inherently cleaner burning fuel that is ubiquitous in the US and can be produced domestically. The combustion of natural gas emits about 30% less CO_2 than fuel oil.

The applicant considered two scenarios for clean fuels. The first scenario is using 100% dedicated natural gas operation. The second scenario includes 1,000 hr/yr of ULSD oil fuel firing as a limited backup fuel (500 hours per CT).

***Energy Efficiency*:** Energy efficiency falls under the general category of lower polluting processes/practices. Applying technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review for GHGs, but it also may achieve collateral reductions of emissions of other pollutants. There are different categories of energy efficient improvements:

- Technologies or processes that maximize the efficiency of the individual emissions unit, and
- Options that could reduce emissions by improving the utilization of thermal energy and electricity that is generated and used onsite.

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including GHGs).

4.1.2. Step 2: Eliminate Technically Unfeasible Options

In order to establish that an option is "feasible" the control option must have been demonstrated in practice or can be reasonably installed and operated.

***Clean Fuels*:** The use of natural gas as the primary fuel to run the CT is technically feasible and is being proposed for the Suwannee River simple cycle CTs. Two scenarios were considered: exclusively using natural gas to run the CTs and using natural gas as the primary gas along with ULSD oil as the backup fuel.

***Energy Efficiency*:** Efficient power generation is technically feasible and is being proposed for the Suwannee River simple cycle CTs. DEF considered the GE7FA.03, GE7FA.04, GE7FA.05, and Siemens SGT6-5000F(ee) for turbine selection.

***Carbon Capture and Storage (CCS)*:** The DEP recognizes the logistical hurdles that the installation and operation of a CCS system presents which set this pollution technology apart from other add on controls that are typically used to reduce emissions of other regulated pollutants. It should also be noted that, while CCS may be available, all current CCS projects for power plants are either in the demonstration stage or newly permitted and there have been no CCS demonstrations on simple cycle combustion turbines. In fact, the EPA considers CCS technically infeasible due to the variable operation of simple cycle combustion turbines and the flue gas cooling and heat integration issues[5].

4.1.3. Step 3: Rank Remaining Control Technologies

Based on the discussion in Steps 1 and 2, clean fuels and energy efficiency were considered technically feasible as control options. Further analysis of each of them is included in Step 4.

***Clean Fuels*:** The combustion of natural gas emits about 30% less CO_2 than oil.

***Energy Efficiency*:** The GE7FA.03, GE7FA.04, GE7FA.05, and Siemens SGT6-5000F(ee) CT were compared to each other. The applicant only considered those CT that were at the same level of efficiency or higher than

[5] Pio Pico Energy Center (PSD Permit Number SD 11-01) Fact Sheet and Ambient Air Quality Support Report, June 2011, pp 15-22.

their proposed model GE 7FA.03. The top control is a combination of the cleanest fuel and the most energy efficient combustion turbine. In Step 4 the economic, energy and environmental impacts of these technologies are analyzed.

4.1.4. Step 4: Economic, Energy, and Environmental Impacts

***Clean Fuels*:** The applicant considered two scenarios: (1) exclusively using 100% non-interruptible natural gas to run the CT and (2) using natural gas as the primary gas along with ULSD fuel oil as the backup fuel.

The DEP has determined that the use of 100% non-interruptible natural gas is not feasible because a backup fuel is required to account for natural gas disruption or curtailment. Thus, the use of natural gas as the primary fuel with ULSD fuel oil as a limited back up is determined feasible for this project

***Energy Efficiency*:** The applicant considered different turbines: GE7FA.03, GE7FA.04, GE7FA.05, and Siemens SGT6-5000F(ee) before choosing the GE7FA.03 as their final choice. As described in **Table 9** below, the GE 7FA.04 and 7FA.05 are more efficient than the GE 7FA.03 as is the Siemens SGT6-5000F(ee). However, these efficiency differences are less than one percent. In addition, a recent ruling (March 18, 2014) by the EPA Environmental Appeals Board (EAB) for the La Paloma Energy Center, LLC (La Paloma) confirmed that marginal differences in efficiency among gas turbines under consideration for a project do not necessarily require selection of the highest efficiency turbine to meet BACT for GHGs[6]. The applicant analyzed potential CO_2 emissions that would be released into the atmosphere on a yearly basis. Since the GE 7FA.04 and 7FA.05 models and the Siemens SGT6-5000F(ee) are higher capacity machines, the CO_2 mass emissions are higher compared to the GE 7FA.03 model. DEF indicates that since the facility does not need the higher output from the larger machines, it would be unreasonable to select these turbines for use. The Department agrees with this conclusion.

TABLE 9 – EFFICIENCY FROM AVAILABLE TURBINE OPTIONS.

Parameters	7FA.03	7FA.04	7FA.05	SGT6-5000F(ee)
Manufacturer	GE	GE	GE	Siemens
Heat rate @ Full Load (Btu/kWh, HHV) [1] Natural Gas	10,051	9,941	9,804	9,808
Calculated Efficiency (%)[1]	34.0	34.3	34.8	34.8
CO_2e emissions (tpy) [2]	453,304	462,176	529,942	563,599

Notes:
1. Calculations by Black & Veatch
2. Assumes machines are operated at maximum capacity. Also assumes machines run on 3,500 hours of natural gas and 500 hours on ULSD fuel oil.

4.1.5. Step 5: Selection of BACT

DEF proposes gross output-based GHG BACT limits of 1,416 pounds CO_2e per megawatt hour (lb CO_2e/MW-hr) on a 12-month rolling average when firing natural gas and 1,982 CO_2e/MW-hr on a 12-month rolling average when firing ULSD fuel oil. The BACT limits are based on per turbine operation, ISO conditions, and a 5 percent design margin and a 3 percent margin for degradation over time.

Considering these metrics, and the high cost associated with CCS, the DEP agrees that the most effective combination of control technologies is the use of the model GE 7FA.03 CT operated using interruptible natural gas service and ULSD fuel oil as limited backup fuel and good combustion practices. Fuel oil use will be limited to a combined total of 1,000 hours per year between the two CT.

Based on the Preliminary Determination & Statement of Basis document for the Shady Hills Generating Station Project by EPA Region IV (final permit obtained January 2014) where a GE 7FA.05 was the selected CT, the GHG BACT limits proposed by DEF appear reasonable. For the Shady Hills project in Florida the selected GHG

[6] EPA EAB Decision on the La Paloma Energy Center, LLC (La Paloma), March 18, 2014.

BACT on a gross output-basis was 1,377 lb CO_2e/MW-hr on a 12-month rolling average when using natural gas and 1,928 CO_2e/MW-hr on a 12-month rolling average for ULSD fuel oil. If the efficiency difference between the two GE models (7FA.03 – 34.0% and 7FA.05 – 34.8%) given in **Table 9** is taken into account, the corresponding GHG BACT numbers for a GR F7A.03 CT would be 1,409 lb CO_2e/MW-hr on a 12-month rolling average when using natural gas and 1,973 CO_2e/MW-hr on a 12-month rolling average for ULSD fuel oil. The Department set these limits as the GHG BACT for the GE 7FA.03 CT for the DEF Suwannee peaker unit project.

DEF proposes that compliance with the Department's GHG BACT emission limits of 1,409 lb CO2e/MW-hr (natural gas) and 1,973 CO_2e/MW-hr (fuel oil) can be achieved through the continuous monitoring of fuel consumption and gross power output along with the use of emission factors (GWP factors as listed in 40 CFR Part 98 Subpart A, Table A-1 amended on November 29, 2013 [78 FR 71948]) to determine total CO_2e emissions rather than the use of Continuous Emissions Monitoring Systems (CEMS). The Department accepts the compliance proposal and the permit will be structured accordingly.

4.2. GHG BACT Analysis for Natural Gas Fuel Heaters

CCS is not practical for control of CO_2 emissions from the natural gas fuel heaters due to the small amount of CO_2 emissions potential from this equipment. In addition, as previously described, the heaters operate in two modes; standby mode and dew point heating mode. Consequently, while these units will operate continuously, only 4,000 hours will be at full load while the remaining 4,860 hours will only be at 40% load making the addition of control equipment problematic. Therefore, CCS was not included as an available control technology in the following BACT analysis.

4.2.1. Step 1 and 2: Identify all Available Control Technologies and Eliminate Technically Infeasible Control Options

Clean Fuels: The DEP recognizes that the natural gas heaters in this BACT analysis utilize natural gas as the only fuel source, which is a cleaner fuel with respect to GHG emissions and constitutes a lower polluting method of operation.

***Energy Efficiency*:** The natural gas heaters will be used to warm up the natural gas flowing through the pipeline before feeding into the CT. The heaters supply heat based on the natural gas conditions. Therefore, the amount of fuel used in the heater is regulated to that necessary for the natural gas delivered to the CT. The indirect-fired natural gas fuel heaters operate at a high thermal efficiency, usually greater than 75%. Additionally, the natural gas fuel heater operation is limited by fuel usage.

Energy efficiency, a fuel use limitation, and clean fuels through the regulation of the amount of fuel used is considered to be the only technically feasible CO_2 control option for the natural gas heaters.

4.2.2. Step 3 and 4: Rank Remaining Control Technologies and Evaluation of Impacts

Based on the discussion in Steps 1 and 2, the technically feasible control options for GHGs from the natural gas fuel heaters are energy efficiency, use of a cleaner fuel and limitation on fuel use. There are no anticipated adverse environmental impacts associated with the use of these controls as BACT.

4.2.3. Step 5: Select BACT

The applicant proposes using highly efficient (>=75%) fuel heaters using good combustion practices and clean burning natural gas as BACT. DEF proposes a combined natural gas usage BACT limit in the heaters of 56.8 million standard cubic feet of gas per year which equates to each heater operating 5,904 hours per year at full load. In addition, DEF also proposes a combined 3,191 TPY CO_2e BACT emissions limit for both heaters, based on a 12-month rolling average. DEF proposes compliance with the natural gas usage limit and the combined 3,191 TPY CO2e heater emissions limit by monitoring the monthly fuel flow to each heater and using GWP factors as listed in 40 CFR Part 98 Subpart A, Table A-1 amended on November 29, 2013 [78 FR 71948] to determine CO_2e emissions. The Department accepts this GHG BACT determination.

4.3. GHG BACT Analysis for Fire Pump Engine

For the same reasons cited for the natural gas heaters, CCS was not included as an available control technology in the following BACT analysis.

4.3.1. Step 1 and 2: Identify all Available Control Technologies and Eliminate Technically Infeasible Control Options

Clean Fuels: The applicant considered the possibility of operating a biodiesel- or natural gas-fired emergency fire pump. However, biodiesel was eliminated as non-feasible due to unknown storage life issues. Additionally, spark ignited combustion engines (gasoline or natural gas fired) are not recommended for use with emergency fire pump engines.

***Energy Efficiency*:** The emergency fire pump is designed to meet the applicable NSPS and National Emission Standards for Hazardous Air Pollutants for non-road engines (subparts IIII and subpart ZZZZ, respectively); thus, this unit will maximize efficiency while meeting the required emissions standards. In conjunction with maximizing efficiency, the applicant also proposed proper maintenance and operating procedures. Additionally, the fire pump will be limited to 100 hours per year.

Energy efficiency, limitation of hours of operation and clean fuels through the regulation of the amount of fuel used is considered to be the only technically feasible CO_2 control option for the emergency fire pump.

4.3.2. Step 3 and 4: Rank Remaining Control Technologies and Evaluation of Impacts

Based on the discussion in Steps 1 and 2, the technically feasible control options for GHGs from the emergency fire pump are energy efficiency through the regulation of fuel use of a cleaner fuel, and limitation of the operating hours. There are no anticipated adverse environmental impacts associated with the use of these controls as BACT.

4.3.3. Step 5: Select BACT

For the emergency fire pump DEF proposes using ULSD fuel oil, following the manufacturer's recommended maintenance procedures in an effort to keep the unit operating as efficiently as practical and limited operating hours of 100 per year, excluding emergencies as BACT.

The emergency fire pump accounts for less than one percent of the total GHG emissions potential of the Project. Given the limited use of the emergency fire pump engine and the relatively small amount of GHG emissions, the Department has determined the use of clean fuel combined work practice standards along with limiting operational non-emergency hours to 100 hours or less is more appropriate than a numeric BACT limit.

4.4. GHG BACT analysis for Sulfur hexafluoride (SF_6) Insulated Circuit Breakers

4.4.1. Step 1: Identify all Available Control Technologies

The applicant identified alternative (non-SF_6) dielectric fluids, minimization of SF_6, and good operational practices as the available control techniques in their permit application for the proposed circuit breakers. Historically, dielectric fluids such as dielectric oils have been used in high voltage applications. However, the use of these materials in circuit breakers has been predominantly replaced with SF6, which has superior dielectric and arc quenching properties. Modern SF_6 circuit breakers are designed as totally enclosed pressure systems with low potential SF_6 fugitive emissions. The proposed circuit breakers will have a pressure gage with internal set points for operation limitations. Leakage is typically guaranteed to be no more than 0.5% by weight. In addition, circuit breakers have density alarms that provide warnings when a leak occurs. Further, this equipment is routinely inspected to insure proper operation since the equipment is necessary for safe operation of the Project.

4.4.2. Step 2: Eliminate Technically Infeasible Control Options

Circuit breakers using SF_6 with alarms and periodic inspection are technically feasible for the Project. The use of alternative dielectric fluids is not practical for high voltage applications. Circuit breakers using SF_6 insulating gas are presently superior in their performance to alternative systems using dielectric oil, high pressure air blast, or vacuum circuit breakers.

4.4.3. Step 3 and 4: Rank Remaining Control Technologies and Evaluate Impacts

Based on the discussion in Steps 1 and 2, the only technically feasible control option for SF_6 emissions from circuit breakers is the use of modern enclosed systems with alarms and periodic inspection. There are no anticipated adverse environmental impacts associated with the use of modern enclosed circuit breaker systems with alarms and periodic inspection.

4.4.4. Step 5: Select BACT

The most effective control of fugitive SF_6 emissions is using three totally enclosed systems equipped with leak detection along with good operational practices such as:

- Pressure gages with internal set points for operation limitations,
- Repair of leaks or replacement of equipment, and
- Continuous monitoring of circuit breaker pressure gage, periodic inspection, and maintenance.

DEF proposes the use of modern, totally enclosed circuit breakers with leak detection alarms having a threshold of 10%, along with good operational practices. The Department agrees with the applicant's BACT analysis for SF_6 insulated circuit breakers.

4.5. GHG BACT Analysis for Fugitive Emissions from On-Site Pipelines

4.5.1. Step 1: Identify all Available Control Technologies

The only feasible control technology to minimize fugitive emissions is to minimize leaks from natural gas pipelines.

4.5.2. Step 2: Eliminate Technically Infeasible Control Technologies

There are no technically infeasible control technologies to be eliminated

4.5.3. Step 3 and 4: Rank Remaining Control Technologies and Evaluation of Impacts

Based on the discussions in Steps 1 and 2, the only technically feasible control option is to minimize natural gas leaks from piping components.

4.5.4. Step 5: Select BACT

The Department agrees with the proposed BACT to minimize GHG fugitive emissions from on-site pipeline and natural gas supply through monitoring and repairing. The applicant will continuously monitor pipeline system pressure against alarm set points to identify leaks. Additionally, natural gas will be treated with mercaptan for human detection of any odor from leaks.

4.6. GHG BACT Summary

The GHG BACT determination for the CT, natural gas heaters, fire pump engine, SF_6 circuit breakers, and the natural gas pipeline are summarized in **Table 10** below.

TABLE 10 – SUMMARY OF GHG BACT DETERMINATIONS.

Emission Unit	GHG BACT
CT	Natural Gas: 1,409 lb CO_2e/MW-hr per CT ULSD Fuel Oil: 1,973 lb CO_2e/MW-hr per CT

Emission Unit	GHG BACT
	(Gross, 12-month rolling average basis at ISO conditions) Combined CT operation of 8,000 hours of which 1,000 hours can be fuel oil Compliance by monitoring of fuel consumption, gross power output and emission factors [1]
Natural Gas Heaters	Gas usage limit of 56.8 million standard cubic feet of gas per year Emissions limit both heaters combined of 3,191 TPY CO_2e (12-month rolling average) Compliance by fuel monitoring and emission factors [1]
Fire Pump Engine	Use of ULSD fuel oil, proper maintenance, and an operating limitation of 100 hours per year (excluding emergencies).
SF_6 Circuit Breakers	Use of modern, totally enclosed SF6 circuit breakers with density (leak detection) alarms having a threshold of 10 percent.
Natural Gas Pipelines	Employment of daily (when practical and weather permitting) audible, visible, and olfactory plant inspection and maintenance routines with leaks tagged and repairs made within 10 days when possible or as soon as practicable thereafter.
1. GWP factors as listed in 40 CFR Part 98 Subpart A, Table A-1 amended on November 29, 2013 [78 FR 71948]	

5. AIR QUALITY IMPACT ANALYSIS

The Suwannee project has the PTE the following PSD-pollutants at levels in excess of their respective PSD SER: $PM/PM_{10}/PM_{2.5}$, and GHG. DEF must provide a demonstration utilizing approved air quality models that the predicted emission levels of these pollutants will not cause or contribute to a violation of the AAQS or PSD increment for each where they apply. PM_{10} and $PM_{2.5}$ have defined national and state AAQS and PM_{10} has defined PSD increments. In addition, significant impact levels (SIL) and significant monitoring concentrations (SMC) are used to determine the scope of the modeling analyses and evaluate the need for pre-construction ambient air monitoring data. Air dispersion modeling is not required for GHG.

5.1. Major Stationary Sources near the Suwannee Plant

To provide some perspective on the relative scale of the proposed Suwannee peaker unit project with regard to $PM_{10}/PM_{2.5}$ emission refer to **Table 11** below. **Table 11** list the largest stationary sources of actual emissions, by pollutant, around the project site, with the project highlighted in **bold text**.

TABLE 11 – LARGEST SOURCES OF $PM_{2.5}/PM_{10}$ (2012) NEAR THE SUWANNEE PLANT.

Owner/Company Name	Site Name	County	Emissions (TPY)
DEF	**Suwannee Project**	**Suwannee**	**35.93 [a]**
Pilgrim's Pride Corp.	Live Oak, FL Feed Mill	Suwannee	31.57
DEF	Suwannee River Plant (Existing)	Suwannee	26.71
Pilgrim's Pride Corp.	Live Oak, FL Poultry Plant	Suwannee	1.9
a. Based upon maximum potential emissions and worst case scenario operating conditions. Includes emissions reduction from Boiler #3			

5.2. Pre-Application Ambient Air Monitoring Surrounding the Project Site

The State of Florida ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in many Florida counties. Pre-Application air quality monitoring is required for PM_{10} if the maximum modeled 24-hour concentration is greater than the PM_{10} significant monitoring concentration (SMC) for the proposed project. However, if the maximum modeled concentration is below the SMC of 10 µg/m³, the applicant can request an exemption from the pre-application monitoring. Since the project's maximum predicted 24 hour PM_{10} impact is less than the SMC (as seen in **Table 13)**, the Department is granting DEF an exemption from PSD pre-application air quality monitoring requirements. For $PM_{2.5}$, there is no SMC, PSD regulations require pre-application ambient air quality monitoring unless an existing monitor is found to be representative. These monitors are used to estimate the existing air quality in the area and to satisfy pre-construction monitoring requirements. **Table 12** below provides the ambient air quality design values for the selected monitors.

The ambient air measurements listed in **Table 12** are values that do not contain 'exceptional events'. An 'exceptional event' is defined by EPA in accordance with 40 CFR 50.14 as an event that affects air quality, is not reasonably controlled or preventable, and is an event caused by human activity that is unlikely to recur at a particular location or natural event.

The applicant conservatively assumed that the highest monitored concentrations of the three sites listed in **Table 12** would be representative of the project site. The values chosen are in bold lettering. The Department agrees that these monitors are representative of the site and as such is not requiring pre-application monitoring for $PM_{2.5}$.

TABLE 12 – AMBIENT AIR QUALITY MEASUREMENTS NEAREST TO THE SUWANNEE PLANT (2011-2013).

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
$PM_{2.5}$	Gainesville, FL (012-001-0023-1)	24-hour [a]	2011-2013	20.0 [d]	35	$\mu g/m^3$
		Annual [b]	2011-2013	7.4 [d]	12	$\mu g/m^3$
$PM_{2.5}$	Jacksonville, FL (012-031-0098-1 and 12-031-0032-1)	24-hour [a]	2011-2013	**22.7** [c]	35	$\mu g/m^3$
		Annual [b]	2011-2013	8.08 [c]	12	$\mu g/m^3$
$PM_{2.5}$	Tallahassee, FL (012-073-0012-1)	24-hour [a]	2011-2013	22.0 [d]	35	$\mu g/m^3$
		Annual [b]		**8.9** [d]	12	

a. Three year average of the arithmetic annual means.
b. Three year average of the annual 4th highest daily 8-hour maximum.
c. Averaged using the maximum value for 2011, 2012, and 2013 from the highest of the three monitors located in Duval County. For example, site ID number 0098 was used in 2011 and site ID number 0032 was used for 2012 and 2013.
d. DEP corrected these concentration numbers submitted by DEF in permit application.

TABLE 13 – MAXIMUM PREDICTED AIR QUALITY IMPACTS OF THE PROJECT COMPARED TO CLASS II SIL.

Pollutant	Averaging Time	Max Impact [b] ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Significant Impact?
$PM_{2.5}$	24-Hour	0.99679	1.2	No
$PM_{2.5}$	Annual	0.14653	0.3	No
PM_{10}	24-Hour	1.21757	5	No
PM_{10}	Annual	0.18073	1	No

5.3. Existing Ambient Air Quality near the Suwannee Plant –$PM_{2.5}$

$PM_{2.5}$ (also known as PMfine) is an important indicator of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources, as well as from fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.

The reported compliance values for $PM_{2.5}$ for the monitors throughout the state of Florida are shown in **Figure 12** below. These monitors indicate that the areas around Suwannee County are well within attainment of all applicable national and state NAAQS.

5.4. Air Quality Impact Modeling

5.4.1. Models, Emissions Data, and Meteorological Data

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the project in the surrounding Class II areas. AERMOD is a Gaussian steady-state plume dispersion modeling system that simulates pollutant dispersion methods 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: the AERMET meteorological processor and the AERMAP terrain processor.

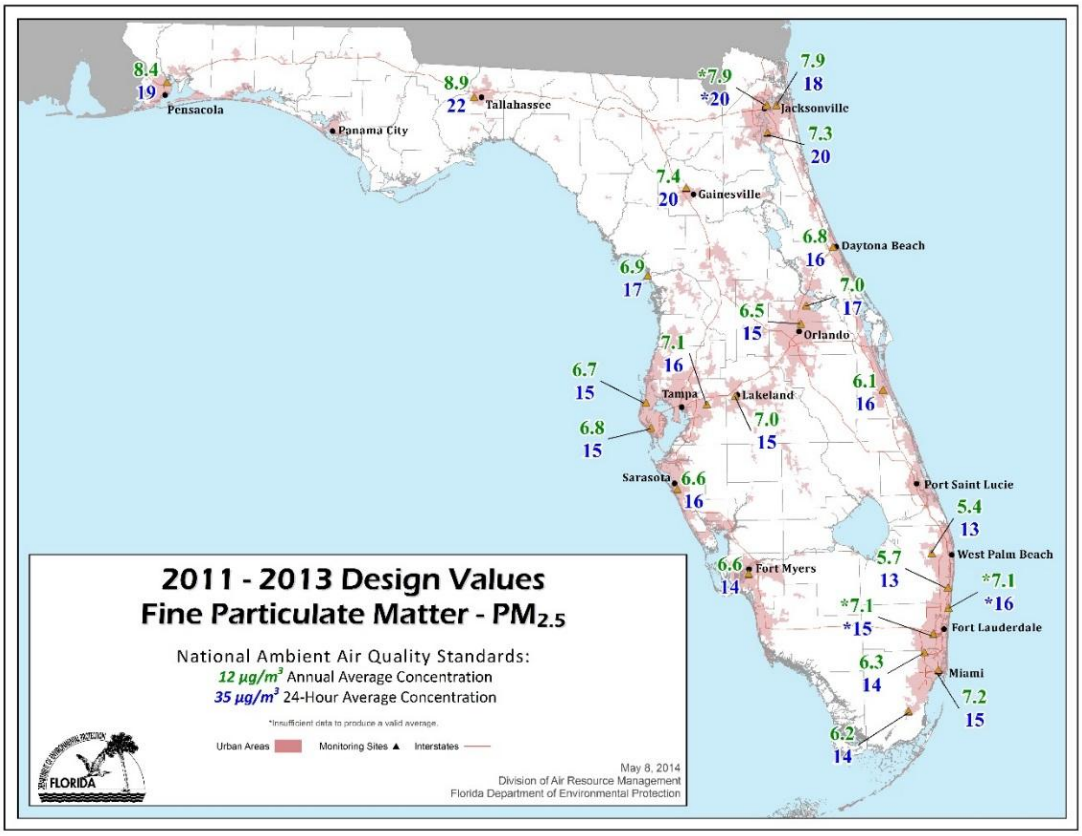


Figure 12. Florida $PM_{2.5}$ Design Values.

The applicant used a series of specific model features recommended by the EPA that are referred to as the regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered.

The AERMET meteorological data used with the AERMOD model consisted of a continuous 5-year period of hourly surface weather observations from the National Weather Service (NWS) Automated Surface Observing System (ASOS) station located at the Tallahassee Regional Airport (KTLH). The upper air sounding data used was also collected from the Tallahassee Regional Airport (KTLH). This data was compiled by the DEP for the period 2008 through 2012 with the inclusion of a land cover and use analysis input from AERSURFACE, and a detailed wind data from AERMINUTE. The ASOS station at KTLH is located approximately 112 km due west of the project site and is the closest primary weather station considered to have representative meteorological data. Although the ASOS site is a large distance away from the site, both areas have a very similar Bowen Ratio and Albedo. The surface roughness of the two sites vary greatly, however, DEP is confident that predicted maximum concentration differences would be relatively small if the KTLH site had a similar surface roughness. The terrain between the two sites is mostly flat, the wind direction and wind speed frequencies measured at the ASOS location are considered to be representative of the project site.

5.4.2. Significant Impact Analysis

The general modeling approach for the significant impact analysis for the Suwannee project followed the EPA and the DEP modeling guidelines for determining compliance with NAAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD SER due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the SIL for Class I (designated areas such as National Parks) and Class II

areas (everywhere else). For the proposed project, emissions increases above the PSD SER occur only for PM_{10} and $PM_{2.5}$. A significant impact analysis was completed for this pollutants to determine if the project may cause an increase in ground-level concentration greater than the SIL.

If the modeling for a particular pollutant shows ground-level increases less than it's SIL, the DEP will evaluate the need for any further modeling. If the modeled concentrations from the project exceed the SIL, then additional refined modeling, including emissions from nearby facilities and/or projects (cumulative modeling), is required to determine the proposed project's impacts compared to the NAAQS and PSD increments for those pollutants.

5.4.2.1. *Class II SIL*

The applicant is seeking permitted authority to operate two turbines for up to 4,000 hours per year using natural gas, of which ULSD fuel oil could be used up to 500 hours per year. To determine the 'worst case scenario' for emissions, each turbine model was evaluated at a range of operating temperatures, loads, and fuels.

In the Class II modeling analysis, receptor locations used in both modeling analyses were based on Universal Transverse Mercator (UTM) coordinates from Zone 17, North American Datum 1983 (NAD83). A combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. A discrete Cartesian grid of 5,850 receptors was located at the following intervals and distances:

- Every 50 meter (m) along the property boundary and fence line;
- Every 100 m from 1 km to 2.5 km
- Every 250 m from 2.5 to 5 km
- Every 500 m from 5 km to 10 km

The modeling results shown in **Table 13** above are the maximum modeled impacts based on load and fuel. The results demonstrate that maximum concentrations due to the project are predicted to be less than the SIL for all pollutants. As a result, the DEP believes that additional modeling analysis is not required.

Secondary $PM_{2.5}$ formation from the emissions of SO_2, NO_X and VOC is expected to be minimal. As a result of the Suwannee Project, there is a net decrease in NO_x of 240.46 tons/year and a minimal increase in SO_2 and VOC's of 36.61 and 20.94 tons per year respectively. Currently, air dispersion and transport models do not account for the contributions these compounds make in the formation of secondary $PM_{2.5}$. However, estimates of the relationship between $PM_{2.5}$ and its precursors can be made. Because secondarily formed $PM_{2.5}$ takes time for the chemistry conversions, this component of the $PM_{2.5}$ is more widespread and diffuse. Such a minimal increase in SO_2 and VOC, however, would not affect compliance with meeting the NAAQS or PSD increments.

5.4.2.2. *Class I SIL*

Class I areas considered close to the project site are Bradwell Bay Wilderness, Chassahowitzka Wilderness, Okefenokee Wilderness, Saint Marks Wilderness, and Wolf Island Wilderness. The EPA-approved CALPUFF non-steady-state puff dispersion model is recommended for evaluation of emission impacts at distances greater than 50 km. This model was used to evaluate pollutant dispersion and visibility impairment in the Class I areas. Meteorological input data used in the modeling analysis was provided by the NPS for the years 2001-2003. The maximum pollutant concentrations predicted for the proposed Suwannee project are compared to the PSD Class I SILs in **Table 14** below. The impacts are the highest first high for both CT's and represent 100% load using ULSD. The modeling results indicate that maximum concentrations due to the project are predicted to be less than the Class I SILs. As a result, the DEP believes that PSD increment analysis is not necessary.

TABLE 14 – MAXIMUM PREDICTED AIR QUALITY IMPACTS OF THE PROJECT COMPARED TO CLASS I SIL.

Pollutant	Averaging Time	BBW	CW	OW	SMW	WIW	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10} [b]	Annual 24-Hour	0.00192 0.03816	0.00102 0.02260	0.00281 0.05758	0.00281 0.04660	0.00110 0.02047	0.16 0.32	No No
$PM_{2.5}$ [a,b]	Annual 24-hour	0.00192 0.03816	0.00102 0.02260	0.00281 0.05758	0.00281 0.04660	0.00110 0.02047	0.06 0.07	No No

a. Assumes 100% of PM_{10} consists of $PM_{2.5}$, i.e., the most conservative estimate.
b. Modeled at 100% load with two CT's using ULSD

5.4.3. Class I Area Impacts- Air Quality Related Values (AQRV)

According to the U.S. Department of the Interior, an AQRV is defined as "all those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment." An analysis of a project's impacts on AQRV in Class 1 areas is required as part of an application for an air construction permit.

In October 2010, the Federal Land Managers (FLMs), consisting of the National Park Service, U.S. Forest Service, and U.S. Fish and Wildlife Service, issued the Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report- Revised (2010). Based on the report, the FLM recommended initial screening criteria that would exempt a source from AQRV impact review based on a source's annual emissions and distance from a Class I area.

The FLM will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRV if its total SO_2, NO_X, PM_{10}, and sulfuric acid mist (SAM) annual emissions in TPY (based on 24-hour maximum allowable emissions), divided by the distance (km) from the Class I area (Q/D) is 10 or less. The FLM would not request any further Class I AQRV impact analyses from such sources. **Table 15** below shows the Q/D values of all the Class I areas under consideration when running ULSD at 100% load. Each area shown are greater than the screening criterion; therefore, additional analysis is required to assess visibility impairment.

TABLE 15– FLAG GUIDANCE SCREENING ANALYSIS.

Class I Areas	Distance (Km)	Q/D Ratio	Analysis Required?
Chassahowitzka Wilderness	183	19.16	**Yes**
Saint Marks Wilderness	81	43.28	**Yes**
Wolf Island Wilderness	207	16.94	**Yes**
Okefenokee Wilderness	74	47.38	**Yes**
Bradwell Bay Wilderness	129	27.18	**Yes**

5.4.3.1. *Class I Area Visibility Impacts*

Certain Class I areas are protected against visibility impairment due to plume blight from nearby sources and regional haze from long distance sources. An assessment of the project's regional haze impacts was conducted using the current EPA-approved CALPUFF v.5.8 Level 130731 air quality program. Background light extinction Method 8, with sub-mode 5 monthly relative humidity data for the Class I areas in accordance with current FLM guidance was used. The assessment evaluated the 98th percentile of the 24-hour average impacts. The results indicate that the project will not have an adverse effect on visibility in any of the Class I areas as shown in **Table 16**.

TABLE 16 – VISIBILITY IMPAIRMENT ANALYSIS FOR THE ENP (SIEMENS F5).

Class I Areas	98th Percentile Maximum Visibility Impairment (%) [a]			Threshold (%)
	2001	2002	2003	
Chassahowitzka Wilderness	0.73	0.78	0.64	5
Saint Marks Wilderness	1.16	1.45	1.33	5
Wolf Island Wilderness	0.51	0.50	0.53	5
Okefenokee Wilderness	1.22	1.54	1.25	5

5.4.3.2. *Class I Area Nitrogen Deposition Impacts*

The Suwannee project reduces levels of NO_x through netting, and only minimally increases levels of SO_2, therefore, the DEP believes that a Class I nitrogen and sulfur deposition impact analysis is not necessary.

5.5. Additional Impact Analysis

5.5.1. Growth-Related Impacts Due to the Proposed Project

The impacts associated with the construction of the Suwannee project are expected to be minor. Construction will last for approximately 16 months, and although there is an expected increase in the labor force, these workers are expected to commute from nearby communities and is not expected to result in permanent commercial or residential growth. The impacts associated with the temporary increase in vehicular traffic are expected to be negligible.

5.5.2. Impact on Soils and Vegetation

Emissions of pollutants have the potential to negatively affect soils and vegetation near the project site. To analyze these potential impacts, the applicant conducted a secondary NAAQS analysis to determine if there are any effects on public welfare, including vegetation and soils. The maximum potential air quality impacts for the 24-hour PM_{10} and 24-hour $PM_{2.5}$ are much less than the secondary NAAQS, thus the project's impacts on vegetation and soil in the vicinity are expected to be negligible.

5.5.3. Impact on Wildlife

Impacts to wildlife in the vicinity of the project are expected to be negligible as well. Conservative estimates of the project's pollutant emissions are expected to be below the applicable NAAQS and PSD increments.

5.6. Conclusion

Based on the results presented in the air quality and additional impacts analyses, the Department has reasonable assurance that the increased pollutant emissions associated with this project will not cause or contribute to any violation of an NAAQS or PSD increment nor will there be adverse impact on soils, vegetation, wildlife, or, in Class I areas, any AQRV.

6. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the 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 application, the reasonable assurances provided by the applicant, and the conditions specified in the Draft permit.

Justin Rivard is responsible for reviewing and preparing the ambient air quality analyses and reviewing the application, preparing the draft permit and writing the technical document. Details of the analyses may be obtained by contacting: Mr. Justin Rivard (Air Modeling) by phone at 850/717 9011 or by email Justin.rivard@dep.state.fl.us or Mr. David Read, PE (BACT Determinations) by phone at 850/717-9075 or by email at david.read@dep.state.fl.us.