TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Florida Power & Light Company (FPL)
700 Universe Boulevard
Juno Beach, FL 33408

Okeechobee Clean Energy Center
ARMS Facility ID No. 0930117

PROJECT

Draft Permit No. PSD-FL-434
Project No. 0930117-001-AC

Construction of Combined Cycle Unit 1

COUNTY

Okeechobee 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

January 12, 2016

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

The Florida Power & Light Company (FPL) proposes to construct the Okeechobee Clean Energy Center (OCEC), which is an electric power plant with a Standard Industrial Classification Code of SIC No. 4911. The proposed facility is located in unincorporated Okeechobee County, Florida, approximately 27 miles north-northeast of Okeechobee and 24 miles west of Vero Beach. The proposed facility is located in the northeastern corner of the county, less than a mile from the border with Indian River County. The site can be accessed from Florida Route 60 and 226th Court in Indian River County, by following 226th Court south to the Okeechobee County line. **Figure 1** below shows the location of Okeechobee County, while **Figure 2**shows a satellite view of the site, located between Florida Route 60 and Florida's Turnpike. The Universal Transverse Mercator (UTM) coordinates are Zone 17, 520.6 kilometers (km) East, and 3056.7 km North.

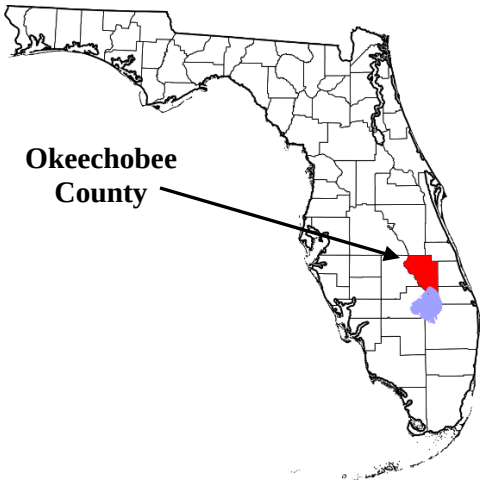

Figure 1. Location of Okeechobee County, Florida.

Figure 2. Proposed Okeechobee Clean Energy Center site.

OCEC Unit 1 will consist of three combustion turbines (CTs) and one steam turbine, in a "3-on-1" combined cycle configuration. Each of the CTs of Unit 1 will have a nominal gross capacity of 350 megawatts (MW). Each CT will be equipped with a heat recovery steam generator (HRSG) that will generate steam from the hot exhaust gases. Additional power will be generated in the steam turbine from this steam. The total nominal generating capacity of Unit 1 will be 1,600 MW, net. These CTs will be primarily fueled with natural gas, with ultra-low-sulfur diesel (ULSD fuel oil) as a limited-use backup fuel. Additional acreage at the site may possibly be used for solar photovoltaic generation in the future. An artist's rendering of the project is shown in **Figure 3**.

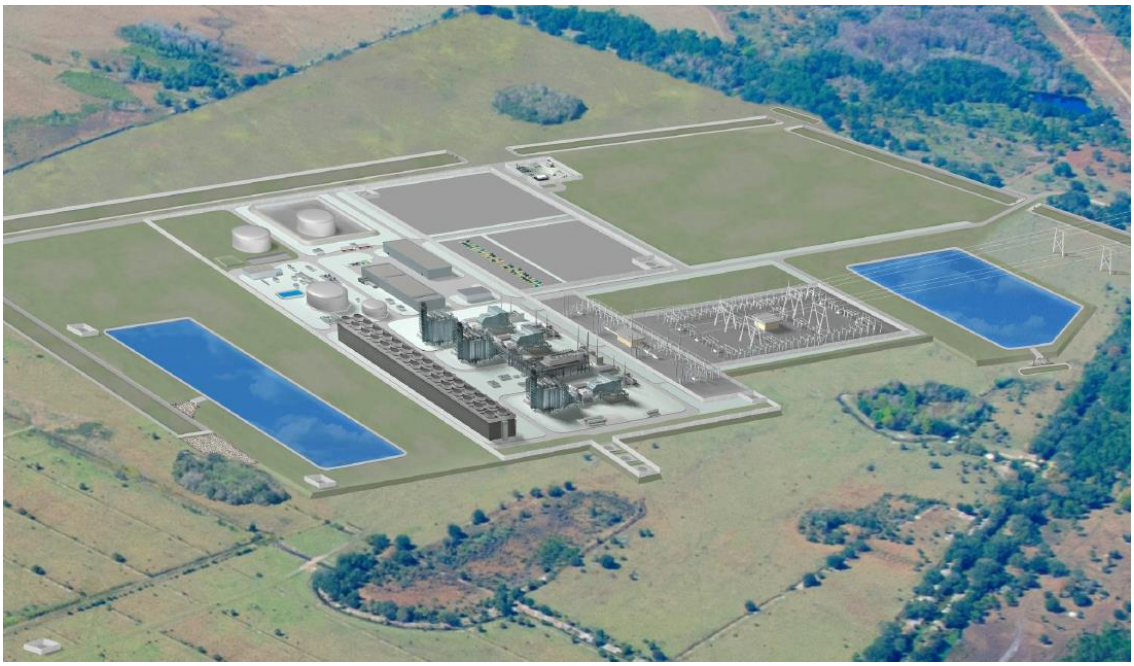

Figure 3. Artist's rendering of OCEC.

Additional equipment at the OCEC site will include a storage tank for ULSD fuel oil, a natural gas-fired auxiliary boiler, three emergency generators, two natural gas heaters, one fire water pump diesel engine, two propane-fired engines for the hurricane shelter, a mechanical draft cooling tower, and circuit breakers.

1.2. Project Description

FPL submitted an application for an air construction permit subject to the preconstruction review requirements of the Prevention of Significant Deterioration (PSD) of Air Quality pursuant to Rule 62-212.400, F.A.C. This application is for a project to construct OCEC Unit 1 and its associated equipment.

The combustion turbines to be used in OCEC Unit 1 are the General Electric 7HA.02 turbines, each with a nominal capacity of 350 MW. These turbines will be fueled primarily with natural gas; FPL has requested the equivalent of 500 hours per year per CT at base load on ULSD fuel oil, as a backup fuel.

A schematic of a 3-on-1 combined cycle unit, such as OCEC Unit 1, is shown in **Figure 4**. Each CT is connected via a shaft to an electric generator. The combustion of natural gas (or ULSD fuel oil) in the CT causes the shaft to spin, and the electric generator converts this motion into electricity. Additionally, the hot exhaust gases from each CT pass through a HRSG. The HRSG is essentially a heat exchanger that captures heat from the exhaust and uses it to convert water to steam. The steam then drives a steam turbine which is connected to another electric generator. The HRSGs of OCEC Unit 1 will <u>not</u> be equipped with duct burners.

The heat input capacity for each of the CTs is 3,028 million British thermal units per hour (MMBtu/hr), based on lower heating value, when firing natural gas at 100 percent capacity and an ambient temperature of 35 °F. When using wet compression to cool the incoming air, the heat input is 3,095.7 MMBtu/hr at an ambient

temperature of 75 °F. This corresponds to a possible natural gas usage of up to 8.86×10^{10} cubic feet per year for Unit 1, if operating 8,760 hours on gas. The applicant has requested the equivalent of 500 hours per year on ULSD fuel oil at full load. This corresponds to a maximum of approximately 33.6 million gallons of ULSD fuel oil per year for Unit 1.

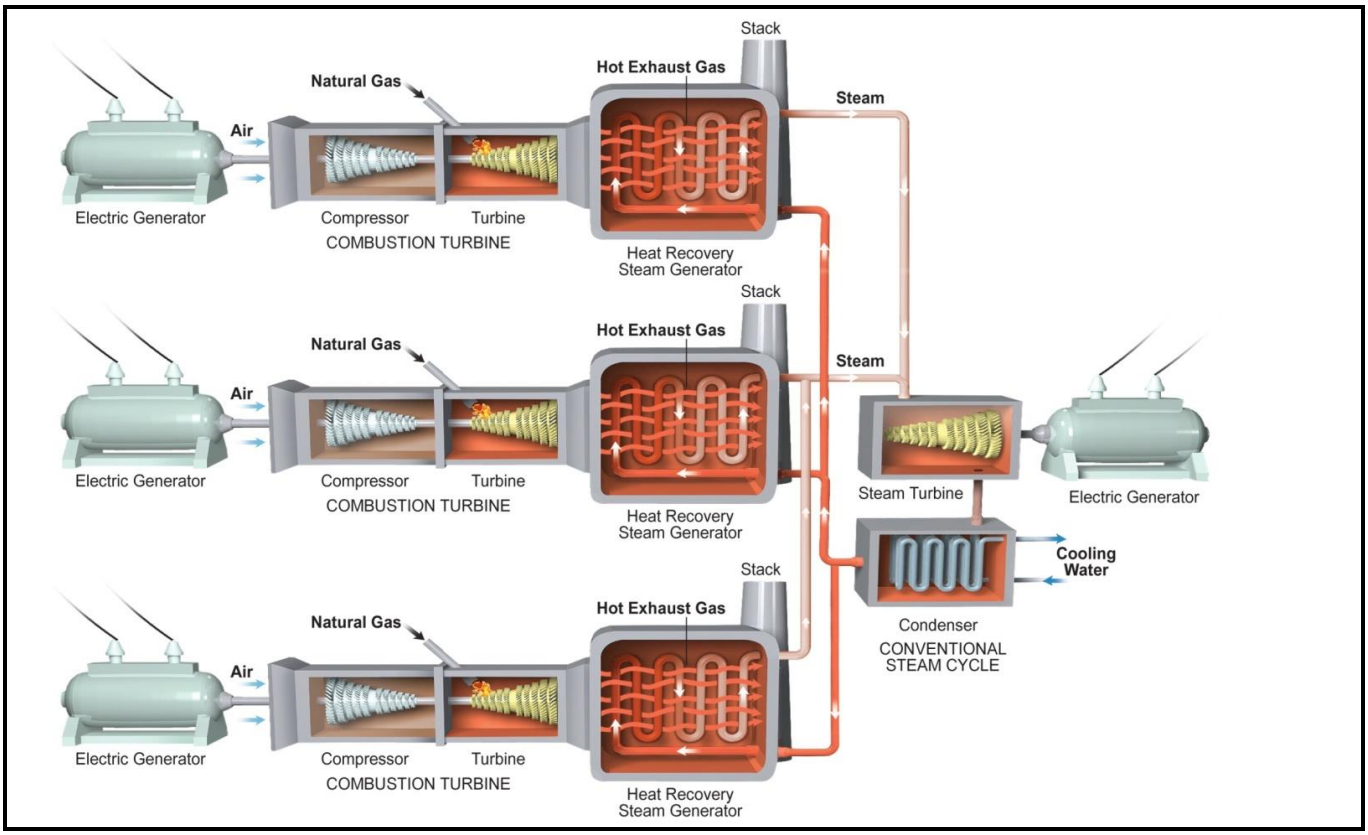

Figure 4. Schematic of a 3-on-1 combined cycle unit.

Several other air emissions units are included in the construction of OCEC Unit 1:

- One natural gas-fired auxiliary boiler, with a capacity of 99.8 MMBtu/hr, by higher heating value. This boiler will be used for startups or shutdowns to provide steam to the steam cycle, and it will be fueled exclusively with natural gas.
- One nominal 7-million-gallon ULSD fuel oil fuel oil storage tank.
- Three ULSD fuel oil -fueled emergency generators. These will be operated only in emergencies, and for testing and maintenance.
- Natural gas heaters (two, one of which is a spare). These will have a heat input of 10 MMBtu/hr or less and are used as necessary to heat natural gas above the dew point.
- One fire water pump diesel engine. This will be operated only in emergencies, and for testing and maintenance.
- Two propane-fueled emergency engines for the hurricane shelter. These will be operated only in emergencies, and for testing and maintenance.
- One 30-cell mechanical draft cooling tower.
- Approximately 17 circuit breakers containing sulfur hexafluoride (SF_6).

The emissions units (EU) listed in **Table 1** will be constructed as part of this project.

TABLE 1 – EMISSIONS UNITS TO BE CONSTRUCTED IN THIS PROJECT.

EU No.	Description
001	Unit 1A – One nominal 350 MW combustion turbine with HRSG
002	Unit 1B – One nominal 350 MW combustion turbine with HRSG
003	Unit 1C – One nominal 350 MW combustion turbine with HRSG
004	One nominal 99.8 MMBtu/hr auxiliary boiler
005	One nominal 7-million-gallon ULSD fuel oil storage tank
006	Three nominal 3,300 kW ULSD fuel oil emergency generators
007	Two natural gas heaters
008	One nominal 422 hp diesel fire pump engine
009	Two nominal 25 kW propane emergency generators
010	Mechanical draft cooling tower
011	Circuit breakers

1.3. Processing Schedule

- September 25, 2015 Department received the application for an air pollution construction permit; application complete.
- January 12, 2016 Department issued the draft permit package.

2. APPLICABLE REGULATIONS

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, 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 OCEC and this project.

- The 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 facility is not a major source of hazardous air pollutants (HAP).
- The facility has units regulated under Clean Air Act, Title IV, Acid Rain provisions, Phase II.
- The 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 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.

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 (Department) to establish air quality regulations as part of the Florida Administrative Code (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

3. PSD APPLICABILITY REVIEW

3.1 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).

Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), total reduced 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 hydrogen chloride (HCl), and MSW landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(189)(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"*. The OCEC is a major stationary source because it meets this definition and will emit, or has the PTE, 100 TPY or more of any PSD pollutant

PSD applicability for a "modification" to an existing major stationary source is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(282), F.A.C. Any *"net emissions increase"* as defined in Rule 62-210.200(210), 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 PTE 100 or 250 TPY as applicable) for only one PSD pollutant, a project is subject to PSD review for any PSD pollutant that exceeds the corresponding SER given in **Table 3**.

TABLE 3 – LIST OF SIGNIFICANT EMISSIONS RATES. [1]

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. "CO_2e" means carbon dioxide equivalents and refers to greenhouse gas (GHG) emissions. The calculation of GHG emissions is defined in 40 CFR 98, Subpart A, Table A-1.

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 a PSD review for GHGs emissions if the source would emit or have the potential to emit 75,000 tons per year of GHGs on a CO_2e basis. Under this framework, a source cannot become subject to PSD review solely on the basis of GHG emissions.

3.2 PSD Applicability for the Project

The project is located in Okeechobee County, which is in an area that is currently in attainment with the AAQS or otherwise designated as unclassifiable. The facility is a "fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input", which is one of the 28 listed PSD major facility categories, and emits or has the potential to emit 100 tons per year or more of at least one PSD pollutant. Therefore, the facility is a major stationary source and the project is subject to a PSD applicability review. The OCEC Unit 1 project will emit the following PSD pollutants: SO_2, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SAM, VOC and GHG. **Table 4** identifies the estimated emissions based on the initial application.

TABLE 4 – SUMMARY OF THE APPLICANT'S PSD APPLICABILITY ANALYSIS.

Pollutant	Project Potential Emissions	PSD Significant Emissions Rate	Subject to PSD Review?
CO	540 tons/year	100 tons/year	**Yes**
NO_X	398 tons/year	40 tons/year	**Yes**
PM	425 tons/year	25 tons/year	**Yes**
PM_{10}	254 tons/year	15 tons/year	**Yes**
$PM_{2.5}$	254 tons/year	10 tons/year	**Yes**
SAM	49 tons/year	7 tons/year	**Yes**
SO_2	254 tons/year	40 tons/year	**Yes**
VOC	71 tons/year	40 tons/year	**Yes**
Pb	~0 pounds/year	1200 pounds/year	No
GHG	5.46×10^6 tons/year	75,000 tons/year	**Yes**

[1] U.S. Supreme Court opinion dated June 23, 2014, *UARG v EPA*. EPA guidance dated July 24, 2014.

As shown in **Table 4**, the project is subject to PSD preconstruction review for emissions of: CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SAM, SO_2, VOC and GHGs. The PTE for each emissions unit is summarized in **Table 5**.

TABLE 5 – PTE FOR INDIVIDUAL OCEC UNIT 1 EMISSION UNITS (TONS PER YEAR).

Pollutant	Emissions Unit								
	3 CTs	Auxiliary Boiler	Natural Gas Heater	ULSD fuel oil Emergency Generators	Fire Pump Engine	Propane Hurricane Shelter Engines	Cooling Tower	ULSD fuel oil Storage Tank	Circuit Breakers
SO_2	253	0.56	0.24	0.007	0.00021	8.81×10^{-5}	-	-	-
PM	245	0.74	0.32	0.22	0.005	4.41×10^{-4}	178.67	-	-
PM_{10}	245	0.74	0.32	0.22	0.005	4.41×10^{-4}	7.84	-	-
$PM_{2.5}$	245	0.74	0.32	0.22	0.005	4.41×10^{-4}	0.011	-	-
NO_X	382	4.99	4.25	6.98	0.13	0.11	-	-	-
CO	524	7.98	3.57	3.82	0.031	0.249	-	-	-
VOC (as methane)	68.6	0.54	0.23	0.22	0.003	0.217	-	1.55	-
SAM	49.2	-	-	-	-	-	-	-	-
Pb	0.032	-	-	-	-	-	-	-	-
GHGs (CO_2e)	5,442,525	11,671	5,072	724	22.5	5.6	-	-	1,043

Emissions of HAP from combustion turbines at major sources of HAP are regulated under 40 CFR 63 Subpart YYYY. A major source of HAP is defined as a facility which emits or has the potential to emit more than 25 tons per year of hazardous air pollutants, or more than 10 tons per year of an individual HAP. According to the application[2], the PTE for total HAPs is 23.1 tons per year, and the greatest PTE for an individual HAP is 9.6 tons per year of formaldehyde. Therefore, the facility will not be considered a major source of HAP, and Subpart YYYY is not applicable.

4. DEPARTMENT'S PROJECT REVIEW

4.1 Overview

This project entails the construction of a 3-on-1 combined cycle unit. It will consist of three GE 7HA.02 combustion turbines with nominal generating capacity of 350 MW each.

FPL has requested unrestricted hours of operation for each of the turbines, though only 500 hr/yr, base load equivalent, may be fueled by ultra-low-sulfur distillate (ULSD) fuel oil. The primary fuel for the turbines will be natural gas. These are intended for base-load service, and they will be expected to have a high capacity

[2] OCEC Unit 1 PSD application in Oculus

factor. For example, in their 2015 Ten Year Site Plan[3] to the Florida Public Service Commission, FPL estimated a capacity factor of approximately 80% for OCEC Unit 1 for its first year of operation, with a 96.7% availability factor. The estimated in-service date for Unit 1 is 2019.

These turbines will incorporate inlet air cooling consisting of evaporative cooling and wet compression. In this arrangement, water from an evaporative cooling medium cools the inlet air stream. This results in a cooler, denser stream of air, which allows for a greater throughput of air to the turbines and additional power output. Wet compression also increases power output by increasing mass flow through the introduction of water droplets near the compressor inlet.

4.2 BACT Process

"Best Available Control Technology" or "BACT" is defined in Rule 62-210.200(32), 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, 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, 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.*

(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 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.

5. BACT REVIEW FOR COMBUSTION TURBINES (EU NOS. 001, 002, 003)

5.1 Greenhouse Gas Emissions

5.1.1 *Discussion*

Three greenhouse gases are expected to be emitted from the gas turbines in this project: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

Carbon dioxide is the primary product of combustion of carbon-based fuels in air. The exothermic reaction between fuels and molecular oxygen in air results in the breaking of carbon-carbon bonds or carbon-hydrogen bonds in fuels, the release of energy in the form of heat, and the formation of CO_2 and water. In the case of CH_4, which is the main component of natural gas, the reaction is summarized as follows:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

Small amounts of CH_4 are expected from this project. As the primary fuel for the turbines, any methane that remains uncombusted represents a lost opportunity to generate electricity. Methane emissions will be minimized for this reason. However, very small amounts of CH_4 emissions will likely occur.

[3] Available at Florida Public Service Commission website

A very small amount of N_2O can be produced as a combustion byproduct. At the high temperatures associated with combustion, atmospheric nitrogen (N_2) and oxygen (O_2) react to form, among other byproducts, N_2O.

Greenhouse gases are categorized and compared on an "equivalency" basis according to their "global warming potential" (GWP). The GWP of a substance is calculated by determining the ratio of the amount of warming due to the emission of a unit mass of the substance, integrated over a chosen time period, to the amount of warming due to the emission of a unit mass of CO_2, integrated over the same time period. The most commonly used time period for GWP calculations is 100 years. The US EPA uses GWP values of unity for CO_2, 25 for CH_4, and 298 for N_2O. Multiplying emissions of each of these three gases by its respective GWP, and summing the result, yields a CO_2-equivalent (CO_2e) greenhouse gas emissions estimate.

FPL estimates that 1,814,175 tons per year, CO_2e, of greenhouse gases will be emitted per turbine due to this project. Of this, 1,812,029 tons, or 99.88% of the total CO_2e emissions, is due to CO_2. Since non-CO_2 GHGs comprise a miniscule fraction of the total GHG emissions from this project, in both absolute terms and CO_2e terms, strategies for minimizing GHG emissions focus almost exclusively on CO_2.

5.1.2 *New Source Performance Standard*

The turbines of OCEC Unit 1 are subject to the NSPS in 40 CFR 60, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (40 CFR 60.5520(a)). Under this subpart, base load combustion turbines that combust more than 90% natural gas are subject to a standard of 1,000 lb CO_2 per megawatt-hour (MWh), gross, on a 12-operating-month rolling average basis. For gas or oil-fired turbines under Subpart TTTT, and under the Acid Rain continuous monitoring provisions of 40 CFR 75, emissions of CO_2 may be measured using a continuous emissions monitor, or through fuel use monitoring and emissions factors. This NSPS limit sets a floor for the BACT limit; the GHG BACT limit may not be less stringent than this NSPS limit.

5.1.3 *BACT Analysis*

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

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

Clean Fuels: The use of low-emitting fuels is a common strategy for minimizing emissions of GHGs. The use of natural gas results in CO_2 emissions that are approximately 30% less than emissions from oil and 45% less than emissions from coal, per unit of heat input. According to the US Energy Information Administration (EIA)[4], natural gas results in significantly less CO_2 than other fossil fuels (see **Table 6**). The use of natural gas as the primary fuel for these turbines is feasible and is being proposed for the OCEC Unit 1.

TABLE 6 – CO_2 EMISSIONS FOR VARIOUS FOSSIL FUELS.

Fuel	CO_2 (lb / MMBtu)
Anthracite coal	228.6
Bituminous coal	205.7
Lignite coal	215.4
Subbituminous coal	214.3
Diesel fuel	161.3
Gasoline	157.2

[4] Information from EIA website.

Fuel	CO_2 (lb / MMBtu)
Propane	139.0
Natural gas	117.0

The applicant has proposed ULSD fuel oil as a backup fuel because a non-interruptible natural gas supply cannot be guaranteed. FPL has requested that ULSD fuel oil be available as a backup fuel, limited to a base load equivalent of 500 hours of usage per turbine per year. The Department agrees that this limited use of ULSD fuel oil is appropriate. Together, the turbines will be limited to firing 33.6 million gallons of ULSD fuel oil per 12-month period, rolled monthly. This is the equivalent of 500 hours of operation at peak load for each turbine.

Energy Efficiency: Energy efficiency entails optimizing the amount of electrical output produced per unit of heat input. For a given unit of electrical output, greater efficiency reduces the amount of fuel used and the amount of CO_2 emitted. Energy efficiency has been included in essentially all BACT determinations for GHGs from combustion turbines. Efficient power generation is technically feasible and is being proposed for OCEC Unit 1. The GE 7HA.02 is one of the most efficient frame-type turbines available on the market at present, with a simple cycle efficiency at ISO conditions of 41.6%, based on lower heating value[5]. In a combined cycle configuration, the net efficiency by lower heating value is approximately 62%. Therefore, this project includes the use of an efficient turbine in an efficient combined cycle configuration.

CCS: Carbon capture and storage entails capturing the CO_2 from flue gas, transporting it to an appropriate location for storage, and sequestering it underground. This CO_2 is usually used for processes such as enhanced oil recovery, in which the CO_2 aids in the production of fossil fuels from underground. Deep saline formations, which are large, porous rock formations, also present a potential opportunity for underground CO_2 storage.

The separation and capture of CO_2 from the effluent stream can be performed using several different technologies, such as absorption, adsorption, low-temperature distillation, gas separation membranes, or mineralization and biomineralization. The transport of CO_2 from the facility to its ultimate storage site is most commonly accomplished via pipeline, at a pressure of over 1,000 pounds per square inch. CO_2 can also be transported in insulated tanks at low temperature via seagoing vessels, rail, or truck. Potential locations for long-term underground storage of CO_2 include depleted oil and gas reservoirs, un-mineable coal seams, and underground saline formations.

FPL does not believe that CCS is technically feasible or commercially available for this project. According to FPL,"[a]ll current CCS projects for power plants are primarily in the demonstration stage." Additionally, FPL states that "[t]here are no CCS systems commercially available for full-scale power plants in the United States."

FPL points to the federal government's Interagency Task Force on Carbon Capture and Storage, which concluded that the research and development needed to be able to introduce CCS on a wide scale could lead to cost-effective deployment after the year 2020. FPL also cites the multi-year process required for Safe Drinking Water Act permitting of a CO_2 storage site.

By way of comparison, the Mississippi Power Kemper plant, designed with CCS for enhanced oil recovery (EOR) in mind, is still in the construction phase and is intentionally located near oil fields to make EOR more feasible. Similarly, the SaskPower Boundary Dam Carbon Capture Project in southern Saskatchewan is located near Saskatchewan oil fields to facilitate EOR. CO_2 not used for EOR at the SaskPower project will be stored in a nearby (less than 2 miles from the plant) brine-filled sandstone formation. This confluence of local opportunities for EOR and amenable geology is clearly not the case for the proposed OCEC Unit 1.

The Department agrees that CCS is not technically feasible for this project. In addition to the reasons stated by FPL, the lack of proximity to a suitable location for EOR also makes CCS infeasible, given the limited existing technology. The oil fields in Collier County and Lee County, largely associated with the Sunniland Trend oil

[5] GE "7HA.01/.02 Gas Turbine" product fact sheet

reserve, are more than 80 miles to the south or southwest of the OCEC site. Infrastructure is not currently in place for transporting compressed CO_2 to these facilities, and developing such infrastructure would substantially alter the project and incur a significant reduction in the efficiency of the plant. For these reasons, CCS is not considered to be a component of BACT for this project.

Oxidation Catalyst: The use of catalytic oxidation technology is primarily used to reduce CO emissions, but it can also be used to reduce emissions of CH_4. Catalytic oxidation can convert CH_4, with a GWP of 25, to CO_2, with a GWP of 1. This technology would be most attractive to sources with high emissions rates of CH_4.

FPL does not consider an oxidation catalyst to be technically feasible for CH_4 control for this project. Oxidation catalyst would yield a practically imperceptible reduction in GHG emissions, due to the very small amount of CH_4 expected from this project. Furthermore, FPL estimates that the additional CO_2 emissions arising from the backpressure that results from the use of oxidation catalyst would negate any reductions in CH_4 emissions, in terms of CO_2-equivalent GHG emissions. Therefore, the Department agrees that an oxidation catalyst would not be economically feasible for GHG control for this project given the already low CH_4.

Selection of BACT

Through the analysis outlined above, FPL proposes a combination of clean fuels and energy efficiency as BACT for this project. The Department agrees with this conclusion. This is also consistent with all other recent GHG BACT determinations for natural gas combined cycle (NGCC) electric generating units, according to reviews of US EPA's RACT/BACT/LAER clearinghouse (RBLC)[6], by both FPL and the Department.

FPL has proposed numerical GHG emissions limits, in terms of pounds of CO_2e per MWh, that reflect the usage of clean fuels and efficient generation. FPL's proposed GHG primary BACT emission limits for natural gas operation is 870 lb/MWh. This would apply under most operating conditions, but not during certain transient operating modes, such as startup, shutdown and fuel switching. The Department does not necessarily agree with or endorse this applicant estimate.

FPL's analysis for the proposed natural gas primary BACT limit entailed a review of data from five other similar 3-on-1 combined cycle units in the FPL system: namely, West County Energy Center Units 1, 2 and 3; Cape Canaveral Energy Center Unit 3; and Riviera Beach Energy Center Unit 5. FPL analyzed how these units were operated during the period from August 1, 2014, through August 1, 2015. This analysis included whether the units were in "3-on-1", "2-on-1", "1-on-1", or simple cycle operation, and at full load or partial load. These load patterns were then applied to emissions data for the 7HA.02 turbine. This calculated load distribution led to an estimated emissions rate of 808.4 lb/MWh, while an additional 2% commercial margin and 5% margin for performance degradation result in a rate of 866 lb/MWh. Finally, FPL rounded this to 870 lb/MWh.

The load can have a large effect on efficiency, because combustion turbines generally operate most efficiently at higher loads. The CT/steam turbine (3-on-1, 2-on-1, etc.) configuration also has an impact on the overall efficiency of the unit.

To calculate a proposed primary BACT limit for ULSD fuel oil operation, a detailed operational history of similar units was unavailable. Rather, FPL based the analysis on the emissions that would be expected from equal amounts of operation at 100% load, 75% load and 50% load for the 7HA.02 turbine. This calculated load distribution led to an estimated emissions rate of 1128 lb/MWh, while an additional 2% commercial margin and 5% margin for performance degradation result in a rate of 1208 lb/MWh. Finally, FPL rounded this to 1210 lb/MWh.

FPL also requested that during certain transient operating modes, such as startup, shutdown and fuel switching, the primary BACT not apply. Rather, FPL requests that a "secondary BACT" limit, equal to the NSPS, apply during these modes of operation.

[6] EPA RBLC

The applicant's requested averaging period for the GHG emissions limit is 36 operating months, rolled monthly. Each turbine would demonstrate compliance with the GHG BACT limit on this basis.

To determine whether FPL's requested GHG emission limits reflect BACT, the Department analyzed recent emissions data from FPL's 3-on-1 combined cycle fleet within Florida, as well as other publicly available information.

In FPL's 2015 Ten-Year Site Plan to the Florida Public Service Commission, the "Average Net Incremental Heat Rate" for these OCEC Unit 1 turbines is given as 6,304 Btu/kWh (by higher heating value). FPL's application[7] also cites this same base heat rate in its calculations. The Department converted this figure to an expected base load CO_2 emissions rate of 738 lb CO_2 per MWh:

$$6{,}304\,\frac{Btu}{kWh} \times \frac{117\ lb\ CO_2}{10^6 Btu} \times \frac{1000\ kWh}{MWh} = 738\,\frac{lb\ CO_2}{MWh}$$

This would be the expected "new and clean" emissions rate for OCEC Unit 1, operating at base load conditions. However, such efficiency would not be achieved at lower loads, at which it is often necessary to operate turbines, even those in combined cycle configurations meant to meet base loads. Therefore, there does need to be an accommodation for operation at loads less than 100%. For example, FPL's proposed GHG BACT limit for natural gas operation is approximately 17.8% greater than this rate, including approximately 10% for various operating modes (3-on-1, 2-on-1, etc.), 5% for degradation, and 2% for vendor margin.

The Department analyzed the CO_2 emissions rates from the five Florida 3-on-1 units FPL considered above. According to FPL filings with the Florida Public Service Commission[8], Unit 1 "is projected to be the most fuel-efficient [combined cycle] unit on FPL's generation system." The three combined cycle units at West County Energy Center utilize Mitsubishi G class turbines, which would have a smaller generating capacity and a slightly less efficient operating profile than the proposed GE H class turbines for OCEC Unit 1. West County Units 1 and 2 began operation in 2010, while West County Unit 3 began operation in 2011. Cape Canaveral Unit 3 and Riviera Beach Unit 5 each utilize Siemens H class turbines, which should have similar efficiency profiles to the GE H class turbines in OCEC Unit 1. Cape Canaveral Unit 3 began operation in 2013, while Riviera Beach Unit 4 began operation in 2014. The CO_2 emissions rates for these five 3-on-1 units, gathered from the US EPA Clean Air Markets Division (CAMD) website[9], are shown in **Figure 5**.

The annual average CO_2 emissions rate for these units has remained no greater than 811 lb CO_2 per MWh for the units' entire history, which is considerably less than FPL's original request of 870 lb CO_2 per MWh for this project. It is also worth noting that the data in **Figure 5** include periods of startup and shutdown, and possible oil usage, which are excluded from FPL's original GHG BACT request of 870 lb CO_2 per MWh. GE estimates that the 7HA.02 combined cycle efficiency (approximately 61 to 62%) is very close to the value of ">60%" estimated by Siemens for its H-class turbines[10]; therefore, the expected efficiency of OCEC Unit 1 should be similar to that of Cape Canaveral Unit 3 and Riviera Beach Unit 5, which have emitted CO_2 at rates less than 800 lb per MWh for their brief operating histories. These rates are consistent with FPL's estimate (above) of 808.4 lb/MWh for OCEC Unit 1, before the addition of vendor and performance degradation margins.

[7] OCEC Unit 1 PSD application in Oculus
[8] PSC Docket No. 150196-EI, Filed November 3, 2015
[9] http://ampd.epa.gov/ampd
[10] Fischer, W.J., and Nag, P., "H-Class High Performance Siemens Gas Turbine (SGT-8000H series)." From Power-Gen International conference, Las Vegas, Nevada, 2011.

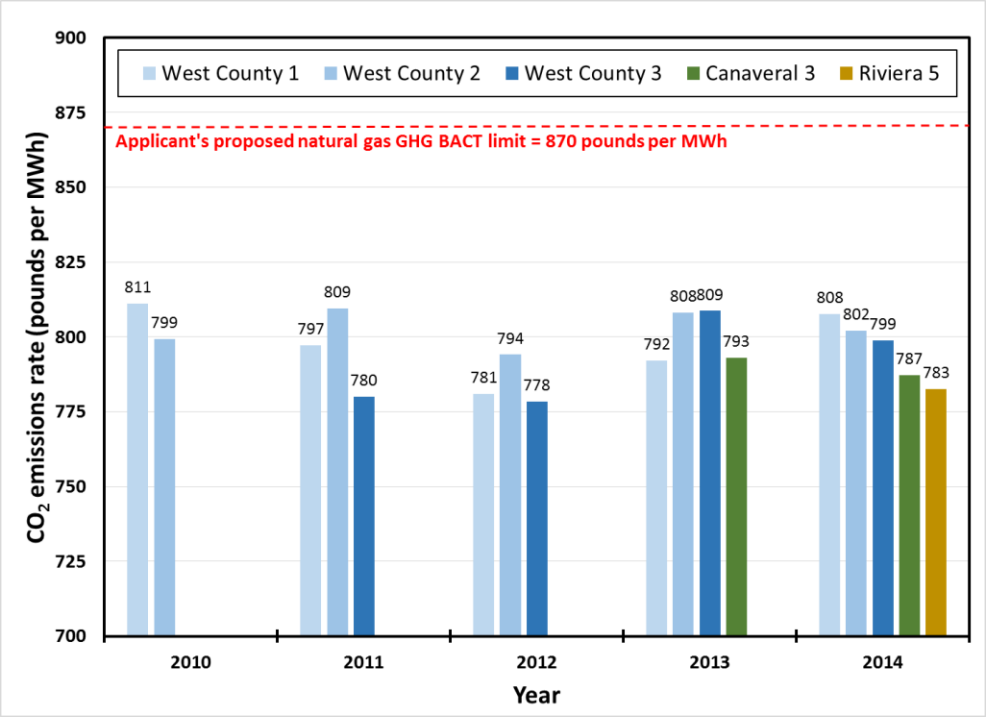

Figure 5. FPL 3-on-1 NGCC CO_2 Emissions Rate.

The average emissions rate for all of the electricity generated from these five units over the 2010-2014 time period is 795.7 lb/MWh. Additionally, for the first three quarters of 2015, the collective emissions rate for these units was 792.9 lb/MWh. These are somewhat close to, though smaller than, FPL's *a priori* estimate of 808.4 lb/MWh for OCEC Unit 1. It also demonstrates that there should be no need to include a 2% "vendor margin" in the GHG BACT limit for OCEC Unit 1, given the operating profiles of these in-service turbines, together with FPL's projections that OCEC Unit 1 will be the most efficient combined cycle unit in its fleet. However, bearing in mind the relatively short amount of time these turbines have been in service, the inclusion of a margin for degradation is a reasonable request. In fact, OCEC will be one of the first commercial installations of the 7HA.02 turbine, making their long-term in-service performance unknown.

To further examine transient modes of operation, such as startup, shutdown and fuel switching, the Department analyzed data from West County Energy Center Units 1 through 3. For the years 2010 to 2014, according to CAMD data, each of the nine CTs underwent an average of approximately 70 to 80 startups per year. Given the fast startup and shutdown times for these turbines, and the fact that they are used as base load units, they spend a small fraction of their time, and emit a small fraction of their total GHG emissions, during startups and shutdowns. According to the CAMD data, the West County units spent 88.5% of their operating hours emitting at rates between 750 and 850 lb/MWh; this can be taken as an approximation of the amount of time spent in normal/non-transient operation. Similarly, these units emitted 90.7% of their total CO_2 emissions during non-transient operation, emitting at rates between 750 and 850 lb/MWh. Because these transient events impacted emissions rates so little, West County Units 1 through 3 achieved an average emissions rate of 797 lb/MWh for the 2010-2014 time period, including all startups and shutdowns.

While past performance is one indicator of future emissions of this proposed unit, there are other considerations that should be taken into account. For example, the limited operational history of these turbines leads to uncertainty in their future performance. Base-load units are usually in service for 30 years or more, and the amount of degradation of the turbines cannot be known in advance. Additionally, the incorporation of more non-dispatchable solar photovoltaic (PV) sources into the grid may potentially increase the need for lower-load CT operation, in order to more readily respond to sudden drops in solar PV output. Finally, as newer,

presumably more efficient, turbines are brought into the generation system, the OCEC Unit 1 may fall in the order of dispatch, resulting in fewer operating hours, more startups and shutdowns, more 2-on-1 or 1-on-1 operation, and accelerated deterioration. These uncertainties may warrant additional flexibility to be incorporated into GHG BACT limits for combined cycle units.

Additionally, turbine manufacturers often create service packages or upgrade packages that allow turbine heat rate to be maintained, or even improved, over the life of the turbine. For example, GE offers compressor and gas path upgrades that improve the heat rate of its 7F series of turbines by 2 to 3 percent or more. These upgrades have recently been installed, or will soon be installed, at FPL's Fort Myers and Martin facilities. The six turbines of Fort Myers Unit 2 were installed in approximately the year 2000. By 2015, the turbines had essentially been upgraded from the 7FA.03 to the 7F.05, improving expected performance by approximately 5%. At FPL Martin, Units 3 and 4 were built in the late 1990s, and an upgrade from 7FA.03 to 7FA.04, with an expected 3.5% improvement in performance, is currently in progress. Similarly, Martin Unit 8 was built in approximately 2005. Its turbines were upgraded from 7FA.03 to 7FA.04 in 2012, with an expected improvement in performance of 2.5%. The turbines are again being upgraded to 7F.05, with an expected improvement in performance of 3%. While some degradation of the turbines is to be expected, the availability of maintenance procedures and upgrades to improve heat rate mitigates some of the need to adjust for degradation.

The turbines in this project should be able to achieve average emissions rates considerably lower than the proposed BACT natural gas rate originally requested by FPL. The operation of FPL's existing 3-on-1 fleet shows that OCEC Unit 1 should be able to operate below 800 lb/MWh, likely near 780 lb/MWh. However, this assumes that this new unit will be operated in a similar manner to the existing 3-on-1 fleet. In order to allow for possible performance degradation and possible changes in the requirements of overall electric grid, the Department will utilize FPL's estimate of 808.4 lb/MWh and apply a 5% margin, which yields 848.8 lb/MWh. The Department will set a GHG BACT limit for periods of natural gas usage of <u>850 lb CO_2 per MWh, gross</u>, excluding periods of transient operations, such as startups, shutdowns, fuel switching, etc. This limit is approximately 15% higher than the unit's expected "new and clean" base-load emissions rate. During transient modes of operation such as startups or shutdowns of the entire combined-cycle unit, startups or shutdowns of individual CTs, fuel switches, and Dry Low-NO_X tuning, the Department will adopt as a "Secondary BACT" the limits in NSPS Subpart TTTT.

Alternatively, if one replicates FPL's analysis of operating conditions but bases the analysis on actual operating conditions in each mode during calendar year 2014, the baseline emissions rate would be 796 lb/MWh. For the sake of illustration, applying an additional 7% margin to this figure yields 852 lb/MWh, which is essentially equal to the Department's proposed limit.

Nearly all of the data in the above analysis focused on the use of natural gas, since it will be the primary fuel for these turbines. There is insufficient data available to perform a similar analysis for ULSD fuel oil usage. There is also considerable uncertainty and unpredictability surrounding the need to use backup fuel and the conditions under which the turbines would be operated on ULSD fuel oil. Therefore, the Department generally agrees with the applicant's assessment of a GHG BACT emissions standard for ULSD fuel oil and will set a standard during ULSD fuel oil firing of <u>1,210 lb CO_2 per MWh, gross</u>, excluding periods of transient operations, such as startups, shutdowns, fuel switching, etc. Again, during transient modes of operation such as startups and shutdowns, the Department will adopt as a "Secondary BACT" the limits in NSPS Subpart TTTT.

Additionally, the Department recognizes that the climatic and environmental impacts of GHGs are generally analogous to a "cumulative" framework, rather than an "acute" one. The Department plans to set the averaging period for GHG BACT for Unit 1 as a <u>12-month rolling average</u>, treating all of Unit 1 as one unit. This averaging period is consistent with EPA's NSPS Subpart TTTT limits, which are also on a 12-month rolling average basis.

The Department and the applicant identified several recent GHG BACT determinations for combined cycle units, issued between 2012 and 2014. These have ranged from 793 lb/MWh to 1000 lb/MWh, with most

between 900 and 950, though nearly all of these to date have been for less efficient turbine models than the 7HA.02. The Department's proposed natural gas BACT limit for OCEC Unit 1 is on the more stringent end of the set of combined cycle limits.

The Department's proposed BACT limits are similar to those issued by US EPA for the H-frame turbines at FPL's Port Everglades Energy Center[11]; these limits were 830 lb CO_2e per MWh, net, for natural gas, and 1,248 lb CO_2e per MWh, net, for ULSD fuel oil. Additionally, three combined-cycle facilities using 7HA.02 turbines have been permitted in 2015 in Texas: the GHG BACT limit for the Colorado Bend Energy Center is 879 lb/MWh, gross, excluding startup and shutdown, while the limit for combined cycle operation at the Cedar Bayou and Bertron Electric Generating Stations is 825 lb/MWh (though this limit excludes all simple-cycle operation, all operation below 60% load, startup, and shutdown). Finally, in November 2015, the GHG BACT determination was issued for the CPV Towantic facility, consisting of 7HA.01 turbines in a 2-on-1 configuration, in Connecticut. The Towantic BACT limit included a maximum allowable heat rate of 7,220 Btu/kWh, net, which corresponds to an emissions rate of 845 lb/MWh, net, excluding startups and shutdowns; this is comparable to approximately 820-840 lb/MWh, gross. The Department's proposed GHG BACT limits are consistent with these other H-frame GHG BACT limits, given each facility's unique circumstances in the electric grid.

The composite standard with which the permittee will be required to show compliance will consist of a weighted average of the natural gas and ULSD fuel oil standards, weighted by the generation from each fuel over the appropriate compliance period, as discussed above:

$$Composite\ Standard = \frac{MWh_{gas}}{Total\ MWh} \times Limit_{gas} + \frac{MWh_{ULSD}}{Total\ MWh} \times Limit_{\text{ULSD fuel oil}}$$

where MWh_{gas} = Gross output from gas firing for compliance period,

$MWh_{ULSD\ FUEL\ OIL}$ = Gross output from ULSD FUEL OIL firing for compliance period,

$Total\ MWh$ = Total gross output for compliance period = $MWh_{gas} + MWh_{ULSD\ FUEL\ OIL}$

$Limit_{gas}$ = GHG BACT limit for natural gas operation = 850 lb CO_2 / MWh, and

$Limit_{ULSD\ FUEL\ OIL}$ = GHG BACT limit for ULSD fuel oil operation = 1,210 lb CO_2 / MWh.

The Composite Standard may be no greater than 1,000 lb CO_2 / MWh, regardless of this formula.

Compliance with the GHG BACT limit for these turbines will be in accordance with the continuous monitoring requirements of NSPS Subpart TTTT and 40 CFR 75. This includes options for continuous monitoring of fuel use, combined with the use of emissions factors for CO_2, or the use of a continuous emissions monitor for CO_2. Either of these methods accurately determines CO_2 emissions.

5.1.4 *Consideration of Hybrid Technologies*

It is worth noting that the Department's proposed GHG BACT standard did not take into account the handful of integrated solar/NGCC plants in planning or operation. These plants combine NGCC units with solar thermal technology, with both the solar thermal heat and the CT exhaust heat feeding a single steam turbine. Examples include FPL's Martin Clean Energy Center and the Palmdale Hybrid Power Plant in California. The integration of steam derived from solar energy can significantly decrease the GHG emissions from a power plant per unit of electricity produced. However, to consider such technologies when evaluating BACT for a fossil fuel-fired plant would constitute a fundamental redefinition the project. Therefore these hybrid technologies were not considered when determining BACT for OCEC Unit 1.

[11] EPA GHG PSD Permit No. PSD-EPA-R4010, though this permit has subsequently been rescinded.

5.2 NO_X Emissions

5.2.1 *Discussion*

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 various 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.

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.

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.

5.2.2 *NO_X Controls*

The following discussion of NO_X controls and their associated performance in some cases uses various CT models as examples.

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 other techniques as discussed below.

The applicant has proposed wet injection during ULSD fuel oil firing as part of BACT for OCEC Unit 1.

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 6** below; this is a DLN design used in other models of GE turbines, but the general principle is the same for the 7HA.02 model.

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.

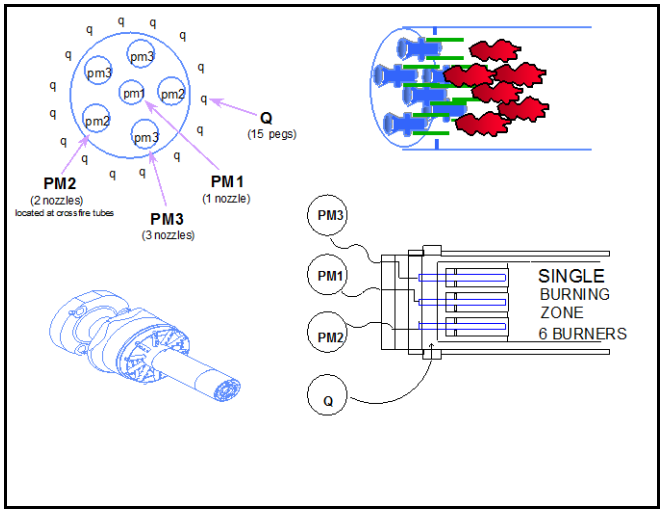

Figure 6. GE DLN-2.6 Fuel Nozzle Arrangement.

The use of DLN combustors can result in very low NO_X emissions for many turbines. **Table 7** below summarizes the results of the new and clean tests conducted on a dual-fuel GE 7FA.03 CTG with DLN-2.6 combustors operating in simple cycle mode and burning natural gas at the existing Tampa Electric (TECO) Polk Power Station.[12]

TABLE 7 – 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

In contrast to the smaller F-class turbines discussed above, DLN technologies are not as dramatically effective on larger H-class turbines. Without additional technologies beyond DLN, GE estimates[13] NO_X emissions for the 7HA.02 turbine of 25 ppmvd @15% O_2, which is considerably greater than the single-digit NO_X values for the F-class turbine in **Table 7**. However, this is still much less than uncontrolled NO_X emissions, which can be in the vicinity of 200 ppm. Therefore there is still a substantial benefit to the use of DLN combustors on the 7HA.02. The applicant has proposed DLN combustors as part of BACT for OCEC Unit 1.

Selective Catalytic Reduction (SCR): 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 (NH_3) 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 (H_2O) according to the following simplified reaction:

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

The catalysts are available for applications at temperatures between roughly 300 and 1,100 degrees Fahrenheit (°F) and typically are comprised of titanium oxide (as TiO_2), vanadium (as V_2O_5) and tungsten (as WO_3). The formulations contain progressively less vanadium and become more costly for the higher temperature applications. There are numerous examples of SCR installations at continuous duty combined cycle units

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

[13] GE 7HA.01/7HA.02 Gas Turbine Product Specifications website

throughout Florida. In combined cycle units, the catalyst can be placed at an optimal temperature (roughly 400 to 600 °F) for the purposes of high efficiency and lowest cost within the heat recovery steam generator. In such applications, NO_X emissions on the order of 2.0 ppmvd @15% O_2 are achieved when firing natural gas.

At higher temperatures, vanadium can actually contribute to ammonia oxidation forming more NO_X or forming nitrogen without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and } 4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

Therefore, less V_2O_5 is used in formulations for higher temperature applications. The lowest cost for a given application may involve cost optimization between the selection of a catalyst formulation and the equipment to cool gas to the operating temperature of the formulation.

SCR is commonly employed in base-load fossil-fueled plants such as OCEC Unit 1. FPL has proposed SCR as part of BACT for OCEC Unit 1.

Catalytic Combustion – XONON: XONON operates by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation. This technology has been demonstrated on turbine technologies up to approximately 15 MW. Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[14] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines. As such, the technology is not feasible at this time for the OCEC project.

EMx (Formerly SCONO$_X$): EMx is a NO_X and CO control system. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. One benefit is that it does not require ammonia injection. However, this technology employs a catalyst that may be poisoned by even the very small amount of sulfur present in natural gas. Finally, this technology has not been employed on large turbines, greater than approximately 80 MW. The turbines of OCEC Unit 1 are roughly four times the size of the largest turbines on which this technology has been employed. EMx costs much more than SCR, is mechanically very complicated and requires on-site hydrogen production from natural gas. It is neither feasible nor cost-effective for this project.

Selective Non-Catalytic Reduction (SNCR): SNCR entails the injection of ammonia or urea into the exhaust gas stream. It has been used in a wide variety of application, and it is an effective way to reduce NO_X emissions. SNCR is similar to SCR, though without the use of a catalyst.

Thermal DeNOx: Thermal DeNOx is a patented version of SNCR, using ammonia as the reducing agent. Thermal DeNOx has been employed on boilers, furnaces, and incinerators, but not on combustion turbines.

NOxOUT: Similar to SNCR, in the NOxOUT process, aqueous urea is injected into the flue gas stream, at high temperatures. The reaction, in the presence of O_2, converts urea, NO and O_2 to N_2, CO_2 and water. The commercial application of NOxOUT has been limited to boilers and municipal waste combustors, and it has not been demonstrated on combined cycle combustion turbines.

Non-Selective Catalytic Reduction (NSCR): NSCR employs a three-way catalyst to reduce emissions of NO_X and CO. This technology is often employed on spark-ignition internal combustion engines, but is not commonly used on NGCC units.

5.2.3 *Requirements of 40 CFR Part 60 on the Combustion Turbines with Respect to NO$_X$*

As stated in the definition of BACT given above, *"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,*

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

61, and 63". The three new combustion turbines 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. **Table 8** below includes the emission standards applicable to the OCEC Unit 1 project.

TABLE 8 – 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

A NO_X standard of 96 ppmvd @15% O_2 is provided for combustion turbines operating at less than 75% of peak load. The NO_X emissions standards under NSPS Subpart KKKK apply at all times; therefore they can provide a useful Secondary BACT backstop during transient operating modes when Primary BACT limits might not be achievable.

5.2.4 *Applicant's NO_X BACT Proposal*

The applicant proposes the following BACT determination for the control of NO_X emissions from the three proposed CTs:

- NO_X emissions will be controlled using wet injection during ULSD fuel oil firing, DLN combustors during natural gas firing and SCR when firing both fuels.
- NO_X emissions while firing natural gas shall be limited to 2.0 ppmvd @15% O_2 as BACT on a 24-hour block average basis;
- NO_X emissions for limited ULSD fuel oil fuel oil use shall be limited to 8.0 ppmvd @15% O_2 as BACT on a 24-hour rolling average basis;
- During startups, shutdowns, fuel switching, DLN tuning and malfunctions, the Secondary BACT limit, rather than the Primary BACT limits above, applies. The Secondary BACT limit is equal to the NSPS Subpart KKKK limit. Demonstrating compliance with the NSPS Subpart KKKK limit shall be sufficient for demonstrating compliance with the Secondary BACT limit during such transient modes of operation;
- Each CT may operate up to the base-load equivalent of 500 hours/year using ULSD fuel oil; and
- Compliance shown by a NO_X continuous emissions monitoring system (CEMS).

5.2.5 *Department's Draft NO_X BACT Determination*

The Department concurs with the applicant's Primary and Secondary NO_X BACT proposal as described above. A NO_X CEMS will be used to demonstrate continuous compliance with the BACT and NSPS Subpart KKKK emission limits

In summary, the Department's NO_X Primary BACT is:

- *Natural Gas*: 2.0 ppmvd @15% O_2 on a 24-hour block average basis with compliance by CEMS.
- *Fuel Oil*: 8.0 ppmvd @15% O_2 on a 24-hour block average basis with compliance by CEMS.

Conditions such as startup, shutdowns, malfunctions, and fuel switching, which are generally not subject to the Primary BACT limit, will be subject to a Secondary BACT limit, which is equivalent to the applicable NSPS Subpart KKKK emissions standards. Demonstrating compliance with the NSPS Subpart KKKK limit for NO_X will be sufficient for demonstrating compliance with the Secondary NO_X BACT limit.

These turbines will be subject to work practices for startup and shutdown, which will minimize emissions of NO_X and other pollutants. Gas will be the only permitted fuel for startup of the turbines, up to a load of 40%, except for periods of gas curtailment or periods during which gas is not reasonably available, or for purposes of testing and maintenance. Additionally, operators will be required to follow the manufacturer's recommended procedures for startup and shutdown of the turbines, all operators will need to be trained in these procedures, and FPL will have to maintain documentation of this training for all operators. Finally, the limitation on ULSD fuel oil usage further serves to reduce NO_X emissions.

This combination of numerical emission limits and work practice standards assures that there is an applicable BACT emission limitation on NO_X at all times.

The Department and the applicant examined the set of recent BACT determinations issued to NGCC units for NO_X. All Florida NO_X BACT determinations for NGCC units between 2003 and 2012 have included DLN and SCR, with a limit of 2.5 or 2.0 ppmvd@15% O_2. This is consistent with NO_X BACT limits issued in other states, which have generally been 2.0 ppmvd@15% O_2 since before 2010. Additionally, the ULSD fuel oil NO_X limit of 8.0 ppmvd@15% O_2 is consistent with other recent permits, such as Permit No. 0950137-020-AC for Unit B at the Curtis C. Stanton Energy Center in Orlando. The proposed OCEC Unit 1 NO_X BACT limits are very consistent with other recent NO_X BACT limits.

5.3 SO_2 and SAM Emissions

5.3.1 *Draft BACT Determination*

A review of the determinations for SO_2 and SAM from combustion turbines contained in the EPA RACT/BACT/LAER Clearinghouse shows that the exclusive use of low-sulfur fuels constitutes the top control option for SO_2 and SAM. The use of low-sulfur fuels means that fuel sulfur was reduced to very low levels at the gas conditioning facility or refinery prior to distribution to the end user.

For this project, FPL proposed, and the Department accepts, as BACT the use of clean natural gas with a sulfur fuel specification less than 2 grains per 100 standard cubic feet of natural gas (2 gr./100 scf), and ULSD fuel oil, which is less than 0.0015% sulfur by weight. Because this is a standard based on fuel composition, it applies at all times; no special provisions for transient modes of operation, such as startup, shutdown, or malfunction are necessary.

5.3.2 *Requirements of 40 CFR Part 60 on the Combustion Turbines with Respect to SO_2*

The Department's draft BACT limits are considerably more stringent that the NSPS in 40 CFR 60, Subpart KKKK, of 20 gr./100 scf for natural gas and 0.05% sulfur by weight for fuel oil. The NSPS requires fuel sampling or purchase contracts showing the sulfur content of the fuel. FPL will demonstrate compliance with the BACT limit and NSPS through purchase contracts or records for natural gas and fuel oil reflecting this sulfur content limit.

5.4 CO and VOC Emissions

5.4.1 *Discussion*

The same emissions control technologies are generally used for CO and VOC, which is why the two pollutants are considered together here. CO and VOC are products of incomplete combustion, when fuel is not oxidized completely to CO_2 and H_2O. Important parameters in CO formation are combustion temperature, fuel residence time, and stoichiometric ratio and mixing of fuel and air. Emissions of CO and VOC can be controlled through both the careful tuning of combustion and through add-on technologies.

From **Table 7**, above, it is clear that existing DLN technologies on other GE turbine models are capable of producing very low emissions rates for CO and VOC. The DLN-2.6 technology on the GE 7FA.03 turbine led to CO emissions below 2 ppmvd@15% O_2 for all turbine loads greater than 50% and VOC emissions below 1 at ppmvd@15% O_2 the same loads. These low emissions were achieved using only good combustion practices (GCPs), without any additional capture or destruction technologies. However, given the very limited history of the 7HA.02 turbine and its DLN technology, it is unclear if these turbines will perform as well as other GE models.

There are no NSPS or NESHAP limits for CO or VOC that apply to OCEC Unit 1.

5.4.2 *Evaluation of Control Options*

The applicant evaluated several options for control of CO and VOC emissions.

Combustion Controls: The tuning of combustion and careful mixing of air and fuel can optimize complete combustion of fuel, preventing emissions of CO and VOC. GCPs are very effective at reducing emissions of CO and VOC – for example, see **Table 7**. FPL proposes the use of GCPs as a component of BACT for CO and VOC.

Oxidation Catalyst: Catalytic oxidation is primarily intended to reduce emissions of CO, with small decreases in VOC. In the presence of an oxidation catalyst, which is generally a precious metal, excess O_2 in the exhaust stream oxidizes CO to form CO_2. These catalysts require a high temperature, and as a result the catalyst bed is generally placed in the high-temperature region upstream of the HRSG.

FPL has not proposed the use of an oxidation catalyst as a component of BACT. Rather, the expected low emissions from using GCP should bring CO emissions in line with other BACT emission limits for CO and VOC.

EMx: As was noted in the discussion of NO_X, EMx is also a control technology for CO emissions. For the same reasons it was not considered to be appropriate as a NO_X control for this project, FPL also does not include EMx in its proposal for BACT for CO and VOC.

Startup and Shutdown Work Practice Standards: Emissions of CO can be rather high at low turbine loads, such as during periods of startup and shutdown. At these low loads, CO emissions can briefly be on the order of hundreds of ppmvd. FPL has proposed work practice standards that will serve to reduce CO and VOC emissions associated with startups and shutdowns. These include starting up only on natural gas as long as it is available and following the manufacturer-recommended procedures for startup and shutdown.

5.4.3 *Applicant's CO and VOC BACT Proposal*

The applicant proposes the following BACT determination for the control of CO and VOC emissions from the three proposed CTs:

- CO and VOC emissions will be controlled using good combustion practices.
- CO emissions while firing natural gas shall be limited to 4.3 ppmvd @15% O_2 at base load (≥90%);
- CO emissions while firing natural gas shall be limited to 7.1 ppmvd @15% O_2 at non-base load (<90%);
- CO emissions while firing ULSD fuel oil shall be limited to 10.0 ppmvd @15% O_2 at base load (≥90%);
- CO emissions while firing ULSD fuel oil shall be limited to 13.6 ppmvd @15% O_2 at non-base load (<90%);
- VOC emissions while firing natural gas shall be limited to 1.0 ppmvd @15% O_2;
- VOC emissions while firing ULSD fuel oil shall be limited to 2.0 ppmvd @15% O_2;
- Work practice standards that limit CO and VOC emissions during startups and shutdowns apply;
- Each CT may operate up to the base-load equivalent of 500 hours/year using ULSD fuel oil; and

- Compliance shown by stack test.

The Department does not necessarily agree with this applicant proposal.

5.4.4 *Department's Draft CO and VOC BACT Determination*

The Department agrees that the combination of good combustion practices and startup/shutdown work practice standards constitute BACT for CO and VOC for this project.

To determine an appropriate numerical emission standard, the Department examined the EPA RBLC as well as recent stack test information from the FPL 3-on-1 NGCC units analyzed above: West County Units 1, 2, and 3; Cape Canaveral Unit 3; and Riviera Beach Unit 5. All of these are large G- or H-class turbines, though none are the 7HA.02, which FPL proposes for this project. However, the similar turbines at other FPL facilities give examples of reasonable performance expectations for large combined cycle turbines subject to CO BACT limits. The highest CO stack test from the 3-on-1 turbines from each facility are shown in **Table 9**. Nearly all CO natural gas stack tests have measured emissions less than 1.0 ppmvd @15% O_2. Similarly, most CO stack tests on ULSD fuel oil were in the range 0.5 to 4.3 ppmvd @15% O_2, though the greatest was slightly less than 8 ppmvd @15% O_2.

TABLE 9 – HIGHEST CO STACK TESTS FROM FPL 3-ON-1 COMBINED CYCLE FACILITIES (PPMVD @15% O_2).

Unit	Natural Gas	ULSD fuel oil	Years of tests
Cape Canaveral Unit 3	0.76	2.51	2013
West County Units 1, 2, and 3	1.06	7.74	2010-2013
Riviera Beach Unit 5	0.51	0.99	2014

Additionally, recent BACT limits for GE 7F.05 simple cycle turbines at FPL's Fort Myers and Lauderdale plants were 4.0 and 9.0 ppmvd @15% O_2, for natural gas and ULSD fuel oil operation, respectively. These recent stack tests and permits suggest that lower CO emissions than those proposed by the applicant should be achievable. However, given the lack of operating history of the 7HA.02 turbine, it is reasonable to allow some accommodation for this rather new turbine technology.

Additionally, since no CEMS for CO is proposed, it will be rather difficult to assess CO emissions at low loads. However, manufacturer product information[15] shows that emissions limits for the 7HA.02 can be met down to turbine loads of 40%. Additional information from the applicant suggests that the non-base-load CO limits should be achievable down to approximately 30% load for gas and 50% load for ULSD fuel oil. Additional non-base-load CO compliance tests will be required, and an additional work practice standard will be included in the permit, prohibiting the operation of each turbine at a load lower than that load at which compliance with the non-base-load CO limit was achieved, other than during startups, shutdowns, DLN tuning, fuel switching, and documented malfunctions. Subsequent non-base-load CO tests will be required annually for gas and for ULSD fuel oil, for years in which a turbine is run for more than 400 hours on ULSD fuel oil. Non-base-load CO tests for ULSD fuel oil will be required for each Title V operating permit renewal.

The VOC emissions limits are extremely unlikely to be exceeded. Therefore, after an initial test, compliance with the VOC limits will be demonstrated through compliance with the CO limits.

The Department's draft CO and VOC BACT limit is summarized below:

- CO and VOC emissions will be controlled using good combustion practices.
- CO emissions while firing natural gas shall be limited to 4.3 ppmvd @15% O_2 at base load (≥90%);
- CO emissions while firing ULSD fuel oil shall be limited to 10.0 ppmvd @15% O_2 at base load (≥90%);

[15] GE 7HA.01/7HA.02 Gas Turbine Product Specifications website

- CO emissions while firing natural gas shall be limited to 7.1 ppmvd @15% O_2 at non-base load (≥~40% and <90%);
- CO emissions while firing ULSD fuel oil shall be limited to 13.6 ppmvd @15% O_2 at non-base load (≥~40% and <90%);
- VOC emissions while firing natural gas shall be limited to 1.0 ppmvd @15% O_2;
- VOC emissions while firing ULSD fuel oil shall be limited to 2.0 ppmvd @15% O_2;
- Work practice standards that limit CO and VOC emissions during startups and shutdowns apply;
- Each CT will be subject to a test-based minimum operating load for each fuel, other than during startups, shutdowns, DLN tuning, fuel switching, and documented malfunctions;
- Each CT may operate up to the base-load equivalent of 500 hours/year using ULSD fuel oil; and
- Compliance shown by initial stack test for CO and VOC, by annual stack test for base-load and non-base load CO on gas, and by stack tests prior to operating permit renewal for non-base-load CO on ULSD fuel oil (or more frequently if a CT is run on ULSD fuel oil for more than 400 hours in a year).

The combination of numerical limits and work practices assures that there is an applicable emissions limitation on CO and VOC at all times.

5.5 Particulate Matter (PM, PM_{10}, and $PM_{2.5}$) Emissions

PM is a mixture of the solid particles and liquid droplets in the emissions stream. PM can consist of many different chemical components. PM emissions from turbines generally result from noncombustible trace constituents of the fuel. Filterable PM is the portion of total PM that exists in the stack in the solid or liquid state, while condensable PM is in the gas phase in the stack, but condenses shortly after emitted to the ambient air, forming particulate matter. There are no NSPS or NESHAP limits for CO or VOC that apply to OCEC Unit 1.

For CTs, the use of clean fuels and GCPs are essentially the only technologies that are employed for PM control. A review of EPA's RBLC confirms this. Add-on technologies, such as a baghouse or electrostatic precipitator are capable of capturing filterable PM before it is emitted; however, PM emissions from CTs are generally so low as to make add-on PM controls infeasible and unnecessary.

The applicant has proposed the use of clean fuels and GCPs as BACT for PM for OCEC Unit 1. The Department's determination is that GCPs and clean fuels do constitute BACT for PM for this unit. The restrictions on sulfur content of both natural gas and liquid fuel, and the work practices for startups and shutdowns, will serve as an effective continuous emission limitation for PM. Additionally, an emissions standard for opacity (10%) will help ensure proper combustion and low emissions of PM.

5.6 Summary of BACT Limits for CTs

The emission limits for these turbines are summarized in **Table 10**.

TABLE 10 – SUMMARY OF BACT EMISSION LIMITS FOR TURBINES.

Pollutant		Emission Standard	Basis	Compliance Method	Averaging Time
NO_X	Gas	2.0 ppmvd @15% O_2	Primary BACT (Normal operating conditions)	CEMS	24-hr block avg.
		15.0 ppmvd @15% O_2 (for turbine loads ≥ 75%)	NSPS KKKK, Secondary BACT		30-operating-day rolling avg.
	Oil	8.0 ppmvd @15% O_2	Primary BACT		24-hr block avg.
		42.0 ppmvd @15% O_2	NSPS KKKK,		30-operating-day

Pollutant		Emission Standard	Basis	Compliance Method	Averaging Time
		(for turbine loads ≥ 75%)	Secondary BACT		rolling avg.
NO_X	Gas or oil	96.0 ppmvd @15% O_2 (for turbine loads < 75%)	NSPS KKKK, Secondary BACT		30-operating-day rolling avg.
CO	Gas	4.3 ppmvd @15% O_2 (for turbine loads ≥ 90%)	BACT	Initial and annual stack tests	Three 1-hr runs
		7.1 ppmvd @15% O_2 (for turbine loads < 90%)			
	Oil	10.0 ppmvd @15% O_2 (for turbine loads ≥ 90%)		Initial stack test, subsequent tests in accordance with Specific Condition **17.c**	
		13.6 ppmvd @15% O_2 (for turbine loads < 90%)			
$PM/PM_{10}/PM_{2.5}$		2.0 gr. sulfur/100 SCF natural gas 0.0015% sulfur fuel oil	BACT	Fuel record keeping	N/A
		10 percent opacity		Visible emissions annual test	6-minute block
SO_2 and SAM		2.0 gr. sulfur/100 SCF natural gas 0.0015% sulfur fuel oil	BACT	Fuel record keeping	N/A
GHGs	Gas	850 lb/MWh	Primary BACT	CEMS or fuel-use monitoring (40 CFR 75)	12-month rolling avg.
	Oil	1,210 lb/MWh			
	Gas or oil	1,000 lb/MWh	NSPS TTTT, Secondary BACT		
VOC	Gas	1.0 ppmvd @15% O_2	BACT	Initial stack test, CO as proxy thereafter	Three 1-hr runs
	Oil	2.0 ppmvd @15% O_2			

6. BACT REVIEW FOR AUXILIARY BOILER (E.U. NO. 004)

6.1 Discussion

The auxiliary boiler will have a maximum design heat input rating of 99.77 MMBtu per hour and will be exclusively fired with pipeline natural gas. Because the design heat input capacity is between 10 and 100 MMBtu per hour, the unit will be subject to NSPS 40 CFR 60 Subpart Dc for small steam generating units. Because natural gas-fired boilers are inherently low emitting, this subpart does not include any numerical emission limits for natural gas boilers.

The boiler will be used during the startup and shutdown sequences of the CTs to provide steam to the steam cycle. This can be useful in assisting with startup of the steam turbine. The applicant has proposed to limit the operation of the boiler to no more than 2,000 hours per year.

6.2 BACT Analysis

A review of the RBLC shows that clean fuels, GCPs, and low-NO_X burners (LNBs) are most commonly included in BACT determinations for small boilers, while flue gas recirculation (FGR) is also sometimes included as a method to reduce NO_X emissions. FPL has proposed the use of clean fuels, GCPs, and LNBs as BACT for this unit.

6.2.1 *GHG Emissions*

The applicant proposes the use of a natural gas-fired boiler. Additionally, this boiler will be run for no more than 2000 hours per year. For the reasons described in Section 5.1, above, natural gas has the lowest associated GHG emissions of all fossil fuels.

The Department has determined that the use of natural gas along with limiting operational hours to 2000 hours or less per year constitute GHG BACT for this EU.

6.2.2 *SO_2 and SAM Emissions*

The applicant proposed the use of pipeline natural gas for this unit. This gas will contain no more than 2 gr. sulfur per 100 scf. The Department agrees that the use of this clean fuel constitutes BACT for SO_2 and SAM for this unit.

6.2.3 *NO_X Emissions*

The applicant has proposed the use of GCPs and LNBs as BACT for NO_X, with a limit of 0.05 lb per MMBtu. FGR would provide minimal marginal benefit beyond these proposed technologies. This standard is equal to other recent BACT limits for auxiliary boilers in Florida, including at FPL's Cape Canaveral and Riviera Beach Energy Centers. This would result in NO_X emissions of no more than 5 tons per year.

The applicant's request is appropriate for this emissions unit. Compliance will be demonstrated through an initial stack test and subsequent stack tests before each Title V operation permit renewal. During startups and shutdowns, the use of natural gas, GCPs, and LNBs provide a meaningful limitation on NO_X emissions.

6.2.4 *CO and VOC Emissions*

The applicant has proposed the use of GCPs and LNBs as BACT for CO. However, the applicant did not propose a numerical standard. Other recent BACT limits for auxiliary boilers in Florida, including at FPL's West County Energy Center and Duke Energy Florida's Bartow plant in St. Petersburg have included limits of 0.08 lb per MMBtu, which is the figure used by FPL in its calculations of expected emissions from this unit. This would result in CO emissions of no more than 8 tons per year.

The Department's draft determination of BACT for CO for this unit includes the use of GCPs and LNBs, and a limit of 0.08 lb per MMBtu. Compliance will be demonstrated through an initial stack test and subsequent stack tests before each Title V operation permit renewal. During startups and shutdowns, the use of natural gas, GCPs, and LNBs provide a meaningful limitation on CO emissions.

BACT for VOC includes the use of GCPs and LNBs. Emissions of VOC are expected to be less than 1 ton per year from this boiler, and the same techniques that reduce CO emissions will also reduce VOC emissions. CO will be used as a proxy for VOC for this unit, and no VOC stack tests will be required.

6.2.5 *$PM/PM_{10}/PM_{2.5}$ Emissions*

The applicant has proposed that the use of clean fuels constitutes BACT for particulate matter for this emissions unit. PM emissions are expected to be less than 1 ton per year. The Department agrees that the use of natural gas, with sulfur content less than 2 gr. per 100 scf, is BACT for PM for this boiler. Additionally, an emissions standard for opacity (10%) will help ensure proper combustion and low emissions of PM. This will be demonstrated through an annual test for visible emissions.

7. BACT REVIEW FOR ULSD FUEL OIL STORAGE TANK (E.U. NO. 005)

FPL believes that the storage tanks are 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 agrees that these storage tanks are not subject to NSPS Subpart Kb. The Department sets BACT for these storage tanks to minimize VOC emissions as the use of

pressure relief valves together with vacuum relief valves. With these technologies, VOC emissions from the storage tank are expected to be less than 2 tons per year. In lieu of pressure relief valves and vacuum relief valves, FPL as an alternative, can use tanks with internal floating roofs or the equivalent to minimize VOC emissions.

8. BACT REVIEW FOR EMERGENCY GENERATORS (E.U. NO. 006) AND FIRE PUMP ENGINE (E.U. NO. 008)

8.1 Discussion

The emergency generators are three 3,300-kilowatt compression-ignition ULSD fuel oil -fired internal combustion engines. Each engine will have a design fuel flow rate of approximately 214 gallons per hour. The fire pump engine is a 422-horsepower compression-ignition ULSD fuel oil -fired internal combustion engine. This engine will have a design fuel flow rate of approximately 20 gallons per hour. These engines are intended for emergency service, and they will be limited to 100 hours per year of non-emergency use for testing and maintenance.

8.2 BACT Analysis

Energy efficiency and clean fuels are the only practical control strategies for emergency engines such as these. Spark ignition combustion engines, such as those that use natural gas or gasoline, are often not recommended for use with emergency generators or fire pump engines due to difficulties with storing sufficient quantities of fuel. Therefore, the only technically feasible control option for these engines is energy efficiency with ULSD fuel oil.

8.2.1 *GHG Emissions*

The applicant proposes the use of an efficient ULSD fuel oil-fueled engine. Additionally, these engines will be run for no more than 100 hours per year in non-emergency situations. The Department has determined that the use of an efficient engine along with limiting operational non-emergency hours to 100 hours or less constitute GHG BACT for these EUs.

8.2.2 *SO_2 and SAM Emissions*

The use of ULSD fuel oil is required by NSPS 40 CFR 60 Subpart IIII and the GHG BACT, above. ULSD fuel oil has the lowest possible sulfur content of fuels that can be used for the fire pump engine (15 parts per million). FPL requests the use of ULSD fuel oil as BACT for SO_2 and SAM, given its low sulfur content and the lack of alternatives, and the Department agrees with this determination.

8.2.3 *VOC, NO_X., CO, and PM/PM_{10}/$PM_{2.5}$ Emissions*

Emissions of VOC (as non-methane hydrocarbons), NO_X, CO, and PM are limited under NSPS 40 CFR 60 Subpart IIII. FPL has requested that, given the limited use of these engines, the BACT limits for these pollutants equal their NSPS limits. The Department agrees that the NSPS limits, and the restriction on non-emergency operation, are an appropriate choice for BACT for this emissions unit.

The NSPS Subpart IIII emission limits will likely be met through the purchase of engines certified to meet the emissions standards. The standards for the emergency generators, if they are model year 2011 or later, are summarized in **Table 11** (from 40 CFR 89 Subpart B, as referenced by 40 CFR 60 Subpart IIII).

TABLE 11 – EMISSION STANDARDS FOR ULSD FUEL OIL EMERGENCY ENGINES.

Emergency Generator (Larger than 560 kW)	**CO** (g/kW-hr) [1]	**PM** (g/kW-hr)	**NMHC[2] + NO_X** (g/kW-hr)	**Diesel Fuel [3]** (sulfur)
2011 and later	3.5	0.20	6.4	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 emission standards for the fire pump engine, from 40 CFR 60 Subpart IIII, are summarized in **Table 12**. FPL will likely meet these requirements by purchasing a certified engine.

TABLE 12 – EMISSION STANDARDS FOR FIRE PUMP ENGINES.

Fire Pump Engine (Between 225 kW and 450 kW)	**CO** (g/kW-hr) [1]	**PM** (g/kW-hr)	**NMHC + NO_X** (g/kW-hr)	**Diesel Fuel** [1] (sulfur)
2009 and later	3.5	0.20	4.0	15 ppm
1. 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				

9. BACT REVIEW FOR NATURAL GAS HEATERS (E.U. NO. 007)

The fuel heaters are small natural gas-fueled units, rated at 9.9 MMBtu per hour. Only one fuel heater will be used at any given time; the second is a spare. FPL has proposed BACT for these fuel heaters as the use of natural gas with sulfur content less than 2 gr. per 100 scf, along with the work practice standard of using only heaters with a NO_X emissions rate design value of 0.l lb per MMBTU or less. In the unlikely scenario of the heater being run 8,760 hours per year, this would yield 4.3 tons per year of NO_X and 3.6 tons per year of CO. These design/work practice standards are sufficient for BACT for this unit.

10. BACT REVIEW FOR PROPANE EMERGENCY GENERATORS (E.U. NO. 009)

10.1 Discussion

The propane-fired emergency generators are two small 25-kilowatt spark-ignition internal combustion engines. Each engine will have a design fuel flow rate of 0.4 MMBtu per hour. These small engines will be located at the hurricane shelter for emergency generation. These engines are intended for emergency service, and they will be limited to 100 hours per year of non-emergency use for testing and maintenance.

10.2 BACT Analysis

Energy efficiency and clean fuels are the only practical control strategies for small emergency engines such as these. The use of propane is feasible for these engines because of their small size, and the small size of the tanks that are needed to store the fuel. Therefore, the use of efficient engines with clean propane fuel is technically feasible for this emissions unit.

10.2.1 *GHG Emissions*

The applicant proposes the use of an efficient propane-fueled engine. Additionally, these engines will be run for no more than 100 hours per year in non-emergency situations. The Department has determined that the use of an efficient engine along with limiting operational non-emergency hours to 100 hours or less constitute GHG BACT for this EU.

10.2.2 *SO_2 and SAM Emissions*

Propane contains essentially no sulfur. The use of propane will result in negligible emissions of SO_2 and SAM. Therefore the use of propane fuel constitutes BACT for these pollutants for this emissions unit.

10.2.3 *VOC, NO_X, CO, and PM/PM_{10}/$PM_{2.5}$ Emissions*

These engines are regulated under NSPS 40 CFR 60 Subpart JJJJ. FPL has requested that, given the limited use of these engines, the BACT limits for these pollutants equal their NSPS limits. The Department agrees that the NSPS limits, and the restriction on non-emergency operation, are an appropriate choice for BACT for this emissions unit.

The emission standards for the propane-fired emergency generators, from 40 CFR 60 Subpart JJJJ, are

summarized in **Table 13**. FPL will likely meet these requirements by purchasing a certified engine.

TABLE 13 – EMISSION STANDARDS FOR PROPANE-FUELED EMERGENCY ENGINES.

Propane Emergency Engines (Between 19 kW and 75 kW)	**CO** (g/kW-hr)	**NMHC + NO_X** (g/kW-hr)
2009 and later	387	10

11. BACT REVIEW FOR MECHANICAL DRAFT COOLING TOWER (E.U. NO. 010)

Cooling towers use a fan to move air through a re-circulated water system. Water droplets may be introduced into the surroundings, and any dissolved solids in the water can result in particulate matter. The "drift rate" is the measure of how much water is lost to the surroundings. A review of the RBLC for BACT determinations for cooling towers shows that a work practice standard to limit the design drift rate is the main method of preventing PM emissions from cooling towers. The most common drift rate in BACT determinations is 0.001%. FPL has proposed the use of a high-efficiency drift eliminator, with a design drift rate of 0.0005%. The Department agrees that this constitutes BACT for this unit.

12. BACT REVIEW FOR CIRCUIT BREAKERS (E.U. NO. 011)

12.1 *Discussion*

Circuit breakers require the use of materials with high dielectric strength for electric insulation. Sulfur hexafluoride (SF_6) is commonly used for this purpose. The GWP of SF_6 is 23,900. In spite of this high GWP, SF_6 is still generally used because of its superior dielectric and arc-quenching properties, and because it is not flammable (unlike some dielectric oils). Circuit breakers can typically be certified to have a leak rate of no more than 0.5% per year. The applicant estimates that 17 circuit breakers will be needed for this project.

12.2 *BACT Analysis*

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 SF_6, 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 gauge 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.

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.

The only technically feasible control technologies for SF_6 in this project are the use of modern enclosed circuit breakers with a leakage rate of no more than 0.5% which are thoroughly tested, equipped with leakage detection systems and alarms, and periodic inspections. The permit includes the following work practice standards as BACT. The permittee will monitor the circuit breakers remotely and continuously through the plant control system. Preventive maintenance will be performed in accordance with manufacturer instructions, and the permittee will submit a circuit breaker monitoring plan to the Department after the equipment is selected and placed in service.

13. AIR QUALITY ANALYSIS

As a part of this review, Rules 62-212.400(7) and 62-212.400(5), F.A.C., require the applicant to perform a current air quality analysis and a source impact analysis for each PSD applicable pollutant. The emission rates in **Table 4** are based on the worst-case operating scenario for each pollutant and indicate that CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SAM, SO_2, VOC and GHG are subject to review.

13.1 Current Air Quality Analysis

13.1.1 *State Level*

The State of Florida has generally good ambient air quality and is currently in attainment of all national ambient air quality standards (NAAQS) in the vicinity of the project site. Air pollutant emissions have seen a significant decrease in the past fifteen years as is shown in **Figure 7**. Statewide actual annual emissions from stationary (industrial) sources of SO_2 have decreased 78%, NO_X 68%, PM 61%, VOC 44%, and CO 43% since 2000 while the population of Florida has increased over three million, or nearly 22%, through the same period. A variety of national rules that are currently being implemented are expected to maintain these lower levels or even reduce them further in the foreseeable future.

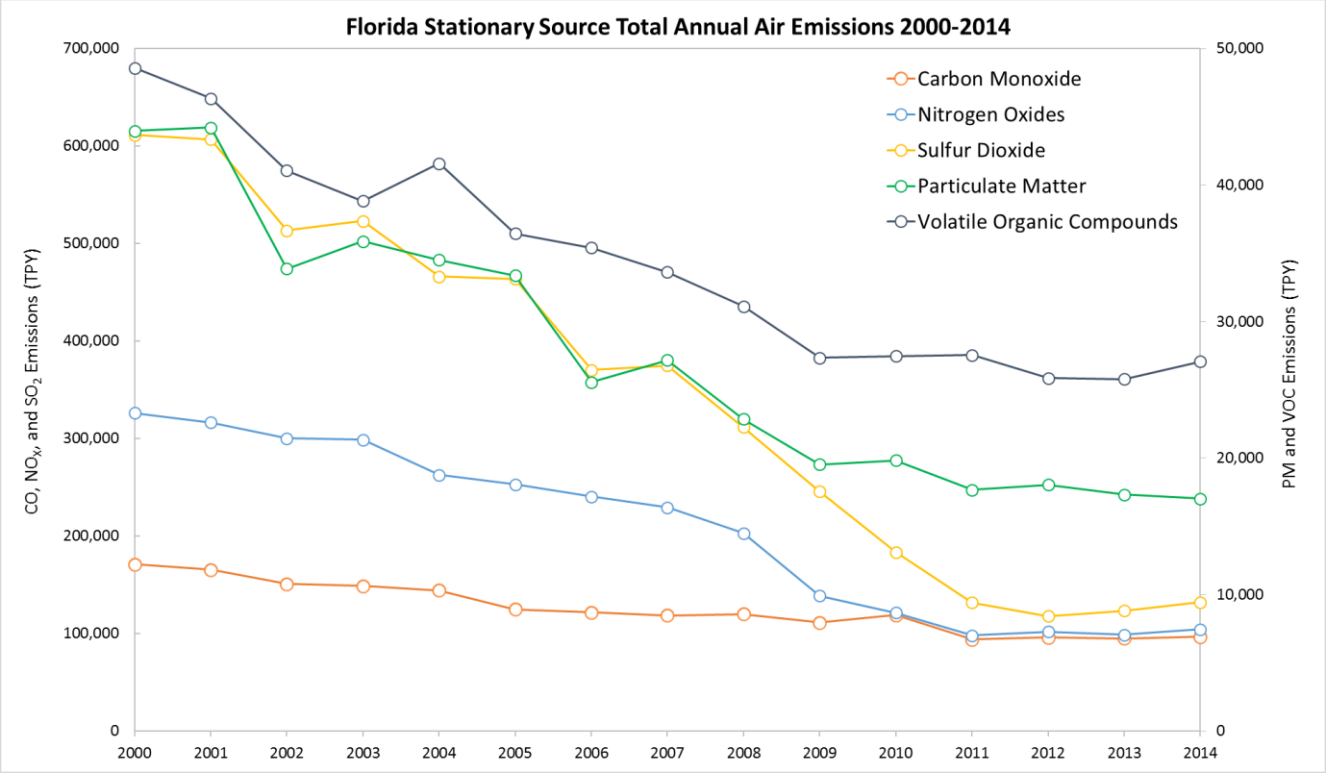

Figure 7. Actual annual emissions of criteria air pollutants in Florida from 2000 to 2014. (CO, SO_2, and NO_X are on the left-hand scale, while VOC and PM are on the right-hand scale.)

13.1.2 *County Level*

Okeechobee County, 2014 population just 39,149, is very rural in nature and is among the least densely populated counties in Florida. The nearest significant population center to the project site is the city of Vero Beach almost 40 km east. Given the small total combined emissions of all criteria pollutants from stationary point sources in the county (less than 250 TPY since 2012) **Table 14** below includes emissions from nearby Indian River, St. Lucie, Osceola, and Brevard Counties as well in order to best represent the current emissions

trends in the area. As is shown, the downward trend in statewide stationary source emissions is reflected in this area.

TABLE 14 – ACTUAL ANNUAL EMISSIONS OF CRITERIA POLLUTANTS BY STATIONARY SOURCES IN OKEECHOBEE, INDIAN RIVER, OSCEOLA, BREVARD, AND ST. LUCIE COUNTIES, FLORIDA IN 2005 AND 2014.

Pollutant	2000 Actual Emissions (tons)	2014 Actual Emissions (tons)	Percent Change
CO	2,965.5	1,871.4	-37%
NO_X	9,220.3	879.9	-91%
PM	1,709.1	198.7	-88%
SO_2	18,840.0	128.2	-99%
VOC	2,503.8	1,110.4	-56%

13.1.3 *Nearby Sources*

The area surrounding the project site contains very few significant stationary sources of air pollutants. **Table 15** through **Table 19** provide some perspective on the relative size of the project and nearby sources by comparing its maximum potential future emissions with the actual 2014 emissions from the five largest sources within 50 km. The existing sources in the area are generally small and outside of population areas. In addition, all of these sources are located more than 30 km away from the project site (**Figure 8**).

TABLE 15 – ACTUAL 2014 EMISSIONS OF NO_X FROM THE LARGEST STATIONARY SOURCES NEAR THE PROJECT SITE, COMPARED TO THE MAXIMUM FUTURE POTENTIAL EMISSIONS FROM THE PROJECT.

Owner	Facility Name	County	2014 NO_x Emissions (tons)
Florida Power and Light	*This Project*	Okeechobee	398
Florida Gas Transmission Co	FGTC Compressor Station 20	St. Lucie	77.8
Florida Municipal Power Agency	Treasure Coast Energy Center	St. Lucie	35.8
Okeechobee Landfill, Inc.	Okeechobee Landfill	Okeechobee	33.5
Tropicana	Fort Pierce Citrus Processing Facility	St. Lucie	20.7
INEOS New Planet Bioenergy	INPB IRC Facility	Indian River	17.2

TABLE 16 – ACTUAL 2014 EMISSIONS OF PM_{10} FROM THE LARGEST STATIONARY SOURCES NEAR THE PROJECT SITE, COMPARED TO THE MAXIMUM FUTURE POTENTIAL EMISSIONS FROM THE PROJECT.

Owner	Facility Name	County	2014 PM_{10} Emissions (tons)
Florida Power and Light	*This Project*	Okeechobee	254
Florida Municipal Power Agency	Treasure Coast Energy Center	St. Lucie	14.2
Tropicana	Fort Pierce Citrus Processing Facility	St. Lucie	12.6
Okeechobee Landfill, Inc.	Okeechobee Landfill	Okeechobee	8.0
Titan Florida LLC	Fort Pierce RMC & Block Plant	St. Lucie	1.7
INEOS New Planet Bioenergy	INPB IRC Facility	Indian River	1.5

TABLE 17 – ACTUAL 2014 EMISSIONS OF CO FROM THE LARGEST STATIONARY SOURCES NEAR THE PROJECT SITE, COMPARED TO THE MAXIMUM FUTURE POTENTIAL EMISSIONS FROM THE PROJECT.

Owner	Facility Name	County	2014 CO Emissions (tons)
Florida Power and Light	*This Project*	Okeechobee	540
Okeechobee Landfill, Inc.	Okeechobee Landfill	Okeechobee	177.2
Tropicana	Fort Pierce Citrus Processing Facility	St. Lucie	26.5
Florida Gas Transmission Company	FGTC Compressor Station 20	St. Lucie	21.5
Ranger Construction Industries	Ranger/Ft Pierce Asphalt Plant	St. Lucie	20.0
Florida Municipal Power Agency	Treasure Coast Energy Center	St. Lucie	14.9

TABLE 18 – ACTUAL 2014 EMISSIONS OF SO_2 FROM THE LARGEST STATIONARY SOURCES NEAR THE PROJECT SITE, COMPARED TO THE MAXIMUM FUTURE POTENTIAL EMISSIONS FROM THE PROJECT.

Owner	Facility Name	County	2014 SO_2 Emissions (tons)
Florida Power and Light	*This Project*	Okeechobee	254
Intersil Corporation	Intersil Corporation – Palm Bay	Brevard	23.8
Okeechobee Landfill, Inc.	Okeechobee Landfill	Okeechobee	11.4
Tropicana	Fort Pierce Citrus Processing Facility	St. Lucie	6.9
Florida Municipal Power Agency	Treasure Coast Energy Center	St. Lucie	3.9
INEOS New Planet Bioenergy	INPB IRC Facility	Indian River	3.0

TABLE 19 – ACTUAL 2014 EMISSIONS OF VOC FROM THE LARGEST STATIONARY SOURCES NEAR THE PROJECT SITE, COMPARED TO THE MAXIMUM FUTURE POTENTIAL EMISSIONS FROM THE PROJECT.

Owner	Facility Name	County	2014 VOC Emissions (tons)
Tropicana	Fort Pierce Citrus Processing Facility	St. Lucie	215.8
S2 Yachts, Inc.	S2 Yachts, Pursuit Division	St. Lucie	110.1
Florida Power and Light	*This Project*	Okeechobee	71
Maverick Boat Company, Inc.	Maverick Boat Company	St. Lucie	70.8
Piper Aircraft Inc.	Piper Aircraft Inc.	Indian River	43.5
Okeechobee Landfill, Inc.	Okeechobee Landfill	Okeechobee	18.6

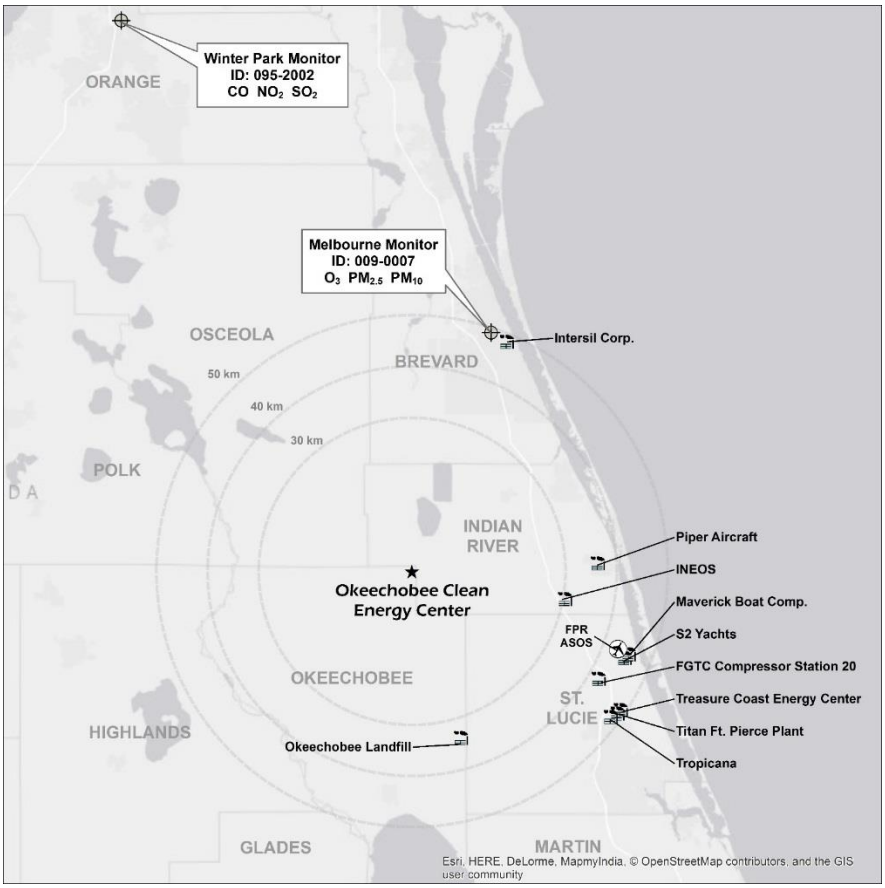

Figure 8. Reference map for the Okeechobee Clean Energy Center including monitors used to characterize the air quality near the project site and the largest sources of air pollutants within 50 km.

13.1.4 *Monitors*

Florida has a robust ambient air monitoring network operated by the Florida Department of Environmental Protection (DEP) and its partners (local air pollution control programs). The network monitors concentrations of each of the criteria pollutants and includes monitors in Florida counties containing 92% of the population (**Figure 9**). The monitors shown in **Figure 8** are representative of the project site and are used to evaluate the existing air quality in the area. All of the representative monitors are described in **Table 20** and are used to satisfy the preconstruction monitoring requirements for PSD review contained in Rule 62-212.400(7), F.A.C. These monitoring sites are located in areas much more urbanized than the rural setting of the project. As a result, the monitoring data is likely higher than the actual ambient air quality where the project is located in northeast Okeechobee County, and therefore provides conservative estimates. The design values at these monitors are well below the applicable NAAQS.

13.2 Source Impact Analysis

A source impact analysis is required by Rule 62-212.400(5), F.A.C. to demonstrate that allowable emission increases from the proposed project will not cause or contribute to a violation of any NAAQS or PSD increment as defined in 40 CFR Part 50 and 40 CFR 52.21(c) respectively. This analysis is performed using approved air quality models and analysis techniques as described in Appendix W (Guideline on Air Quality Models) of 40 CFR 51.

It should be noted that for CO, NO_2, $PM_{2.5}$, and PM_{10}, ambient impacts are significantly higher when firing ULSD fuel oil versus firing natural gas. As such, all estimated concentrations for these pollutants for short-term averaging periods assume continuous, i.e. 8,760 hours per year, ULSD fuel oil usage despite this fuel being designated as backup only with an annual limit of 500 hours. Therefore, the estimates presented here are considered to be conservative in nature.

13.2.1 Dispersion Modeling Approach

Dispersion modeling for the source impact analysis typically occurs in six steps:

1. **Class II SIL Analysis**: Initial modeling is performed to determine if the maximum predicted concentrations due to the new source(s) alone are likely to cause a significant impact on ambient air quality. Modeling is performed using five years of actual meteorological data and the highest resultant concentrations are compared to the EPA suggested significant impact levels (SILs) for each pollutant that is subject to PSD review. For each pollutant that is less than the SIL, steps two and three are skipped. For all others, refined NAAQS and Class II increment analyses are required.

2. **NAAQS Analysis**: Cumulative source modeling is performed for each pollutant and averaging time that exceeded the Class II SIL. This analysis includes modeled emissions from all nearby sources that are considered to have a significant impact and a non-modeled background concentration intended to represent all other sources of pollutants. The resulting concentrations are evaluated on a receptor-by-receptor basis for comparison to each NAAQS using the following metrics:

- CO 1-Hour Average: Highest of yearly second-high 1-hour average concentrations;
- CO 8-Hour Average: Highest of yearly second-high 8-hour average concentrations;
- NO_2 1-Hour Average: 5-year average of the yearly 8th-high daily maximum 1-hour average concentration;
- NO_2 Annual Average: Highest annual mean over five years;
- $PM_{2.5}$ 24-Hour Average: 5-year average of the yearly 8th-high 24-hour average concentration;
- $PM_{2.5}$ Annual Average: 5-year average of the annual mean;
- PM_{10} 24-Hour Average: 6th-high 24-hour concentration over five years;

- SO_2 1-Hour Average: 5-year average of the yearly 4th-high daily maximum 1-hour average concentration;
- SO_2 24-Hour Average: Highest of yearly second-high 24-hour average concentrations;
- SO_2 Annual Average: Highest annual mean over five years.

3. **Class II Increment Analysis**: Cumulative source modeling is performed with nearby PSD increment consuming or expanding sources. For annual averaging periods, the highest five-year annual average is compared to the increment. For all other short-term averaging periods, the 2nd-highest concentration from each of five years is compared.

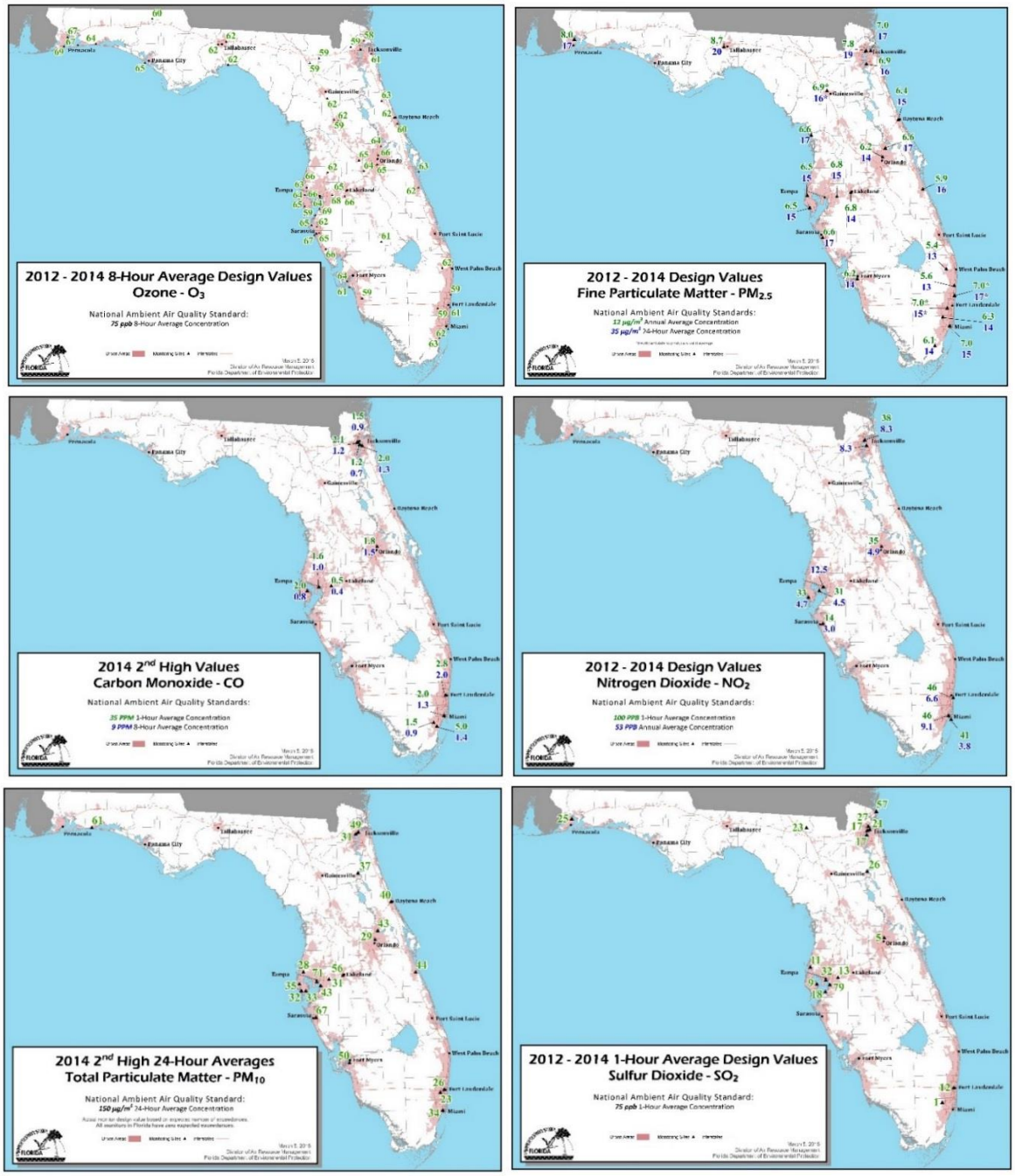

Figure 9. Florida Design Values for 2012-2014 for each of the Criteria Pollutants.

TABLE 20 – CRITERIA POLLUTANT DESIGN VALUES FOR EACH FLORIDA DEP AMBIENT AIR MONITOR CHOSEN TO CONSERVATIVELY CHARACTERIZE THE PROJECT AREA AS PART OF THE PRECONSTRUCTION MONITORING REQUIREMENT OF PSD REVIEW.

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
CO	Winter Park, FL (095-2002)	1-Hour	2014	1.8[j]	35[b]	ppm
		8-Hour	2014	1.7[j]	9[b]	ppm
NO_2	Winter Park, FL (095-2002)	1-Hour	2012 – 2014	35	100[c]	ppb
		Annual	2014	4.9	53[d]	ppb
Ozone	Melbourne, FL (009-0007)	8-hour	2012 - 2014	0.062	.070[e]	ppm
PM_{10}	Melbourne, FL (009-0007)	24-hour	2012 – 2014	60[j]	150[f]	$\mu g/m^3$
$PM_{2.5}$	Melbourne, FL (009-0007)	24-hour	2012 - 2014	17	35[g]	$\mu g/m^3$
		Annual	2012 - 2014	5.9	12[h]	$\mu g/m^3$
SO_2	Winter Park, FL (095-2002)	1-Hour	2012-2014	5	75[i]	ppb
		24-Hour	2014	6[j]	140[b]	ppb
		Annual	2014	1.0	30[d]	ppb

a. Units are in: micrograms per cubic meter ($\mu g/m^3$); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded more than once per year.
c. Three-year average of the annual 98th percentile, daily maximum 1-hour average concentration.
d. Arithmetic annual mean.
e. Three-year average of the annual 98th percentile, daily maximum 8-hour average concentration.
f. Not to be exceeded more than once per year on average over a three-year period.
g. Three-year average of the annual 98th percentile, daily 24-hour average concentrations.
h. Three-year average of the arithmetic annual means.
i. Three-year average of the annual 99th percentile, daily maximum 1-hour average concentration.
j. Exceedance based standard - Maximum 2014 concentration given for comparison

4. **Class I SIL Analysis**: A Class I analysis is typically required if a source is within 200 km of a Federal Class I area, and is sometimes advisable for greater distances. Almost all of Florida is within, or close to this distance of at least one Class I area and therefore an analysis is always required. This analysis is identical to the Class II SIL analysis except that the SILs are smaller and only evaluated within the boundaries of the Class I area.
5. **Class I Increment Analysis**: For those pollutants that exceed the applicable Class I SIL, an increment analysis is required. Again this analysis mirrors the Class II increment analysis except with smaller increments that are only evaluated within the Class I area.
6. **Class I AQRV Visibility and Deposition Analysis:** A visibility and deposition analysis is required for any Class I area that does not pass a specific screening criteria.

13.2.2 *Models*

There are two EPA-approved air quality models that are generally used to assess source impacts: AERMOD and CALPUFF.

The AERMOD (AMS (American Meteorological Society)/EPA Regulatory Model) modeling system is a near-field, Gaussian, steady-state plume dispersion model 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. The system is comprised of the AERMET meteorological processor, the AERMAP terrain processor, and the actual AERMOD model. AERMOD was commissioned by EPA for regulatory use and was developed by AERMIC (AMS/EPA Regulatory Model

Improvement Committee) from 1991 to 2005 when EPA officially promulgated it as the preferred regulatory model. Between 2005 and 2014 the program has undergone ten major updates. It is the recommended model for assessing air quality impacts up to 50 km from the source.

CALPUFF is a multi-layer, multi-species, non-steady-state, puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollution transport, transformation and removal. It is capable of evaluating sub-grid scale effects as well as longer range effects such as pollutant removal, chemical transformation, and visibility. It is approved for use on scales of tens to hundreds of kilometers and is generally utilized for long-range transport between 50 and 300 km from the source. In Florida, this model is typically only used for Class I analyses as most sources are more than 50 km from any Class I area.

For this project, AERMOD was used to evaluate the Class II SILs for $PM_{2.5}$, PM_{10}, NO_2, SO_2, and CO; CALPUFF was used to evaluate the Class I SILs for the $PM_{2.5}$ and PM_{10} 24-hour and annual averages, the NO_2 annual average, and the SO_2 annual, 24-hour, and 3-hour averages.

13.2.3 *Class II SIL Analysis*

The general modeling approach for the SIL, NAAQS, and PSD increment analyses followed current EPA and DEP modeling guidance. Multiple scenarios involving different fuels and operating scenarios were modeled by the applicant in order to identify the worst case operating scenario for each pollutant. The applicant used a series of specific model features recommended by EPA that are referred to as the regulatory options and the latest version of each model component available at the time of the analysis. It should be noted that ambient concentrations of modeled pollutants in the area near the project site are significantly below the applicable NAAQS for each and therefore use of SILs in this case satisfies Section 165(a)(3) of the CAA.

13.2.3.1Meteorological Data

The AERMET v.14134 meteorological input used with the AERMOD v.14134 model consisted of a concurrent 5-year period of hourly surface-weather observations from the National Weather Service (NWS) Automated Surface Observing System (ASOS) station at St. Lucie County International Airport (FPR) and upper air sounding (RAOB) data from Florida International University (FIU) in Miami (**Figure 8**). This data was compiled by DEP for the period 2009 - 2013 and included land cover and land use parameters derived from the 1992 National Land Cover Database (NLCD) by AERSURFACE v.13016 and 1-minute ASOS wind data extracted by AERMINUTE v.11059 with a minimum wind speed threshold of 0.5 meters per second (m/s). The ASOS station at FPR is located approximately 44 km ESE of the project site and is the closest primary weather station. **Table 21** summarizes the annual average land use parameters for the project site and the ASOS location. These parameters were derived seasonally and for twelve 30-degree wind direction sectors. Given the similarity of the land surrounding both sites, the ASOS data are considered to be representative of the project site.

TABLE 21 – ANNUAL AVERAGE LAND USE PARAMETER COMPARISON BETWEEN THE FPR ASOS STATION AND THE PROJECT SITE.

Location	Albedo	Bowen Ratio	Surface Roughness
FPR ASOS Station	0.15	0.44	0.061
Okeechobee Project Site	0.15	0.31	0.160

13.2.3.2Building Downwash

Building downwash effects were simulated for each HRSG structure and the cooling tower at the facility. For each stack, direction-specific building heights and maximum projected widths were calculated by the Building Profile Input Program (BPIP v.04274) incorporating the Plume Rise Model Enhancement (PRIME) algorithm. This wind direction-specific information was then output to AERMOD which simulates aerodynamic downwash based on stack and building locations and heights.

13.2.3.3Receptors and Terrain

A combination of fence line, near-field, and far-field receptors was chosen for predicting maximum concentrations in the vicinity of the project for comparison to the Class II SILs. Receptor locations used in the modeling analysis were based on Universal Transverse Mercator (UTM) coordinates from Zone 17 North, North American Datum 1983 (NAD83). The modeling domain was set as a 30 km X 30 km grid centered at UTM 17N east and north coordinates of 520,500 and 3,056,100 meters, respectively. A discrete Cartesian grid of 5,631 receptors was located at the following intervals and distances:

- 50 m spacing along the property boundary and fence line;
- 100 m spacing from the fence line to 2,000 m from the domain origin;
- 250 m spacing from 2,000 m to 5,000 m from the domain origin;
- 500 m spacing from 5,000 m to 15,000 m from the domain origin.

This receptor placement is considered to be sufficient to resolve the areas of highest concentration in Florida's flat terrain.

Base elevations were extracted from the US Geological Survey's (USGS) 1-second National Elevation Dataset (NED) by AERMOD's terrain processor AERMAP v.11103 for all receptors and sources.

13.2.3.4Onsite Modeled Sources

The SIL analysis evaluates whether the increase in potential emissions from the new project alone are capable of significantly contributing to a modeled NAAQS exceedance. The three new CT/HRSGs were modeled with twenty-four different sets of parameters for each pollutant in order to identify the worst case scenarios: four inlet temperatures (35°F, 59°F, 75°F, and 95°F), at three loads (100%, 75%, and 50%), and operating on two fuels (natural gas and ULSD fuel oil). The worst case scenario differed for each pollutant, and thus all 24 scenarios are summarized in **Table 22**.

TABLE 22 – MODELING PARAMETERS FOR NEW SOURCES ASSOCIATED WITH THE PROJECT.

Stack Parameter	Units	100% Load				75% Load				50% Load			
		35°F	59°F	75°F	95°F	35°F	59°F	75°F	95°F	35°F	59°F	75°F	95°F
Height	ft	149	149	149	149	149	149	149	149	149	149	149	149
Diameter	ft	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6
Firing Natural Gas													
Exit Temp	°F	177	180	182	184	171	171	176	182	168	169	172	178
Exit Velocity	ft/sec	49.9	50.8	50.3	50.1	39.9	39.4	39.4	39.4	32.8	32.3	32.2	31.9
Firing ULSD fuel oil													
Exit Temp	°F	205.4	203.8	208	213.1	191	188	193	194	175	174	177	180
Exit Velocity	ft/sec	55.3	53.8	53.9	54.6	42.3	40.8	41.6	39.1	32.3	31.0	31.2	29.6

13.2.3.5Results

The results of the SIL modeling that are summarized in **Table 23** indicate that refined cumulative source modeling is needed for the 1-hour average NO_2 and 24-hour average PM_{10} and $PM_{2.5}$ impacts to demonstrate compliance with the NAAQS. It should be noted that the SILs for $PM_{2.5}$ have been vacated and remanded to EPA. However, based on EPA guidance and given that the average $PM_{2.5}$ design values in the area of the project site are less than half of the applicable NAAQS (**Figure 9**), DEP is continuing to use the SILs in a manner consistent with previous permitting action.

TABLE 23 – MAXIMUM PREDICTED AIR QUALITY IMPACTS FOR THE PROJECT, COMPARED TO THE CLASS II SILS.

Pollutant	Averaging Time	Max Impact (µg/m^3)	SIL (µg/m^3)	Percent of SIL	Significant Impact?
CO	8-Hour	17.5	500	4%	No
	1-Hour	28.0	2000	1%	No
NO_2	Annual	0.61	1	61%	No
	1-Hour	**17.8**	**7.5**	**237%**	**Yes**
PM_{10}	Annual	0.20	1	20%	No
	24-Hour	**15.1**	**5**	**302%**	**Yes**
$PM_{2.5}$	Annual	0.21	0.3	70%	No
	24-Hour	**8.3**	**1.2**	**683%**	**Yes**
SO_2	Annual	0.18	1	18%	No
	24-hour	2.4	5	48%	No
	3-hour	4.6	25	18%	No
	1-hour	4.5	7.86	57%	No

13.2.4 *Cumulative Dispersion Modeling*

Cumulative source modeling that evaluates whether the combined air quality impacts from all nearby significant sources will comply with the NAAQS and increment for each pollutant is performed for each pollutant that exceeds the SIL. In order to assess cumulative impacts, the potential emissions from the most significant nearby sources are added to the modeling platform developed for the SIL analysis. A monitored background concentration intended to represent all non-modeled anthropogenic and natural pollutant sources is added to the results which are then compared to the NAAQS.

13.2.4.1Significant Impact Area

Receptor placement and the choice of which sources to explicitly model are based on the establishment of a significant impact area (SIA). The SIA is the area in which the proposed project has the potential to significantly contribute to a NAAQS exceedance, i.e. a circular area with a radius equal to the distance from the source to the most distant receptor with a modeled SIL violation. The radii of the SIAs for the 24-hr $PM_{2.5}$, 24-hr PM_{10}, and 1-hr NO_2 NAAQS analyses for this project were estimated to be 14.7 km, 4.7 km, and 8.6 km respectively.

13.2.4.2Background Source Choices

Background source emission data were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. EPA recommends that the list of explicitly modeled sources should remain small and that professional judgment should be used in the decision process. NO_X sources within 35 km of the modeling area and PM sources within 50 km were examined to determine whether significant impacts would be expected. The nearest source of NO_x with more than 5 TPY of emissions is more than 30 km from the project site. The nearest source of PM over 25 TPY is over 40 km away. Given this lack of large sources nearby, the Q/d screening method which utilizes the ratio of annual emissions to distance from the project to determine a rough estimate of potential significance resulted in the decision to not include any explicitly modeled background sources in the cumulative modeling demonstrations. This is supported by recent EPA guidance suggesting that any source more than 10 km from the project site is unlikely to have a significant impact in the modeled area on timescales as short as 1 hour.

13.2.4.3Background Development and Monitors

The background concentration is based on monitoring data and is designed to take into account all existing natural or anthropogenic sources that are not explicitly modeled. There are a variety of ways to develop a background concentration that differ in complexity and conservatism. For this project, the least complex, most

conservative method was utilized. The background concentration added to the model results was simply the design value for the nearest NO_2, PM_{10}, or $PM_{2.5}$ monitor.

13.2.4.4NO_2 NAAQS

The NO_2 NAAQS analysis is more complex than for other pollutants. This is mainly due to the fact that the emitted pollutant, NO_X, is not the controlled pollutant, NO_2. NO_X is the sum of the nitrogen-oxide species NO and NO_2. In general, a large portion of the NO_X emitted from sources is NO. Once the plume leaves the stack, oxidation reactions between NO and ozone in the ambient air convert a certain amount of the NO to NO_2. EPA guidance acknowledges the complexity and issues involved with this analysis and recommends a three-tiered approach to determining the ratio of NO_2 to NO_X, both in-stack and in the ambient air:

- Tier 1: 100% conversion of NO to NO_2;
- Tier 2: 80% ambient conversion of NO to NO_2 on an hourly average and 75% on an annual average;
- Tier 3: Default in-stack ratios of 50% conversion (or lower if defensible) with up to 90% ambient conversion utilizing either the ozone limiting method (OLM) or plume volume molar ratio method (PVMRM) algorithms.

For this analysis, the Tier 2 method, also called the Ambient Ratio Method (ARM), was utilized and the results in **Table 24** demonstrate that the project is not expected to cause or significantly contribute to an exceedance of the NO_2 NAAQS.

13.2.4.5$PM_{2.5}$ and PM_{10} NAAQS

The $PM_{2.5}$ NAAQS analysis is also more complicated than for other pollutants. $PM_{2.5}$ is directly emitted by sources, 'primary $PM_{2.5}$, but is also created in the free atmosphere by other processes such as condensation of other pollutants. This 'secondary $PM_{2.5}$' cannot be modeled with AERMOD due to the complex chemistry involved and is discussed in a later section. The results of the cumulative analysis of direct $PM_{2.5}$ and PM_{10} (**Table 24**) demonstrate that the project is not expected to cause or significantly contribute to an exceedance of the NAAQS for either $PM_{2.5}$ or PM_{10}.

TABLE 24 – CUMULATIVE MODELING RESULTS FOR THE PROJECT COMPARED TO THE NAAQS.

Pollutant	Averaging Time	Maximum Concentration (µg/m^3)			NAAQS (µg/m^3)	Percent of NAAQS
		Sources	Background	Total		
NO_2	1-Hour	12.0	65.8	77.8	188	41%
$PM_{2.5}$	24-Hour	4.5	17	21.5	35	61%
PM_{10}	24-Hour	6.6	76	82.6	150	55%

13.2.4.6Class II Increment Analysis

The PSD increment represents the limit above an established baseline concentration that new sources may increase the local ambient ground level concentrations of a pollutant. PSD increment modeling is similar to NAAQS modeling in that it is a cumulative analysis that takes into account the impact from nearby increment consuming sources, only a background concentration is not added. A PSD increment has not yet been established for the 1-hour NO_2 standard; therefore, PSD increment analyses are necessary only for 24-hour average PM_{10} and $PM_{2.5}$ impacts for this project. Five years were modeled individually using AERMOD, including all of the same modeling parameters from the NAAQS analyses and no background sources, and the highest annual, second-high concentrations were then compared to the increment. The results shown in **Table 25** indicate that no exceedance of an allowable PSD Class II increment is expected for this project.

TABLE 25 –MODELING RESULTS FOR THE PROJECT COMPARED TO THE ALLOWABLE PSD CLASS II INCREMENTS.

Pollutant	Averaging Time	Max Concentration (µg/m^3)	Increment (µg/m^3)	Increment Consumed
$PM_{2.5}$	24-Hour	7.6	9	84%
PM_{10}	24-Hour	8.0	30	27%

13.2.5 *Class I Analysis*

All areas not explicitly designated as Class I in 40 CFR 81 Subpart D (such as national parks and wilderness areas) are considered Class II areas. While the NAAQS apply to all areas equally, more stringent SILs and increments exist for Class I areas. A Class I analysis is required for any project that may affect a Federal Class I area. The Class I areas closest to the project site are Everglades National Park (ENP), 203 km to the south and Chassahowitzka National Wilderness Area (CNWA), 211 km to the northwest (**Figure 10**). There are no other Class I areas within 350 km of the site.

13.2.5.1Class I SIL Analysis

The CALPUFF model was used to evaluate the Class I SILs for the $PM_{2.5}$ and PM_{10} 24-hour and annual averages, the NO_2 annual average, and the SO_2 annual, 24-hour, and 3-hour averages. The EPA-approved CALPUFF v.5.8.4 was processed with a CALMET meteorological dataset developed by the Federal Land Managers (FLMs) and provided by DEP. This dataset is comprised of a domain encompassing all of Florida with a 4 km horizontal resolution and spans the years 2001-2003. Post-processing was performed with CALPOST v.6.221. All regulatory options and building downwash were utilized. The receptor grid was created and provided by the FLMs and includes 901 receptors in ENP and 113 receptors in CNWA. The results shown in **Table 26** and **Table 27** indicate that a cumulative Class I increment analysis is required for 24-hour $PM_{2.5}$ at both CNWA and ENP.

TABLE 26 – MAXIMUM PREDICTED AIR QUALITY IMPACTS AT ENP FOR THE PROJECT COMPARED TO THE CLASS I SILS.

Pollutant	Averaging Time	Max Impact (µg/m^3)	SIL (µg/m^3)	Percent of SIL	Significant Impact?
NO_2	Annual	0.001	0.1	1.0%	No
PM_{10}	Annual	0.0036	0.2	1.8%	No
	24-Hour	0.146	0.3	49%	No
$PM_{2.5}$	Annual	0.004	0.06	6.7%	No
	24-Hour	**0.146**	**0.07**	**209%**	**Yes**
SO_2	Annual	0.001	0.1	1.0%	No
	24-Hour	0.030	0.2	15%	No
	3-Hour	0.067	1.0	6.7%	No

TABLE 27 – MAXIMUM PREDICTED AIR QUALITY IMPACTS AT CNWA FOR THE PROJECT COMPARED TO THE CLASS I SILS.

Pollutant	Averaging Time	Max Impact (µg/m^3)	SIL (µg/m^3)	Percent of SIL	Significant Impact?
NO_2	Annual	0.003	0.1	3.0%	No
PM_{10}	Annual	0.0062	0.2	31%	No
	24-Hour	0.099	0.3	33%	No
$PM_{2.5}$	Annual	0.006	0.06	10%	No
	24-Hour	**0.099**	**0.07**	**141%**	**Yes**
SO_2	Annual	0.001	0.1	1.0%	No
	24-Hour	0.024	0.2	12%	No
	3-Hour	0.079	1.0	7.9%	No

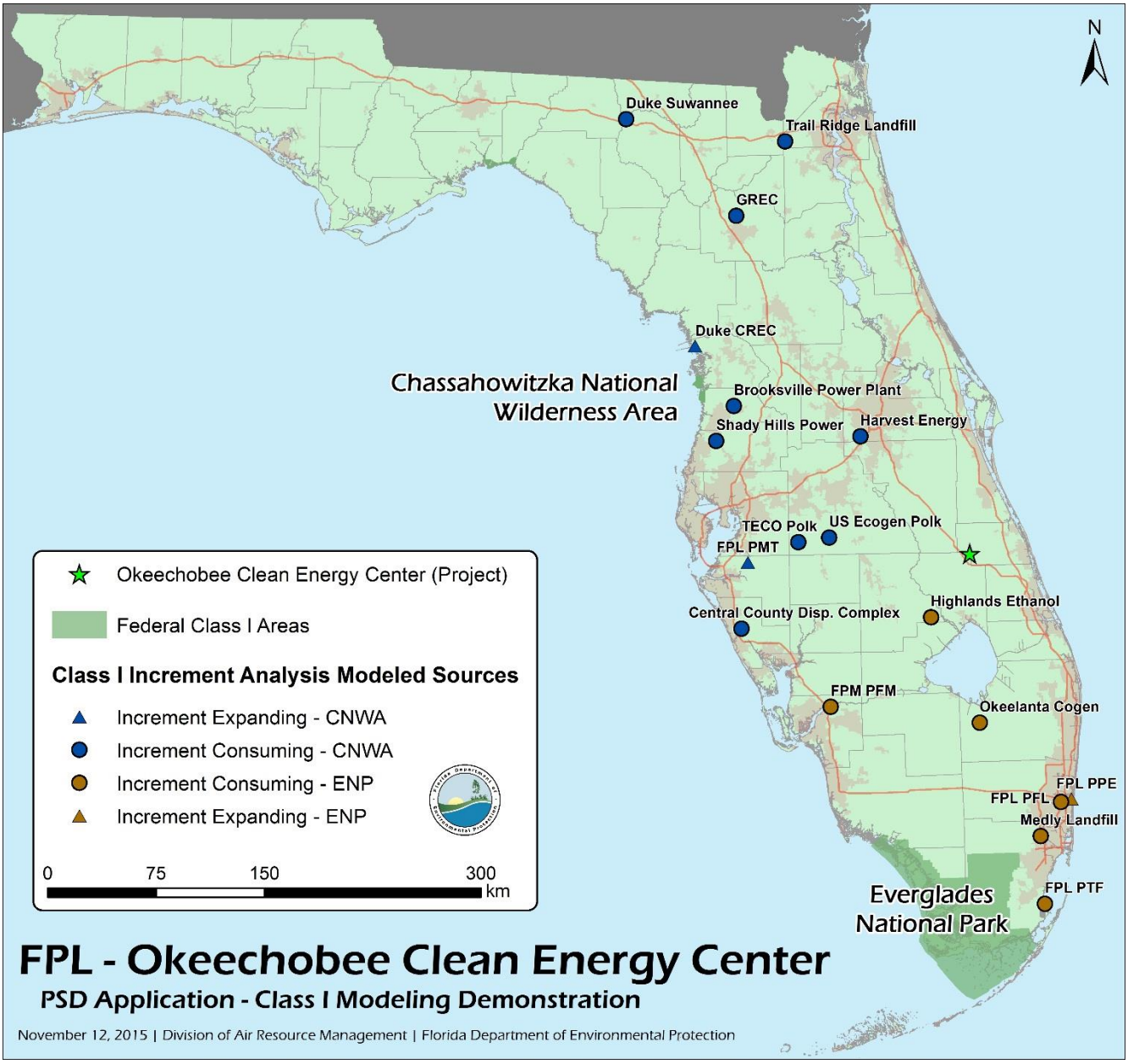

Figure 10. Map of federal Class I areas near the project site and all sources included in the PSD Class I Increment Analysis.

13.2.5.2Class I Increment Analysis

The Class I PSD increment analysis is similar to the Class II analysis except that it is performed only in the Class I areas. Due to the long distance between the project site and the nearest Class I areas, ENP and CNWA, CALPUFF was used to evaluate the 24-hour $PM_{2.5}$ Class I increment.

The following assumptions were made by the applicant in preparing the background source inventory:

- $PM_{2.5}$ emissions were assumed to be equal to PM_{10} emissions unless $PM_{2.5}$ emissions were available;

- Increment consuming sources were modeled at the maximum permitted rate; if permitted rates were not available, potential emissions were calculated;
- Increment expanding sources were modeled using actual emissions;
- Condensable $PM_{2.5}$ emissions were calculated, when available, and added to the filterable emission for increment consuming sources;
- SO_2 and NO_x emissions were included for each source in order to calculate secondary $PM_{2.5}$ formation
- Where available, SAM emissions were entered as primary sulfate; if not, they were assumed to be 10% of emitted SO_2.

Permitted facilities within 200 km of each Class I area were analyzed to determine potential significance. In general, sources not chosen to be modeled either have minimal $PM_{2.5}$ emissions (1 lb/hr or less) or emit less than 500 TPY and are located more than 25 km from a Class I area. The final background source inventories are summarized below in **Table 28** and illustrated in **Figure 10.**

TABLE 28 – BACKGROUND SOURCE INVENTORIES FOR 24-HOUR $PM_{2.5}$ PSD CLASS I INCREMENT ANALYSES.

Facility		UTM Coordinates (km)		Applicable Class I Area		Modeled Maximum $PM_{2.5}$ Emissions (TPY)		
ID	Description	East	North	Name	Dist. (km)	Consuming	Expanding	Net Change
053-0380	Brooksville Power	360.00	3,162.50	CNWA	22.20	33.30	-	33.00
017-0004	Duke Crystal River	334.30	3,204.50	CNWA	29.90	184.00	(1,915.40)	(1,731.00)
101-0373	Shady Hills	347.00	3,139.00	CNWA	37.70	297.80	-	298.00
095-1340	Harvest Energy	447.25	3,139.41	CNWA	110.90	4.20	-	4.00
001-0131	GREC	365.01	3,293.83	CNWA	120.20	58.30	-	58.00
105-0233	TECO - Polk	402.45	3,067.36	CNWA	124.30	332.90	(134.60)	198.00
081-0010	FPL PMT	367.15	3,054.23	CNWA	124.50	-	(5,304.20)	(5,304.00)
105-0444	U.S. Ecogen Polk	424.01	3,069.93	CNWA	134.10	97.20	-	97.00
115-0089	Central County SW	361.63	3,008.57	CNWA	169.20	20.80	-	21.00
031-0358	Trail Ridge Landfill	399.51	3,344.04	CNWA	178.30	20.70	-	21.00
121-0003	Duke Suwannee	290.66	3,362.12	CNWA	194.10	332.00	-	332.00
				CNWA Total Emissions		1,381.20	(7,354.20)	(5,973.00)
025-0615	Medley Landfill	565.04	2,860.02	ENP	20.60	31.00	-	31.00
025-0003	FPL PTF	567.20	2,813.20	ENP	20.80	0.03	-	0.03
011-0037	FPL PFL	580.24	2,883.61	ENP	47.70	1,095.00	(539.00)	556.00
011-0036	FPL PPE	587.40	2,885.30	ENP	54.00	576.00	(1,176.00)	(601.00)
099-0332	Okeelanta Cogen	524.90	2,940.10	ENP	91.80	27.00	-	27.00
071-0002	FPL PFM	422.30	2,952.00	ENP	95.70	438.00	(283.00)	155.00
055-0061	Highlands Ethanol	493.20	3,013.20	ENP	155.00	28.00	-	28.00
				ENP Total Emissions		2,195.03	(1,998.00)	196.03

The total amount of consumed increment was calculated as the sum of primary and secondary $PM_{2.5}$ consumed increment. To be conservative, the increment expansion of secondary $PM_{2.5}$ due to significant local reductions of NO_x and SO_2 emissions were not included. The results from the 24-hour $PM_{2.5}$ increment analysis are presented in **Table 29**. The total predicted consumed increment due to all sources is less than the applicable Class I PSD increment at both ENP and CNWA.

TABLE 29 – PREDICTED 24-HOUR $PM_{2.5}$ IMPACTS FOR THE PROJECT COMPARED TO THE CLASS I INCREMENTS.

Class I Area	Predicted Consumed Primary PM2.5			Predicted Consumed Secondary PM2.5			Total Predicted Consumed PM2.5			Max Increment Consumed
	2001	2002	2003	2001	2002	2003	2001	2002	2003	
ENP	0.11	0.08	0.08	0.11	0.15	0.21	0.22	0.23	0.29	15%
CNWA	0.14	0.16	0.11	0.23	0.25	0.19	0.37	0.41	0.30	21%

13.2.6 *Ozone Analysis*

Projects with VOC or NO_X potential emissions increases of 40 TPY or greater are required to perform a source impact analysis for ozone. The applicant estimated maximum annual potential VOC and NO_X emissions from the project to be 71.4 and 398 TPY respectively and is therefore required to provide an analysis for ozone; however, ozone site-specific modeling is not typically completed for single source permitting because of its complexity involving computationally intensive models such as the Community Model for Air Quality (CMAQ) and the Weather Research and Forecasting Model (WRF).

Ozone is a secondarily formed pollutant that is known to be caused by the regional emissions of VOC and NO_X in combination with certain meteorological conditions (temperature, humidity, solar insolation, etc.). Ambient ozone levels in Okeechobee County, as inferred from monitors in neighboring counties (62 ppb in the much more urban Brevard and Palm Beach counties), are well within attainment of even the recently promulgated 70 ppb 2015 ozone NAAQS. As previously shown in **Figure 7**, actual emissions of ozone precursors have declined dramatically over the past ten years despite significant increases in population. These reductions are far greater than the increase in VOC and NO_x emissions from this project. Ambient levels of ozone have also decreased over the last 15 years (**Figure 11**) due to improvements in motor vehicle emissions rates and the implementation of national rules such as the Clean Air Interstate Rule (CAIR) and continued reductions in both average motor vehicle fleet emissions and stationary source emissions are expected to further improve ozone air quality.

For these reasons, DEP has reasonable assurance that the project will not significantly contribute to or cause any violation of the ozone NAAQS.

13.2.7 *Secondary $PM_{2.5}$ Analysis*

Secondary $PM_{2.5}$ is formed through chemical reactions involving gaseous precursors such as SO_2 and NO_X. Projects that involve a potential increase in these precursor pollutants above their SER require an analysis of the potential impact of secondary $PM_{2.5}$ formation; however, current regulatory air dispersion and transport models, such as the EPA recommended AERMOD modeling system used in this analysis, do not account for these processes. Per EPA guidance, for projects "where precursor emissions levels are marginally higher than the level of the SERs, monitored background levels are very low, and the primary $PM_{2.5}$ impacts are also very low or not correlated in space and time with secondary formation such that the combination of the background and primary impacts are still well below the level of the NAAQS," a qualitative assessment of secondary $PM_{2.5}$ formation is sufficient.

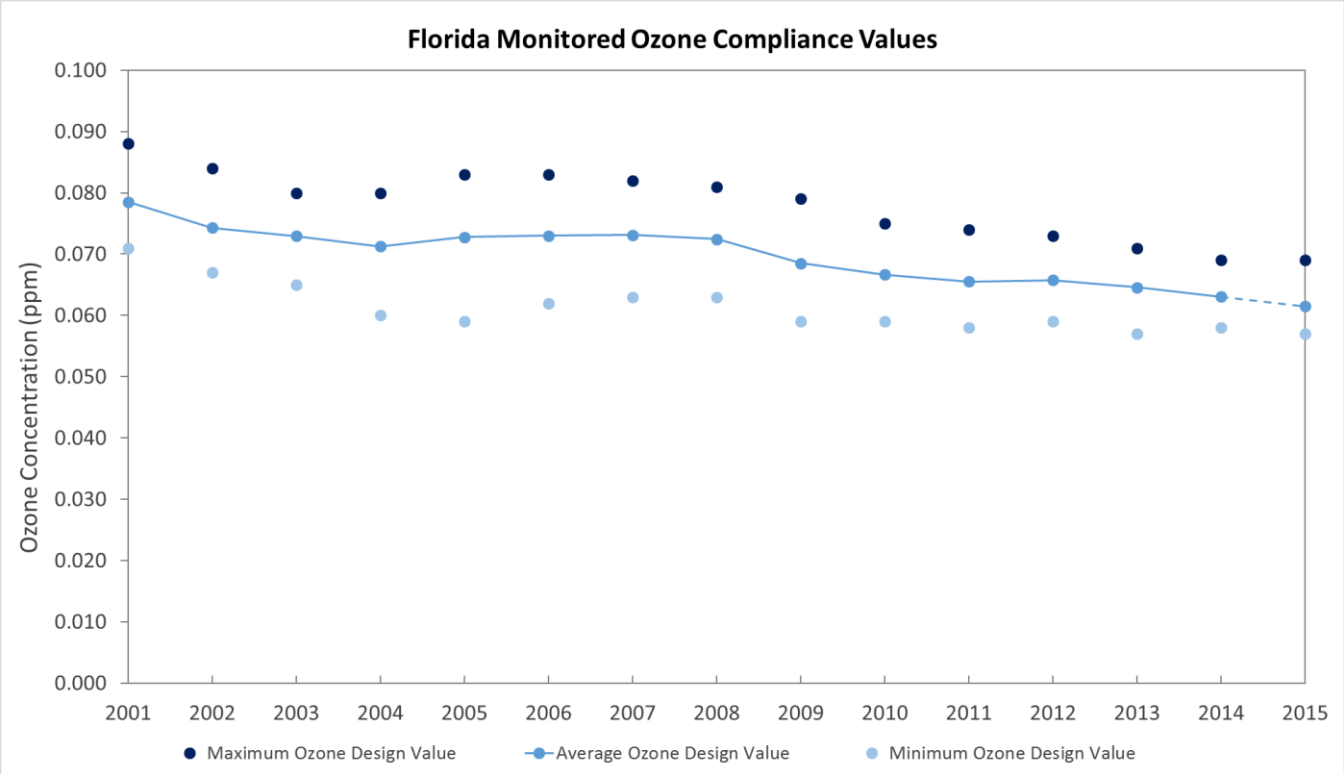

Figure 11. Florida monitored ambient ozone concentration trend 2001-2015.

The project has predicted maximum annual potential emissions of 254 tons of SO_2, 398 tons of NO_X, and 71.4 tons of VOC. The formation of secondary $PM_{2.5}$ from these emissions is expected to be minimal. Secondary $PM_{2.5}$ formation occurs slowly through time causing the impact to be more widespread and diffuse than the impact from direct $PM_{2.5}$ emissions. The air quality, with respect to particulate matter, in Okeechobee County, as inferred from monitors in neighboring counties (design values for 24-hour/Annual $PM_{2.5}$ are 16/5.9 µg/m^3 for Brevard County and 13/5.4 µg/m^3 for Palm Beach County), is very good and the project is not expected to have a significant negative impact for several reasons: as previously mentioned, statewide emissions of NO_X and SO_2 have decreased dramatically in the past decade and **Figure 7** shows that these decreases are orders of magnitude larger than the small increase in emissions from the proposed project; the monitored $PM_{2.5}$ design values in the vicinity are well within attainment (**Table 20**); statewide monitored concentrations have fallen significantly in the past decade (**Figure 12**); and there are very few sources of either direct $PM_{2.5}$ or $PM_{2.5}$ precursors in Okeechobee County (**Table 15 - Table 19**).

Given these factors, DEP has reasonable assurance that the proposed project will not significantly contribute to or cause any violation of a NAAQS or increment with respect to secondary $PM_{2.5}$ formation.

13.3 Additional Impacts Analysis

The applicant is required by Rule 62-212.400(8), F.A.C. to provide an analysis of the project's potential impacts on visibility, soils, vegetation, and wildlife due to the proposed project or any general commercial, residential, or industrial growth associated with the project.

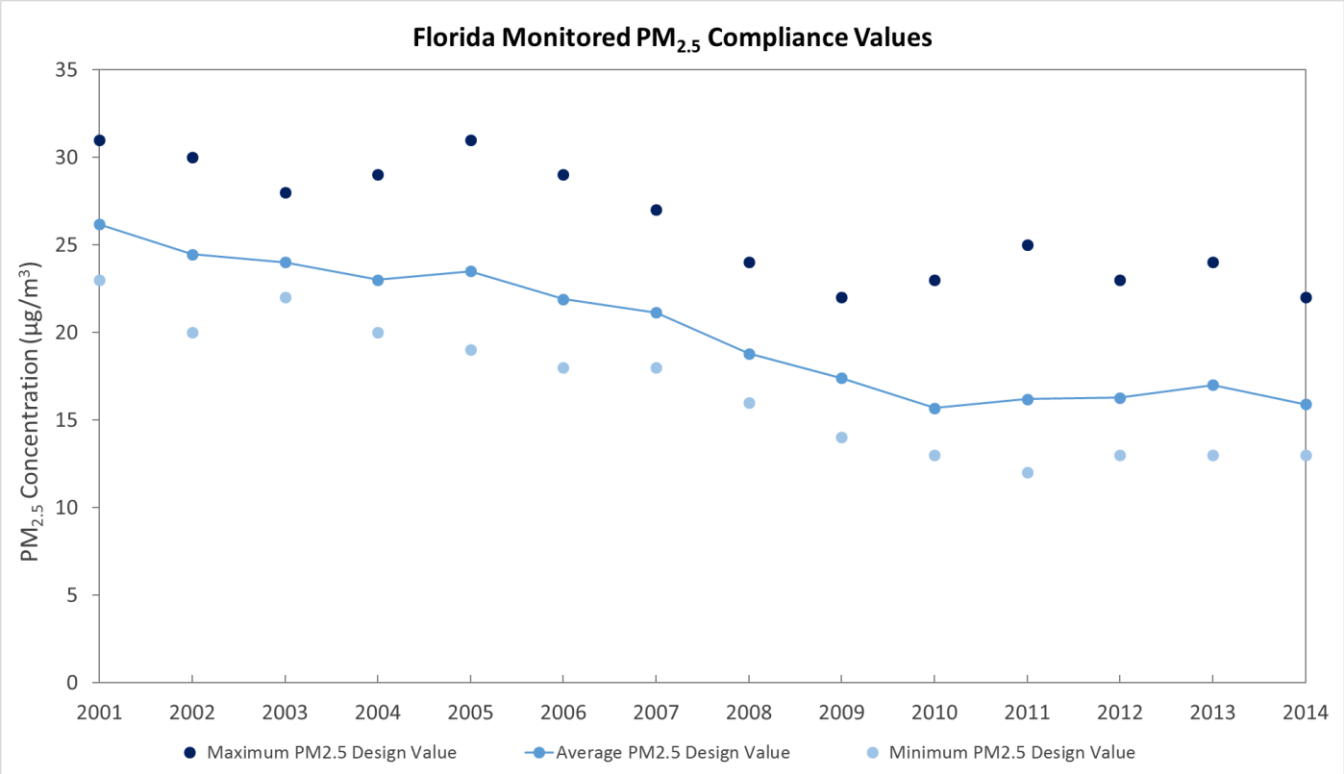

Figure 12. Florida monitored ambient $PM_{2.5}$ concentration trend 2001-2014.

13.3.1 *Growth*

The 18-24 month construction phase of this project will require approximately 290 workers to commute to the site. Once construction is complete, about 30 permanent personnel will remain. This is a small fraction of the population in the area and no air quality impacts are expected from the small increase in vehicular traffic. Operation of the facility is not expected to result in any commercial or industrial growth in the area because existing commercial and industrial infrastructure is more than sufficient to meet the needs of the facility.

13.3.2 *Soils, Vegetation, and Wildlife*

Emissions of pollutants have the potential to negatively affect soils, vegetation and wildlife near sources. The project's maximum predicted air quality impacts are less than the NAAQS which were established to protect both public health and welfare. In addition, secondary NAAQS have been set to protect against visibility impairment and damage to animals, crops, vegetation, and buildings. All ambient air quality impacts from the project have been predicted to remain well below the applicable secondary NAAQS as well and therefore the impact on soils, vegetation, and wildlife is expected to be negligible.

13.3.3 *Class I AQRV*

The Federal Land Manager (FLM) for every Class I area that may be affected by a source is charged with protecting all air quality related values (AQRV), including visibility and deposition, in that area. An AQRV analysis is generally required for all PSD projects and the applicant completed such an analysis for this project using CALPUFF for both ENP and CNWA.

13.3.3.1Visibility Analysis

For distances greater than 50 km, visibility impairment is considered to take the form of regional haze rather than a distinct plume. The visibility degradation in ENP and CNWA is based on a change in the light-extinction coefficient which is the attenuation of light per unit distance due to scattering and absorption by gases and

particles in the atmosphere. The visibility threshold at each receptor is met if the 98th percentile daily average change in light extinction is less than 5% or 0.5 deciview (dv) for each modeled year.

The visibility analysis followed the most recent guidance from the FLM's AQRV Workgroup (FLAG) Phase I Report. CALPOST was used to predict visibility impairment based on the CALPUFF model outputs. CALPOST was run using Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5) and the background aerosol levels were derived from the 20% best natural days. Emissions were based on 24-hr maximum rates of SO_2, NO_2, PM, and sulfuric acid mist (SAM). ULSD fuel oil backup fuel emission rates were based on a conservative 24 hours per day, 365 days per year. In ENP, the predicted visibility impact due to the project was estimated to be just 0.051 dv when firing natural gas and 0.118 dv for ULSD fuel oil. In CNWA, the predicted visibility impact due to the project was estimated to be just 0.069 dv when firing natural gas and 0.126 dv for ULSD fuel oil. These values are well below the 0.5 dv threshold (**Table 30** and **Table 31**). As a result, the project is not expected to have an adverse impact on visibility in ENP or CNWA.

TABLE 30 – SUMMARY OF AQRV VISIBILITY ANALYSIS FOR THE PROJECT IN EVERGLADES NATIONAL PARK.

SCCT Operation	98th Percentile Visibility Impairment (dv)			Visibility Impairment Threshold (dv)	Max % of Threshold
	2001	2002	2003		
Natural Gas – 24 hours (Primary)	0.045	0.051	0.046	0.5	10%
ULSD fuel oil – 24 hours (Backup)	0.086	0.118	0.109	0.5	24%

TABLE 31 – SUMMARY OF AQRV VISIBILITY ANALYSIS FOR THE PROJECT IN CHASSAHOWITZKA NATIONAL WILDERNESS AREA.

SCCT Operation	98th Percentile Visibility Impairment (dv)			Visibility Impairment Threshold (dv)	Max % of Threshold
	2001	2002	2003		
Natural Gas – 24 hours (Primary)	0.059	0.069	0.058	0.5	14%
ULSD fuel oil – 24 hours (Backup)	0.118	0.126	0.120	0.5	25%

13.3.3.2Deposition Analysis

In addition to visibility impairment, total nitrogen and sulfur deposition is also a part of the AQRV analysis. Again, this analysis was performed using the CALPUFF model and followed the most recent FLM guidance. Annual average total deposition (wet and dry) of nitrogen and sulfur oxides were calculated to be far below the threshold of 0.01 kg/ha/yr. These results, summarized below in **Table 32** and **Table 33**, indicate that the project is not expected to have a significant impact with respect to deposition in ENP or CNWA.

TABLE 32 – SUMMARY OF AQRV DEPOSITION ANALYSIS FOR THE PROJECT IN EVERGLADES NATIONAL PARK.

SCCT Operation	Deposition Type	Average Annual Deposition (kg/ha/yr)			Deposition Threshold (kg/ha/yr)	Max % of Threshold
		2001	2002	2003		
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Sulfur	0.0006	0.0009	0.0006	0.01	9.0%
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Nitrogen	0.0002	0.0005	0.0004	0.01	5.0%
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Total	0.0008	0.0014	0.0010	0.01	14.0%

TABLE 33 – SUMMARY OF AQRV DEPOSITION ANALYSIS FOR THE PROJECT IN CHASSAHOWITZKA NATIONAL WILDNERNESS AREA.

SCCT Operation	Deposition Type	Average Annual Deposition (kg/ha/yr)			Deposition Threshold (kg/ha/yr)	Max % of Threshold
		2001	2002	2003		
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Sulfur	0.0013	0.0019	0.0016	0.01	19.0%
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Nitrogen	0.0008	0.0011	0.0010	0.01	11.0%
Natural Gas – 8,260 hours/year ULSD fuel oil – 500 hours/year	Total	0.0021	0.0030	0.0026	0.01	30.0%

13.4 Conclusion

Based on the results presented in the air quality impact analysis, the Department has reasonable assurance that the increased pollutant emissions associated with the project will not cause or significantly contribute to any violation of a NAAQS or PSD increment; in addition, the Department finds that there will be no adverse impact on soils, vegetation, wildlife, or AQRVs in Class I areas.

14. 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 application, reasonable assurances provided by the applicant, and the conditions specified in the Draft Permit. John Dawson is the project engineer responsible for reviewing the application and drafting the permit. Brian Himes is the meteorologist responsible for reviewing and approving the ambient air quality analyses. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 by phone at 850-717-9085 or by email at john.dawson@dep.state.fl.us.