FPL.

May 7, 2015

Jeffery Koerner, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air resource Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: FPL Fort Myers Combustion Turbine (CT) Peaker Project
FDEP Facility 0710002
Air Construction/PSD Permit Application

Dear Mr. Koerner:

Please find enclosed an Air Construction/PSD Application for the Fort Myers CT Peaker Project (Project) that would replace the generation of 10 existing gas turbines (GTs) with two highly efficient and lower emitting CTs at the Fort Myers Power Plant. Also enclosed is a $7,500 check (No. 5000367749) for processing a PSD Application.

Applications for three CTs were submitted in July 2013 to FDEP for an Air Construction/PSD Permit for non-greenhouse gases (GHG) and to EPA Region IV for PSD review of GHG (Reference FDEP Project Number 0710002-019-AC/PSD-FL-424.) These applications were withdrawn in December 2013. FPL plans to go forward with two CTs at the Fort Myers Plant to replace the generation of 10 gas turbines. In addition, FPL has selected the CT vendor (General Electric). Two of the existing GTs at the Fort Myers Plant will be retained for black start capability and generation. The black start diesel generators originally contemplated in 2013 will not be part of this applicaton.

We look forward to working with FDEP on this Project. If you have any comments or questions regarding the attached application, please feel free to contact Ken Proctor at (561) 691-7068. You may also contact John Hampp at (561) 691-2894 for technical questions.

Sincerely,
Florida Power & Light Company

Matthew J. Raffenberg

Matthew J. Raffenberg
Director of Environmental Licensing and Permitting

cc: Randall LaBauve, FPL
Ken Proctor, FPL
Scott Goorland, Esq., FPL
Ken Kosky, Golder Associates

REPORT

# AIR CONSTRUCTION PERMIT APPLICATION FOR THE FLORIDA POWER & LIGHT COMPANY FORT MYERS COMBUSTION TURBINE PEAKER PROJECT LEE COUNTY, FLORIDA


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## List of Acronyms

| | |
|---|---|
| °C | degrees Celsius |
| °F | degrees Fahrenheit |
| $\mu g/m^3$ | micrograms per cubic meter |
| AAQS | Ambient Air Quality Standards |
| AERMOD | American Meteorological Society and U.S. Environmental Protection Agency Regulatory Model |
| AOR | Annual Operating Report |
| AQRV | air quality related value |
| BACT | Best Available Control Technology |
| BPIP | Building Profile Impact Program |
| Btu/lb | British thermal unit per pound |
| Btu/kWh | British thermal unit per kilowatt hour |
| Btu/scf | British thermal unit per standard cubic foot |
| CAA | Clean Air Act |
| CEM | continuous emissions monitoring |
| cf/yr | cubic foot per year |
| CFR | Code of Federal Regulations |
| $CH_4$ | methane |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| $CO_2e$ | carbon dioxide equivalent |
| CT | combustion turbine |
| DLE | dry low emissions |
| ENP | Everglades National Park |
| EPA | U.S. Environmental Protection Agency |
| F.A.C. | Florida Administrative Code |
| FDEP | Florida Department of Environmental Protection |
| FGT | Florida Gas Transmission Company, LLC |
| FIU | Florida International University |
| FPL | Florida Power & Light |
| ft | foot |
| FR | Federal Register |
| FFFSGU | fossil fuel fired steam generating unit |
| g/bhp-hr | grams per brake horsepower-hour |
| g/s | grams per second |
| GEP | Good Engineering Practice |
| gr/100 scf | grains per 100 standard cubic feet |
| GT | Gas Turbines, (typically referred to the older existing machines on the Project Site) |
| GHG | greenhouse gas |
| HAP | hazardous air pollutant |

| | |
|---|---|
| HFCs | hydrofluorocarbons |
| HHV | higher heating value |
| hp | horsepower |
| hr/yr | hours per year |
| HRSG | heat recovery steam generator |
| HSH | highest, second highest |
| Hz | hertz |
| I | Interstate highway |
| ICW | Intracoastal Waterway |
| km | kilometer |
| kW | kilowatt |
| lb/hr | pound per hour |
| lb/MMBtu | pound per million British thermal units |
| lb/MW-hr | pound per megawatt-hour |
| LHV | lower heating value |
| m | meter |
| MACT | Maximum Available Control Technology |
| MMBtu/hr | million British thermal units per hour |
| MMcf/hr | million cubic feet per hour |
| MPS | Mitsubishi Power Systems |
| MW | megawatt |
| NAAQS | National Ambient Air Quality Standards |
| NAD83 | North American Datum 83 |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| $N_2O$ | nitrous oxide |
| $NO_2$ | nitrogen dioxide |
| $NO_x$ | nitrogen oxides |
| NP | National Park |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| NWA | National Wilderness Area |
| NWS | National Weather Service |
| $O_2$ | oxygen |
| PFCs | perfluorocarbons |
| PFM | Plant Fort Myers the abbreviation for the FPL Fort Myers Plant |
| PM | particulate matter |
| $PM_{2.5}$ | particulate matter less than 2.5 microns |
| $PM_{10}$ | particulate matter less than 10 microns |
| ppb | parts per billion |
| ppbvd | parts per billion by volume dry |
| ppm | parts per million |

| | |
|---|---|
| ppmvd | parts per million by volume dry |
| PSD | Prevention of Significant Deterioration |
| psia | pound per square inch absolute |
| psig | pound per square inch gauge |
| QA/QC | quality assurance/quality control |
| RICE | reciprocating internal combustion engines |
| SAM | sulfuric acid mist |
| scf/yr | standard cubic foot per year |
| SCR | selective catalytic reduction |
| SCRAM | Support Center for Regulatory Air Models |
| SER | significant emissions rate |
| SIL | significant impact level |
| $SF_6$ | sulfur hexafluoride |
| $SO_2$ | sulfur dioxide |
| S.R. | State Road |
| ST | steam turbine |
| TPY | tons per year |
| TSP | total suspended particulate |
| TTN | Technology Transfer Network |
| ULSD | ultra low sulfur distillate “light oil” |
| USGS | U.S. Geological Survey |
| UTM | Universal Transverse Mercator |
| VOC | volatile organic compound |
| WCEC | West County Energy Center |

## 1.0 INTRODUCTION

Florida Power & Light Company's (FPL's) existing Fort Myers Plant is located in Lee County Florida (see Figure 1-1) and includes one block of 12 simple cycle gas turbines (GT1 through GT12). GT Units 1 through 12 (EUs 003 through 014) began operation in May 1974. Each GT has a gross capacity of 63 megawatts (MWs). GT Units 1 through 12 are currently authorized to operate under Florida Department of Environmental Protection (FDEP) Title V Permit No. 0710002-018-AV on No. 2 distillate oil and specification used oil.

FPL planned in 2013 to bring three new CTs into service at Fort Myers Plant to replace the 12 GTs and submitted an Air Construction/Prevention of Significant Deterioration (PSD) application to FDEP in July 2013. A separate PSD Permit application was submitted to EPA Region 4 for Greenhouse Gases (GHGs) since FDEP did not have authority for PSD review of GHGs at the time. These applications were withdrawn [FDEP Project No. 0710002-019-AC (PSD-FL-424)].

FPL now plans on going forward with the Fort Myers Combustion Turbine Peaker Project (i.e., "Project") using specific combustion turbines selected for the Project now installing two CTs. In addition, FPL has decided to keep two of the existing GTs at the Fort Myers Plant for black start capability and the generation, and black start diesel generators originally contemplated will no longer be part of the Project.

This Air Construction Permit/Prevention of Significant Deterioration (PSD) Application consists of two nominal 200 MW combustion turbines (CTs) that will replace 10 existing GTs, effectively changing out the combustion technology of FPL's peaking resources to reduce emissions. These two CTs will be located at FPL's Fort Myers Plant and will be referred to as the Fort Myers CT Peaker Project ("Project"). The new CTs will be designated Units 3C and 3D.

Decommissioning of ten of the existing GTs will occur after the new CTs are operational in order to maintain peak service capability in southwest Florida. There will be no overlap of operation between 10 of the existing GT units and the new CTs, after the new CTs become operational.

There will be significant benefits associated with the Project. The two new CTs will be more energy efficient than the existing 10 GTs and will provide cleaner energy to FPL's customers. For the same amount of generation, the new CTs will use 30 percent less fuel and have approximately 90 percent lower $NO_X$ emission rates. The maximum total air quality impacts for the Project are predicted to be well below existing levels and in compliance with the new NAAQS for $NO_2$. For pollutants such as $NO_2$, the Project's total air quality impacts are predicted to be significantly (40 percent or more) lower, than those predicted for the existing GTs.

The CTs being proposed for the Project are the General Electric 7F.05 CTs. Each CT will utilize inlet air cooling consisting of evaporative cooling and wet compression. Evaporative cooling systems achieve adiabatic cooling using water in the form of water evaporated from evaporative cooling media. The evaporating water cools the inlet air stream when the water droplets are converted to water vapor. Inlet air temperature is reduced as heat is transferred at a rate of 1,075 British thermal units per pound (Btu/lb) of evaporated water. The result is a cooler, denser air stream, allowing additional power to be produced. Wet compression introduces water droplets near the compressor inlet resulting in increased power through compressed air cooling and increased mass flow. The CTs will use natural gas and ultra low sulfur distillate (ULSD) oil as fuel. ULSD oil will be used for up to the equivalent of 500 hours per year (hr/yr) per CT at base load conditions..

Natural gas will be transported to the facility via pipeline. ULSD oil will be delivered to the facility by truck and will be stored in two existing fuel oil storage tanks.

The U.S. Environmental Protection Agency's (EPA's) PSD regulations are promulgated under Title 40, Part 51.166 of the Code of Federal Regulations (40 CFR 51.166). Florida's PSD regulations are codified in FDEP Rule 62-212.400, Florida Administrative Code (F.A.C.), and have been approved by EPA. The Florida PSD regulations incorporate the requirements of EPA's PSD regulations. Under these requirements, the existing Fort Myers Plant is classified as an existing major facility. A modification to an existing major facility that results in a significant net emissions increase equal to or exceeding the significant emissions rates (SERs) listed in the Florida regulations under Section 62-212.400, Table 62-212.400-2, F.A.C., is classified as a major modification and will be subject to the PSD preconstruction permitting program for those pollutants that exceed the PSD SERs.

The procedures for determining applicability of the PSD permitting program to the Project are specified in FDEP Rule 62-212.400(2), F.A.C. For each regulated pollutant, PSD is triggered as a result of a modification at an existing facility if the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the SER for that pollutant. For a new emission unit, the potential emissions for the new emission unit is compared to the SER.

On June 3, 2010, EPA promulgated regulations related to PSD and Title V GHG Tailoring Rule [75 Federal Register (FR) 31514-31608]. This change in EPA's PSD regulations requires PSD review and approval for new major projects and modifications exceeding the PSD thresholds for review. This application includes information to address PSD review of GHGs under EPA's rules and the Supreme Court Decision [*Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (Case No. 12-1146)]. FDEP received EPA-approval on May 19, 2014, for implementing the PSD program for

GHGs under Florida’s State Implementation submitted to EPA on December 19, 2013 (79 FR 28607.28612).

This Application is being filed for the purpose of obtaining an Air Construction/PSD permit for the Project in accordance with FDEP’s federally approved major source air construction permit program under Florida's federally required State Implementation Plan. This Air Construction Permit Application Report is divided into seven major sections.

- Section 1.0 presents an introduction to the Project
- Section 2.0 presents a description of the Project, including air emissions and stack parameters
- Section 3.0 provides a review of the regulatory analysis conducted, including PSD and nonattainment requirements, applicable to the Project
- Section 4.0 includes the control technology review including a Best Available Control Technology (BACT) analysis including GHG
- Section 5.0 discusses the ambient air monitoring analysis
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the Project with NAAQS and PSD Increments.
- Section 7.0 presents the additional impact analysis required for PSD review.
- Appendices which include emission calculations, BACT determinations and FDEP Form No. 62-210.900(1): Application for Air Permit – Long Form.

# 2.0 PROJECT DESCRIPTION

## 2.1 Facility Description

The existing FPL Fort Myers Plant is located within unincorporated Lee County, Florida. The existing plant is situated within approximately 460 acres of land owned by FPL. The facility is located on Palm Beach Boulevard (Site Road 80), Fort Myers, Florida. Figure 2-1 presents the conceptual facility plot plan for the Project.

## 2.2 New Combustion Turbines

The GE 7F.05 CTs will use low-$NO_x$ combustion technology or equivalent when firing natural gas and water injection when firing ULSD oil to minimize formation of $NO_x$. Natural gas and ULSD oil will be used as fuel. While FPL envisions that the new CTs will be operated as peaking and emergency capacity like the existing GTs, FPL is conservatively seeking permitting authority for maximum operation of 3,390 hr/yr (base load equivalent hours) for each CT of which ULSD oil usage is up to 500 hr/yr (base load equivalent hours) for each CT. This is an accepted operating assumption for permitting simple-cycle combustion turbine units in Florida.

## 2.3 Source Emission Units and Stack Parameters

The Project's air emission units are:

- Two simple cycle CTs
- Circuit breakers containing sulfur hexafluoride ($SF_6$)

Each of these emission units is discussed in the following paragraphs.

Estimated emissions for the GE 7F.05 CTs of non-GHG pollutants are presented in Tables 2-1 and 2-2, respectively, for natural gas and ULSD oil firing. Maximum potential annual emissions for the CTs are calculated for regulated air pollutants using a turbine inlet temperature of 59°F using evaporative cooling and wet compression. The CT performance using evaporative cooling and wet compression is relatively constant from 59$^{o}$ F to 95$^{o}$ F (or about a 2% output over the range). A turbine inlet temperature of 59°F is conservative, since the annual average temperature is about 75°F. To produce the maximum annual emissions, it is assumed that each CT would operate for 3,390 hours. Of the 3,390 operating hours, an average of 2,890 hr/yr is assumed to be natural gas firing. For the remaining average of 500 hr/yr, the CTs are assumed to operate on ULSD oil for reliability purposes. Table 2-3 presents a summary of potential emissions for various operating conditions such as turbine inlet temperature of the CTs.

A process flow diagram of the new CT configuration, operating at base load conditions with a compressor inlet temperature of 75°F, is presented in Figure 2-2.

A fundamental objective of the Project is to replace existing, first generation peaking capability in southwest Florida while reducing $NO_X$ emission rates. The GE 7F.05 has been selected for the Project meeting the requirements of BACT established by the FDEP Air Construction/PSD Permit. This will be achieved by state-of-the-art CT combustion technology that has $NO_X$ emission rates that achieve BACT emission levels for simple cycle CTs while rapidly producing highly efficient peaking generation. Therefore the CTs will achieve $NO_X$ concentrations determined as BACT while achieving emission limits of CO and VOCs also established as BACT. For the Project, the GE 7F.05 CTs will achieve NOx concentrations of 9 parts per million by volume dry (ppmvd) conditions, corrected to 15 percent oxygen ($O_2$) when firing natural gas and 42 ppmvd corrected to 15 percent $O_2$ when firing ULSD oil. In addition, for CO, the CTs when operating at base load to 90% load will achieve 4 ppmvd corrected to 15 percent $O_2$ when firing natural gas and 9 ppmvd corrected to 15 percent $O_2$ when firing ULSD oil. Corresponding VOC emissions must achieve emission rates of 1.4 ppmvw at base load operation when firing natural gas and 3.5 ppmvw when firing ULSD oil.

## 2.4 Annual Emissions for the Project including GHGs

On June 3, 2010, EPA promulgated regulations related to PSD and Title V Greenhouse Gas Tailoring Rule (75 FR 31514-31608). In EPA's promulgation, GHGs are defined to include an aggregate group of six GHGs: $CO_2$, $CH_4$, nitrous oxide ($N_2O$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and $SF_6$. Each of these GHGs has a specific Global Warming Potential that is calculated as "$CO_2$ equivalent emissions" or $CO_2e$ that is equivalent to one ton of $CO_2$.

For the Project, the GHGs emitted are $CO_2$, $CH_4$, and $N_2O$ with one ton of $CH_4$ equivalent to 25 tons of $CO_2e$ and one ton of $N_2O$ equivalent to 298 tons of $CO_2e$.

GHGs for the CTs were calculated based on the actual annual heat input and emission factors from 40 CFR 75, Appendix G for $CO_2$ and 40 CFR Part 98, Subpart C. These GHG emissions for the CTs are presented in Table 2-4 and show the total annual $CO_2e$ emissions for these pollutants. Table 2-5 presents a summary of the GHG emissions for the Project.

$SF_6$ is an electrical insulator and interrupter in equipment that transmits and distributes electricity. $SF_6$ has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulting oils. The Project will have circuit breakers containing $SF_6$.

Circuit breakers associated with the Project are estimated to contain approximately 125 lbs of $SF_6$. Based on the guaranteed leak rate, not to exceed 0.5 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 125 lb $SF_6$ x 0.005 leakage/year = 0.625 lb $SF_6$/year
- 0.625 lb $SF_6$/year x 22,800 equivalent carbon dioxide ($CO_2$e)/lb $SF_6$ (Table A-1, 40 CFR Part 98) = 14,250 lb $CO_2$e (7.1 tons $CO_2$e)

For PSD applicability purposes, the potential emissions from the Project are compared to PSD Significant Emission Rates in Table 2-6. This is consistent with FDEP Rule 62.212.400(2)(a)2. Since two of the existing GTs will remain for black start capability and generation, no emissions decreases are being assumed to occur for 10 of the existing GTs. Therefore, potential emissions from the project are being compared to the PSD Significant Emission Rates. The only change in additional PSD applicability in this approach from that considered in the Air Construction/PSD Permit is that PSD review is triggered by $SO_2$ emissions. The Supreme Court issued a decision that indicated that GHG alone could not trigger PSD review [*Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (Case No. 12-1146)]. Rather, PSD for GHGs could only be triggered if PSD were required for other air pollutants. PSD review is required for GHG emissions greater than the listed PSD threshold of 75,000 tons $CO_2$e and if PSD is also triggered for a non-GHG pollutant. As shown in Table 2-6, PSD review is applicable for $SO_2$, PM/$PM_{10}$/$PM_{2.5}$, $NO_x$, and GHGs; PSD review is required for GHGs since PSD review is required for a regulated PSD pollutant.

Table 2-7 presents a summary of emissions for hazardous air pollutants (HAPs). The Fort Myers Plant is a major source of HAPs based on the major source threshold of potential emissions of 10 TPY or more for a single HAP or 25 TPY or more for total HAPs. The Project's HAP emissions as shown in Table 2-7 are less than the major source thresholds for HAPs.

## 2.5 Layout, Structures, and Stack Sampling Facilities

A conceptual facility plot plan of the Project is presented in Figure 2-1. Typical dimensions of the structures associated with the CTs are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with FDEP Rule 62-297.310(6), F.A.C.

## 2.6 Proposed Conditions

FPL requests that the permit conditions for the combustion turbines associated with the Fort Myers CT Peaker Project be consistent with the permit conditions for the Lauderdale CT Peaker Project (FDEP Permit No. 0110037-011-AC; PSD-FL-423) with the revisions submitted to the Department on April 9, 2015 for that project. The CTs for Lauderdale and Fort Myers projects are the same model (GE 7F.05) with only minor differences in physical characteristics (i.e., stack height) and performance (slight difference in mass flow due to stack and internals).

# 3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to federal, state, and local air regulatory requirements and their applicability to the Project.

## 3.1 National, State, and Local AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary NAAQS were promulgated to protect the public health with an adequate margin of safety and secondary NAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with NAAQS are designated as attainment areas. New sources to be located or modified sources located in or near these areas may be subject to more stringent air permitting requirements.

## 3.2 PSD Requirements

### *3.2.1 General Requirements*

Under federally approved Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued.

PSD is applicable to a "major facility" and certain "modifications" that occur at a major facility. A major facility is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Net emission increases from a modification at a major facility that exceed the PSD SERs are also subject to PSD review.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of $SO_2$, $PM_{10}$, and $NO_2$ concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. Florida has adopted the EPA class designations and allowable PSD increments for $SO_2$, $PM_{10}$, and $NO_2$.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Florida's PSD regulations are found in FDEP Rule 62-212.400, F.A.C. Major new facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts (see Table 3-2):

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new major facility or major modification made to an existing major facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements for a new major facility or major modification are presented in the following sections.

### *3.2.2 Greenhouse Gases*

On June 3, 2010, EPA issued a ”Tailoring Rule” that “tailors” the applicability provisions of the PSD and Title V programs to enable EPA and state agencies to phase in permitting requirements for GHGs. The first phase of the Tailoring Rule began on January 2, 2011, and continued through June 30, 2011. During this period GHG sources became subject to PSD if the increase in GHG emissions from a project exceeded 75,000 TPY of $CO_2e$ or more and the project was required to undergo PSD review for other air regulated pollutants. The second phase of the Tailoring Rule began on July 1, 2011, and continues thereafter for new major GHG emitting facilities and major modifications. New major sources with the potential to emit 100,000 TPY $CO_2e$ or more of GHG will be considered major sources for PSD permitting purposes and are required to undergo PSD review. Additionally, any physical change or change in the method of operation at a major source resulting in a net GHG emissions increase of 75,000 TPY $CO_2e$ or more will be subject to PSD review. The Supreme Court issued a decision that indicated that GHG alone could not trigger PSD review. Rater, PSD for GHGs could only be triggered if PSD were required for other air pollutants (Case No. 12-1146). PSD review is required for GHG emissions greater than the listed PSD SER of 75,000 tons $CO_2e$ if PSD is required for other PSD pollutants.

For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases: $CO_2$, $N_2O$, $CH_4$, HFCs, PFCs, and $SF_6$.

Once major sources become subject to PSD, these sources must meet the various PSD requirements in order to obtain a PSD permit. However, there are no ambient air quality standards or PSD increments for GHGs. Therefore, the requirements for a source impact analysis, air quality analysis (monitoring), and additional impact analyses are not required. PSD review for GHGs principally involves the control technology review that includes a determination of BACT. The EPA published the PSD and Title V permitting guidance for GHGs in March 2011 that provides guidance on BACT analyses for GHG emissions.

### 3.2.3 Control Technology Review

A new major facility or major modification must perform a control technology review, which requires that all applicable federal and state emission limiting standards be met and that BACT be applied to control emissions from the source (FDEP Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the SER (see Table 3-2).

BACT is defined in FDEP Rule 62-210.200(40), F.A.C., as:

> *(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:*
>
> *1. Energy, environmental and economic impacts, and other costs,*
>
> *2. All scientific, engineering, and technical material and other information available to the Department, and*
>
> *3. The emission limiting standards or BACT determinations of Florida and any other State.*
>
> *(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*
>
> *(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*
>
> *(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

The BACT requirements are intended to ensure that the control systems incorporated in the design of a new facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the new facility. BACT must, at a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

For GHG emissions, control technology review is conducted by EPA under its regulations in 40 CFR 52.21. EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases*", March 2011). This EPA guidance supplements previous EPA guidance on the determination of BACT that is specific to BACT determinations for GHG emissions.

### 3.2.4 Source Impact Analysis

A source impact analysis must be performed for a new major facility or major modification to a major source for each pollutant, subject to PSD review, for which net emissions exceed the SER (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAAQS and allowable PSD increments. Designated EPA models that are approved by FDEP normally must be used in performing the impact analysis. Specific applications for other than EPA approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised)*. The source impact analysis for criteria pollutants to address compliance with NAAQS and PSD Class II increments may be limited to the new source if the impacts as a result of the new source are below significant impact levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. Although these levels have not been officially promulgated as part of the federal PSD regulations and may not be binding for states in performing PSD reviews, the levels serve as a guideline in assessing a source's impact in a Class I area. FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records can be used for impact analysis. A 5 year period can be used with corresponding evaluation of highest, second highest short term concentrations for comparison to NAAQS or PSD increments. The term "highest, second highest" (HSH) refers to the highest of the second highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second highest concentration is significant because short term NAAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

Because there are no NAAQS or PSD increments applicable to GHG emissions, these analyses are not conducted for PSD review for GHG.

### 3.2.5 Air Quality Monitoring Requirements

In accordance with requirements of FDEP Rule 62-212.400(5)(f), F.A.C., PSD review for a new major facility or major modification must consider an analysis of continuous ambient air quality data in the area affected by the proposed major PSD source or major modification. For a new major facility or major modification, the affected pollutants are those that the facility potentially would emit above the SERs.

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a proposed major stationary facility is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions of the pollutant from the facility would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (FDEP Rule 62-212.400-3, F.A.C.). If a facility's predicted impacts are less than the *de minimis* levels, then preconstruction monitoring is not required.

Because there are no ambient monitoring methods applicable to GHG emissions, these analyses are not conducted for PSD review for GHG.

### 3.2.6 Source Information/GEP Stack Height

Source information must be provided to adequately describe the proposed facility or major modification subject to PSD review.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant cannot be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP (FDEP Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters; or
2. A height established by applying the formula:

$$Hg = H + 1.5\,L$$

where:

Hg = GEP stack height,

H = Height of the structure or nearby structure, and

L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

### *3.2.7 Additional Impact Analysis*

In addition to air quality impact analyses, Florida PSD regulations require analyses for applicable pollutants of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of a new major facility or major modification subject to PSD review [FDEP Rule 62-212.400(5)(e), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

Because GHG emissions will not cause visibility impairment or direct impacts to soils and vegetation, these analyses are not conducted for PSD review for GHG.

### *3.2.8 Air Quality Related Values*

An Air Quality Related Value (AQRV) analysis is required for projects for those pollutants undergoing PSD review to assess the potential impact on AQRVs in PSD Class I areas. The nearest Class I areas to the Project are the Everglades National Park (ENP), located about 48 km (29 miles) from the Project, and the Chassahowitzka National Wilderness Area (NWA), located more than 300 km (180 miles) from the Project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and*

*those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*

*Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the NP and bioindicators of air pollution (e.g., lichens) must also be evaluated.

## 3.3 Nonattainment Rules

FDEP has nonattainment provisions (FDEP Rule 62-212.500, F.A.C.) that apply to all new major facilities or major modifications to major facilities located in a nonattainment area. In addition, for these facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Project is located in Lee County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment New Source Review (NSR) requirements are not applicable.

## 3.4 Emission Standards

### *3.4.1 New Source Performance Standards*

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The Project will be subject to one or more NSPS. EPA promulgated new NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. Subpart KKKK replaces Subpart GG for CTs.

#### *Combustion Turbine*

$NO_x$ and $SO_2$ emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK. $NO_x$ emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15 ppmvd corrected to 15 percent $O_2$ and 42 ppmvd corrected to 15 percent $O_2$ for natural gas and oil firing, respectively. $SO_2$ emissions are limited to using a fuel with a sulfur content of no greater than

0.05 percent and 20 gr/10 scf of sulfur for oil and natural gas firing, respectively. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK.

There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. These are summarized below:

*40 CFR 60.7 Notification and Record Keeping*

- *(a)(1) Notification of the date of construction - 30 days after such date.*
- *(a)(3) Notification of actual date of initial startup - within 15 days after such date.*
- *(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date*

*60.7 (b) Maintain records of all startups, shutdowns, and malfunctions.*

- *(c) Excess emissions reports – semi-annually by the 30th day following 6-month period (required even if no excess emissions occur).*
- *(d) Maintain file of all measurements for 2 years.*

*60.8 Performance Tests*

- *(a) Must be performed within 60 days after achieving maximum production rate, but no later than 180 days after initial startup.*
- *(d) Notification of Performance tests at least 30 days prior to them occurring.*

### 3.4.2 National Emission Standards for Hazardous Air Pollutants

EPA has promulgated maximum achievable control technology (MACT) standards under the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) regulations. Maximum annual potential HAPs emissions were presented in Table 2-7. Additional detail on the HAP emission calculations is also presented in Appendices A and B.

The Fort Myers Plant remains a major source of HAPs due to the combined emissions of Units 4 and 5 and the potential emissions associated with the Project. Therefore, certain MACT standards under the NESHAP regulations would apply. Under the NESHAPs of 40 CFR Part 63, Subpart YYYY applies to the CTs.

### 3.4.3 Florida Rules

FDEP has adopted the EPA NSPS by reference in FDEP Rule 62-204.800(8): Subsection (b)82 for stationary gas turbines. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

### 3.4.4 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, NESHAP, Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in FDEP Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

This Application is being filed for the purpose of establishing federally enforceable emission limitations that ensure the Project will not result in a significant net increase in emissions of any regulated air pollutant, in accordance with FDEP's federally approved minor source air construction permit program under Florida's federally approved SIP.

### 3.4.5 Local Air Regulations

There are no local air pollution regulations in Lee County. The FDEP South District located in Fort Myers is the air compliance authority for the county.

## 3.5 Source Applicability

### 3.5.1 Area Classification

The Project is located in Lee County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Lee County and surrounding counties are designated as PSD Class II areas for $SO_2$, PM [total suspended particulate (TSP)], and $NO_2$. The nearest Class I area to Project is the ENP, located approximately 97 km (60 miles) from the Project, and Chassahowitzka NWA, located more than 300 km (180 miles) from the Project.

### 3.5.2 PSD Review

#### Pollutant Applicability

The FPL Fort Myers Plant is considered to be a major facility under FDEP PSD rules because the emissions of several regulated pollutants are will exceed 100 TPY and the emissions units are one of the 28 listed major source categories under the PSD rules. The Project is defined as a major modification under the PSD rules and PSD review is required for any pollutant for any PSD-regulated air emissions that exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD review for PM (TSP), $PM_{10}$, $PM_{2.5}$, $NO_x$, and GHG. (Note: EPA no longer requires PSD review for HAPs. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

### *Emission Standards*

$NO_x$ and $SO_2$ emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK adopted by reference by FDEP in Rule 62-204.800(8)(b)78, F.A.C. $NO_x$ emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15 ppmvd corrected to 15 percent $O_2$ and 42 ppmvd corrected to 15 percent $O_2$ for natural gas and oil firing, respectively. $SO_2$ emissions are limited to using a fuel with a sulfur content of no greater than 0.05 percent and 20 gr/100 scf of sulfur for oil and natural gas firing, respectively. These requirements are summarized in Section 4.2. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. The proposed emissions for CTs being considered for the Project will be well below the specified limits (see Section 4.0).

EPA has promulgated MACT standards under the NESHAP regulations and applicability is based on whether a source is major or minor for HAPs. A facility is classified as a major source of HAPs when the maximum potential emissions for all emission units located at the facility exceed 10 TPY of a single HAP and 25 TPY for all HAPs. The Fort Myers Plant will remain a major source of HAPs due to the combined potential emissions of the Project along with the existing combustion turbines associated with Units 4 and 5.

The NESHAP Subpart YYYY applies to the CTs being considered if the aggregate use of oil by existing and new turbines exceeds 1,000 hours during any calendar year. The equipment vendor indicates that the CTs being proposed will meet the proposed MACT of 91 parts per billion by volume dry (ppbvd) corrected to 15 percent $O_2$ for formaldehyde. FDEP adopted this EPA rule by reference in Rule 62-204.800(8)(b)82, F.A.C.

### *Ambient Monitoring*

For the Project, the impacts will be less than the PSD de minimis monitoring concentrations for certain pollutants (see Section 5.0). As a result, an air quality monitoring impact analysis for these pollutants is not required by NSR under FDEP air regulations. For $O_3$ and $PM_{2.5}$, air quality monitoring data are provided, which demonstrate that Lee County is in attainment of the NAAQS for these pollutants. These data are presented in Section 5.0 of this application.

### *GEP Stack Height Impact Analysis*

The GEP stack height regulations allow any stack to be at least 65 meters (213 ft) high. The CT stacks will be 80 ft. These stack heights do not exceed the GEP stack height. However, as discussed in Section

6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT emissions caused by nearby structures is included in the modeling analysis.

### 3.5.3 Local Air Regulations

As specified in Subsection 3.4.5, there are no local air pollution regulations in Lee County; therefore, permitting requirements for the Project will comply with FDEP permitting requirements.

### 3.5.4 Other Clean Air Act Requirements

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR 72), allowance system (Part 73), continuous emission monitoring (CEM) (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78). FDEP adopted these rules by reference in Rule 62-204.800(16) F.A.C. (permit provisions), Rule 62-204.800(17) F.A.C. (allowance system), Rule 62-204.800(19) F.A.C.[ continuous emission monitoring (CEM)], Rule 62-204.800(21), F.A.C. (excess emission procedures), and Rule 62-204.800(22), F.A.C. (appeal procedures).

EPA's Acid Rain Program applies to all existing and new utility units, except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations are applicable to the Project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold $SO_2$ emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT for new units. An allowance is a market based financial instrument that is equivalent to 1 ton of $SO_2$ emissions. Allowances can be sold, purchased, or traded.

$NO_x$ monitoring is required for natural gas-fired and oil-fired affected units using CEM or alternate procedures. $SO_2$ monitoring is also required, although use of CEM is optional. When an $SO_2$ CEM system is selected to monitor $SO_2$ mass emissions, a flow monitor is also required. Alternately, $SO_2$ emissions may be determined using procedures established in Appendix D, 40 CFR 75 (FDEP Rule 62-204.800(19)(b)4, F.A.C.; flow proportional oil sampling or manual daily oil sampling). $CO_2$ emissions must also be determined either through a CEM (e.g., as a diluent for $NO_x$ monitoring) or calculation.

Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I; FDEP Rule 62-204.800(19)(b)1-9, F.A.C.). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart KKKK. New units are required to meet the requirements by not later than 90 days after the unit commences commercial operation.

# 4.0 CONTROL TECHNOLOGY DESCRIPTION

## 4.1 Introduction

### *4.1.1 Applicability and BACT Approach*

The PSD regulations require new major stationary sources or major modifications to existing major sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. As discussed in previous sections, PSD review is required for the Project.

There are NSPS regulations which are applicable to emissions of $NO_x$ and $SO_2$ from the CTs. The Clean Air Act specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS standards, which were discussed in Section 3.5.2. Subsection 4.2 presents the BACT analysis for non-GHG pollutants including $NO_x$, $SO_2$, and $PM/PM_{10}/PM_{2.5}$.

The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current guidelines suggesting that a "top-down" approach be followed in BACT analyses. The CAA and corresponding implementing regulations require that a BACT analysis be conducted on a case by case basis taking into consideration the amount of emissions reductions that each available emissions reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique.

EPA has recommended since 1990 that permitting authorities use the five step "top down" BACT process to determine BACT. The top down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest ranked ("top") option. The top ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this "top down" process into the following five steps:

Step 1: Identify all available control technologies
Step 2: Eliminate technically infeasible options
Step 3: Rank remaining control technologies
Step 4: Evaluate most effective controls and document results
Step 5: Select the BACT

### 4.1.2 Overview of Control Technology

The use of clean fuels (natural gas and ULSD oil) and combustion controls will minimize air emissions and ensure compliance with applicable emission-limiting standards. Using clean fuels will minimize emissions of $SO_2$, sulfuric acid mist (SAM), $PM/PM_{10}/PM_{2.5}$ and other fuel bound contaminants. Combustion controls will minimize the formation of $NO_x$ and the formation of CO and VOCs by combustor design. Further $NO_x$ reduction will be achieved by water injection during oil firing. The combination of these techniques has been determined to represent BACT on previous projects based on an evaluation of economic, energy, and environmental impacts. The following subsections present a summary of the best available control technology and practices for the Project.

In recent permitting actions, the FDEP has established BACT for heavy-duty simple-cycle industrial gas turbines like the ones proposed for this Project. These decisions established emission rates that were achieved through the use of advanced low-NOx combustors for limiting $NO_X$, the use of good combustion practices for control of CO and VOCs and clean fuels (natural gas and ULSD oil) for control of $SO_2$, SAM, $PM_{10}$ and $PM_{2.5}$. The BACT proposed for the Project's CTs is consistent with these recent FDEP permits.

The Project CTs will have two modes of operation (dual fuel) for which a BACT analysis has been performed. The results of the analysis have concluded that the following emission limits constitute BACT for the project.

CTs—Natural Gas Fired

- The CTs will utilize state-of-the-art low-$NO_X$ combustion technology which will achieve gas turbine exhaust $NO_X$ levels of no greater than 9 ppmvd corrected to 15 percent $O_2$
- Emission of $SO_2$, and $PM_{10}$ and $PM_{2.5}$ will be limited by firing primarily natural gas and 10-percent opacity
- Emissions of GHGs will be limited through the use of highly efficient CT technology.

CTs—ULSD Oil Fired

- The CT will utilize water injection to achieve gas turbine exhaust $NO_X$ levels of no greater than 42 ppmvd corrected to 15 percent $O_2$
- Hours of operation will be limited to an equivalent to 500 hours per year per CT at base load
- Emission of $SO_2$, and $PM_{10}$ and $PM_{2.5}$ will be limited by firing ULSD oil and 10 percent opacity
- Emissions of GHGs will be limited through the use of highly efficient CT technology.

Table 4-1 presents the proposed BACT emission limits for the Project.

## 4.2 Non-GHG Control Technology Review – BACT Analysis

### *4.2.1 Combustion Turbines*

### Nitrogen Oxides

#### *Feasibility*

A review of the most recent BACT determinations for similar projects (Appendix Tables B-1 and B-2) demonstrates that emission levels equal to those proposed for the Project, as a result of the proposed low $NO_X$ combustion technology, have been approved by regulatory agencies as BACT for similar simple cycle CTs. Available information suggests that feasible control technologies available, and in order of highest to lowest control efficiency, for simple cycle CTs are as follows:

1. Selective catalytic reduction ("Hot" SCR)
2. Low $NO_X$ combustion technology
3. Wet-injection for oil firing

SCONOx™ was an available technology in the previous decade but has not been installed nor demonstrated on large frame CT such as the "F" class combustion turbines in either simple cycle or more commonly combined cycle configurations. This technology is not considerable available or feasible for simple cycle CTs. Other available technologies such as NOxOut, Thermal DeNOx, NSCR, and XONON™ were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project.

#### *Technology Description*

The "Top Down" BACT analysis was performed for the following alternatives:

1. Selective catalytic reduction (SCR) and advanced low-$NO_x$ combustors at an emission rate of 2.5 ppmvd corrected to 15 percent $O_2$ when firing natural gas and 12 ppmvd when firing oil (typical for combined-cycle units).
2. Advanced low-$NO_x$ combustors at an emission rate of 9 ppmvd corrected to 15 percent $O_2$ when firing gas
3. Wet Injection at an emission rate of 42 ppmvd corrected to 15 percent $O_2$ when firing oil

SCR is a post-combustion process where $NO_X$ in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. The reaction occurs typically between 600°F and 750°F, which has limited SCR application primarily to combined cycle units where such temperatures occur in the heat-recovery steam generator (HRSG). Exhausts from simple cycle operation range up to 1,200°F, thus limiting the direct application of SCR on this mode of operation. Higher cost ceramic catalyst can accommodate temperatures up to 850 to 1,000°F and application have been installed on aero-derivative gas turbines. Most recently, Mitsubishi Power Systems America (MPSA) installed SCR on four large nominal 200 MW Siemens "F" Class CTs at the Marsh Landing facility in California. This application is natural gas only and required to meet LAER rather than BACT. The MPSA SCR system involves gas cooling to maintain temperatures in range applicable for SCR. In-duct cooling using ambient air would maintain temperatures in the applicable range of SCR with turbine flow of about 2,600,000 acfm and up to 1,200°F temperatures in the exhaust gas. This approach could be accomplished with an electric powered fan rated at about 2,000 hp (1,491 kW) as well as mixing/SCR chamber similar in six to a small HRSG. A similar application when firing distillate oil has not been demonstrated on a "F" Class simple cycle gas turbine.

Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic, and special precautions in materials and ammonia injection rates must be implemented to minimize their formation. The use of natural gas and ULSD limit the potential for ammonium salts to cause corrosion but particulate matter is formed and emitted in the gas stream.

Ammonia injected in the SCR system that does not react with $NO_X$ is emitted directly into the atmosphere and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 10 ppmvd.

While "hot" SCR is technically feasible for the Project, BACT emission levels equivalent to SCR control have not been permitted on similar sized simple cycle CTs by FDEP or any other state agency in EPA Region 4 (see Tables B-1 and B-2).

Low-$NO_X$ combustion technology has been offered and installed by manufacturers to reduce $NO_X$ emissions by inhibiting thermal $NO_X$ formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. $NO_X$ emissions of 25 ppmvd (corrected to 15 percent $O_2$) and less have been offered by manufacturers for advanced combustion turbines. Advanced in this context are the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) combustion turbines. This technology is truly pollution prevention because $NO_X$ emissions are inhibited from forming.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980s) and was the primary method of reducing $NO_X$ emissions from CTs prior to the 1990s. Indeed, this method of control was first mandated by the NSPS to reduce $NO_X$ levels to 75 ppmvd (corrected to 15 percent $O_2$ and heat rate). Wet injection is still the primary means of reducing $NO_X$ formation in the combustion process when firing oil. When firing ULSD oil, $NO_X$ is limited using water injection to 42 ppmvd corrected to 15 percent $O_2$.

Although SCONOx™ was commercially available in the late 1990s and early 2000s, it was never demonstrated on “F” Class or larger combustion turbines in either combined cycle or simple cycle modes. The SCONOx™ system has been only operated on a 32 MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The SCONOx™ technology installed on an “F” Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that $O_2$ is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a “F” Class turbine. Although the amount of sulfur in natural gas is very low, the SCONOx™ catalyst is poisoned by sulfur compounds, requiring the installation of the SCOSOx™ to further remove sulfur compounds as part of the overall system. The ability of SCOSOx™ to further remove compounds that will poison the catalyst as part of the overall SCONOx™ system has not been demonstrated when firing ULSD oil. Recent contacts with vendors of SCONOx™ technology have indicated that application of SCONOx has not been applied on large (80 MW or larger) CTs.

The recent permitting trend for advanced simple-cycle combustion turbines is the use of low-$NO_X$ combustors and water injection for ULSD oil firing (see Appendix B, Table B-2). Indeed, the recent simple cycle Florida project, Shady Hills Power Project, L.P. Unit Nos. 4 and 5, have been permitted with this technology in 2012. The Shady Hills project is a GE 7F.05 CT rated at 210 MW and is allowed to operate 3,390 hours per year including 500 hr/yr of ULSD oil.

As discussed previously, the new CTs will be fired with natural gas and ULSD oil will be used not to exceed an equivalent of 500 hr/yr per CT at base load conditions. The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible, and demonstrated control technology and emission rate alternatives for the simple cycle units.

### *Impacts Analysis*

Economic—The total capital costs of SCR for the Project exceed \$15,000,000 per CT. The total annualized cost of applying SCR with low-$NO_X$ combustion technology ranges from is approximately \$3.3 million. The incremental cost effectiveness of adding SCR to the low- $NO_X$ combustors and water injection (for oil firing) is estimated at over \$20,000 per ton of $NO_X$ removed, based on 3,390 hours of operation with 500 hour of oil firing. Detail calculations are provided in Tables 4-2 and 4-3.

It should be noted that CTs associated with the Project are replacements for less efficient GTs with higher $NO_X$ emission rates that are operated to supply high demand periods and provide fast-start power for unit outages or other factors that limit base load and intermediate load generation. The typical operation will be less than the potential emissions and therefore the actual cost per ton of $NO_X$ removed will be much higher.

Environmental—As discussed in Section 1.0, the Project will replace 36 existing GTs that, with high $NO_X$ emission rates and low stack heights, would not disperse emissions sufficiently to meet the new 1-hour $NO_2$ NAAQS. The Project will eliminate this potential air quality issue while provide more efficient electric power. The use of low-NOx combustor technology is truly "pollution prevention". While additional controls beyond low-$NO_X$ combustors (i.e., SCR and SCR with water injection) would further reduce emissions slightly, the effect will not be significant. For example, the installation of hot SCR would reduce potential $NO_X$ emissions by about 146 TPY per CT while causing emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate (see Table 4-4). Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 43.7 TPY per unit at the end of the catalyst's life. Potential emissions of ammonium sulfate and bisulfate will increase emissions of $PM_{10}$ and $PM_{2.5}$; up to 6.5 TPY per unit could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the Project. More importantly, the need for tempering air required 2,000 hp (1,491 kW) fans that would require 0.6 percent of the produced power or about 5,054 MWh per year. This power, which would otherwise be available to the electrical system, will have to be replaced. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, were calculated. As calculated, the net reduction in primary and secondary emissions with SCR when all criteria pollutants are considered will be up to 47 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were calculated to be about 4,500 TPY. As noted, the emissions including $CO_2$ would be greater with SCR than that proposed using low-$NO_X$ combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (Section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Energy—Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 1 percent more than with advanced low-NOx combustors. This penalty is the result of the SCR pressure drop, which would be about 10 (according to the SCR template) inches of water and would amount to about 1,567,000 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 6,173,000 kWh per year including the tempering air fan. Taken together, the total lost generation and energy requirements of SCR of 7,740,000 kWh per year could supply the monthly electrical needs of about 645 residential customers. To replace this lost energy, an additional 74,910 British thermal units per year (Btu/yr) or about 75 million cubic feet per year ($ft^3$/yr) of natural gas would be required.

Technology Comparison—The Project will use an advanced heavy-duty industrial gas turbine with advanced low-$NO_X$ combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is low-$NO_X$ combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the GE Frame 7F.05 advanced machine is about 220 MW compared to the 70 MW to 120 MW conventional machines. The higher initial firing temperature results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing lower air pollutant emissions (e.g., $NO_X$, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal $NO_X$ generated, this NOx increase is controlled through combustor design.

The amount of $NO_X$ control achieved by the low-$NO_X$ combustion technology on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater $NO_X$ emission formation. Since the advanced machine has higher firing temperatures, the $NO_X$ emissions without the use of low-$NO_X$ combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NOx reduction on the advanced CT.

The second unique attribute of the advanced machine is the use of low-$NO_X$ combustors that will reduce $NO_X$ emissions to 9 ppmvd when firing natural gas. Thermal $NO_X$ formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control will result in $NO_X$ emissions of about 0.033 lb/$10^6$ Btu when firing gas, which is more than 10 times lower than the existing 10 GTs the Project is replacing.

Since the purpose of the Project is to replace first-generation simple cycle units, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The existing gas turbines at the FPL Fort Myers Plant are early combustion turbines. The heat rates for these GTs are in the range of 15,000 Btu/kWh or higher. In contrast, the Project will have CTs that have heat rates in the range of 10,000 to 11,000 Btu/kWh at base load conditions. The $NO_X$ emission rates will not only be more than 10 times lower on a heat input basis but more than 15 times lower on a generation basis (i.e., lb $NO_X$ /MWh basis)

### *Proposed BACT and Rationale*

The proposed BACT for the Project is advanced low-$NO_X$ combustion technology. EPA updated the NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. The Subpart KKKK emissions requirements applicable to combustion turbines greater than 30 MW apply to CTs associated with the Project. The $NO_x$ emissions are limited to 15 ppm corrected to 15 percent $O_2$ or 0.43 lb/MW-hr for natural gas firing and 42 ppm corrected to 15 percent $O_2$ or 1.3 lb/MW-hr for ULSD oil firing. For the Project, the $NO_x$ emissions are limited to 9 ppm corrected to 15 percent $O_2$ and about 0.33 lb/MW-hr or less when natural gas firing under base load conditions. $NO_X$ from oil firing will be controlled using water injection (42 ppmvd corrected to 15 percent oxygen). This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds.
2. The estimated incremental cost of SCR is approximately at over $20,000 per ton of $NO_X$ removed and is similar to cost for other Projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst). While $NO_X$ emissions would be reduced by about 146 TPY per unit with SCR, the net emissions reduction associated with the entire Project would not be as great. There are three additional factors that must be considered:

a. The Project replaces the generation of 10 less efficient and higher emitting GTs with low stack heights that have concomitantly higher air quality impacts. Emissions are reduced by over a factor of 10 on a heat input basis and by over a factor of 15 on a generation basis.

b. SCR will increase direct emissions. Ammonia slip would occur, and it may be as high as 43.7 TPY per unit. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 6.5 TPY per unit additional particulate matter may be formed.

c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced because the Project would be an efficient peaking power plant while operating. Any peaking power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the emissions of an additional 2.8 TPY of criteria pollutants. An additional 4,450 TPY of carbon dioxide would also result.

4. The energy impacts of SCR will reduce potential electrical power generation by more than 7 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 645 residential customers.

5. The proposed BACT (i.e., low-$NO_x$ combustion technology) provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). Low-$NO_x$ combustion technology at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to existing GTs the Project is replacing, the use of the CTs associated with the Project will result in over 15 times less $NO_x$ emission while producing the same amount of electricity.

### PM/$PM_{10}$/$PM_{2.5}$ and $SO_2$

The PM/$PM_{10}$/$PM_{2.5}$ emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas-fired or oil-fired CTs.

The use of clean fuels, characterized by low PM and trace contaminant contents and advanced combustion techniques, results in negligible PM and $PM_{10}$ emissions. Emission limits based on the use of clean fuels (i.e., natural gas and ULSD oil) have been established as BACT for PM/$PM_{10}$ emissions in previous PSD permits.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the project.

There are no technically feasible methods for controlling the $PM/PM_{10}/PM_{2.5}$ emissions from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for $PM/PM_{10}/PM_{2.5}$ emissions.

BACT determination for emissions of $SO_2$ from CTs have overwhelmingly been the use of clean fuels, characterized by low sulfur and trace contaminant contents, results in negligible $SO_2$ , as well as $H_2SO_4$ Mist (SAM) emissions. For $SO_2$ emissions, Subpart KKKK requirements limit emissions to 0.9 lb/MW-hr or a potential total sulfur content equivalent to 0.06 lb/MMBtu if multiple fuels are fired. For the Project, the $SO_2$ emissions are less than about 0.06 lb/MW-hr when firing natural gas and about 0.03 lb/MW-hr when firing ULSD oil. Natural gas and ULSD oil are the cleanest fuels available with maximum sulfur contents of 2 gr/100 scf for natural gas and 0.0015 percent sulfur for ULSD oil. $SO_2$ and sulfuric acid mist emission limits based on use of natural gas and ULSD oil have been established as BACT in previous PSD permits.

## 4.3 BACT for GHGs

### *4.3.1 Applicability and BACT Approach*

The PSD regulations require new major stationary sources or major modifications to existing major sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. As discussed in previous sections, PSD review is required for the Project.

As described in Section 3, BACT cannot be less stringent than any applicable NSPS. There is currently no NSPS applicable to the Project for GHGs. EPA re-proposed NSPS for electricity utility units on January 8, 2014 that will not likely be finalized till well into 2015. However, it is not expected that the NSPS would apply to the Project since the NSPS would be applicable only to stationary combustion turbines that actually supply one-third of its potential electric output to a utility grid on a 3-year rolling basis as shown below:

> **§ 60.5509 Am I subject to this subpart?**
> (2) A stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and was constructed for the purpose of

supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.

Although the maximum potential operating hours requested is 3,390 hr/yr or 39.7 percent, the Project's CTs will not provide one-third of its electric output to the gird based on historical operation of FPL's simple cycle peaking units. This was recognized in EPA's preamble to the proposed regulation by stating: "simple cycle combustion turbines that are generally designed for operation during peak demand will usually supply less than one-third of their potential electric output to the grid, would not be affected by today's proposal." 79 FR 1445. In addressing the applicability concerns related to peaking units, EPA went on to say: "The EPA believes the combination of the actual sales criteria and the three year rolling average to determine if the sales criteria are met will address this concern." 79 FR 1445. Therefore, the proposed NSPS is not an applicable criteria for using as an emission limit being considered for simple cycle peaking units. EPA Region 4 also expressed this conclusion in the final GHG PSD permit for Shady Hills Generating Station a two simple cycle GE 7F.05 CTs (Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions Permit PSD-EPA-R4013, United States Environmental Protection Agency, Region 4, Atlanta, Georgia, dated 1/14/14).

The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current guidelines suggesting that a "top-down" approach be followed in BACT analyses. The CAA and corresponding implementing regulations require that a BACT analysis be conducted on a case-by-case basis taking into consideration the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique.

### *4.3.2 Definition of the Project*

In recent permitting actions, the FDEP has established BACT for heavy-duty simple-cycle industrial CTs like the ones proposed for this Project. These decisions established emission rates that were achieved through the use of advanced low-$NO_x$ combustors for limiting $NO_x$, the use of good combustion practices for control of CO and VOCs and clean fuels (natural gas and ULSD oil) for control of $SO_2$, sulfur acid mist (SAM), $PM_{10}$, and $PM_{2.5}$. The BACT proposed for the Project's non-GHG emissions are consistent with these recent FDEP permits.

The Project CTs must have two modes of operation (dual fuel) and the basis of the Project is to replace 10 of the existing GTs with CTs achieving emission performance that would be determined by FDEP to be BACT for $NO_x$ with correspondingly low CO emission rates. The CTs and other emission units non-GHG pollutant basis is summarized below:

**CTs—Natural Gas-Fired**

- The CTs must utilize state-of-the-art low-$NO_X$ combustion technology which will achieve gas turbine exhaust $NO_X$ levels of no greater than 9 ppmvd corrected to 15 percent $O_2$.
- CO emissions must achieve 4 ppmvd corrected to 15 percent $O_2$ at base load and good combustion practices will be utilized.

**CTs—ULSD Oil-Fired**

- The CT must utilize water injection to achieve gas turbine exhaust $NO_X$ levels of no greater than 42 ppmvd corrected to 15 percent $O_2$.

- CO emissions must achieve 9 ppmvd corrected to 15 percent $O_2$ at base load and good combustion practices will be utilized.

The purpose of the Project is to replace existing 40+ year old GTs with two new CTs going into service by December 31, 2016, continuing to provide emergency and peaking duty service for FPL's electric system. Emergency and peaking duty service refers to meeting the needs of power generation when there is an electric demand caused by unit outages or system electric disruptions, and/or high electrical demand. As a result, short startup periods are required and simple-cycle CT technologies meet the requirements.

For the Project, the emergency and peaking service operation varies based on the circumstances. For emergency service, the representative average operation per CT start is less than 30 minutes with over 40 independent starts per year. For peaking service, the representative average operation is between 4 and 8 hours with over 200 starts per year. The Project's site is also a factor since its location is near the end of the natural gas transmission system where natural gas may not be available for emergency or peaking service. As a result, considerable oil operation could occur in any year.

In EPA's recently proposed "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," [77 Fed. Reg. 22392 (April 13, 2012)], the agency notes that peaking units "generally operate differently" than combined cycle combustion turbines. EPA points out that "simple cycle turbines are generally used much less often (and thus have lower GHG emissions) and are generally used to meet peak demand rather than base or intermediate load requirements." 77 FR 22392, 22398.

Simple cycle CTs serve a fundamentally different purpose from combined cycle CTs that are installed for intermediate and base load generation needs. This is acknowledged by EPA in the recently proposed GHG NSPS discussed above. The distinction between simple cycle units and intermediate/base load units such as combined cycle was upheld by the EPA Environmental Appeals Board on the Pio Peco Energy Center case where EPA has discretion to distinguish such purposes.

Therefore the evaluation of combined cycle CTs represents re-definition of the source and as such is not included in this application.

### *4.3.3 GHG Control Technology Review – BACT Analysis*

EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases,*" March 2011). EPA believes, in BACT reviews of GHGs, that the "top down" approach should be followed, but that it is important to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes, and practices at the emitting unit. In general, a more energy-efficient technology burns less fuel than a less energy-efficient technology on a per-unit-of-output basis. Thus, considering the most energy-efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated New Source Review (NSR) pollutants (e.g., $NO_X$, $SO_2$, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, EPA emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs).

The following subsections provide the BACT analysis for the Project.

### *4.3.4 Combustion Turbines*

The BACT analysis for the GHG emissions from the CTs followed the EPA suggested five-step "top down" process as described in the following subsections. Since the CTs will be identical, the emphasis of the BACT evaluation is the GHG emissions and performance of a single CT.

***Step 1 – Identify all Available Control Technologies***

The first step in the top down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- Inherently Lower Emitting Processes/Practices/Designs
- Add-On Controls
- Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-On Controls

EPA recommends that the BACT analysis should consider potentially applicable control techniques from all of the above three categories.

GHGs under EPA regulations are considered as a single air pollutant, which is the aggregate group of the six principal gases, $CO_2$, $N_2O$, $CH_4$, HFCs, PFCs, and $SF_6$. $CO_2$ emissions result from the oxidation of carbon in the fuel. $CH_4$ emissions result from incomplete combustion and $N_2O$ emissions result primarily from the temperature of combustion. $CO_2$, $N_2O$, and $CH_4$ are the GHGs that will be emitted from the CTs.

EPA recommends that permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration. In its PSD and Title V Permitting Guidance for GHGs, EPA emphasizes two mitigation approaches for $CO_2$: 1) energy efficiency and 2) carbon capture and storage (CCS).

The GHG emissions from the Project will also include $CH_4$. However, emissions of $CH_4$ from CTs are less than 0.04 percent of the total $CO_2e$ GHG emissions. As a result, control options for these pollutants are not practicable although an oxidation catalyst system can potentially reduce $CH_4$ emissions.

**Project Timing and Construction**

Existing gas turbines cannot be decommissioned until the new CT replacement generation is constructed and in operation. The simple cycle GTs serve as emergency and peaking backup for FPL's system and are required to remain in-service until the new CTs can take their place. Therefore, the infrastructure of the existing GTs must remain.

**Clean Fuels**

The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30 percent less $CO_2$ than oil, and about 45 percent less $CO_2$ than coal (source: www.naturalgas.org). The fuels for the CTs will be natural gas and ULSD oil. It is important to recognize that the definition of BACT in 40 CFR 52.21(b)(12) includes use of "clean fuels" as a pollution control technique. The EPA PSD and Title V Permitting Guidance for GHGs states that clean fuels which would reduce GHG emissions should be considered while recognizing at the same time that the BACT analysis does not need to include a clean fuel option that would fundamentally redefine the source. Therefore, the proposed CTs will be fired with "clean fuels" as included in the definition for BACT in the CAA Part 169(3).

**Aeroderivative Combustion Turbines**

Smaller aeroderivative CTs are available in units up to 100 MW per CT. However, the use of these CTs, if feasible, would result in increased uncontrolled emissions of $NO_x$ and CO compared to the proposed Project, potentially resulting in selective catalytic reduction (SCR) and oxidation catalyst pollution control technology being required. The emission guarantees $NO_x$ and CO for the aeroderivative CTs without add-on controls are higher than for the CTs being considered for the Project.

Aeroderivative CTs have typical $NO_x$ emissions guarantees of 15 to 25 ppmvd at 15 percent $O_2$ and typical CO emissions guarantees of 25 to 50 ppmvd at 15 percent $O_2$ with the use of dry low $NO_X$ technology. To achieve the same emission levels for $NO_x$ and CO required for the Project, additional pollution controls to reduce $NO_x$ and CO would be needed, e.g., SCR and oxidation catalyst. For this Project, compared to the proposed GE 7F.05 CTs, smaller CTs in this range would result in higher capital costs per MW and operating costs associated with operation and maintenance, ammonia, catalyst replacement, and lost energy through parasitic load from the SCR (backpressure and operational electrical demand of process equipment). SCR would result in additional environmental impact as a result of emissions of ammonium ($NH_4$) in the form of catalyst slip. In addition, the emergency service using both natural gas and ULSD oil will introduce demands that SCR cannot meet for these short durations. The use of a CO oxidation catalyst would also result in higher operating costs associated with operation and maintenance, catalyst replacement, and lost energy through parasitic load, and would convert the CO emissions to $CO_2$, resulting in a negligible environmental benefit. Aeroderivative CTs of this size would result in higher operating costs and additional environmental impacts of other pollutants while resulting in no significant benefit in $CO_2$e reduction.

The largest available aeroderivative CT is the GE LMS100 that has a capacity of 100 MW. To meet the Project's requirements at least 4 LM100 CTs would be required. The land requirements for the LM100 CT alone are approximately the same as a single GE 7F.05 CT without consideration of the cooling requirements and installation of SCR and supporting systems. The land requirements alone would double with corresponding impacts.

Additional water is also required for aeroderivative CTs. The LMS100 requires inter-cooling which can be achieved through water or air cooling. Air cooling requires a significantly larger area than water cooling, and is less effective in southern Florida. Water for cooling and emissions control results in additional environmental impacts associated with water withdrawal and discharge.

These factors related to the LMS100 will be discussed further in Step 4.

**Energy Efficiency**

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

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

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including $CO_2$). Several recent BACT determinations for GHG emissions concluded that high efficiency power generation technology is the only available and feasible control technology. Efficient peaking power production is technically feasible and is proposed for the Project.

**Carbon Capture and Storage**

CCS falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. EPA suggests that CCS is an add-on pollution control technology that is "available" for large $CO_2$ emitting facilities including fossil fuel-fired power plants and industrial facilities with high purity $CO_2$ streams. As a result, EPA suggests that CCS be considered in Step 1 of the BACT analysis.

CCS is composed of three main components: $CO_2$ capture and/or compression, transport, and storage.

Carbon Capture – Before $CO_2$ gas can be sequestered, it must be captured as a relatively pure gas, so that it can be feasibly stored. Most power plants and other large point sources use air-fired combustors, a process that exhausts $CO_2$ diluted with nitrogen. Flue gas from natural gas combined cycle plants contains only about four percent $CO_2$ by volume. For effective carbon sequestration, the $CO_2$ in the exhaust gases must be separated and concentrated due to the low percent by volume.

The most likely options currently identifiable for $CO_2$ separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

Carbon Transport – After the $CO_2$ is captured, it must be transported to a carbon sequestration site. Pipelines are the most common method for transporting large quantities of $CO_2$ over long distances. Shipping $CO_2$ via pipeline involves compressing gaseous $CO_2$ to a pressure above 1,160 pounds per square inch (psi), to increase $CO_2$ density and make it easier and less expensive to transport. A $CO_2$ pipeline would be similar to a high pressure natural gas pipeline and is technically possible. $CO_2$ also can be transported as a liquid in seagoing vessels or via tankers on roads or railways. In these instances, the $CO_2$ is held in insulated tanks at low temperatures and relatively low pressures.

Carbon Storage – In a CCS system, $CO_2$ is captured, it is transported, if necessary, and then stored. Geologic formations such as depleted oil and gas reservoirs, unmineable coal seams, and underground saline formations are potential options for long term storage. Pressurized $CO_2$ is injected into the deep geologic formations through drilled wells. Under high pressure, $CO_2$ turns to liquid and can move through a formation as a fluid. Once injected, the liquid $CO_2$ tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the $CO_2$ and prevent further upward migration. When $CO_2$ is injected into a coal seam, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells. There are other mechanisms for $CO_2$ trapping as well: $CO_2$ molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of the porous rock.

Deep saline formations, which are layers of porous rock saturated with brine, present an enormous potential for geologic storage of $CO_2$. However, there is not much experience with saline formations such as that acquired through resource recovery from oil and gas reservoirs and coal seams. There is ongoing research focused on storage in organic rich shale, which is a thin horizontal layer of sedimentary rock with low vertical permeability and in basalt formations, which are geologic formations of solidified lava. Other possible options include liquid storage in deep ocean areas.

The paper "Realistic Costs of Carbon Capture" provides cost comparisons for electric generation using CCS (Harvard Kennedy School, July 2009). As provided in Annex C using data from National Energy Technology Laboratory (NETL), Electric Power Research Institute (EPRI) and SFA, the range of avoided cost in dollars per metric ton of $CO_2$ separated is from \$63 to \$83 equivalent to \$70 to \$93 short tons of $CO_2$ separated, based on two advanced natural gas-fired F class turbines. Based on a cost of \$70 per short ton of $CO_2$, and an estimated annual $CO_2$ rate of 450,000 short tons from each of the Project's CTs, the annual cost for separation alone would be over \$30 million/CT. This cost assumes that the separation equipment could be operational during the short operational periods required for the Project. Additionally per footnote of Annex C, this cost does not include expenses associated with transportation, injection and storage.

The maximum potential emissions of $CO_2$ for each CT were estimated to about 494,552 tons per year (TPY) including distillate oil firing (Table 2-5). Assuming 90 percent $CO_2$ removal, the annualized cost for $CO_2$ would be calculated at $67.40 per ton of $CO_2$ removed and sequestered. This cost however is based on estimates for a combined cycle unit where exhaust temperatures are about 93°C (200°F). The cost for additional exhaust gas cooling would have to be considered. Moreover, as discussed later, the representative number of start and shutdowns would be 240 per year, with considerable number starts (i.e., 40) involving only 30-minute operation. The ability of cooling and absorption equipment to handle this cycling has not been technically demonstrated.

**Oxidation Catalyst**

Catalytic oxidation technology, which is primarily designed to reduce CO emissions, will also reduce $CH_4$ emissions but to a lesser extent. Oxidation catalysts operate at elevated temperatures where excess $O_2$ in the exhaust reacts with $CH_4$ to form $CO_2$. As a result, 25 lb of $CO_2$e are reduced to 2.75 lb of $CO_2$. At the very best only about 87 percent of the $CO_2$e could be reduced. Assuming a 90 percent removal of $CH_2$ the maximum control is only about 80 percent removal of $CO_2$e.

The total amount of $CO_2$e resulting from $CH_4$ emissions is only 0.06 percent of total $CO_2$e emissions and is about 282 tons $CO_2$e/CT. The secondary emission caused by the backpressure was estimated to be over 900 tons of $CO_2$. This clearly demonstrates the infeasibility of an oxidation catalyst to control $CH_4$ emissions.

***Step 2 – Identification of Technically Feasible Control Alternatives***

Under the second step of the top down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available.

**Energy Efficiency**

Efficient power generation is technically feasible and is being proposed for the CTs. This is discussed in detail in Step 4.

**Carbon Capture and Storage**

In its PSD and Title V permitting guidance for GHGs, EPA states that it does not believe CCS will be a technically feasible BACT option in certain cases at this time. To establish that an option is technically feasible, the permitting record should show either that an available control option has been demonstrated in practice or is available and applicable, with the term "applicable" generally meaning a technology can reasonably be installed and operated on the source type under consideration. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that set it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants. In addition, other add-on controls typically have an existing accessible infrastructure in place to address waste disposal and other offsite needs. It should also be noted that while CCS may be available according to EPA, it is not "commercially available." All current CCS projects for power plants are primarily in the demonstration stage.

Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, developing a site for secure long-term storage and environmental permitting for underground GHG sequestration. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations.

There are no CCS systems commercially available for full-scale power plants in the United States. On February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage, composed of 14 Executive Departments and Federal Agencies. The Task Force delivered several recommendations to the President on August 12, 2010. The Task Force, co-chaired by the U.S. Department of Energy (DOE) and the EPA, recommended a comprehensive and coordinated strategy to overcome the barriers to the widespread, cost effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. These projects, to be deployed with the help of federal funding, are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities. The Task Force concluded that such research and development efforts were designed to reduce the cost of CCS and facilitate cost-effective deployment after 2020. However, widespread deployment of CCS will occur only if the technology is commercially available at economically competitive prices. Therefore, the application of CCS is very much in the development stage and not commercially available.

In November 2010, EPA published the final rule for Federal requirements of Underground Injection Control (UIC) for $CO_2$ Geologic Sequestration (GS) Wells, as authorized by the Safe Drinking Water Act (SDWA). The final rule establishes new federal requirements for the underground injection of $CO_2$ for the purpose of long-term underground storage, or GS, and a new well class – Class VI – to ensure the protection of underground sources of drinking water (USDWs) from injection-related activities. Therefore, authorization must be obtained from FDEP under this federally delegated program prior to GS. Permitting for a Class VI well takes many years as exploratory wells are likely required for $CO_2$ sequestration, including drilling deep holes, testing, etc., prior to approval of an injection well. Indeed, the exploratory well process to assess the formation can take over two years for drilling, testing, and approval of the start of an injection well process.

EPA Region IX's "Fact Sheet and Ambient Air Quality Impact Report" for the Pio Pico Energy Center presents information concluding that absorption of $CO_2$ requires turbine exhaust temperatures of about 50°C (about 120°F) to improve absorption and minimize solvent loss. As presented in Figure 2-2 of the application, the exhaust temperature of the CTs is about 590°C (about 1,100ºF). The CTs must have fast start capability requiring simple cycle operation that cannot be achieved in combined cycle mode that includes a heat recovery steam generator (HRSG). In their analysis, EPA Region 9 states for the Flour and BP Central Gas Facility (CGF) using $CO_2$ absorption by monoethanolamine (MEA):

"The integral nature of the HRSG to the overall process for the CGF is notable because it would essentially require conversion of the turbines from simple-cycle to combined-cycle operation. Therefore, based on this information, we conclude that while carbon capture with an MEA absorption process is feasible for a combined-cycle operation, it is not feasible for simple-cycle units (*i.e.,* those without a HRSG). Given that combined-cycle gas turbines are not technically feasible for the proposed Project, as discussed above, CCS is also technically infeasible for the proposed Project."

Carbon capture systems (CCS) would require considerable space for the cooling system, $CO_2$ absorption systems and compression. As described above, the exhaust for a simple cycle CT would require, similar to hot SCR systems, a cooling chamber and ambient air fans to reduce the temperature. This would significantly increase the volume of gas required for $CO_2$ absorption and concomitant increase in absorber sizes and space requirements. Alternatively, a cooling system using water could be used but this would require a significant water quantity. The footprint for each CT would increase by 2 to 3 times and prohibit their location within the area shown in Figure 2-1.

Based on these considerations, it can be reasonably concluded that CCS is not applicable to the Project, and consequently not technically feasible.

**Oxidation Catalyst**

Catalytic oxidation is an available control technology for $CH_4$, although no approval for its use for this purpose has occurred. The oxidation catalyst will reduce $CH_4$ with the following reaction:

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

While $CH_4$ emissions can be reduced using an oxidation catalyst, the amount of $CO_2e$ reduced is less than 0.05 percent. Moreover, the amount of potential $CO_2e$ that could be reduced from the Project combined cycle unit is 40 times lower than the EPA GHG thresholds. Therefore, the addition of an oxidation catalyst to the Project for GHG control is neither practicable nor feasible to reduce $CH_4$.

***Step 3 – Rank Remaining Control Technologies***

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2 above, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness.

Based on the discussion in Steps 1 and 2, the only technically feasible control option for GHGs is energy efficiency.

***Step 4 – Economic, Energy, and Environmental Impacts***

Under Step 4 of the top down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The “top” control option and in the case of GHG the “top” energy reduction technology should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The “top” control option for the CTs is energy efficiency. The CTs will operate in the simple cycle mode to produce electric energy during high demand periods. The CTs being considered are among the most efficient available and 40 percent more energy efficient than the existing GT technology they are replacing. The new CTs will use natural gas as the primary fuel and ULSD oil as a backup fuel. These fuels are the most efficient for this application

The efficiency of the generation technology in producing electricity in an amount necessary to meet demands and fuel utilized are the most important aspects in GHG emissions from electric generation projects. Together, efficiency, fuel type and operational dispatch/cycling dictate the amount of GHG emissions per unit of generation.

The measure of the efficiency for an electrical generating facility is the units’ heat rate. Heat rate is a measurement of how efficiently a unit uses heat energy. It is expressed as the number of British thermal units (Btu) of heat required to produce a kilowatt-hour of energy based on higher heat value (HHV). A heat rate of 3,413 Btu/kWh reflects an efficiency of 100 percent from thermal energy to electrical energy.

The CTs' heat rate (or energy efficiency) was compared to data obtained from the U.S. Energy Information Administration (EIA). In 2011, there were 940 GTs with a net summer capacity of 56,032 MWs (EIA, 2012). The average tested heat rates for GTs when firing natural gas and distillate oil were (based on HHV for 2012):

- Natural gas – 11,449 Btu/kWh net (29.8 percent efficiency)
- Distillate oil – 13,662 Btu/kWh net (25.0 percent efficiency)

The Project will replace the capacity of 10 existing GTs at the Fort Myers Plant. The existing GTs are first-generation gast turbines The heat rates for these units are:

- Average expected net operating heat rate of 14,764 Btu/kWh with an actual operating net heat rate of about 19,000 Btu/kWh

**LMS100**

As discussed in Step 1 of the BACT analysis, aero-derivative CTs such as the LMS100 must have the ability to meet the fundamental Project requirements. These requirements were the ability to meet low $NO_X$ emissions without SCR, have a relatively small footprint that can be installed on the existing site, cost-effective and proven performance, and durability. The following is information regarding the economic and environmental factors for why this technology is not appropriate as BACT for this Project (i.e., Step 4).

On an economic basis, the cost differential between the GE 7F.05 CTs and aero-derivative CTs are similar to the information presented for the Shady Hills Generation Station (Golder Associates Inc. 2012. New Source Review for Greenhouse Gases, Shady Hills Generating Station/EFS Shady Hills LLC, Pasco County, Florida). In this recent analysis of the same GE CTs being considered for this Project, the cost effectiveness for aero-derivative CTs was $60.2 per ton of $CO_2$ reduced for the LMS100 CTs and $285.6 per ton of $CO_2$ reduced for LM600 CTs higher than the GE 7F.05CT. FPL considers this cost differential between aeroderivative CTs and the CTs considered for this Project to be representative for this Project.

From an environmental perspective, the aero-derivative CTs would require additional NOx controls, a larger area, gas compression and additional water compared to the larger CTs being considered for the Project.

- Additional Controls: The LMS100 has a $NO_x$ emission rate of 25 ppmvd corrected to 15 percent oxygen compared to the 9 ppmvd corrected to 15 percent oxygen for the CTs being considered for the Project. The BACT limits for $NO_x$ previously approved as BACT by FDEP is 9 ppmvd corrected to 15 percent oxygen for large CTs that the LMS100 cannot achieve. As a result, an SCR system would be required. This requires additional space and the use of ammonia.
- Space requirements: As shown in Figure 2-1, the footprint of the CTs being considered occupies about 5,000 square feet. In contrast, the LMS100 requires about 15,000 square feet due to the requirements for intercooling, gas compression, SCR systems and cooling systems such as cooling towers. For the Project, an additional 3.5 acres would be required. This space is not available as the northern and eastern undeveloped areas are in conservation easements and wetland mitigation projects.
- The LMS100 requires intercooling and a cooling system (such as a cooling tower) to disperse the rejected heat. For a cooling tower, at least 80,000 gallons/day/CT for cooling tower makeup would be required for this purpose. On an annual basis, about 68 million gallons/year of water would be required. To limit the buildup of salts in the cooling tower, there also would be associated cooling tower blowdown that would require disposal. Assuming five cycles of concentration, about 100,000 gallons/day of cooling tower blowdown would have to be discharged for LMS100 CTs. For the Project, the CTs being considered do not require cooling towers and no discharge is required.

The LMS100 requires increased pressure of natural gas for operation. The natural gas pressure available for the Project would have to be increased for operation of the LMS100. This will require additional gas compressions equipment. Electrical gas compressors are the only feasible alternative that matches the starting requirements for the Project. A gas compressor rated as high as 600 kW per LMS100 will be required resulting in an additional auxiliary load of 1,800 kW while in operation.

**Large Frame CTs**

The heat rate and efficiency of the GE 7F.05 CTs when using natural gas and ULSD oil are as follows (new and clean, 100 percent load, no inlet cooling, based on manufacturer data):

- Natural gas firing – 10,069 Btu (HHV)/kWh (34 percent efficiency) (Base load at 85$^{o}$F).
- Oil firing – 10,064 Btu (HHV)/kWh (34 percent efficiency) (Base load at 85$^{o}$F).

These estimated new and clean 100 percent load heat rates are below the approximate average heat rates for simple cycle CTs in the U.S. and much lower than the existing GTs that the new CTs will replace.

As part of EPA's clean energy initiatives, EPA developed the Emissions & Generation Resource Integrated Database (eGRID) as a resource tool in assessing GHG emissions. eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States with data available based on a variety of geographic regions and locations. Data is also available on a plant-specific basis. Based on the latest available eGrid data, the following are the emissions of $CO_2$ on a generation basis for generation facilities located in the same subregion as the Project:

- Florida Reliability Coordination Council (FRCC) – 1,181.6 lb $CO_2$/MW-hr (net) for all generation (including nuclear), 1,368.2 lb $CO_2$/MW-hr for total combustion.
- FPL – 815.6 lb $CO_2$/MW-hr for all generation (including nuclear); 1,029.2 lb $CO_2$/MW-hr (net) for total combustion generation.

***Step 5 – Select the BACT***

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

**BACT**

Energy efficiency, the only remaining and feasible control technology, is selected as BACT for the GHG emissions from the Project. Energy efficiency plays a major role in affecting GHG emissions and EPA suggests that more emphasis will be given to energy efficiency in GHG BACT analysis. As demonstrated in the discussion in Step 4, the Project meets the requirements of energy efficiency under EPA's GHG BACT guidelines.

The CCS option was eliminated in Step 2 as not technically feasible for the Project. Although EPA considers CCS as available, it is not commercially available. Indeed, EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with $CO_2$ capture and compression. In the Guidance, EPA states that even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, CCS would be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured $CO_2$ near the power plant is feasible. In the case of the Project, CCS is not a technically feasible control technology based on the Project's overall purpose (replacing less efficient peaking units).

FPL proposes a gross output based GHG BACT limit based on a statistical analysis of the turbines under consideration. As described previously, the units will be operated in emergency and peaking service operation that varies substantially based on the electric needs of FPL's over 20,000 MW electric system and support neighboring utilities. During emergency service, the representative average operation per CT start is 30 minutes with over 40 independent starts per year. During peaking service, the representative average operation is between 4 and 8 hours with over 200 starts per year. The Project's location is also a factor since its location is near the end of the natural gas transmission system where natural gas may not be available for emergency or peaking service requiring considerable ULSD oil operation. Therefore GHG limits were developed for gas and ULSD oil operation over the expected loads of operation. For natural gas-firing during normal operation (loads when the CT can comply with emission limits for $NO_X$) the proposed GHG limit is 1,400 lb/$CO_2$ e/MWh calculated as follows:

| **Category** | **Units** | **Estimated Performance** | | |
|---|---|---|---|---|
| Fuel | | Gas | Gas | Gas |
| Turbine Inlet | degree F | 85 | 85 | 85 |
| Evaporative Cooling | | Off | Off | Off |
| Gross Load | % | 100% | 75% | Low [a] |
| Gross Heat Rate | Btu/kWh (HHV) | 10,069 | 10,574 | 13,314 |
| Gross Efficiency | % | 33.9% | 32.3% | 25.6% |
| $CO_2e$ | lb $CO_2e$/MWh | 1,197 | 1,257 | 1,583 |
| Operation | | 50% | 25% | 25% |
| Gas Average $CO_2e$ | lb $CO_2e$/MWh | 1,308 | (Average of 100%, 75% and Low load) | |
| Performance Margin | % | 2% | (Vendor Performance Margin) | |
| Degradation Margin | % | 5% | (Account for normal wear during operation) | |
| Proposed $CO_2e$ | lb $CO_2e$/Mwh[a] | 1,400 | Composite average of 720 operating hours | |

[a] Load at which the CT has achieved compliance with $NO_x$ emission limit.

The proposed GHG limit is based on operating at 50, 25, and 25 percent of the time at baseload, 75 percent load and low load conditions, respectively. "Low" load conditions are the minimum load where the CT can meet the BACT $NO_x$ limits for gas. A total 7 percent margin was added that consisted of 2 percent vendor for performance to account for that lack of vendor guarantees over the operating range and 5 percent to account of normal degradation with time. The latter is especially important for simple cycle CTs that have numerous startups and shutdowns during operation. The 720 hour composite average operating hours, or an equivalent 30-days of operation, would encompass the range of operating conditions that the CTs would likely experience. A 12-month rolling average for peaking units would not be appropriate as some months no or limited operation could occur that would not be representative of normal operation.

For ULSD oil-firing during normal operation (loads when the CT can comply with emission limits for $NO_X$) the proposed limit is 1,874 lb/$CO_2$ e/MWh based on a composite average of 720 operating hours calculated as follows:

| Category | Units | Estimated Performance | | |
|---|---|---|---|---|
| Fuel | | Oil | Oil | Oil |
| Turbine Inlet | degree F | 85 | 85 | 85 |
| Evaporative Cooling | | Off | Off | Off |
| Gross Load | % | 100% | 75% | Low [a] |
| Gross Heat Rate | Btu/kWh (HHV) | 10,064 | 10,683 | 12,351 |
| Gross Efficiency | % | 33.9% | 31.9% | 27.6% |
| $CO_2e$ | lb $CO_2e$/MWh | 1,633 | 1,734 | 2,004 |
| Operation | | 50% | 25% | 25% |
| Gas Average $CO_2e$ | lb $CO_2e$/MWh | 1,751 | (Average of 100%, 75% and Low load) | |
| Performance Margin | % | 2% | (Vendor Performance Margin) | |
| Degradation Margin | % | 5% | (Account for normal wear during operation) | |
| Proposed $CO_2e$ | lb $CO_2e$/MWh[a] | 1,874 | Composite average of 720 operating hours | |

[a] Load at which the CT has achieved compliance with $NO_x$ emission limit.

This proposed limit does not include startups and shutdowns, fuel switches and combustor tuning. CT could have multiple startups and shutdowns in any day and as previously presented operation can be as short as 30 minutes during emergency periods. During startups and shutdowns the CT operates at very low loads with substantially higher heat rates. While startups and shutdowns periods are of short duration (typically less than 30 minutes), the lb/$CO_2$e is substantially higher.

The CTs selected for the Project have fast start options, which are critical to the Project's design criteria to achieve the grid response requirements. Therefore the CTs can be started in traditional start mode or fast start mode. The fast start mode is approximately 10 minutes while the traditional start is 30 minutes to 50 percent load. FPL plans the operation of CTs based on the energy demand requirements. This may include fast and traditional starts depending on the generation needed. Fast starts are intended to be used only when grid responsiveness requirements demand the quicker startup. Shutdown is approximately 10-15 minutes from 100 percent load.

It should be noted that while manufacturers have provided startup and shut down emission estimates, they are not guaranteed and are only estimated from new and clean performance. For the Project the estimated maximum startup and shutdown (SUSD) GHG emissions in lb $CO_2$e/MWh, which includes fuel switches and combustor tuning, are as follows based on natural gas and ULSD firing:

- 3,492 lb $CO_2$e/MWh when firing natural gas
- 3,451 lb $CO_2$e/MWh when firing ULSD oil

As previously presented the Project will replace first generation inefficient gas turbines with efficient CTs. The new CTs would emit much lower GHG emissions for the same amount of generation when compared to the existing gas turbines.

The proposed GHG limit for this Project is similar to the GHG contained in the final PSD Permit for the Shady Hill Generating Station that is using the GE 7F.05 CTs (Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions Permit PSD-EPA-R4013, United States Environmental Protection Agency, Region 4, Atlanta, Georgia, Dated 1/14/14). In this draft GHG PSD permit, the GHG emission limit is 1,377 lb $CO_2$e/MWh for natural gas firing and 1,928 lb $CO_2$e/MWh for distillate oil firing.

The addition of the new CTs to FPL's fleet will further improve FPL's low GHG emission rate that is one of the lowest in the U.S. electric utility industry. Based on the analysis, the proposed BACT emission rates are appropriate for this generation replacement project.

For the composite 720 operating hour rolling proposed GHG limits, FPL is proposing a continuous monitoring and compliance method based on 40 CFR Part 60 Subpart KKKK. This NSPS is for stationary combustion turbines and includes a lb $NO_x$/MWh standards and methods of calculating a composite standard using multiple fuels. FPL proposes similar standards and methods for CO2e/MWH calculations. The suggested permit language is provided below:

1. Permittee shall install and certify monitoring systems required for quantifying $CO_2$ emissions from each CT in accordance with the applicable requirements of 40 CFR Part 75. Consistent with §75.4(b), all applicable certification tests shall be completed within 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR 72.2).

2. Following initial certification, the $CO_2$ continuous measurement system shall be quality assured in accordance with the applicable requirements of 40 CFR Part 75.

3. The $CO_2$ continuous measurement system shall be capable of producing hourly determinations of $CO_2$ mass emissions in tons per hour (tons/hr).

4. In accordance with §75.62, an initial monitoring plan shall be submitted identifying the methodology for which $CO_2$ mass emissions will be continuously monitored. The initial monitoring plan shall be submitted no later than 21 days prior to the initial certification tests.

5. Permittee shall provide notifications as specified in §75.61 for any event related to the continuous measurement of $CO_2$.

6. Permittee shall measure and record, for each CT, the actual heat input (Btu) on an hourly basis in accordance with 40 CFR Part 75.

7. Permittee shall measure and record, for each CT, the following on an hourly basis as described in accordance with the condition of this permit:

a. Gross energy output rate (MW);

d. $CO_2$ mass emission rate (tons $CO_2$/hr) for each CT;

e. Fuel Heat Input rate (mmBtu/hr) for each CT;

f. Unit Operating Time as described in §75.57(b)(2);

g. The type of fuel (natural gas or ULSD) burned for each CT; and

h. Time of each mode of operation: 1. Low or Higher Loads or 2. SUSD.

8. Permittee shall calculate and record, for each CT, the following on an hourly basis for each hour of operation:

a. The 720 operating hour rolling average $CO_2$ emission rate (lbs CO2/$MWh_{gross}$) calculated as the sum of each hourly $CO_2$ mass emission rate (tons $CO_2$/hr) times the unit operating time for the respective hour divided by the sum of the recorded hourly gross energy output ($MWh_{gross}$) for all hours of operation in the 720 operating hour period.

$$AvgCO2Rate_i = \frac{\sum_1^{720} CO2Mrate_i * t_i}{\sum_1^{720} GrossMWh_i}$$

b. The applicable composite standard for the 720 operating hour period (lb $CO_2$/$MWh_{net}$). The applicable composite standard is the average of the applicable standard for each hour of operation in the 720 operating hour period. For hours where multiple emissions standards would apply; the applicable limit for that hour is determined based on the condition that corresponds to the highest emissions standard.

$$CompositeStd = \frac{Limit_{Gas} * MWh_{Gas} + Limit_{Oil} * MWh_{Oil} + Limit_{GasSUSD} * MWh_{GasSUSD} + Limit_{OilSUSD} * MWh_{OilSUSD}}{Total\ MWh}$$

c. The 720 operating hour rolling average heat rate (Btu/$kWh_{gross}$) calculated as the sum of each hourly heat input rate times the unit operating time for the hour divided by the sum of the recorded hourly gross energy output ($MWh_{gross}$) for all hours of operation in the 720 operating hour period times 1,000.

$$AvgHeatRate_i = \frac{\sum_1^{720} HIrate_i * t_i}{\sum_1^{720} GrossMWh_i} * 1{,}000$$

### *4.3.5 Circuit Breakers*

$SF_6$ is an electrical insulator and interrupter in equipment that transmits and distributes electricity. $SF_6$ has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulating oils.

Circuit breakers associated with the Project are estimated to contain approximately 125 lbs of $SF_6$. Based on the guaranteed leak rate, not to exceed 0.5 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 125 lb $SF_6$ x 0.005 leakage/year = 0.625 lb $SF_6$/year

- 0.625 lb $SF_6$/year x 22,900 $CO_2$e/lb $SF_6$ (Table A-1, 40 CFR Part 98) = 14,250 lb $CO_2$e (7.1 tons $CO_2$e)

***Step 1 – Identify All Available Control Technologies***

The first step in the top down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

The available control options include alternative (non-$SF_6$) dielectric fluids and minimizing the fugitive emission of $SF_6$. 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 predominately replaced with $SF_6$ that has excellent dielectric and arc-quenching properties and is not flammable.

Modern $SF_6$ circuit breakers are designed as totally enclosed-pressure systems with low potential $SF_6$ fugitive emissions. Leakage is typically no more than 0.5 percent by weight. It should be recognized that the actual leakage rate is likely 0.1 percent by weight based on EPA's $SF_6$ Emission Reduction Partnership. Circuit breakers have indication that provide a warning if a leak is occurring and corrective action is necessary. In addition, this equipment is routinely inspected to verify proper operation since this equipment is necessary for the safe operation of the CTs.

***Step 2 – Identification of Technically Feasible Control Alternatives***

Under the second step of the top down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available.

Circuit breakers using $SF_6$ with alarms and periodic inspections are technically feasible for the Project. The use of alternative dielectric fluids is not practicable for high-voltage applications. Circuit breakers using $SF_6$ are presently superior in their performance to alternative systems such as dielectric oil, high pressure air blast or vacuum circuit breakers. Moreover, EPA's $SF_6$ Partnership has recognized that there is no clear alternative to using $SF_6$ and fugitive emissions are reduced by implementing detection, repair and replacement strategies [EPA, 2011; ($SF_6$ Emission Reduction Partnership for Electric Power Systems, 2010 Annual Report, December 2011)].

***Step 3 – Rank Remaining Control Technologies***

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2 above, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness.

The most effective control of fugitive $SF_6$ emissions is using a totally enclosed system equipped with leak detection, periodic inspections and maintenance. The expected guarantee meets the requirements of the International Electrotechnical Commission (IEC) standard of 0.5 percent (IEC Standard 62271-1, 2004) that is recognized by the EPA's $SF_6$ Reduction Partnership as an effective criterion for minimizing fugitive $SF_6$ emissions.

***Step 4 – Economic, Energy, and Environmental Impacts***

Under Step 4 of the top down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The "top" control option and in the case of GHG the "top" energy reduction technology should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The "top" control option is the use of $SF_6$ circuit breakers that offer low economic, energy and environmental impacts. $SF_6$ is the preferred gas for electrical insulation, arc-quenching and current insulation for high voltage equipment. It is chemically inert, non-toxic, non-flammable, non-explosive and thermally stable. $SF_6$ exhibits properties that are beneficial from an economic, energy and environmental standpoint when used in totally enclosed systems.

***Step 5 – Select the BACT***

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

***BACT***

Based on the top-down analysis, the only technically feasible controls technologies for the $SF_6$ circuit breakers associated with the Project are the use of modern totally enclosed circuit breakers with a leakage rate of 0.5 percent that are thoroughly tested, equipped with leak detection systems (density alarms) and performing periodic inspections. Together these controls will minimize $SF_6$ fugitive emissions to no more than 7.1 tons $CO_2$e/year.

$SF_6$ breakers will be monitored remotely and continuously through the plant control system to confirm that $SF_6$ integrity is maintained. In the event of an alarm, an inspection will be performed on the breaker. Preventative maintenance will be performed at intervals recommended by the manufacturer or at intervals standard in the electric power industry for the relevant type of breaker. The breaker-specific monitoring program will be submitted after the equipment is selected and placed in service.

## 5.0 AMBIENT MONITORING ANALYSIS

Based on the net emission changes from the proposed Project (see Table 3-3), pre-construction ambient monitoring analyses for $PM_{10}$, $PM_{2.5}$, $NO_2$, $SO_2$ and $O_3$ (based on $NO_X$ or VOC emissions) may be required as part of the PSD application. Ambient monitoring analyses are not required if it can be demonstrated that the Project's maximum air quality impacts will not exceed the PSD significant monitoring concentrations (SMC) and, for $O_3$, the Project's potential emissions will not exceed 100 TPY of $NO_X$ or VOC emissions.

Maximum impacts due to the Project only are predicted to be below the SMC for $PM_{10}$, $PM_{2.5}$, $NO_2$, and $SO_2$ (see Table 6-5). As a result, a pre-construction ambient monitoring analysis is not required for these pollutants as part of the application, except for $PM_{2.5}$ (see the following paragraphs). It should be noted that EPA has not proposed SMC for the 1-hour average $NO_2$ concentration.

For $O_3$, the Project's VOC emissions are less than 100 TPY; however, $NO_X$ emissions are more than 100 TPY or more, which requires that pre-construction ambient monitoring analysis for $O_3$ be submitted as part of the application.

For $PM_{2.5}$, on January 22, 2013, the US Court of Appeals for the District of Columbia vacated the parts of the two PSD rules (40 CFR 51.166 and 40 CFR 52.21) establishing an SMC, finding that EPA was precluded from using the $PM_{2.5}$ SMC to exempt permit applicants from the statutory requirement to compile preconstruction monitoring data (EPA, March 4, 2013) http://www.epa.gov/nsr/documents/20130304qa.pdf. As a result, permitting of new or modified sources requires submittal of monitoring data prior to construction regardless of the source's impact. As a result, $PM_{2.5}$ concentrations from a representative monitor must be submitted as part of the PSD permit application because the Project's $PM_{2.5}$ emissions are greater than the SER.

Based on the impacts of $PM_{10}$, $NO_2$, and $SO_2$ being less than SMC, an exemption from the pre-construction monitoring requirement is applicable pursuant to Rule 62-212.400(3)(e), F.A.C. In addition, ambient $O_3$ and $PM_{2.5}$ monitoring data collected by FDEP at monitoring stations near the Project are considered to be representative of air quality in the Project's vicinity. These data are being used to satisfy the pre-construction monitoring requirement for $O_3$ and $PM_{2.5}$ that primarily form from atmospheric processes and are not directly emitted.

Air quality monitoring data collected in Lee County from 2012 through 2014 for $O_3$ and $PM_{2.5}$ are presented in Tables 5-1 and 5-2, respectively. These data indicate that the maximum air quality concentrations measured in the region are well below applicable standards.

Since the Project's maximum 1-hour average $NO_2$ impacts are predicted to be greater than the significant impact levels for these pollutants (see Table 6-5, 1-Hr $NO_2$ NAAQS Results), more detail analyses are required to demonstrate compliance with the AAQS. For these analyses, total air quality impacts are predicted for the modeled sources which are added to a non-modeled background concentration. The non-modeled background concentrations are estimated from representative ambient air quality monitoring data obtained from air monitoring stations. The 1-hour $NO_2$ monitoring data collected at monitor ID 012-115-1006 in Sarasota, Florida, which is the nearest $NO_2$ monitor to the Fort Myers plant is summarized in Table 5-3.

## 6.0 AIR QUALITY IMPACT ANALYSIS

This section addresses the predicted air quality impacts of regulated air pollutants due to the Project and, as appropriate, background sources. The general modeling approach followed the latest EPA and FDEP modeling guidelines for predicting air quality impacts for regulated pollutants.

As described in Section 1.0, the Project replaces 10 GTs located at the Fort Myers plant in Lee County. While 10 GTs will be retired at the Fort Myers Plant as a result of the Project, this air quality impact assessment only considered the increase in emissions from the two new CTs and does not address the improvement in the air quality from the retirement of the existing GTs. As a result, the analysis results will conservatively reflect the air quality impact due to the overall Projects net emissions increase without consideration of the air quality improvements made by retiring the existing GTs. This air quality improvement would occur both in the vicinity of the Project site and at the ENP and result in the expansion of the PSD Increments in the Class II areas in the Project's vicinity and at the ENP PSD Class I area.

Based on the potential emissions of the Project, the Project's emissions are greater than the PSD SERs for $NO_X$, $PM/PM_{10}/PM_{2.5}$, and $SO_2$ requiring an air quality impact analysis for these pollutants under FDEP rules.

The following sections present a summary of the air quality modeling methodology used for the air quality impact analyses for the Project.

### 6.1 Air Modeling Analysis Approach and Results – PSD Class II Areas

#### Model Selection

The selection of air quality models to calculate air quality impacts for the proposed project must be based on the models' ability to simulate impacts in the vicinity of the facility. The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant impacts due to the proposed project. AERMOD (Version 14134) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technology Transfer Network (TTN). The EPA and FDEP recommend that AERMOD be used to predict pollutant concentrations at receptors located within 50 km of a source. AERMOD calculates hourly concentrations based on hourly meteorological data. AERMOD is applicable for the type of Project sources and area in which the Project is located since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain.

AERMOD was used to predict the maximum pollutant concentrations due to the Project at nearby areas surrounding the facility.

For modeling analyses that will undergo regulatory review, such as determining compliance with NAAQS, the following model features are recommended by EPA for rural mode and are referred to as the regulatory default options in AERMOD:

1. Final plume rise at all receptor locations
2. Stack tip downwash
3. Buoyancy induced dispersion
4. Default wind speed profile coefficients for rural mode
5. Default vertical potential temperature gradients
6. Calm wind processing

The EPA regulatory default options were used to address maximum impacts

## Project Sources

Air quality analyses were performed to assess the maximum impacts of the two new simple-cycle CTs at FPL's existing Fort Myers Plant. The CTs being proposed for the Project are nominal 200 MW units GE 7F.05 CTs.

Summaries of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed GE 7F.05 used in the air modeling analysis are presented in Section 2 for both natural gas-firing and ULSD oil-firing. Air quality impacts were predicted for a range of possible operating conditions. The following 9 CT load and temperature scenarios were evaluated for the GE 7F.05 CTs when firing natural gas and ULSD oil:

- 100 percent load and ambient temperatures of 35°F, 59°F, and 95°F
- 75 percent load and ambient temperature of 35°F, 59°F, and 95°F
- 50 percent load and ambient temperature of 35°F, 59°F, and 95°F

The new CTs will have stack heights of 100.5 feet and an inner diameter of 23 feet. Building downwash effects were included in the modeling analysis to account for the nearby structures. In addition, for cumulative source impact assessments, building downwash effects were included in the modeling analysis for the Fort Myers Plant's existing sources.

### Building Downwash Effects

The dimensions of structures associated with the CTs were provided by the vendors of each type of CT. The primary structures for the CTs are the air inlet structures and the dimensions for each structure are provided in the table below. All structures were processed in the EPA Building Profile Input Program [(BPIP), Version 04274] to determine direction specific structure heights and widths for each 10 degree azimuth direction for each source that was included in the modeling analysis:

| Structure | Height (ft) | Width (ft) | Length (ft) |
|---|---|---|---|
| **For GE F7A.05 CTs** | | | |
| CT Air Inlet | 72.1 | 21.4 | 44.3 |
| CT Building | 22 | 36 | 30 |

### Meteorological Data

Meteorological data used in AERMOD to estimate air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and upper air sounding data collected from the National Weather Service (NWS) stations located at the Fort Myers Page Field Airport (FMY) and Ruskin, respectively. The 5-year period of the meteorological data was from 2009 through 2013 and was prepared by the FDEP using AERMET Version 14134. AERMINUTE Version 11059 was used by FDEP to process 1-minute wind data collected by the automatic surface observing system (ASOS) into hourly averages of wind direction and wind speed. A minimum wind speed threshold of 0.5 meters per second (m/s) was used. The NWS office at the airport is located approximately 14 km (8.5 miles) southwest of the Project site. The areas between the airport and the Fort Myers Plant are flat with very similar land characteristics.

Land use parameters were extracted seasonally and for twelve 30-degree wind direction sectors using AERSURFACE Version 13016. The parameters were taken from the airport (measurement site). The annual average land use parameters for both the airport and application site locations are as follows:

| Location | Albedo | Bowen Ratio | Surface Roughness |
|---|---|---|---|
| NWS Station | 0.16 | 0.60 | 0.093 |
| Project Site | 0.15 | 0.45 | 0.068 |

The results indicate that the Project site's land use parameters are similar to those for the NWS station. As such, the meteorological data with land use values from the NWS site were selected to be used throughout the modeling analysis.

## Receptor Locations

A Cartesian grid was used to predict concentrations on and beyond the property boundary out to 5 km. Receptors were located at the following intervals and distances from the Project:

- Along the property boundary or fence line – 50 meters
- Beyond the fence line to 2 km – 100 meters
- From 2 km to 5 km – 250 meters

More than 2000 receptors were used to estimate the maximum concentrations predicted for the Project.

## Significant Impact Analysis

A significant impact analysis is performed to determine the maximum air quality impact due to only the Project's emissions increases. If the highest predicted impact for a particular pollutant and averaging time exceeds the respective PSD Class II significant impact level (SIL), more detailed modeling analyses are required for that pollutant and averaging time to address compliance with the NAAQS and, if applicable, the allowable PSD increment.

For this Project, SIL analyses were performed for the following pollutants and averaging times:

- $NO_2$: 1-hour and annual averages
- $PM_{10}$: 24-hour and annual averages
- $PM_{2.5}$: 24-hour and annual averages
- $SO_2$: 1-hour, 3-hour, 24-hour and annual averages

The SIL analyses for the 1-hour $SO_2$, 1-hour $NO_2$, and 24-hour and annual $PM_{2.5}$ concentrations are based on the maximum 5-year average concentrations predicted using 5 years of representative meteorological data. The SIL analyses for the 24-hour $PM_{10}$ and 1-hour and 3-hour, 24-hour and annual $SO_2$ concentrations are based on the maximum predicted concentrations over the 5-year period. The SIL analyses for the annual average $NO_2$ and $PM_{10}$ concentrations are based on maximum predicted concentrations for any year over the 5-year period.

The predicted annual average impacts for the significant impact analysis are based on the CTs being limited to 3,390 hr/yr with ULSD oil-firing for each CT limited to 500 hr/yr. For pollutants with higher predicted impacts occurring when firing ULSD oil, the predicted annual impact is based on the maximum of 500 hr/yr of ULSD oil-firing. The short-term impacts are based on an operation of 10 hours per day of ULSD oil firing that conservatively represents operation of the CTs on this fuel. For pollutants with higher predicted impacts occurring when firing natural gas, the predicted annual impact assumes 3,390 hr/yr of natural gas-firing and the short-term impacts assume only natural gas firing.

Once the highest impacts were identified for the combination of ambient temperature and operating load condition (i.e., worst-case operating condition), subsequent analyses were performed with the emissions rates and exit gas operating data for those conditions for each pollutant and CT vendor.

It should be noted that In January 2013, the $PM_{2.5}$ SIL under 40 CFR 51.166(k)(2) and 40 CFR 52.21(k)(2) were vacated and remanded the portions of EPA's rule regarding the SIL to exempt sources from cumulative source modeling [Sierra Club v. EPA, 705 F.3d 458 (D.C. Circuit 2013)]. On March 4, 2013, EPA issued *Draft Guidance for $PM_{2.5}$ Permit Modeling* (Stephen D. Page, Director, OAQPS) that provided preliminary recommendations describing how a stationary source seeking a PSD permit can demonstrate that it will not cause or contribute to a violation of the NAAQS and PSD increments. According to the EPA's draft guidance, with additional justification, the permitting authority may use the same $PM_{2.5}$ SILs that were vacated to demonstrate that a full cumulative source impact analysis is not needed.

Based on the results of the significant impact analysis, only the 1-hour $NO_2$ concentrations were predicted to exceed the SIL. When addressing the NAAQS for 1-hour $NO_2$, the 5-year averages of the 98$^{th}$ (8$^{th}$ highest) percentile of the daily maximum 1-hour average concentrations at each receptor were determined. The maximum 5-year average of these values is used to estimate the maximum impact.

### $NO_2$ Modeling Analysis

A 3-tiers modeling approach based on the EPA modeling guidance document (Tyler Fox, March 1, 2011; Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard), a 3-tiered modeling approach is recommended for modeling $NO_2$ concentrations. These approaches are:

- Tier 1: $NO_X$ emissions are assumed fully converted to $NO_2$
- Tier 2: $NO_X$ emission are assumed 75 percent converted to $NO_2$ on an annual basis and 80 percent converted on a 1-hour basis
- Tier 3: an application of a more detailed modeling approach such as Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limited Method (OLM) to further refine $NO_2$ impacts

For this analysis, a Tier 2 modeling approach was used to predict $NO_2$ concentrations.

## Cumulative Air Quality Analyses

Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with the NAAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling, fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used for this purpose.

Concentrations predicted for the NAAQS analyses include the modeled impacts from sources at the facility, background emission sources in the vicinity of the Fort Myers Plant, and a background concentration that accounts for sources not included in the modeling analysis.

### *Background $NO_2$ Emission Sources*

Current EPA guidance on 1-hour NO2 NAAQS is provided in the EPA memorandum (Tyler Fox, March 1, 2011, see above). The memorandum suggests that background sources within a radius of 10 km are sufficient for addressing any potential source interactions that could occur during a 1-hour averaging time.

Based on the results of the significant impact analysis, an inventory of background $NO_2$ emission sources was requested from FDEP. A summary of the emissions, distances and directions of these sources from the proposed project are summarized in Table 6-1. A detailed list of background sources included in the NAAQS modeling analysis is summarized in Table 6-2.

### *Non-Modeled Background Concentrations*

Summaries of measured ambient concentrations, for use in determining background concentrations, are presented in Section 5.0. The background concentrations are based on averages of monitor measurements from 2012 to 2014. The background concentrations used for the 1-hour $NO_2$ NAAQS modeling analysis is 33.9 µg/m$^3$.

## Model Results

### *Significant Impact/CT Load Analysis – GE 7FA CTs*

The results of the CT load analysis for one CT firing natural gas is presented in Table 6-3 and Table 6-4 presents the CT load analysis results for one CT firing ULSD oil. The predicted maximum project-only impacts due to the two CTs are compared to the significant impact levels in Table 6-5, which presents results for both natural gas and ULSD oil firing. Based on the results presented in Table 6-5, the proposed project's maximum impacts are predicted to be less than the SIL except for the 1-hour $NO_2$ concentrations. As such, a cumulative source modeling analysis is required to determine compliance with the 1-hour $NO_2$ NAAQS.

### *1-hour $NO_2$ NAAQS Results*

The NAAQS modeling results are summarized in Table 6-6. The maximum predicted 1-hour $NO_2$ concentration due to all sources is 92.3 µg/m$^3$, which when added to the background concentration, results in a total concentration of 126.2 µg/m$^3$, which is well below the NAAQS of 188.1 µg/m$^3$.

## 6.2 Air Modeling Analysis Approach and Results- PSD Class I Area

### Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8) was used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility controlling pollutants) and wet/dry deposition. CALPUFF was used in a manner that is consistent with methodologies recommended in the following document and in subsequent discussions with the FLM.

- FLMs' AQRV Workgroup (FLAG) guidance document, revised in October 2010 and referred to as the FLAG Phase I Report

Parameter settings to be used in CALPUFF were based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults were used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations was used. A fixed monthly ammonia background concentration of 0.5 ppb was used. For predicting 24-hour visibility impairment, the FLAG guidance recommends using CALPOST Version 6.221, Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days. In addition, parameters were set to calculate wet and dry (i.e., total) fluxes and concentrations at the evaluated PSD Class I area.

### Project Modeled Emissions

The Project's emission, stack, and operating data as well as building dimensions were modeled for the emission sources as indicated previously.

PM emissions for the Project's stack emissions were speciated into six particle size categories for modeling. All of the condensable PM emissions, which were assumed to be 50-percent of the total stack emissions were evenly split into two smallest size categories – 0 to 0.625 microns and 0.625 to 1 micron. The filterable PM emissions, which were assumed to be 50-percent of the total PM emissions were evenly split into 4 particle size categories – 0 to 0.625, 0.625 to 1, 1 to 1.25, and 1.25 to 2.5 microns. Therefore, all of the $PM_{10}$ emissions were assumed equal to $PM_{2.5}$ emissions. Results of the individual size categories were grouped to obtain total $PM_{10}$/$PM_{2.5}$ impact.

Note that emissions for sulfuric acid mist were input directly into CALPUFF as $SO_4$.

## Building Downwash Considerations

The same methods used in the PSD Class II analyses to assess building downwash were used in these analyses.

## Meteorological Data

The far-field air modeling analyses were conducted using meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were developed using CALMET Version 5.8 and were originally developed by VISTAS and recompiled for Version 5.8 by the FLM. The dataset have 4-km spacing and cover the period from 2001 to 2003. For this Project, meteorological data from VISTAS subdomain No. 2 were used for the far-field modeling analysis.

## Receptor Locations

The FLM has developed receptors to represent the boundary and internal areas of all PSD Class I areas. The Class I analysis used the receptors developed by the FLM for ENP.

## Significant Impact Analysis

Significant impact analyses were performed to assess the Project's impacts at the PSD Class I area. The maximum predicted $NO_2$, $PM_{10}$, and $PM_{2.5}$ concentrations due to the Project were compared to EPA's proposed PSD Class I significant impact levels. If the Project's impacts exceed the proposed EPA PSD Class I significant impact levels, then a more detailed PSD Class I increment analysis will be performed on a pollutant-specific basis. In the PSD Class I incremental analysis, PSD-increment affecting sources will be modeled for comparison to the allowable PSD Class I increments.

The proposed PSD Class I significant impact levels are:

- $NO_2$: annual average – 0.1 µg/m$^3$
- $PM_{10}$: 24-hour – 0.3 µg/m$^3$, and annual average – 0.2 µg/m$^3$

- $PM_{2.5}$: 24-hour – 0.07 μg/m$^3$, and annual average – 0.06 μg/m$^3$

### Model Results

The results of the PSD Class I significant impact analysis for the ENP is presented in Table 6-7. The analysis results indicated that the proposed project's maximum predicted impacts will be less than the Class I SIL and that further analyses to determine compliance with the allowable PSD Class I increments are not required.

## 7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the Project and general commercial, residential, industrial and other growth associated with the Project will have on vegetation, soils, and visibility in the vicinity of the site and impacts at the PSD Class I area of the ENP related to AQRVs. Specifically, this section addresses FDEP Rules 62-212.400(4)(e), (8)(a) and (b), and (9), F.A.C. These rules are:

> (4) Source Information.
>
> (e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.
>
> (8) Additional Impact Analyses.
>
> (a) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (b) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.
>
> (9) Sources Impacting Federal Class I Areas. Sources impacting Federal Class I areas are subject to the additional requirements provided in 40 CFR 52.21(p), adopted by reference in Rule 62-204.800, F.A.C.

### 7.1 Potential Impacts Due to Associated Growth

#### *7.1.1 Impacts of Associated Growth*

As previously discussed, the Project will replace the 10 existing GTs located at the Fort Myers Plant. These existing GTs have a rated gross capacity of about 630 MW and will be replaced with two highly efficient lower emitting CTs with a nominal capacity of 200 MW each, for a total of about 400 MW. Thus, the Project is not in response to growth and will provide significant air quality improvement when compared to the existing GTs.

Construction of the proposed Project will occur over approximately 12 months and will require an average of over 100 workers during that time. It is anticipated that many of these construction personnel will commute to the site. However, no additional permanent workers will be employed for the operation of the facility. The workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth. The existing commercial and industrial infrastructure is adequate to provide any support services that facility might require and would not increase with the operation of the facility.

As demonstrated in Section 6.0, the maximum air quality impacts resulting from the proposed new CT Project are predicted to be low and below the significant impact levels for all by the 1-hour NO2 concentrations. The predicted cumulative source 1-hour NO2 impacts demonstrate that the Fort Myers Plant and background sources will comply with the NAAQS. In fact, the retirement of 10 GTs at the existing Fort Myers Plant is expected to significantly improve air quality in the area.

## 7.2 Potential Air Quality Effect Levels on Soils, Vegetation and Wildlife

### *7.2.1 Soils*

The potential and hypothesized effects of atmospheric deposition on soils include:

- Increased soil acidification
- Alteration in cation exchange
- Loss of base cations
- Mobilization of trace metals

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

### *7.2.2 Vegetation*

The concentrations of the pollutants, duration of exposure, and frequency of exposure influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions, interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

In general, the effects of air pollutants on vegetation occur primarily from $SO_2$, $NO_2$, $O_3$, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below those that result in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

## Nitrogen Dioxide

$NO_2$ can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of $NO_2$ can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru, et al., 1979).

For plants that have been determined to be more sensitive to $NO_2$ exposure than others, acute exposure (1, 4, and 8 hours) caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 µg/m$^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered $NO_2$ sensitive) to $NO_2$ concentrations of 2,000 to 4,000 µg/m$^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short-term exposure to $NO_x$ at concentrations of 564 µg/m$^3$ caused adverse effects in lichen species (Holopainen and Karenlampi, 1984).

## Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 µg/m$^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 µg/m$^3$ did not appear to be injurious to the tested plants.

### Sulfur Dioxide (and Sulfuric Acid Mist)

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When $SO_2$ in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed $SO_2$ effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-1 and 7-2, respectively. $SO_2$ gas at elevated levels has long been known to cause injury to plants. Acute $SO_2$ injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury is usually evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of $SO_2$ range from 2.5 to 25 µg/m$^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term $SO_2$ exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour $SO_2$ concentrations of 790 to 1,570 µg/m$^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour $SO_2$ concentrations of 1,570 to 2,100 µg/m$^3$. Resistant species (injured at concentrations above 2,100 µg/m$^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 µg/m$^3$ $SO_2$ for 8 hours were not visibly damaged. This finding support the levels cited by other researchers on the effects of $SO_2$ on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour $SO_2$ concentrations of 920 µg/m$^3$. Jack pine seedlings exposed to $SO_2$ concentrations of 470 to 520 µg/m$^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m$^3$ $SO_2$ for 24 hours a day for 1 week demonstrated a 48-percent reduction in photosynthesis (Carlson, 1979).

$SO_2$ is considered to be the primary factor causing the death of lichens in most urban and industrial areas. The first indications of damage from $SO_2$ include the inhibition of nitrogen fixation, increased electrolyte leakage, and decreased photosynthesis and respiration followed by discoloration and death of the algal component of the lichen (Fields 1988). Sensitive species are damaged or killed by annual average levels of sulfur dioxide ranging from 8 to 30 μg/m$^3$, and very few lichens can tolerate levels exceeding 125 μg/m$^3$ (Johnson 1979, DeWit 1976, Hawsworth and Rose 1970, LeBlanc et al. 1972). In another study, two lichen species exhibited signs of $SO_2$ damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 μg/m$^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).

Acidic precipitation is formed from $SO_2$ emissions during the burning of fossil fuels. This pollutant is oxidized to sulfur trioxide in the atmosphere and dissolves in rain to form sulfuric acid mist (SAM), which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, SAM has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton et al., 1950).

#### Ozone

$O_3$ can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis, and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. $O_3$ can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

### *7.2.3 Wildlife*

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary NAAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of $NO_x$, and particulates that are reported to cause physiological changes are shown in Table 7-3.

### *7.2.4 Impact Analysis Methodology*

A screening approach was used that compared the Project's maximum predicted ambient concentrations of air pollutants of concern in the vicinity of the site and the ENP PSD Class I Area with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted to determine the effects of air contaminants on plant species as well as those species reported to occur in the vicinity of the site and in the PSD Class I area. It is recognized that effect threshold information is not available for all species found in these areas, although studies have been performed on a few of the common species and on other species known to be sensitive indicators of effects. Species of lichens, which are symbiotic organisms comprised of green or blue-green algae and fungi, have been used worldwide as air pollution monitors because relatively low levels of sulfur-, nitrogen-, and fluorine-containing pollutants adversely affect many species, altering lichen community composition, growth rates, reproduction, physiology, and morphological appearance (Blett et al., 2003).

## 7.3 Impacts on Soils, Vegetation, Wildlife, and Visibility in the Project's Vicinity

### *7.3.1 Impacts on Vegetation and Soils*

Vegetative communities in the vicinity of the Project area are occupied by areas of Brazilian pepper (*Schinus terebinthifolius*) and cabbage palm (*Sabal palmetto*) hammock, Australian pine (*Casuarina equisetifolia*), Melaleuca (*Maleleuca quinquenervia*) and cat-tail (*Typha domingensis*) marsh. The Brazilian pepper and cabbage palm hammock, Australian pine, Melaleuca are dominated by invasive exotic species that out compete native vegetation and do not provide quality habitat for wildlife. The Caloosahatchee National Wildlife Refuge, a combination of mangroves and mixed forested wetlands, is located north the Fort Myers Plant across the Caloosahatchee River.

Soils in the areas not developed by the existing power facilities and urban development are primarily Caloosa fine sand, Immokalee sand, Matkacha gravelly fine sand Felda fine sand, in order of area (USDA, 2015). These soils are typically well drained.

According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the proposed Project are predicted to be below the NAAQS and PSD increments. The NAAQS were established to protect both public health and welfare. Public welfare is protected by the secondary NAAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings (EPA, 2007).

Since the project's impacts on the local air quality are predicted to be less than the NAAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible. With regard to $O_3$ concentrations, the Project's VOC and $NO_x$ emissions (precursors to $O_3$ formation) represent an insignificant increase in VOC and $NO_x$ emissions for Lee County.

### 7.3.2 Impacts on Wildlife

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from the FPL Fort Myers Plant will cause adverse effects to wildlife due to the new CT Project's low impacts, which are predicted to be below the NAAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely. In addition, the Project replaces 10 GTs located at the existing Fort Myers Plant which is expected to provide a huge improvement in the air quality of the area.

## 7.4 Impacts to the Everglades National Park PSD Class I Area

### 7.4.1 Identification of AQRVs and Methodology

An AQRV analysis was conducted to assess the potential risk to AQRVs at the ENP due to the emissions from the proposed Project. The ENP is located between 96.9 and 224.9 km and to the southeast of the Fort Myers Plant and is the only PSD Class I area located within 200 km.

The U.S. Department of the Interior in 1978 defined AQRVs to be:

- All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
- Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

### 7.4.2 Impacts to Soils

The soils of the ENP are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs, coupled with the low ground-level concentrations of air pollutants predicted from the proposed Project emissions, precludes any significant impact on soils at the ENP.

### 7.4.3 Impacts to Vegetation

#### Nitrogen Dioxide

The maximum 1-, 3-, and 8-hour average $NO_2$ concentrations due to the proposed Project are predicted to be 1.492, 0.9954, and 0.446 µg/m$^3$, respectively, at the ENP. These concentrations are approximately 0.01 to 0.04 percent of the levels that could potentially injure 5 percent of vascular plant foliage (i.e., 3,800 to 15,000 µg/m$^3$; see previous subsections), and 0.26 percent of the concentration that caused adverse effects in lichen species in acute exposure scenarios (564 µg/m$^3$; see previous subsections). For a chronic exposure, the maximum annual $NO_2$ concentration due to the Project is predicted to be 0.006 µg/m$^3$ at the Class I area, which is less than 0.0003 percent of the levels that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 µg/m$^3$; see previous subsections).

Although it has been shown that simultaneous exposure to $SO_2$ and $NO_2$ results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone, and usually occurs at unnaturally high levels of each gas. Therefore, the project's predicted concentrations at the ENP are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

#### Particulate Matter

The maximum 8-hour $PM_{10}$ concentration due to the Project is predicted to be 0.146 µg/m$^3$ at the ENP. This impact is 0.07 percent of the values that affected plant foliage (i.e., 210 µg/m$^3$, see previous subsections). As a result, no significant effects to vegetative AQRVs within the ENP are expected as a result of the Project's PM emissions.

### Sulfur Dioxide

The maximum annual average $SO_2$ concentration resulting from the Project is 0.0002 µg/m$^3$, less than 0.01% of the concentration that damaged the most sensitive lichen species (8 µg/m$^3$). The maximum 3-, and 24-hour average $SO_2$ concentrations for the Project are predicted to be 0.05, and 0.012 µg/m$^3$, respectively, at the Class I area. The maximum 3-hour average $SO_2$ concentration predicted for the project at the Class I area is less than 0.001 percent of the acute exposure that caused damage to sensitive species of vegetation (i.e., 790 µg/m$^3$). The modeled annual incremental increase in $SO_2$ adds only slightly to background levels of this gas and poses no threat to vegetation within the Everglades NP.

### VOC and $NO_X$ Emissions and Impacts to Ozone

VOC and $NO_x$ emissions are precursors to $O_3$ formation. Since the proposed Project includes retirement of 10 GTs at the Fort Myers plant, the VOC and $NO_x$ emissions will actually decrease in Lee County.

### Summary

In summary, the phytotoxic effects of the new CT project's emissions within the ENP are expected to be minimal. It is important to note that emissions were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

## *7.4.4 Impacts to Wildlife*

The Project's low emissions are well below the NAAQS, which are protective of soils, vegetation, and wildlife resources. The maximum predicted impacts of the project in the Class I area are up to six orders of magnitude lower than values of potential impacts to wildlife shown in Table 7-1. No significant effects on wildlife AQRVs from $NO_x$, CO, PM, or VOCs are expected.

## *7.4.5 Impacts Upon Visibility*

### Introduction

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of $PM_{10}$ and $NO_x$ are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the ENP. Visibility can take the form of plume blight for nearby areas or regional haze for long distances (e.g., distances beyond 50 km). Because the closest approach of the ENP from the Fort Myers Plant is 96.9 km the change in visibility was analyzed as regional haze and the following methodology was used to address AQRVs.

## Methodology

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient ($b_{ext}$). The $b_{ext}$ is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: $b_{exts}$ = the extinction coefficient calculated for the source

$b_{extb}$ = the background extinction coefficient

The analysis was conducted in accordance with the most recent guidance from the FLM's AQRV Workgroup (FLAG) Phase I Report (June 27, 2008) (FLAG) document. The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed project. The visibility threshold is a change in extinction of 5 percent (or 0.5 deciviews) and the threshold is not exceeded if the 98$^{th}$-percentile change in light extinction is less than 5 percent or 0.5 deciview for each modeled year.

Processing of visibility impairment for this study was performed with the California Puff (CALPUFF, Version 5.8) model and the CALPUFF post-processing program CALPOST Version 6.221. The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. For predicting visibility impairment, the FLAG guidance recommends using Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days.

Emissions input to CALPUFF include the maximum rates for $SO_2$, $NO_2$, PM, and sulfuric acid mist.

The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater is that species' effect on visibility.

Filterable PM was speciated into coarse (PMC), fine (PMF), and elemental carbon (EC). The default extinction efficiencies for these species are 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameters greater than 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM was speciated into sulfate ($SO_4$) and secondary organic aerosols (SOA). The extinction efficiencies for these species are 3 x f(RH) and 4, respectively, where f(RH) is the relative humidity adjustment factor. These speciations were conducted in POSTUTIL.

Results are provided for both natural gas and ULSD oil firing.

### Results

The results of the visibility analysis at the ENP are presented in Table 7-4. When firing natural gas, the maximum predicted visibility impairment is 0.036 dv which is well below the FLM's criteria of a 0.5 change in dv. For ULSD oil, the predicted impact is 0.132 dv. As a result, the Project is not expected to have an adverse impact on the existing regional haze at the PSD Class I area of the ENP.

## *7.4.6 Sulfur and Nitrogen Deposition*

### General Methods

As part of the AQRV analyses, total nitrogen (N) deposition rate was predicted for the project at the ENP. The deposition analysis criterion is based on the annual averaging period. The total deposition is estimated in units of kilograms per hectare per year (kg/ha/yr) of N. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species $NO_3$), wet and dry deposition;
- Nitric acid (species $HNO_3$), wet and dry deposition;
- Nitrogen oxides ($NO_x$), dry deposition; and
- Ammonium sulfate (species $SO_4$), wet and dry deposition.

For S deposition, the species include:

- $SO_2$, wet and dry deposition; and
- $SO_4$, wet and dry deposition

The CALPUFF model produces results in units of micrograms per square meter per second (µg/m$^2$/s), which are then converted to units of kg/ha/yr.

Deposition analysis threshold (DATs) for total nitrogen and sulfur deposition of 0.01 kg/ha/yr was provided by the FLM (January 2002). A DAT is the additional amount of nitrogen deposition within a Class I area below which estimated impacts from a new or modified source are considered insignificant. The maximum deposition predicted for the project is, therefore, compared to this DATs or significant impact levels.

### Results

The maximum predicted total annual nitrogen and sulfur deposition due to the proposed project at the ENP is summarized in Table 7-5. The maximum annual deposition rate predicted for the project is 0.0007 kg/ha/yr which is well below the FLM’s criteria of 0.01 kg/ha/yr.

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# TABLES

**Table 2-1: Stack, Operating, and Emission Data for Combustion Turbines (CT)—Natural Gas Combustion**

| Parameter | Units | Simple Cycle Operation: Base Load Turbine Inlet Temperature 35° F | 59° F | 95° F | 75% Load Turbine Inlet Temperature 35° F | 59° F | 95° F | Low Load Turbine Inlet Temperature 35° F | 59° F | 95° F |
|---|---|---|---|---|---|---|---|---|---|---|
| CT Stack Data | | | | | | | | | | |
| Height | ft | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 |
| Diameter | ft | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Temperature | $^oF$ | 1,102 | 1,087 | 1,131 | 1,121 | 1,153 | 1,204 | 1,215 | 1,215 | 1,215 |
| Velocity | ft/sec | 115.13 | 114.99 | 116.78 | 92.58 | 93.27 | 90.12 | 77.45 | 77.73 | 78.66 |
| Maximum Hourly Emissions per Unit | | | | | | | | | | |
| $SO_2$ | gr/100 cf | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| | lb/hr | 12.5 | 12.7 | 13.0 | 9.8 | 9.8 | 9.2 | 7.5 | 7.4 | 7.2 |
| $PM_{10}/PM_{2.5}$ | lb/hr | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 |
| $NO_x$ | ppmvd@15%O2 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 |
| | lb/hr | 72.5 | 74.2 | 71.5 | 57.1 | 56.8 | 53.4 | 43.9 | 43.1 | 42.0 |
| CO | ppmvd@15%O2 | 4.0 | 4.0 | 4.0 | 7.2 | 7.1 | 6.9 | 7.4 | 7.5 | 7.7 |
| | lb/hr | 19.6 | 20.1 | 19.3 | 27.8 | 27.3 | 24.9 | 22.0 | 21.8 | 21.9 |
| VOC (as methane) | ppmvd@15%O2 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.1 | 1.1 | 1.1 |
| | lb/hr | 3.4 | 3.4 | 3.4 | 2.7 | 2.7 | 2.5 | 2.1 | 2.1 | 2.2 |
| Sulfuric Acid Mist | lb/hr | 1.9 | 1.9 | 2.0 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.1 |

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015.

**Table 2-2: Stack, Operating, and Emission Data for Combustion Turbines (CT)-ULSD Oil Combustion**

| | | Simple Cycle Operation | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **Units** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| CT Stack Data | | | | | | | | | | |
| Height | ft | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 |
| Diameter | ft | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Temperature | °F | 1,130 | 1,106 | 1,142 | 1,153 | 1,184 | 1,215 | 1,215 | 1,215 | 1,215 |
| Velocity | ft/sec | 115.73 | 115.31 | 116.45 | 93.28 | 92.76 | 89.84 | 77.14 | 76.90 | 75.16 |
| Maximum Hourly Emissions per Unit | | | | | | | | | | |
| $SO_2$ | %S | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% |
| | lb/hr | 3.59 | 3.59 | 3.55 | 2.83 | 2.78 | 2.60 | 2.19 | 2.14 | 2.01 |
| $PM/PM_{10}/PM_{2.5}$ | lb/hr | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| $NO_x$ | ppmvd@15%O2 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 | 42 |
| | lb/hr | 390.1 | 382.7 | 384.0 | 305.3 | 299.6 | 294.0 | 235.7 | 231.1 | 223.0 |
| CO | ppmvd@15%O2 | 9.00 | 9.00 | 9.00 | 13.70 | 13.50 | 13.40 | 14.04 | 14.30 | 14.60 |
| | lb/hr | 50.01 | 49.91 | 48.20 | 59.80 | 57.87 | 53.92 | 47.61 | 47.39 | 45.44 |
| VOC (as methane) | ppmvd@15%O2 | 2.12 | 2.12 | 2.09 | 3.89 | 3.92 | 3.99 | 3.88 | 3.90 | 3.96 |
| | lb/hr | 8.35 | 8.45 | 8.34 | 6.63 | 6.47 | 6.15 | 5.28 | 5.27 | 5.15 |
| Sulfuric Acid Mist | lb/hr | 0.55 | 0.55 | 0.54 | 0.43 | 0.43 | 0.40 | 0.34 | 0.33 | 0.31 |
| Lead | lb/hr | 0.033 | 0.033 | 0.033 | 0.026 | 0.026 | 0.024 | 0.020 | 0.020 | 0.018 |

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015.

**Table 2-3: Summary of Maximum Potential Annual Emissions for the Combustion Turbines**

| | Maximum Hourly Emissions (lb/hr) Fuel for Ambient Temperature and Load | | | | | | Maximum Emissions (tons/year) Operating Scenario | Operating Hours | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | SC-NG 100 % Load | 3,390 | 2,890 | 2,890 | 2,890 | 1,890 | 2,390 |
| | | | | | | | SC-ULSD 100 % Load | 0 | 500 | 0 | 0 | 0 | 0 |
| | | | | | | | SC-NG 75 % Load | 0 | 0 | 0 | 0 | 500 | 0 |
| | | | | | | | SC-ULSD 75 % Load | 0 | 0 | 500 | 0 | 0 | 0 |
| | | | | | | | SC-NG 50 % Load | 0 | 0 | 0 | 0 | 500 | 1,000 |
| | | | | | | | SC-ULSD 50 % Load | 0 | 0 | 0 | 500 | 500 | 0 |
| **Pollutant** | **SC-NG 59 °F 100% Load** | **SC-ULSD 59 °F 100% Load** | **SC-NG 59 °F 75% Load** | **SC-ULSD 59 °F 75% Load** | **SC-NG 59 °F 50% Load** | **SC-ULSD 59 °F 50% Load** | **TOTAL** | **3,390** | **3,390** | **3,390** | **3,390** | **3,390** | **3,390** |
| One Combustion Turbine | | | | | | | | | | | | | |
| $SO_2$ | 12.7 | 3.6 | 9.8 | 2.8 | 7.4 | 2.1 | | 21.5 | 19.2 | 19.0 | 18.9 | 16.8 | 18.9 |
| $PM/PM_{10}/PM_{2.5}$ | 10.6 | 50.0 | 10.6 | 50.0 | 10.6 | 50.0 | | 18.0 | 27.8 | 27.8 | 27.8 | 27.8 | 18.0 |
| $NO_x$ | 74.2 | 382.7 | 56.8 | 299.6 | 43.1 | 231.1 | | 125.7 | 202.9 | 182.1 | 165.0 | 152.8 | 110.2 |
| CO | 20.1 | 49.9 | 27.3 | 57.9 | 21.8 | 47.4 | | 34.0 | 41.5 | 43.5 | 40.8 | 43.1 | 34.9 |
| VOC (as methane) | 3.4 | 8.4 | 2.7 | 6.5 | 2.1 | 5.3 | | 5.8 | 7.0 | 6.5 | 6.2 | 5.7 | 5.1 |
| Sulfuric Acid Mist | 1.9 | 0.5 | 1.5 | 0.4 | 1.1 | 0.3 | | 3.3 | 2.9 | 2.9 | 2.9 | 2.6 | 2.9 |
| Lead | 0.00 | 0.03 | 0.00 | 0.03 | 0.00 | 0.02 | | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| Two Combustion Turbines | | | | | | | | | | | | | |
| $SO_2$ | 25.4 | 7.2 | 19.5 | 5.6 | 14.8 | 4.3 | | 43 | 38 | 38 | 38 | 34 | 38 |
| $PM/PM_{10}/PM_{2.5}$ | 21.2 | 100.0 | 21.2 | 100.0 | 21.2 | 100.0 | | 36 | 56 | 56 | 56 | 56 | 36 |
| $NO_x$ | 148.4 | 765.3 | 113.6 | 599.1 | 86.1 | 462.1 | | 251 | 406 | 364 | 330 | 306 | 220 |
| CO | 40.1 | 99.8 | 54.6 | 115.7 | 43.7 | 94.8 | | 68 | 83 | 87 | 82 | 86 | 70 |
| VOC (as methane) | 6.8 | 16.9 | 5.3 | 12.9 | 4.3 | 10.5 | | 11.6 | 14.1 | 13.1 | 12.5 | 11.5 | 10.3 |
| Sulfuric Acid Mist | 3.9 | 1.1 | 3.0 | 0.9 | 2.3 | 0.7 | | 6.6 | 5.9 | 5.8 | 5.8 | 5.2 | 5.8 |
| Lead | 0.00 | 0.07 | 0.00 | 0.05 | 0.00 | 0.04 | | 0.00 | 0.02 | 0.01 | 0.01 | 0.01 | 0.00 |

Source: General Electric Company, 2015; Golder, 2015.

**Table 2-4: Greenhouse Gas (GHG) Emissions for Combustion Turbine**

| Pollutant | Maximum Heat Input at 75 °F (MMBtu/hr) | | Emission Factor [a] (lb/MMBtu) | | Hourly GHG Emissions (lb/hr) | | Operating Hours | | Annual GHG Emissions (TPY) | | $CO_2e$ Emission Rate [b] (lb/hr) | | $CO_2e$ Emission Rate [b] (TPY) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Natural Gas | Distillate Fuel Oil | Natural Gas | ULSD Oil | Natural Gas | USLD Oil | Natural Gas | USLD Oil | Natural Gas | USLD Oil | Natural Gas | Distillate Fuel Oil | Natural Gas | USLD Oil | Total |
| Natural Gas Only | | | | | | | | | | | | | | | |
| $CO_2$ | 2,262.4 | 0.0 | 118.9 | 162.3 | 268,907.7 | 0.0 | 3,390 | 0 | 455,798.5 | 0 | 268,907.7 | 0.0 | 455,798.5 | 0 | 455,798.5 |
| $CH_4$ | 2,262.4 | 0.0 | 0.002204 | 0.006612 | 5.0 | 0.0 | 3,390 | 0 | 8.5 | 0 | 124.7 | 0.0 | 211.3 | 0 | 211.3 |
| $N_2O$ | 2,262.4 | 0.0 | 0.0002204 | 0.001322 | 0.5 | 0.0 | 3,390 | 0 | 0.8 | 0 | 148.6 | 0.0 | 251.9 | 0 | 251.9 |
| | | | | | | | | | | Total | 269,180.9 | 0.0 | 456,261.7 | 0.0 | 456,261.7 |
| Natural Gas & USLD | | | | | | | | | | | | | | | |
| $CO_2$ | 2,262.4 | 2,353.7 | 118.9 | 162.3 | 268,907.7 | 381,977.2 | 2,890 | 500 | 388,571.6 | 95,494.3 | 268,907.7 | 381,977.2 | 388,571.6 | 95,494.3 | 484,065.9 |
| $CH_4$ | 2,262.4 | 2,353.7 | 0.002204 | 0.006612 | 4.9864 | 15.5629 | 2,890 | 500 | 7.2 | 3.9 | 124.7 | 389.1 | 180.13 | 97.27 | 277.4 |
| $N_2O$ | 2,262.4 | 2,353.7 | 0.0002204 | 0.001322 | 0.4986 | 3.1126 | 2,890 | 500 | 0.7 | 0.8 | 148.6 | 927.5 | 214.72 | 232 | 446.6 |
| | | | | | | | | | | Total | 269,180.9 | 383,293.8 | 388,966.5 | 95,823.5 | 484,789.9 |
| | | | | | | | | | | Maximum Total | | | 456,261.7 | 95,823.5 | 484,789.9 |

[a] $CO_2$ based on 40 CFR Part 75 Appendix G, Section 2.3.
$CH_4$ and $N_2O$ based on Table C-2, Subpart C, 40 CFR 98. Emission factors in lb/MMBtu

| Pollutant | Natural Gas | Distillate Fuel Oil |
|---|---|---|
| $CO_2$ | 118.9 | 162.3 |
| $CH_4$ | 0.002204 | 0.006612 |
| $N_2O$ | 0.0002204 | 0.0013224 |

Conversion factor from kg/MMBtu to lb/MMBtu: 2.204

[b] $CH_4$ and $N_2O$ are multiplied by $CO_2e$ factor

| Pollutant | $CO_{2e}$ Factor |
|---|---|
| $CH_4$ | 25 |
| $N_2O$ | 298 |

**Table 2-5: Summary of Potential GHG Emissions**

| | Greenhouse Gases ($CO_2e$) |
|---|---|
| **Emission Unit Maximum Potential Emissions** | |
| **2 CTs**[a] | 969,580 |
| **Circuit Breakers**[c] | 7.1 |
| **Total:** | 969,587 |
| **Netting Calculations** | |
| **Potential Emissions - Baseline Actual Emissions** | 969,587 |
| **PSD Significant Emission Rate for GHGs** | 75,000 |

[a] Based on 3,390 hour/year operation

[c] Breakers with 125 lb of $SF_6$ each at 0.5% maximum leakage/yr; GWP of 22,800 lb $CO_2e$/lb $SF_6$

**Table 2-6: Summary of Maximum Potential Annual Emissions for the Fort Myers Peaker Project**

| Pollutant | Project Maximum Potential Annual Emissions (TPY) 2 CT [a] | SF$_6$ Circuit Breakers | TOTAL | PSD Applicability: PSD Significant Emission Rate (TPY) | PSD Applicability: PSD Review Required? |
|---|---|---|---|---|---|
| $SO_2$ | 43 | NA | 43.0 | 40 | YES |
| PM | 56 | NA | 55.6 | 25 | YES |
| $PM_{10}$ | 56 | NA | 55.6 | 15 | YES |
| $PM_{2.5}$ | 56 | NA | 55.6 | 10 | YES |
| $NO_x$ | 406 | NA | 405.7 | 40 | YES |
| CO | 87 | NA | 86.9 | 100 | NO |
| VOC (as methane) | 14.1 | NA | 14.1 | 40 | NO |
| Sulfuric Acid Mist | 6.6 | NA | 6.6 | 7 | NO |
| Lead | 0.016 | NA | 0.0 | 0.6 | NO |
| Greenhouse Gases ($CO_2$e) | 969,580 | 7 | 969,587 | 75,000 | YES |

[a] Potential Operation (hours): 3,390

Note: Neg.= negligible; NA= not applicable

Source: Golder, 2015.

**Table 2-7: Summary of Maximum Potential Annual HAP Emissions**

| Pollutant | Maximum Potential Annual Emissions (TPY) 2 CTs | TOTAL | HAP Major Source Threshold (TPY) |
|---|---|---|---|
| Total HAPs | 3.4 | 3.4 | 25 |
| Single HAP | 1.6 [a] | 1.6 | 10 |

Notes: NA= not applicable.

[a] Based on formaldehyde emissions

Source: Golder, 2015

**Table 3-1: National and State AAQS, Allowable PSD Increments and Significant Impact Levels**

| Pollutant | Averaging Time | National and Florida AAQS (µg/m³) | | PSD Increments (µg/m³) | | Significant Impact Levels (µg/m³) | |
|---|---|---|---|---|---|---|---|
| | | Primary Standard | Secondary Standard | Class I | Class II | Class I | Class II |
| Particulate Matter ($PM_{10}$) [a] | Annual Arithmetic Mean | NA | NA | 4 | 17 | 0.2 | 1 |
| | 24-Hour Maximum | 150 | 150 | 4 | 30 | 0.3 | 5 |
| Particulate Matter ($PM_{2.5}$) [a] | Annual Arithmetic Mean | 12 | 15 | 1 | 4 | 0.06 | 0.3 |
| | 24-Hour Maximum | 35 | 35 | 2 | 9 | 0.07 | 1.2 |
| Sulfur Dioxide [b] | Annual Arithmetic Mean | 80 | NA | 2 | 20 | 0.1 | 1 |
| | 24-Hour Maximum | 365 | NA | 5 | 91 | 0.2 | 5 |
| | 3-Hour Maximum | NA | 1,300 | 25 | 512 | 1 | 25 |
| | 1-Hour Maximum | 197 | NA | NA | NA | NA | 7.9 [e] |
| Carbon Monoxide | 8-Hour Maximum | 10,000 | 10,000 | NA | NA | NA | 500 |
| | 1-Hour Maximum | 40,000 | 40,000 | NA | NA | NA | 2,000 |
| Nitrogen Dioxide [c] | Annual Arithmetic Mean | 100 | 100 | 2.5 | 25 | 0.1 | 1 |
| | 1-Hour Maximum | 188 | NA | NA | NA | NA | 7.6 [e] |
| Ozone [d] | 1-Hour Maximum | NA | NA | NA | NA | NA | NA |
| | 8-Hour Maximum | 147 | 147 | NA | NA | NA | NA |
| Lead | Rolling 3-Month Average | 0.15 | 0.15 | NA | NA | NA | NA |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On October 17, 2006, EPA promulgated revised $PM_{10}$ and $PM_{2.5}$ AAQS; the $PM_{2.5}$ AAQS had been promulgated on July 18, 1997. For $PM_{10}$, the annual standard was revoked and the 24-hour standard was retained. The 24-hour $PM_{2.5}$ standard was revised to 35 µg/m³ based on the 3-year averages of the 98th percentile values. The annual $PM_{2.5}$ standard of 15 µg/m³, 3-year averages at community monitors, was retained.

[b] On June 23, 2010, EPA promulgated the 1-hour $SO_2$ standard at a level of 75 parts per billion (ppb), based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations (effective August 23, 2010). EPA is also revoking both the existing 24-hour and annual primary $SO_2$ standards, effective one year after the designation of an area, pursuant to section 107 of the Clean Air Act.

[c] On February 9, 2010, EPA promulgated the 1-hour $NO_2$ standard at a level of 100 ppb, based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations (effective April 12, 2010).

[d] On March 27, 2008, EPA promulgated revised AAQS for ozone. The $O_3$ standard was modified to be 0.075 ppm (147 µg/m³) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less.

[e] For $NO_2$ and $SO_2$ 1-hour averaging period, an interim Class II significant impact level is shown.

Sources: FR, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Florida Chapter 62.204, F.A.C.
Golder, 2013.

**Table 3-2: PSD Significant Emission Rates and De Minimis Monitoring Concentrations**

| Pollutant | Regulated Under | Significant Emission Rate (TPY) | De Minimis Monitoring Concentration (μg/m$^3$) [a] |
|---|---|---|---|
| Sulfur Dioxide | NAAQS, NSPS | 40 | 13, 24-hour |
| Particulate Matter [PM(TSP)] | NSPS | 25 | NA |
| Particulate Matter ($PM_{10}$) | NAAQS | 15 | 10, 24-hour |
| Particulate Matter ($PM_{2.5}$) [c] | NAAQS | 10, or | 4, 24-Hour |
| | NAAQS | 40 of $SO_2$, or | NA |
| | NAAQS | 40 of $NO_X$ | NA |
| Nitrogen Dioxide | NAAQS, NSPS | 40 | 14, annual |
| Carbon Monoxide | NAAQS, NSPS | 100 | 575, 8-hour |
| Volatile Organic Compounds (Ozone) | NAAQS, NSPS | 40 or $NO_X$ | 100 TPY[b] |
| Lead | NAAQS | 0.6 | 0.1, 3-month |
| Sulfuric Acid Mist | NSPS | 7 | NM |
| Total Fluorides | NSPS | 3 | 0.25, 24-hour |
| Total Reduced Sulfur | NSPS | 10 | 10, 1-hour |
| Reduced Sulfur Compounds | NSPS | 10 | 10, 1-hour |
| Hydrogen Sulfide | NSPS | 10 | 0.2, 1-hour |
| Mercury | NESHAP | 0.1 | 0.25, 24-hour |
| MWC Organics (dioxin/furans) | NSPS | $3.5 \times 10^{-6}$ | NM |
| MWC Metals (as PM) | NSPS | 15 | NM |
| MWC Acid Gases ($SO_2$ + HCl) | NSPS | 40 | NM |
| MSW Landfill Gases (as NMOC) | NSPS | 50 | NM |
| Greenhouse Gases [d] | -- | 0 (mass basis), and | NM |
| | -- | 75,000 ($CO_2$e basis) | NM |

Note: Ambient monitoring requirements for any pollutants may be exempted if the impact of the increase is less than de minimis monitoring concentrations.

NA = not applicable
NM = no ambient measurement method established; therefore, no *de minimis* concentration has been established
mg/m$^3$ = micrograms per cubic meter
MWC = municipal waste combustor
MSW = municipal solid waste
NMOC = non-methane organic compounds

[a] Short-term concentration threshold for monitoring requirement applicability.
[b] No *de minimis* concentration; an increase in VOC OR $NO_x$ emissions of 100 TPY or more will require a monitoring analysis for ozone
[c] Any emission rate of these pollutants.
[d] On July 20, 2011, biogenic $CO_2$ emissions were deferred from consideration in the significant emission rates for 3 years. This deferral was vacated by the US Court of Appeals on July 12, 2013.

Source: 40 CFR 52.21.
Rule 62-212.400, F.A.C.

**Table 3-3: Maximum Emission Increases Due to the Potential Emissions of the Project Compared to the PSD Significant Emission Rates**

| Pollutant | Pollutant Emissions | | |
|---|---|---|---|
| | Emission Increase* (TPY) | Significant Emission Rate (TPY) | PSD Review |
| Sulfur Dioxide | 44 | 40 | Yes |
| Particulate Matter [PM (TSP)] | 56 | 25 | Yes |
| Particulate Matter ($PM_{10}$) | 56 | 15 | Yes |
| Particulate Matter ($PM_{2.5}$) | 56 | 15 | Yes |
| Nitrogen Dioxide | 404 | 40 | Yes |
| Carbon Monoxide | 87 | 100 | No |
| Volatile Organic Compounds | 14 | 40 | No |
| Lead | 0.016 | 0.6 | No |
| Sulfuric Acid Mist | 6.8 | 7 | No |
| Total Fluorides | NEG | 3 | No |
| Total Reduced Sulfur | NEG | 10 | No |
| Reduced Sulfur Compounds | NEG | 10 | No |
| Hydrogen Sulfide | NEG | 10 | No |
| Mercury | NEG | 0.1 | No |
| Greenhouse Gases | 989,111 | 75,000 | Yes |

Note: NEG = Negligible.

* See Table 2-6.

**Table 4-1: Proposed BACT Emission Limits for CTs**

| Pollutant | CT(s) | Fuel | Operating Mode | Proposed BACT Emission Limits | Compliance Methods |
|---|---|---|---|---|---|
| $NO_x$ | GE 7F.05 | Natural Gas | Normal Operation[a] | 9 ppmvd at 15% $O_2$ | Initial: EPA Methods- 7E or 20, Continuous Monitoring (Subpart KKKK) |
| | GE 7F.05 | ULSD Oil | Normal Operation[a] | 42 ppmvd at 15% $O_2$ | Initial: EPA Methods- 7E or 20, Continuous Monitoring (Subpart KKKK) |
| $PM/PM_{10}$ | GE 7F.05 | Natural Gas | Normal Operation[a] | 10% Opacity | Initial/Annual: EPA Method 9 |
| | GE 7F.05 | ULSD Oil | Normal Operation[a] | 10% Opacity | Initial/Annual: EPA Method 9 |
| $SO_2$ and SAM[c] | GE 7F.05 | Natural Gas | Normal Operation[a] | 2 grains S/100 scf | Initial/Annual: 40 CFR Part 75 Fuel Sampling |
| | GE 7F.05 | ULSD Oil | Normal Operation[a] | 0.0015% S | Initial/Annual: 40 CFR Part 75 Fuel Sampling |
| $CO_2$ - Equivalent | GE 7F.05 | Natural Gas | Normal Operation[a] | 1,398 lb $CO_2$e/MWh | 40 CFR Part 75; composit average of 720 operating hours |
| | GE 7F.05 | ULSD Oil | Normal Operation[a] | 1,871 lb $CO_2$e/MWh | 40 CFR Part 75; composit average of 720 operating hours |
| $CO_2$ - Equivalent | GE 7F.05 | Natural Gas | Startup/Shutdown | 3,492 lb $CO_2$e/MWh | 40 CFR Part 75; 12-month rolling average of startup/shutdown periods |
| | GE 7F.05 | ULSD Oil | Startup/Shutdown | 3,451 lb $CO_2$e/MWh | 40 CFR Part 75; 12-month rolling average of startup/shutdown periods |

Notes: CT = combustion turbine; ULSD = ultra low sulfur distillate

[a] excluding startup, shutdown and fuel switching.

[b] $SO_2$ and SAM fuel sulfur also used to demonstrate compliance for $PM/PM_{10}$ $PM_{2.5}$.

**Table 4-2: Capital Cost for Hot Selective Catalytic Reduction for General Electric Simple Cycle Combustion Turbine Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing.**

| Cost Component | Costs | | Basis of Cost Component |
|---|---|---|---|
| Direct Capital Costs | | | |
| Hot SCR Associated Equipment | 10,232,248 | | Cost of new Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, 2011 |
| Ammonia Storage Tank | included | | |
| Flue Gas Ductwork | included | | |
| Instrumentation | included | | |
| Emission Monitoring | $511,612 | 5% | of SCR Associated Equipment |
| Freight | $511,612 | 5% | of SCR Associated Equipment |
| Total Direct Capital Costs (TDCC) | 11,255,473 | | |
| Direct Installation Costs | | | |
| Foundation and supports | $900,438 | 8% | of TDCC and RCC;OAQPS Cost Control Manual |
| Handling & Erection | $1,575,766 | 14% | of TDCC and RCC;OAQPS Cost Control Manual |
| Electrical | $450,219 | 4% | of TDCC and RCC;OAQPS Cost Control Manual |
| Piping (Ammonia Injection Grid) | included | | Vendor Estimate |
| Insulation for ductwork | $112,555 | 1% | of TDCC and RCC;OAQPS Cost Control Manual |
| Painting | $112,555 | 1% | of TDCC and RCC;OAQPS Cost Control Manual |
| Site Preparation (General Facilities) | $562,774 | 5% | of TDCC and RCC;OAQPS Cost Control Manual |
| Project Contingencies | $1,125,547 | 10% | of TDCC and RCC;OAQPS Cost Control Manual |
| Total Direct Installation Costs (TDIC) | $4,839,853 | | |
| Total Capital Costs (TCC) | $16,095,326 | | Sum of TDCC and TDIC |
| Indirect Costs | | | |
| Engineering | included | | |
| PSM/RMP Plan | $50,000 | | Engineering Estimate |
| Construction and Field Expense | $804,766 | 5% | of Total Capital Costs; OAQPS Cost Control Manual |
| Contractor Fees | $1,609,533 | 10% | of Total Capital Costs; OAQPS Cost Control Manual |
| Start-up | $321,907 | 2% | of Total Capital Costs; OAQPS Cost Control Manual |
| Performance Tests | $160,953 | 1% | of Total Capital Costs; OAQPS Cost Control Manual |
| Total Indirect Capital Cost (TInCC) | $2,947,159 | | |
| Total Direct, Indirect and Capital Costs (TDICC) | $19,042,485 | | Sum of TCC and TInCC |

**Table 4-3: Annualized Cost for Selective Catalytic Reduction for General Electric Simple Cycle Operation Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing.**

| Cost Component | Costs | Basis of Cost Component |
|---|---|---|
| Direct Annual Costs | | |
| Operating Personnel | $21,840 | 28 hours/week at $15/hr |
| Supervision | $3,276 | 15% of Operating Personnel;OAQPS Cost Control Manual |
| Ammonia | $32,936 | $556 per ton for anhydrous $NH_3$, 3,390 hr/year |
| PSM/RMP Update | $25,000 | Engineering Estimate |
| Inventory Cost | $12,316 | Capital Recovery (9.44%) for 1/3 catalyst for SCR |
| Catalyst Replacement | $84,125 | 4 years catalyst life; Based on Vendor Budget Estimate |
| Contingency | $5,385 | 3% of Direct Annual Costs |
| Total Direct Annual Costs (TDAC) | $184,878 | |
| Energy Costs | | |
| Electrical (SCR and Cooling) | $145,838 | 330kW/hr (SCR system) and 1,491 kW/hr (fan) @ $0.04/kWh, 3,390 hr/yr |
| MW Loss and Heat Rate Penalty | $112,060 | 0.2% of MW output; EPA, 1993 (Page 6-20)[a] and $3/mmBtu addl fuel costs |
| Total Energy Costs (TEC) | $257,898 | |
| Indirect Annual Costs | | |
| Overhead | $34,831 | 60% of Operating/Supervision Labor and Ammonia |
| Property Taxes (exempt) | $0 | 0% of Total Capital Costs |
| Insurance | $190,425 | 1% of Total Capital Costs |
| Administration | $380,850 | 2% of Total Capital Costs |
| Annualized Total Direct Capital | $2,132,682 | 10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC |
| Total Indirect Annual Costs (TIAC) | $2,738,788 | |
| Total Annualized Costs | $3,181,564 | Sum of TDAC, TEC and TIAC |
| Incremental Cost Effectiveness(9 to 2.5 ppmvd gas and 42 to 12 oil) | $21,833 | $NO_x$ Reduction Only |
| | $34,304 | Net Emission Reduction |

[a] Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20.

**Table 4-4. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing**

| | Incremental Emissions (tons/year) of SCR | | |
|---|---|---|---|
| **Pollutants** | **Primary** | **Secondary** | **Total** |
| Particulate | 6.47 | 0.26 | 6.73 |
| Sulfur Dioxide | | 0.19 | 0.19 |
| Nitrogen Oxides | -145.72 | 1.92 | -143.80 |
| Carbon Monoxide | | 0.39 | 0.39 |
| Volatile Organic Compounds | | 0.07 | 0.07 |
| Ammonia | 43.68 | | 43.68 |
| Total: | -95.58 | 2.83 | -92.75 |
| Carbon Dioxide (additonal from gas firing) | | 4,453.40 | 4,453.40 |

Basis:

| | |
|---|---|
| Lost Energy (mmBtu/year) | 74,910 |

Secondary Emissions (lb/mmBtu): Assumes same emission basis as the new CTs with natural gas and ULSD.

| | |
|---|---|
| Particulate | 0.0071 |
| Sulfur Dioxide | 0.0050 |
| Nitrogen Oxides w/LNB | 0.0512 |
| Carbon Monoxide | 0.0105 |
| Volatile Organic Compounds | 0.0018 |
| Carbon Dioxide (equivalent) | 118.9 |

**Table 5-1: Summary of 8-Hour $O_3$ Measurements in Vicinity of the FPL Fort Myers Plant, 2012 to 2014**

| | | Measurement Period | | Concentration (µg/m³) 8-Hour | |
|---|---|---|---|---|---|
| **Site No.** | **Location** | **Year** | **Months** | **Highest** | **4th Highest**[a] |
| **Ozone AAQS** | | | | **NA** | **157** |
| 012-071-2002 | 5505 Rose Garden Rd | 2014 | Jan-Dec | 115.8 | 108.0 |
| | Cape Corel, FL 33914 | 2013 | Jan-Dec | 133.5 | 129.6 |
| | | 2012 | Jan-Dec | 129.6 | 127.6 |
| | | 3-Yr Average | | | 121.7 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 8-hour $O_3$ standard is met when the 3-year average of the annual 4th highest of the daily concentration is less than 157 µg/m³.

Source: FDEP Quicklook Reports, 2012-2014.

**Table 5-2: Summary of Maximum $PM_{2.5}$ Measurements in Vicinity of the FPL Fort Myers Plant, 2012 to 2014**

| | | | | Concentration (µg/m³) | | |
|---|---|---|---|---|---|---|
| | | Measurement Period | | 24-Hour [a] | | Annual [b] |
| Site No. | Location | Year | Months | Highest | 98th Percentile | Mean |
| | $PM_{2.5}$ AAQS | | | **NA** | **35** | **12** |
| 012-071-0005 | Princeton Street | 2014 | Jan-Dec | 9.7 | 7.4 | 6.6 |
| | Fort Myers Beach, FL | 2013 | 2014 | 11.1 | 11.1 | 5.6 |
| | | 2012 | 2013 | 15.1 | 14.2 | 6.7 |
| | | 3-Yr Average | 2012 | | | 6.3 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 24-hour $PM_{2.5}$ standard is met when the 3-year average of the 98th percentile of the daily values is less than 35 µg/m³.

[b] The annual $PM_{2.5}$ standard is met when the 3-year average of the annual mean values is less than 12 µg/m³.

Source: FDEP Quicklook Reports, 2012-2014.

Source: FDEP Quicklook Reports, 2012-2014.

**Table 5-3: Summary of 1-Hour $NO_2$ Measurements in Vicinity of the FPL Fort Myers Plant, 2012 to 2014**

| Site No. | Location | Measurement Period Year | Measurement Period Months | Concentration (µg/m³) 1-Hour Highest | 1-Hour 2nd Highest | 1-Hour 98th Percentile[a] | Annual Average |
|---|---|---|---|---|---|---|---|
| **$NO_2$ AAQS** | | | | **NA** | **NA** | **188.1** | **100** |
| 012-115-1006 | 4570 17th Street | 2014 | Jan-Dec | 71.5 | 41.4 | 41.4 | 6.7 |
| | Sarasota, FL | 2013 | Jan-Dec | 37.6 | 33.9 | 28.2 | 4.1 |
| | | 2012 | Jan-Dec | 54.5 | 43.3 | 32.0 | 5.2 |
| | | 3-Yr Average | | | | 33.9 | 5.3 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 1-hour $NO_2$ standard is met when the 3-year average of the 98th percentile of the daily 1-hour maximum values is less than 188.1 µg/m³.

Source: FDEP Quicklook Reports, 2012-2014.

**Table 6-1: Summary of the $NO_2$ Facilities Considered for Inclusion in the 1-Hour NAAQS Analysis**

| Facility ID | Facility Description | East (km) | North (km) | Relative to Fort Myers Facility [a] X (km) | Y (km) | Distance (km) | Direction (deg) | Potential $NO_x$ Emissions (TPY) | Include in Modeling Analysis ? [b] |
|---|---|---|---|---|---|---|---|---|---|
| Modeling Area (0km - 10km) [a] | | | | | | | | | |
| 0710002 | FLORIDA POWER & LIGHT (PFM) FORT MYERS POWER PLANT | 422.3 | 2,952.9 | 0.0 | 0.0 | 0.00 | 0 | 2,600 | YES |
| 0710119 | LEE COUNTY DEPT. OF SOLID WASTE MGT. LEE CO. SOLID WASTE RESOURCE REC. FAC. | 424.2 | 2,945.7 | 2.3 | -7.4 | 7.79 | 163 | 950 | YES |
| Beyond Modeling Area (10km - 25km) [a] | | | | | | | | | |
| 0710133 | WASTE MANAGEMENT INC. OF FLORIDA GULF COAST SANITARY LANDFILL | 424.2 | 2942.8 | 2.4 | -10.3 | 10.55 | 167 | 23 | NO |
| 0150028 | AJAX PAVING INDUSTRIES PUNTA GORDA PLANT NO. #2 | 422.6 | 2964.1 | 0.8 | 10.9 | 10.96 | 4 | 21 | NO |
| 0710004 | GULF PAVING CO GULF PAVING CO | 415.2 | 2944.1 | -6.7 | -9.0 | 11.23 | 216 | 14 | NO |
| 7775172 | BETTER ROADS, INC. PLANT NO. 7 - PUNTA GORDA | 423.6 | 2964.0 | 1.7 | 10.8 | 10.95 | 9 | 14 | NO |
| 0150075 | CHARLOTTE COUNTY DEPT OF PUBILC WORKS ZEMEL ROAD SOLID WASTE MANAGEMENT FACIL. | 405.5 | 2964.0 | -16.4 | 10.8 | 19.66 | 303 | 53 | NO |
| 0710265 | COMMUNITY ASPHALT CORPORATION FORT MYERS PLANT | 417.4 | 2931.1 | -4.4 | -22.0 | 22.46 | 191 | 19 | NO |
| 7774822 | AJAX PAVING INDUSTRIES, INC. PLANT #4 | 416.9 | 2930.8 | -5.0 | -22.3 | 22.86 | 193 | 45 | NO |

Note: ND = No data, SID = Significant impact distance for the project

Fort Myers Facility East and North Coordinates (km) are: 421.9 km 2953.1 km
The significant impact distance (SID) for the project is estimated to be: 10 m
EPA recommends that sources to be modeled are expected to have a significant impact in the modeling area. Therefor only sources with 2012 actual annual emissions greater than 30 TPY were included.

[a] "Modeling Area" is the area in which the project is predicted to have a significant impact (10 km). EPA recommends that all sources within this area be modeled.

[b] Background sources with NO2 emissions >25 TPY and within 10km of the project location were included in the NAAQS Analysis.

**Table 6-2: Summary of Sources Included in the 1-Hour $NO_2$ NAAQS Modeling Analysis**

| Facility ID | Facility Name / Emission Unit Description | EU ID | Modeling ID Name | UTM Location X (m) | UTM Location Y (m) | Stack Parameters Height ft | Height m | Diameter ft | Diameter m | Temperature °F | Temperature K | Velocity m/s | Stack Parameter Data Source | $NO_2$ Emission Rate 1-Hour (lb/hr) | 1-Hour (g/sec) | Emissions Data Source |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0710002 | FLORIDA POWER & LIGHT (PFM) FORT MYERS POWER PLANT | | | | | | | | | | | | | | | |
| | 250MW Combined Cycle Combustion Turbine (2A) | 018 | FM2A | 422236.70 | 2953318.85 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | 2007 Title V Renewal Application (1537-1) | 65 | 8.19 | 2007 Title V Renewal Application (1537-1) |
| | 250MW Combined Cycle Combustion Turbine (2B) | 019 | FM2B | 422195.18 | 2953302.63 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | | 65 | 8.19 | |
| | 250MW Combined Cycle Combustion Turbine (2C) | 020 | FM2C | 422152.71 | 2953284.01 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | | 65 | 8.19 | |
| | 250MW Combined Cycle Combustion Turbine (2D) | 021 | FM2D | 422108.81 | 2953265.88 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | | 65 | 8.19 | |
| | 250MW Combined Cycle Combustion Turbine (2E) | 022 | FM2E | 422066.33 | 2953248.22 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | | 65 | 8.19 | |
| | 250MW Combined Cycle Combustion Turbine (2F) | 023 | FM2F | 422023.38 | 2953231.52 | 125 | 38.10 | 19 | 5.79 | 220 | 377.6 | 21.43 | | 65 | 8.19 | |
| | 170 MW Simple Cycle Combustion Turbine #1 (3A) | 027 | FM3A | 421884.99 | 2953029.18 | 100 | 30.48 | 20 | 6.10 | 1116 | 875.4 | 38.64 | | 320 | 40.32 | |
| | 170 MW Simple Cycle Combustion Turbine #2 (3B) | 028 | FM3B | 421903.60 | 2952989.57 | 100 | 30.48 | 20 | 6.10 | 1116 | 875.4 | 38.64 | | 320 | 40.32 | |
| 0710119 | LEE COUNTY DEPT. OF SOLID WASTE MGT. LEE CO. SOLID WASTE RESOURCE REC. FAC. | 001, 002 & 006 | LCSW | 424,221 | 2,945,902 | 276.0 | 84.12 | 6.2 | 1.89 | 240 | 388.7 | 26.47 | October 31, 2012 PSD Application | 231 | 29.08 | October 31, 2012 PSD Application |

Notes:
All emission rates are based on worst case firing fuel oil.

**Table 6-3: Maximum Concentrations Predicted for Emissions of One CT Firing Natural Gas in Simple-Cycle Operation, Ft. Myers (GE7F.05 Units)**

| Natural Gas | Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature | | | | | | | | | Averaging | Maximum Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature [a] | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base Load | | | 75% Load | | | 50% Load | | | | Base Load | | | 75% Load | | | 50% Load | | |
| | 35°F | 59°F | 95° | 35°F | 59°F | 95° | 35°F | 59°F | 95° | Time | 35°F | 59°F | 95° | 35°F | 59°F | 95° | 35°F | 59°F | 95° |
| Generic[b] | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | Annual [c] | 0.06 | 0.06 | 0.06 | 0.08 | 0.07 | 0.08 | 0.09 | 0.09 | 0.09 |
| (10 g/s) - 5 g/s/CT | | | | | | | | | | Annual [d] | 0.04 | 0.04 | 0.04 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 |
| | | | | | | | | | | 24-Hour [c] | 0.62 | 0.62 | 0.60 | 0.78 | 0.77 | 0.79 | 0.94 | 0.93 | 0.92 |
| | | | | | | | | | | 24-Hour [d] | 0.44 | 0.44 | 0.43 | 0.57 | 0.56 | 0.57 | 0.69 | 0.68 | 0.67 |
| | | | | | | | | | | 8-Hour [c] | 1.51 | 1.51 | 1.47 | 1.90 | 1.86 | 1.91 | 2.23 | 2.22 | 2.19 |
| | | | | | | | | | | 3-Hour [c] | 2.26 | 2.63 | 2.21 | 2.71 | 2.67 | 2.72 | 3.08 | 3.07 | 3.04 |
| | | | | | | | | | | 1-Hour [c] | 3.35 | 3.37 | 3.28 | 4.02 | 3.96 | 4.03 | 4.56 | 4.55 | 4.50 |
| | | | | | | | | | | 1-Hour [d] | 1.88 | 1.89 | 1.83 | 2.35 | 2.31 | 2.36 | 2.78 | 2.77 | 2.74 |
| Emissions for 1 CT | | | | | | | | | | | | | | | | | | | |
| $PM_{10}$ | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | Annual [c] | 0.008 | 0.008 | 0.008 | 0.010 | 0.010 | 0.010 | 0.012 | 0.012 | 0.01 |
| | | | | | | | | | | 24-Hour [c] | 0.08 | 0.08 | 0.08 | 0.10 | 0.10 | 0.11 | 0.125 | 0.125 | 0.123 |
| $PM_{2.5}$ | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | 10.60 | Annual [d] | 0.006 | 0.006 | 0.006 | 0.008 | 0.007 | 0.008 | 0.009 | 0.009 | 0.01 |
| | | | | | | | | | | 24-Hour [d] | 0.06 | 0.06 | 0.06 | 0.08 | 0.07 | 0.08 | 0.09 | 0.09 | 0.09 |
| $NO_x$ | 72.54 | 74.18 | 71.50 | 57.10 | 56.81 | 53.44 | 43.90 | 43.06 | 42.00 | Annual [c] | 0.05 | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| | | | | | | | | | | 1-Hour [e] | 1.72 | 1.77 | 1.65 | 1.69 | 1.65 | 1.59 | 1.54 | 1.50 | 1.45 |
| CO | 19.62 | 20.07 | 19.34 | 27.80 | 27.28 | 24.94 | 21.97 | 21.84 | 21.87 | 8-Hour [c] | 0.37 | 0.38 | 0.36 | 0.66 | 0.64 | 0.60 | 0.62 | 0.61 | 0.60 |
| | | | | | | | | | | 1-Hour [c] | 0.83 | 0.85 | 0.80 | 1.41 | 1.36 | 1.27 | 1.26 | 1.25 | 1.24 |
| $SO_2$ | 12.47 | 12.69 | 13.02 | 9.81 | 9.77 | 9.18 | 7.54 | 7.40 | 7.21 | Annual [c] | 0.009 | 0.010 | 0.009 | 0.009 | 0.009 | 0.009 | 0.008 | 0.008 | 0.01 |
| | | | | | | | | | | 24-Hour [c] | 0.10 | 0.10 | 0.10 | 0.10 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 |
| | | | | | | | | | | 3-Hour [c] | 0.35 | 0.42 | 0.36 | 0.33 | 0.33 | 0.31 | 0.29 | 0.29 | 0.28 |
| | | | | | | | | | | 1-Hour [d] | 0.29 | 0.30 | 0.30 | 0.29 | 0.28 | 0.27 | 0.26 | 0.26 | 0.25 |

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2009 to 2013 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field Airport and Ruskin.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2009-2013) for annual $PM_{10}$, $NO_2$ and $SO_2$, 3-hour $SO_2$, 24-hour $SO_2$, 1-hour and 8 hour CO.

[d] Based on highest 5-year average concentration (2009-2013) for annual and 24-hour $PM_{2.5}$, 1-hour $NO_2$ and $SO_2$.

**Table 6-4: Maximum Concentrations Predicted for Emissions of One CT Firing ULSD Oil in Simple-Cycle Operation, Ft. Myers (GE 7F.05 Units)**

Ultra Low-Sulfur Fuel Oil

| | Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature | | | | | | | | | Averaging | Maximum Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature [a] | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Base Load | | | 75% Load | | | 50% Load | | | | Base Load | | | 75% Load | | | 50% Load | | |
| | 35°F | 59°F | 95° | 35°F | 59°F | 95° | 35°F | 59°F | 95° | Time | 35°F | 59°F | 95° | 35°F | 59°F | 95° | 35°F | 59°F | 95° |
| Generic [b] | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | 79.37 | Annual [c] | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 | 0.09 | 0.09 | 0.09 |
| (10 g/s) - 5 g/s/CT | | | | | | | | | | Annual [d] | 0.04 | 0.04 | 0.04 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 |
| | | | | | | | | | | 24-Hour [c] | 0.61 | 0.61 | 0.60 | 0.77 | 0.77 | 0.79 | 0.94 | 0.95 | 0.97 |
| | | | | | | | | | | 24-Hour [d] | 0.43 | 0.44 | 0.42 | 0.56 | 0.56 | 0.57 | 0.69 | 0.69 | 0.71 |
| | | | | | | | | | | 8-Hour [c] | 1.48 | 1.50 | 1.47 | 1.86 | 1.86 | 1.91 | 2.24 | 2.25 | 2.30 |
| | | | | | | | | | | 3-Hour [c] | 2.23 | 2.63 | 2.21 | 2.67 | 2.67 | 2.72 | 3.09 | 3.10 | 3.16 |
| | | | | | | | | | | 1-Hour [c] | 3.30 | 3.34 | 3.27 | 3.96 | 3.95 | 4.03 | 4.58 | 4.59 | 4.68 |
| | | | | | | | | | | 1-Hour [e] | 1.85 | 1.87 | 1.83 | 2.31 | 2.30 | 2.36 | 2.80 | 2.80 | 2.88 |
| Emissions for 1 CT | | | | | | | | | | | | | | | | | | | |
| $PM_{10}$ | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | Annual [c] | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.06 |
| | | | | | | | | | | 24-Hour [c] | 0.38 | 0.39 | 0.38 | 0.48 | 0.48 | 0.50 | 0.59 | 0.60 | 0.61 |
| $PM_{2.5}$ | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | Annual [d] | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 |
| | | | | | | | | | | 24-Hour [d] | 0.27 | 0.27 | 0.27 | 0.35 | 0.35 | 0.36 | 0.43 | 0.44 | 0.45 |
| $NO_x$ | 390.13 | 382.66 | 384.00 | 305.32 | 299.56 | 294.00 | 235.72 | 231.07 | 223.00 | Annual [c] | 0.29 | 0.29 | 0.28 | 0.28 | 0.28 | 0.28 | 0.27 | 0.26 | 0.26 |
| | | | | | | | | | | 1-Hour [d] | 9.09 | 9.02 | 8.85 | 8.88 | 8.69 | 8.74 | 8.30 | 8.17 | 8.08 |
| CO | 50.01 | 49.91 | 48.20 | 59.80 | 57.87 | 53.92 | 47.61 | 47.39 | 45.44 | 8-Hour [c] | 0.94 | 0.94 | 0.89 | 1.40 | 1.35 | 1.30 | 1.34 | 1.34 | 1.32 |
| | | | | | | | | | | 1-Hour [c] | 2.08 | 2.10 | 1.99 | 2.98 | 2.88 | 2.74 | 2.75 | 2.74 | 2.68 |
| $SO_2$ | 3.59 | 3.59 | 3.55 | 2.83 | 2.78 | 2.60 | 2.19 | 2.14 | 2.01 | Annual [c] | 0.003 | 0.003 | 0.003 | 0.003 | 0.003 | 0.002 | 0.002 | 0.002 | 0.002 |
| | | | | | | | | | | 24-Hour [c] | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 |
| | | | | | | | | | | 3-Hour [c] | 0.10 | 0.12 | 0.10 | 0.10 | 0.09 | 0.09 | 0.09 | 0.08 | 0.08 |
| | | | | | | | | | | 1-Hour [d] | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.07 |

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2009 to 2013 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field Airport and Ruskin.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 2 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2009-2013) for annual $PM_{10}$, $NO_2$ and $SO_2$, 3-hour $SO_2$, 24-hour $SO_2$, 1-hour and 8 hour CO.

[d] Based on highest 5-year average concentration (2009-2013) for annual and 24-hour $PM_{2.5}$, 1-hour $NO_2$ and $SO_2$.

**Table 6-5: Summary of Maximum Pollutant Concentrations Predicted for Natural Gas and ULSD Oil Firing, Ft. Myers (Two GE7F.05 Units)**

| Pollutant | Averaging Time | Concentrations ($\mu g/m^3$) Natural Gas Modeled as 8760 Hrs/Yr | ULSD Oil Modeled as 8760 Hrs/Yr | Natural Gas Limited to 3390 hrs/yr | Max. 2,890 hrs/yr Natural Gas & Max. 500 Hrs/Yr ULSD Oil | EPA Class II Significant Impact Levels ($\mu g/m^3$) |
|---|---|---|---|---|---|---|
| $PM_{10}$ | Annual | 0.02 | 0.12 | 0.009 | 0.014 | 1 |
| | 24-Hour | 0.25 | 0.89 | 0.25 | 0.89 | 5 |
| $PM_{2.5}$ | Annual | 0.02 | 0.09 | 0.01 | 0.01 | 0.3 |
| | 24-Hour | 0.18 | 0.89 | 0.18 | 0.89 | 1.2 |
| Tier 1 | | | | | | |
| $NO_2$ | Annual | 0.11 | 0.58 | 0.04 | 0.07 | 1 |
| | 1-Hour | 3.53 | 18.2 | 3.5 | 18.2 | 7.52 |
| Tier 2[b] | | | | | | |
| $NO_2$ | Annual | 0.08 | 0.43 | 0.03 | 0.05 | 1 |
| | 1-Hour | 2.82 | 14.6 | 2.8 | 14.6 | 7.52 |
| CO | 8-Hour | 1.3 | 2.8 | 1.3 | 2.8 | 500 |
| | 1-Hour | 2.8 | 6.0 | 2.8 | 6.0 | 2,000 |
| $SO_2$ | Annual | 0.02 | 0.01 | 0.007 | 0.007 | 1 |
| | 24-Hour | 0.20 | 0.06 | 0.20 | 0.06 | 5 |
| | 3-Hour | 0.84 | 0.24 | 0.84 | 0.24 | 25 |
| | 1-Hour | 0.60 | 0.17 | 0.60 | 0.17 | 7.86 |

**Maximum Hours of Fuel Usage**

| | |
|---|---|
| Natural Gas | 3,390 |
| Fuel Oil | 500 |

[a] Assumes 75% conversion of $NO_x$ to $NO_2$ for annual and 80% converstion of $NO_x$ to $NO_2$ for 1-hour.

## Table 6-6: Maximum Predicted 1-Hour $NO_2$ Impacts Compared to the NAAQS

| Averaging Time and Rank | Maximum Concentration (µg/m³) | | | Receptor Location | | NAAQS (µg/m³) |
|---|---|---|---|---|---|---|
| | Total | Modeled Sources | Background | UTM- East (m) | UTM- North (m) | |
| **GE7FA5 Two CTs** | | | | | | |
| $NO_2$[a, b] | | | | | | |
| 1-Hour, 98th Percentile | 126.2 | 92.3 | 33.9 | 421,730 | 2,953,201 | 188 |

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2009 to 2013 of surface and upper air data from the National Weather Service stations at Fort Myers/Page Field and Ruskin, respectively.
A $NO_X$ to $NO_2$ conversion factor of 80% applies based on EPA's Guideline on Air Quality Models.

[b] The 1-hour $NO_2$ standard is met when the 5-year average of the 98th percentile of the daily 1-hour maximum values is less than 188 µg/m³. Therefore, the 8th highest 1-hour maximum modeled concentration (from 2009 - 2013) was added to a monitoring background based on the 3-year average of the 98th percentile value of the maximum daily 1-hr $NO_2$ monitoring values.

**Table 6-7: Maximum Pollutant Concentrations at the ENP Compared to the PSD Class I Area SIL**

| Pollutant | Averaging Time | Maximum Concentrations[a] at ENP PSD Class I Area ($\mu g/m^3$) GE 7F.05 CTs 8,760 Hrs on Nat.Gas | 8,760 Hrs on Fuel Oil | 3,390 Hrs on Nat.Gas | 2,890 Hrs Nat Gas & 500 Hrs Oil | | PSD Class I SIL ($\mu g/m^3$) |
|---|---|---|---|---|---|---|---|
| $NO_2$ | Annual | 0.001 | 0.006 | 0.0004 | 0.0007 | b | 0.1 |
| | 24-Hour | 0.0352 | 0.180 | 0.0352 | 0.180 | | -- |
| | 8-Hour | 0.0862 | 0.449 | 0.0862 | 0.449 | | -- |
| | 3-Hour | 0.1864 | 0.965 | 0.1864 | 0.965 | | -- |
| | 1-Hour | 0.2938 | 1.523 | 0.2938 | 1.523 | | -- |
| $PM_{10}$ | Annual | 0.001 | 0.0026 | 0.0002 | 0.0003 | b | 0.2 |
| | 24-Hour | 0.012 | 0.058 | 0.012 | 0.058 | | 0.3 |
| | 8-Hour | 0.031 | 0.147 | 0.0311 | 0.147 | | -- |
| $PM_{2.5}$ | Annual | 0.001 | 0.003 | 0.0002 | 0.0003 | b | 0.06 |
| | 24-Hour | 0.012 | 0.058 | 0.012 | 0.058 | | 0.07 |
| $SO_2$ | Annual | 0.001 | 0.0002 | 0.0002 | 0.0002 | b | 0.1 |
| | 24-Hour | 0.013 | 0.004 | 0.013 | 0.004 | | 0.2 |
| | 3-Hour | 0.051 | 0.014 | 0.051 | 0.014 | | 1 |

SIL = Class I Significant Impact Level

[a] Concentrations are based on highest predicted concentrations from CALPUFF v5.8 using 3 years of meteorological data for 2001 to 2003.

[b] Annual concentrations based on 500 hours of fuel oil and 2890 hours of natural gas firing

**Table 7-1: $SO_2$ Effects Levels For Various Plant Species**

| Plant Species | Observed Effect Level (µg/m$^3$) | Exposure (Time) | Reference |
|---|---|---|---|
| Sensitive to tolerant | 920 (20 percent displayed visible injury) | 3 hours | McLaughlin and Lee, 1974 |
| Lichens | 200-400 | 6 hr/wk for 10 weeks | Hart *et al.*, 1988 |
| Cypress, slash pine, live oak, mangrove | 1,300 | 8 hours | Woltz and Howe, 1981 |
| Jack pine seedlings | 470-520 | 24 hours | Malhotra and Kahn, 1978 |
| Black oak | 1,310 | Continuously for 1 week | Carlson, 1979 |

**Table 7-2: Sensitivity Groupings of Vegetation Based on Visible Injury at Different $SO_2$ Exposures [a]**

| Sensitivity Grouping | $SO_2$ Concentration | | Plants |
|---|---|---|---|
| | 1-Hour | 3-Hour | |
| Sensitive | 1,310 - 2,620 μg/m$^3$ (0.5 - 1.0 ppm) | 790 - 1,570 μg/m$^3$ (0.3 - 0.6 ppm) | Ragweeds<br>Legumes<br>Blackberry<br>Southern pines<br>Red and black oaks<br>White ash<br>Sumacs |
| Intermediate | 2,620 - 5,240 μg/m$^3$ (1.0 - 2.0 ppm) | 1,570 - 2,100 μg/m$^3$ (0.6 - 0.8 ppm) | Maples<br>Locust<br>Sweetgum<br>Cherry<br>Elms<br>Tuliptree<br>Many crop and garden species |
| Resistant | >5,240 μg/m$^3$ (>2.0 ppm) | >2,100 μg/m$^3$ (>0.8 ppm) | White oaks<br>Potato<br>Upland cotton<br>Corn<br>Dogwood<br>Peach |

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

**Table 7-3: Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary AAQS**

| Pollutant | Reported Effect | Concentration ($\mu g/m^3$) | Exposure |
|---|---|---|---|
| Sulfur Dioxide[a] | Respiratory stress in guinea pigs | 427 to 854 | 1 hour |
| | Respiratory stress in rats | 267 | 7 hours/day; 5 day/week for 10 weeks |
| | Decreased abundance in deer mice | 13 to 157 | continually for 5 months |
| Nitrogen Dioxide[b,c] | Respiratory stress in mice | 1,917 | 3 hours |
| | Respiratory stress in guinea pigs | 96 to 958 | 8 hours/day for 122 days |
| Particulates[a] | Respiratory stress, reduced respiratory disease defenses | 120 $PbO_3$ | continually for 2 months |
| | Decreased respiratory disease defenses in rats, same with hamsters | 100 $NiCl_2$ | 2 hours |

Sources:
[a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak et al., 1977.

**Table 7-4: Maximum 24-Hour Visibility Impairment Predicted for the Proposed Project at the ENP PSD Class I Area**

| CT / Fuel Type | Visibility Impairment (%) [a] | | | Visibility Impairment Criteria (deciview) |
|---|---|---|---|---|
| | 2001 | 2002 | 2003 | |
| **24-Hours/Day on Natural Gas (Primary)** | 0.027 | 0.036 | 0.033 | 0.5 |
| **24-Hour/Day on ULSD Oil (Backup)** | 0.079 | 0.132 | 0.116 | 0.5 |

SC CTs = Simple Cycle Combustion Turbines

[a] Values presented are 98th-percentile deciviews using CALPUFF v5.8.4 and CALPOST v6.221, MVISBK=8, M8_MODE=5. Background extinctions are based on FLAG 2008 and 20th best natural background values.

**Table 7-5: Maximum Annual Total Nitrogen and Sulfur Deposition Predicted for the Proposed Project at the ENP PSD Class I Area**

| Deposition | Total Deposition (Wet & Dry) (g/m$^2$/s) | Total Deposition (Wet & Dry) (kg/ha/yr)[a,c] | Year | Deposition Analysis Threshold [b] (kg/ha/yr) |
|---|---|---|---|---|
| **2 GE 7F.05 SC CTs** | | | | |
| **Total Sulfur** | 6.38E-13 | 0.0002 | 2001 | 0.01 |
| 24-Hour/Day on ULSD Oil (Backup) | 1.03E-12 | 0.0003 | 2002 | 0.01 |
| | 5.57E-13 | 0.0002 | 2003 | 0.01 |
| **Total Nitrogen** | 1.53E-12 | 0.0005 | 2001 | 0.01 |
| 24-Hour/Day on ULSD Oil (Backup) | 2.08E-12 | 0.0007 | 2002 | 0.01 |
| | 1.29E-12 | 0.0004 | 2003 | 0.01 |

[a] Conversion factor is used to convert g/m$^2$/s to kg/hectare (ha)/yr with the following units:

g/m$^2$/s x 0.001 kg/g
x 10,000 m$^2$/hectare
x 3,600 sec/hr
x 8,760 hr/yr = kg/ha/yr
or
g/m$^2$/s x 3.154E+08 = kg/ha/yr

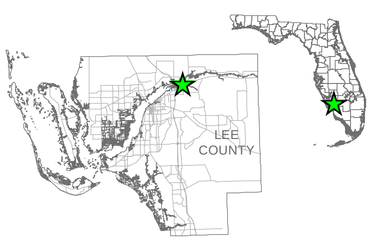
[b] Deposition analysis thresholds (DAT) for nitrogen deposition provided by the U.S. Fish and Wildlife Service, January 2002. A DAT is the additional amount of nitrogen or sulfur deposition within a Class I area, below which estimated impacts from a propsed new or modified source are considered insignificant.

[c] Total nitrogen and sulfur deposition is based on CTs operating 2890 hours/year on natural gas and 500 hours/year on ultra low sulfur fuel oil.

**FIGURES**


LEGEND

★ Project Location




0 5,000 10,000 20,000

Feet

**REFERENCE(S)**

FT MYERS PLANT LOCATION, FPL AND GOLDER ASSOCIATES INC., 2015

COORDINATE SYSTEM: NAD 1983 STATEPLANE FLORIDA EAST FIPS 0901 FEET
PROJECTION: TRANSVERSE MERCATOR
DATUM: NORTH AMERICAN 1983

CLIENT
FPL

PROJECT
FT MYERS PLANT

TITLE
**LOCATION MAP**

CONSULTANT

Golder Associates

| | |
|---|---|
| YYYY-MM-DD | 2015-04-19 |
| DESIGNED | NRL |
| PREPARED | NRL |
| REVIEWED | SM |
| APPROVED | KFK |

| PROJECT NO. | CONTROL | REV. | FIGURE |
|---|---|---|---|
| 13387590-01 | A001 | 0 | **1-1** |

PATH:

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI A

0 1 in


## EQUIPMENT IDENTIFICATION LIST

| DWG REF | DESCRIPTION | |
|---|---|---|
| 1 | COMBUSTION TURBINE UNIT 3C | |
| 2 | COMBUSTION TURBINE UNIT 3D | |
| 3 | | |
| 4 | COMBUSTION TURBINE EXHAUST STACK | 23 FT DIA X 100.5 FT H |
| 5 | COMBUSTION TURBINE EXHAUST SILENCER | |
| 6 | UNIT AUXILIARY TRANSFORMER | |
| 7 | DEMINERALIZED WATER STORAGE TANK | 136 FT DIA X 40 FT H 4,000,000 GAL |
| 8 | DEMINERALIZED WATER TRAILER | |
| 9 | BLACK START DIESEL GENERATOR | |
| 10 | FUEL OIL SUPPLY PUMPS | |
| 11 | GAS YARD | |

## LEGEND

NEW BENCHMARK

NEW CONTROL POINT

## SURVEY CONTROL TABLE

| POINT | FL STATE PLANE | | EXST PLANT GRID | | NOTE |
|---|---|---|---|---|---|
| BM-1 | N 858366.68 | E 726177.25 | N 10495.00 | E 2815.00 | PROPOSED |
| BM-2 | N 859286.18 | E 725771.33 | N 10495.00 | E 2815.00 | PROPOSED |
| BM-3 | N 859429.91 | E 726264.32 | N 10435.00 | E 3325.00 | PROPOSED |
| BM-4 | N 858664.37 | E 726751.62 | N 954.00 | E 3475.28 | PROPOSED |
| CP-1 | N 858960.89 | E 726234.17 | N 10014.91 | E 3114.25 | PROPOSED |
| CP-2 | N 859098.90 | E 726175.69 | N 10164.80 | E 3114.25 | PROPOSED |

NOTE: HORIZONTAL CONTROL IS BASED ON FLORIDA STATE PLANE (NAD 83). VERTICAL CONTROL IS BASED ON THE NGVD 29 DATUM. SUBTRACT 1.16 FROM NGVD 29 DATUM TO OBTAIN NAVD 88 DATUM

BENCHMARKS LISTED ARE PROPOSED BENCHMARKS TO BE ESTABLISHED BY THE CONTRACTOR. BENCHMARKS SHALL BE AS-BUILT ONCE ESTABLISHED AND DRAWING SHOULD BE REVISED ACCORDINGLY AND NOTED WITH "AS-BUILT" NEXT TO EACH COORDINATE IN THE TABLE.

REFERENCE(S)

BASE MAP TAKEN FROM BLACK & VEATCH SITE - ARRANGEMENT OVERALL SITE PLAN 180321-DS-2000.DWG, REV. 4, DATED 2015-03-03 DELIVERED IN .DWG FORMAT

CLIENT
FPL

PROJECT
FT MYERS PLANT

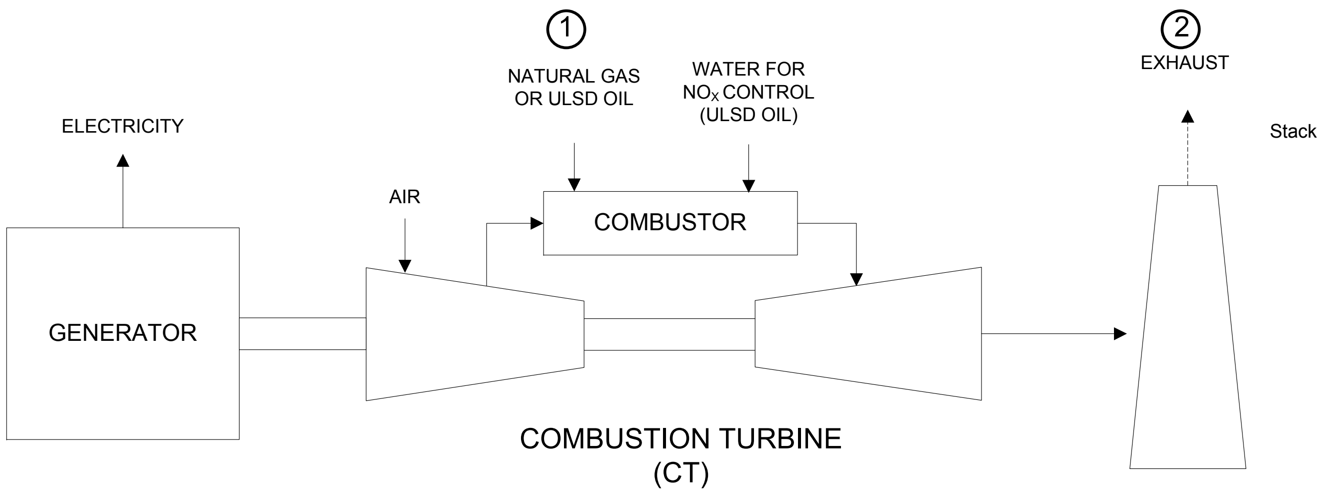
TITLE
# FACILITY PLOT PLAN

CONSULTANT

Golder Associates

| | |
|---|---|
| YYYY-MM-DD | 2015-05-01 |
| DESIGNED | NRL |
| PREPARED | NRL |
| REVIEWED | SM |
| APPROVED | KFK |

| PROJECT NO. | CONTROL | REV. | FIGURE |
|---|---|---|---|
| 13387590-01 | A002 | 0 | 2-1 |




| Parameters | Units | Fuel | GE 7F.05 |
|---|---|---|---|
| (1) CT Heat Input (at 59 °F | MMBtu/hr (HHV) | Gas | 2,318.6 |
| with inlet cooling) | MMBtu/hr (HHV) | Oil | 2,356.2 |
| (2) Mass Flow (at 59 °F with inlet cooling) | lb/hr | Gas | 4,272,000 |
| | lb/hr | Oil | 4,232,844 |
| (2) Stack Velocity | ft/sec | Gas | 114.6 |
| | ft/sec | Oil | 115.0 |
| (2) Stack Temperature | °F | Gas | 1,086 |
| | °F | Oil | 1,108 |
| (2) Stack Height | feet | Gas/Oil | 100.5 |
| (2) Stack Diameter | feet | Gas/Oil | 23 |

Figure 2-2. Process Flow Diagram for Each CT
Baseload Operation, Turbine Inlet Temperature of 59°F
FPL Fort Myers CT Project, Lee County, Florida

Source: GE, 2015; Golder, 2015.

**Process Flow Legend**
Solid/Liquid
Gas
Steam

Golder Associates

## APPENDIX A

## EXPECTED PERFORMANCE AND EMISSION INFORMATION FOR GE 7F.05 CTs AND GE 7FA.04 CTS

**Table GE-A-1: Design Information and Stack Parameters - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_x$ Combustor, Natural Gas**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| Combustion Turbine Performance | | | | | | | | | |
| Heat Input (MMBtu/hr, LHV) | 2,002.9 | 2,038.5 | 2,091.5 | 1,575.5 | 1,568.8 | 1,474.8 | 1,211.8 | 1,188.4 | 1,158.6 |
| Heat Input (MMBtu/hr, HHV) | 2,222.9 | 2,262.4 | 2,321.2 | 1,748.6 | 1,741.1 | 1,636.8 | 1,344.9 | 1,319.0 | 1,285.9 |
| Evaporative Cooler/Wet Compression | None | On | On | None | None | None | None | None | None |
| Fuel heating value (Btu/lb, LHV) | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 | 20,566.0 |
| Fuel heating value (Btu/lb, HHV) | 22,825 | 22,825 | 22,825 | 22,825 | 22,825 | 22,825 | 22,825 | 22,825 | 22,825 |
| Ratio of fuel heating values (HHV/LHV) | 1.110 | 1.110 | 1.110 | 1.110 | 1.110 | 1.110 | 1.110 | 1.110 | 1.110 |
| CT Exhaust Flow | | | | | | | | | |
| Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants) | | | | | | | | | |
| Mass Flow (lb/hr) | 4,296,000.0 | 4,293,000.0 | 4,206,000.0 | 3,413,000.0 | 3,362,000.0 | 3,128,000.0 | 2,697,000.0 | 2,701,000.0 | 2,717,000.0 |
| Temperature (°F) | 1,102.0 | 1,087.0 | 1,131.0 | 1,121.0 | 1,153.0 | 1,204.0 | 1,215.0 | 1,215.0 | 1,215.0 |
| Moisture (% Vol.) | 7.96 | 8.94 | 10.69 | 7.88 | 8.59 | 10.32 | 7.68 | 8.16 | 9.61 |
| Oxygen (% Vol.) | 12.39 | 12.09 | 11.89 | 12.47 | 12.27 | 11.88 | 12.69 | 12.74 | 12.67 |
| Molecular Weight | 28.5 | 28.2 | 28.0 | 28.5 | 28.4 | 28.2 | 28.5 | 28.4 | 28.2 |
| Volume flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,307,787 | 2,325,035 | 2,246,647 | 1,930,715 | 1,937,662 | 1,960,874 |
| Fuel Usage | | | | | | | | | |
| Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)] | | | | | | | | | |
| Heat Input (MMBtu/hr, LHV) | 2,002.9 | 2,038.5 | 2,091.5 | 1,575.5 | 1,568.8 | 1,474.8 | 1,211.8 | 1,188.4 | 1,158.6 |
| Heat Content (Btu/lb, LHV) | 20,566 | 20,566 | 20,566 | 20,566 | 20,566 | 20,566 | 20,566 | 20,566 | 20,566 |
| Fuel Usage (lb/hr) | 97,389 | 99,120 | 101,696 | 76,607 | 76,281 | 71,711 | 58,922 | 57,785 | 56,336 |
| Heat Content (Btu/cf, LHV) | 918 | 918 | 918 | 918 | 918 | 918 | 918 | 918 | 918 |
| Fuel Density (lb/ft$^3$) | 0.0446 | 0.0446 | 0.0446 | 0.0446 | 0.0446 | 0.0446 | 0.0446 | 0.0446 | 0.0446 |
| Fuel Usage (cf/hr) | 2,181,808 | 2,220,588 | 2,278,299 | 1,716,231 | 1,708,932 | 1,606,536 | 1,320,044 | 1,294,553 | 1,262,092 |
| CT Stack Parameters | | | | | | | | | |
| Stack Height (feet) | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 |
| Stack Diameter (feet) | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| CT Stack Flow Conditions | | | | | | | | | |
| Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min | | | | | | | | | |
| Stack Temperature (°F) | 1,102 | 1,087 | 1,131 | 1,121 | 1,153 | 1,204 | 1,215 | 1,215 | 1,215 |
| Volume flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,307,787 | 2,325,035 | 2,246,647 | 1,930,715 | 1,937,662 | 1,960,874 |
| Diameter (feet) | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Velocity (ft/sec)- calculated | 115.1 | 115.0 | 116.8 | 92.6 | 93.3 | 90.1 | 77.4 | 77.7 | 78.7 |

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft² (@14.7 psia).

Source: General Electric Company, 2015; Golder, 2015.

**Table GE-A-2: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_X$ Combustor, Natural Gas, Base Load**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| Particulate Matter (PM10/PM2.5) | | | | | | | | | |
| *$PM_{10}$/$PM_{2.5}$ (lb/hr) = $PM_{10}$ Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV) (front-half & back-half)* | | | | | | | | | |
| $PM_{10}$ Emission Rate (lb/MMBtu, HHV) | 0.00477 | 0.00477 | 0.00477 | 0.00606 | 0.00609 | 0.00648 | 0.00788 | 0.00804 | 0.00824 |
| Heat Input (MMBtu/hr, HHV) | 2,222.9 | 2,262.4 | 2,321.2 | 1,748.6 | 1,741.1 | 1,636.8 | 1,344.9 | 1,319.0 | 1,285.9 |
| $PM_{10}$/$PM_{2.5}$ Emission Rate (lb/hr) | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 |
| Sulfur Dioxide ($SO_2$) | | | | | | | | | |
| *$SO_2$ (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb $SO_2$ /lb S) /100* | | | | | | | | | |
| Fuel Use (scf/hr) | 2,181,808 | 2,220,588 | 2,278,299 | 1,716,231 | 1,708,932 | 1,606,536 | 1,320,044 | 1,294,553 | 1,262,092 |
| Sulfur Content (grains/ 100 cf) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| lb $SO_2$ /lb S (64/32) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| $SO_2$ Emission Rate (lb/hr) | 12.5 | 12.7 | 13.0 | 9.8 | 9.8 | 9.2 | 7.5 | 7.4 | 7.2 |
| Nitrogen Oxides ($No_x$) | | | | | | | | | |
| *$NO_x$ (ppmv actual) = $NO_x$ (ppmd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *$NO_x$ (lb/hr) = $NO_x$ (ppm actual) x Volume flow (acfm) x 46 (mole. wgt $NO_x$) x 2116.8 lb/ft$^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 10.4 | 10.6 | 10.3 | 10.3 | 10.4 | 10.5 | 10.1 | 9.8 | 9.5 |
| $NO_x$, ppmvd @15% $O_2$ (15 ppmvd) | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 | 9.0 |
| Moisture (%) | 7.96 | 8.94 | 10.69 | 7.88 | 8.59 | 10.32 | 7.68 | 8.16 | 9.61 |
| Oxygen (%) | 12.39 | 12.09 | 11.89 | 12.47 | 12.27 | 11.88 | 12.69 | 12.74 | 12.67 |
| Oxygen (%) dry | 13.46 | 13.28 | 13.31 | 13.54 | 13.42 | 13.25 | 13.75 | 13.87 | 14.02 |
| Flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,307,787 | 2,325,035 | 2,246,647 | 1,930,715 | 1,937,662 | 1,960,874 |
| Flow (acfm), dry | 2,641,493 | 2,610,319 | 2,599,902 | 2,125,933 | 2,125,315 | 2,014,793 | 1,782,436 | 1,779,549 | 1,772,434 |
| Exhaust Temperature (°F) | 1,102 | 1,087 | 1,131 | 1,121 | 1,153 | 1,204 | 1,215 | 1,215 | 1,215 |
| $NO_x$ Emission Rate (lb/hr) (Calculated) | 72.5 | 74.2 | 71.5 | 57.1 | 56.8 | 53.4 | 43.9 | 43.1 | 42.0 |
| (lb/hr) (GE | 72.0 | 72.0 | 70.0 | 57.0 | 57.0 | 53.0 | 44.0 | 43.0 | 42.0 |
| Carbon Monoxide (CO) | | | | | | | | | |
| *CO (ppmv wet or actual) = CO (ppmvd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2116.8 lb/ft$^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 4.64 | 4.71 | 4.59 | 8.28 | 8.22 | 8.03 | 8.28 | 8.20 | 8.12 |
| Basis, ppmvd | 5.0 | 5.2 | 5.1 | 9.0 | 9.0 | 9.0 | 9.0 | 8.9 | 9.0 |
| Basis, ppmvd @ 15% $O_2$ | 4.00 | 4.00 | 4.00 | 7.20 | 7.10 | 6.90 | 7.40 | 7.50 | 7.70 |
| Moisture (%) | 7.96 | 8.94 | 10.69 | 7.88 | 8.59 | 10.32 | 7.68 | 8.16 | 9.61 |
| Oxygen (%) | 12.39 | 12.09 | 11.89 | 12.47 | 12.27 | 11.88 | 12.69 | 12.74 | 12.67 |
| Oxygen (%) dry | 13.46 | 13.28 | 13.31 | 13.54 | 13.42 | 13.25 | 13.75 | 13.87 | 14.02 |
| Flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,307,787 | 2,325,035 | 2,246,647 | 1,930,715 | 1,937,662 | 1,960,874 |
| Flow (acfm), dry | 2,641,493 | 2,610,319 | 2,599,902 | 2,125,933 | 2,125,315 | 2,014,793 | 1,782,436 | 1,779,549 | 1,772,434 |
| Exhaust Temperature (°F) | 1,102 | 1,087 | 1,131 | 1,121 | 1,153 | 1,204 | 1,215 | 1,215 | 1,215 |
| CO Emission Rate (lb/hr) | 19.6 | 20.1 | 19.3 | 27.8 | 27.3 | 24.9 | 22.0 | 21.8 | 21.9 |

**Table GE-A-2: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_X$ Combustor, Natural Gas, Base Load**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| Volatile Organic Compounds (VOC) | | | | | | | | | |
| *VOC (ppmv wet or actual) = VOC (ppmvd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt $CH_4$) x 2116.8 lb/ft$^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 1.40 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| Moisture (%) | 7.96 | 8.94 | 10.69 | 7.88 | 8.59 | 10.32 | 7.68 | 8.16 | 9.61 |
| Oxygen (%) wet | 12.39 | 12.09 | 11.89 | 12.47 | 12.27 | 11.88 | 12.69 | 12.74 | 12.67 |
| Oxygen (%) dry | 13.46 | 13.28 | 13.31 | 13.54 | 13.42 | 13.25 | 13.75 | 13.87 | 14.02 |
| Flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,307,787 | 2,325,035 | 2,246,647 | 1,930,715 | 1,937,662 | 1,960,874 |
| Flow (acfm), dry | 2,641,493 | 2,610,319 | 2,599,902 | 2,125,933 | 2,125,315 | 2,014,793 | 1,782,436 | 1,779,549 | 1,772,434 |
| Exhaust Temperature (°F) | 1,102 | 1,087 | 1,131 | 1,121 | 1,153 | 1,204 | 1,215 | 1,215 | 1,215 |
| VOC Emission Rate (lb/hr) as methane | 3.38 | 3.41 | 3.37 | 2.69 | 2.65 | 2.49 | 2.12 | 2.13 | 2.16 |
| Sulfuric Acid Mist (SAM) | | | | | | | | | |
| Sulfuric Acid Mist (lb/hr)= $SO_2$ Emission Rate (lb/hr) x Conversion to $H_2SO_4$ (% by weight)/100 | | | | | | | | | |
| $SO_2$ Emission Rate (lb/hr) | 12.5 | 12.7 | 13.0 | 9.8 | 9.8 | 9.2 | 7.5 | 7.4 | 7.2 |
| Conversion to $H_2SO_4$ (% by weight) | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| SAM Emission Rate (lb/hr) | 1.9 | 1.9 | 2.0 | 1.5 | 1.5 | 1.4 | 1.2 | 1.1 | 1.1 |

Note: ppmvd= parts per million, volume dry; $O_2$= oxygen.

Source: General Electric Company, 2015, Golder 2015.

**Table GE-A-3: Design Information and Stack Parameters - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_x$ Combustor, ULSD Oil, Base Load**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| Parameter | 35° F | 59° F | 95° F | 35° F | 59° F | 95° F | 35° F | 59° F | 95° F |
| Combustion Turbine Performance | | | | | | | | | |
| Heat Input (MMBtu/hr, LHV) | 2,206.1 | 2,209.0 | 2,187.3 | 1,741.5 | 1,709.6 | 1,599.8 | 1,349.0 | 1,318.2 | 1,236.8 |
| Heat Input (MMBtu/hr, HHV) | 2,350.7 | 2,353.7 | 2,330.7 | 1,855.6 | 1,821.6 | 1,704.6 | 1,437.4 | 1,404.6 | 1,317.9 |
| Evaporative Cooler/Wet Compression | None | On | On | None | None | None | None | None | None |
| Fuel heating value (Btu/lb, LHV) | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 | 18,459.0 |
| Fuel heating value (Btu/lb, HHV) | 19,669 | 19,669 | 19,669 | 19,669 | 19,669 | 19,669 | 19,669 | 19,669 | 19,669 |
| Ratio of fuel heating values (HHV/LHV) | 1.066 | 1.066 | 1.066 | 1.066 | 1.066 | 1.066 | 1.066 | 1.066 | 1.066 |
| CT Exhaust Flow | | | | | | | | | |
| Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants) | | | | | | | | | |
| Mass Flow (lb/hr) | 4,244,000.0 | 4,257,000.0 | 4,173,000.0 | 3,373,000.0 | 3,283,000.0 | 3,102,000.0 | 2,687,000.0 | 2,674,000.0 | 2,598,000.0 |
| Temperature (°F) | 1,130.0 | 1,106.0 | 1,142.0 | 1,153.0 | 1,184.0 | 1,215.0 | 1,215.0 | 1,215.0 | 1,215.0 |
| Moisture (% Vol.) | 10.18 | 10.83 | 12.50 | 10.08 | 10.70 | 12.22 | 9.84 | 10.22 | 11.51 |
| Oxygen (% Vol.) | 10.92 | 10.89 | 10.71 | 11.03 | 10.85 | 10.63 | 11.27 | 11.34 | 11.36 |
| Molecular Weight | 28.5 | 28.2 | 28.0 | 28.47 | 28.40 | 28.23 | 28.5 | 28.4 | 28.3 |
| Volume flow (acfm) | 2,885,011 | 2,874,407 | 2,903,037 | 2,325,268 | 2,312,407 | 2,239,523 | 1,922,881 | 1,916,943 | 1,873,664 |
| Fuel Usage | | | | | | | | | |
| Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)] | | | | | | | | | |
| Heat input (MMBtu/hr, LHV) | 2,206.1 | 2,209.0 | 2,187.3 | 1,741.5 | 1,709.6 | 1,599.8 | 1,349.0 | 1,318.2 | 1,236.8 |
| Heat content (Btu/lb, LHV) | 18,459 | 18,459 | 18,459 | 18,459 | 18,459 | 18,459 | 18,459 | 18,459 | 18,459 |
| Fuel usage (lb/hr) | 119,514 | 119,669 | 118,497 | 94,344 | 92,616 | 86,668 | 73,081 | 71,412 | 67,003 |
| CT Stack Parameters | | | | | | | | | |
| Stack Height (feet) | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 | 100.5 |
| Stack Diameter (feet) | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| CT Stack Flow Conditions | | | | | | | | | |
| Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min | | | | | | | | | |
| Stack Temperature (°F) | 1,130 | 1,106 | 1,142 | 1,153 | 1,184 | 1,215 | 1,215 | 1,215 | 1,215 |
| Volume flow (acfm) | 2,885,011 | 2,874,407 | 2,903,037 | 2,325,268 | 2,312,407 | 2,239,523 | 1,922,881 | 1,916,943 | 1,873,664 |
| Diameter (feet) | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 |
| Velocity (ft/sec)- calculated | 115.7 | 115.3 | 116.5 | 93.3 | 92.8 | 89.8 | 77.1 | 76.9 | 75.2 |

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft² (@14.7 psia).

Source: General Electric Company, 2015; Golder, 2015.

**Table GE-A-4: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_x$ Combustor, ULSD Oil, Base Load**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| Particulate Matter (PM10/PM2.5) | | | | | | | | | |
| *$PM_{10}/PM_{2.5}$ (lb/hr) = $PM_{10}$ Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV) (front-half & back-half)* | | | | | | | | | |
| $PM_{10}$ Emission Rate (lb/MMBtu, HHV) | 0.02127 | 0.02124 | 0.02145 | 0.02695 | 0.02745 | 0.02933 | 0.03478 | 0.03560 | 0.03794 |
| Heat Input (MMBtu/hr, HHV) | 2,350.7 | 2,353.7 | 2,330.7 | 1,855.6 | 1,821.6 | 1,704.6 | 1,437.4 | 1,404.6 | 1,317.9 |
| $PM_{10}/PM_{2.5}$ Emission Rate (lb/hr) | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| Sulfur Dioxide ($SO_2$) | | | | | | | | | |
| *$SO_2$ (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb $SO_2$ /lb S) /100* | | | | | | | | | |
| Fuel oil Sulfur Content | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% | 0.0015% |
| Fuel oil use (lb/hr) | 119,514 | 119,669 | 118,497 | 94,344 | 92,616 | 86,668 | 73,081 | 71,412 | 67,003 |
| lb $SO_2$ / lb S (64/32) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| $SO_2$ Emission Rate (lb/hr) | 3.59 | 3.6 | 3.6 | 2.83 | 2.8 | 2.6 | 2.19 | 2.1 | 2.0 |
| Nitrogen Oxides ($NO_x$) | | | | | | | | | |
| *$NO_x$ (ppmv actual) = $NO_x$ (ppmd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *$NO_x$ (lb/hr) = $NO_x$ (ppm actual) x Volume flow (acfm) x 46 (mole. wgt $NO_x$) x 2116.8 lb/ft$^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 55.9 | 55.1 | 53.9 | 55.3 | 55.6 | 54.9 | 53.9 | 52.8 | 50.8 |
| $NO_x$, ppmvd @15% $O_2$ | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 |
| Moisture (%) | 10.18 | 10.83 | 12.50 | 10.08 | 10.70 | 12.22 | 9.84 | 10.22 | 11.51 |
| Oxygen (%) | 10.92 | 10.89 | 10.71 | 11.03 | 10.85 | 10.63 | 11.27 | 11.34 | 11.36 |
| Oxygen (%) dry | 12.16 | 12.21 | 12.24 | 12.27 | 12.15 | 12.11 | 12.50 | 12.63 | 12.84 |
| Flow (acfm) | 2,885,011 | 2,874,407 | 2,903,037 | 2,325,268 | 2,312,407 | 2,239,523 | 1,922,881 | 1,916,943 | 1,873,664 |
| Flow (acfm), dry | 2,591,317 | 2,563,109 | 2,540,158 | 2,090,881 | 2,064,979 | 1,965,853 | 1,733,669 | 1,721,031 | 1,658,005 |
| Exhaust Temperature (°F) | 1,130 | 1,106 | 1,142 | 1,153 | 1,184 | 1,215 | 1,215 | 1,215 | 1,215 |
| $NO_x$ Emission Rate (lb/hr) | 383.4 | 382.7 | 369.5 | 301.2 | 295.8 | 277.6 | 234.0 | 228.7 | 214.8 |
| | 390.1 | 382.0 | 384.0 | 305.3 | 299.6 | 294.0 | 235.7 | 231.1 | 223.0 |

**Table GE-A-4: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)**
**Dry Low $NO_X$ Combustor, ULSD Oil, Base Load**

| | CT Only | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Base Load Turbine Inlet Temperature | | | 75% Load Turbine Inlet Temperature | | | Low Load Turbine Inlet Temperature | | |
| **Parameter** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** | **35° F** | **59° F** | **95° F** |
| Carbon Monoxide (CO) | | | | | | | | | |
| *CO (ppmv wet or actual) = CO (ppmvd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2116.8 lb/$ft^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 11.98 | 11.82 | 11.56 | 18.03 | 17.88 | 17.52 | 18.02 | 17.99 | 17.65 |
| Basis, ppmvd | 13.3 | 13.3 | 13.2 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| Basis, ppmvd @ 15% $O_2$ | 9.0 | 9.0 | 9.0 | 13.7 | 13.5 | 13.4 | 14.0 | 14.3 | 14.6 |
| Moisture (%) | 10.18 | 10.83 | 12.50 | 10.08 | 10.70 | 12.22 | 9.84 | 10.22 | 11.51 |
| Oxygen (%) | 10.92 | 10.89 | 10.71 | 11.03 | 10.85 | 10.63 | 11.27 | 11.34 | 11.36 |
| Oxygen (%) dry | 12.16 | 12.21 | 12.24 | 12.27 | 12.15 | 12.11 | 12.50 | 12.63 | 12.84 |
| Flow (acfm) | 2,885,011 | 2,874,407 | 2,903,037 | 2,325,268 | 2,312,407 | 2,239,523 | 1,922,881 | 1,916,943 | 1,873,664 |
| Flow (acfm), dry | 2,591,317 | 2,563,109 | 2,540,158 | 2,090,881 | 2,064,979 | 1,965,853 | 1,733,669 | 1,721,031 | 1,658,005 |
| Exhaust Temperature (°F) | 1,130 | 1,106 | 1,142 | 1,153 | 1,184 | 1,215 | 1,215 | 1,215 | 1,215 |
| CO Emission Rate (lb/hr) | 50.0 | 49.9 | 48.2 | 59.8 | 57.9 | 53.9 | 47.6 | 47.4 | 45.4 |
| Volatile Organic Compounds (VOC) | | | | | | | | | |
| *VOC (ppmv wet or actual) = VOC (ppmvd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x [1- Moisture(%)/100]* | | | | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | | | | |
| *VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt $CH_4$) x 2116.8 lb/$ft^2$ (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr* | | | | | | | | | |
| Basis, ppm actual | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 | 3.50 |
| Moisture (%) | 10.18 | 10.83 | 12.50 | 10.08 | 10.70 | 12.22 | 9.84 | 10.22 | 11.51 |
| Oxygen (%) wet | 10.92 | 10.89 | 10.71 | 11.03 | 10.85 | 10.63 | 11.27 | 11.34 | 11.36 |
| Oxygen (%) dry | 12.16 | 12.21 | 12.24 | 12.27 | 12.15 | 12.11 | 12.50 | 12.63 | 12.84 |
| Flow (acfm) | 2,885,011 | 2,874,407 | 2,903,037 | 2,325,268 | 2,312,407 | 2,239,523 | 1,922,881 | 1,916,943 | 1,873,664 |
| Flow (acfm), dry | 2,591,317 | 2,563,109 | 2,540,158 | 2,090,881 | 2,064,979 | 1,965,853 | 1,733,669 | 1,721,031 | 1,658,005 |
| Exhaust Temperature (°F) | 1,130 | 1,106 | 1,142 | 1,153 | 1,184 | 1,215 | 1,215 | 1,215 | 1,215 |
| VOC Emission Rate (lb/hr) | 8.35 | 8.45 | 8.34 | 6.63 | 6.47 | 6.15 | 5.28 | 5.27 | 5.15 |
| Sulfuric Acid Mist (SAM) | | | | | | | | | |
| *Sulfuric Acid Mist (lb/hr)= $SO_2$ Emission Rate (lb/hr) x Conversion to $H_2SO_4$ (% by weight)/100* | | | | | | | | | |
| $SO_2$ Emission Rate (lb/hr) | 3.6 | 3.6 | 3.6 | 2.8 | 2.8 | 2.6 | 2.2 | 2.1 | 2.0 |
| Conversion to $H_2SO_4$ (% by weight) | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| SAM Emission Rate (lb/hr) | 0.55 | 0.55 | 0.54 | 0.43 | 0.43 | 0.40 | 0.34 | 0.33 | 0.31 |
| Lead | | | | | | | | | |
| *Lead (lb/hr) = Basis (lb/$10^{12}$ Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/$10^{12}$ Btu* | | | | | | | | | |
| Heat Input (MMBtu/hr, HHV) | 2,350.7 | 2,353.7 | 2,330.7 | 1,855.6 | 1,821.6 | 1,704.6 | 1,437.4 | 1,404.6 | 1,317.9 |
| Emission Rate Basis (lb/$10^{12}$ Btu) | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Lead Emission Rate (lb/hr) | 0.033 | 0.033 | 0.033 | 0.026 | 0.026 | 0.024 | 0.020 | 0.020 | 0.018 |

Note: ppmvd= parts per million, volume dry; $O_2$= oxygen.

Source: General Electric Company, 2015; Golder, 2015

**Table GE-A-5: Regulated and Hazardous Air Pollutant Emission Factors and Emissions for the Combustion Turbine Firing Gas and Distillate Fuel Oil (GE 7F.05)**

| | Combustion Turbine Natural Gas [a] | | | | Combustion Turbine ULSD Oil [a] | | | | Annual Emissions (TPY) [h] | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Scenario 1 | Scenario 2 | Maximum | |
| Pollutant | Reference | Emission Factor (lb/MMBtu) | Units | Emission Rate (lb/hr) | Reference | Emission Factor (lb/MMBtu) | Units | Emission Rate (lb/hr) | CT NG | CT NG & FO | 1 CT | 2 CTs |
| 1,3-Butadiene | b,c | 4.30E-07 | lb/MMBtu | 9.73E-04 | f,c | 1.60E-05 | lb/MMBtu | 3.77E-02 | 1.65E-03 | 1.08E-02 | 1.08E-02 | 2.16E-02 |
| Acetaldehyde | b | 4.00E-05 | lb/MMBtu | 9.05E-02 | | -- | -- | 0.00E+00 | 1.53E-01 | 1.31E-01 | 1.53E-01 | 3.07E-01 |
| Acrolein | b | 6.40E-06 | lb/MMBtu | 1.45E-02 | | -- | -- | 0.00E+00 | 2.45E-02 | 2.09E-02 | 2.45E-02 | 4.91E-02 |
| Benzene | b | 1.20E-05 | lb/MMBtu | 2.71E-02 | f | 5.50E-05 | lb/MMBtu | 1.29E-01 | 4.60E-02 | 7.16E-02 | 7.16E-02 | 1.43E-01 |
| Ethylbenzene | b | 3.20E-05 | lb/MMBtu | 7.24E-02 | | -- | -- | 0.00E+00 | 1.23E-01 | 1.05E-01 | 1.23E-01 | 2.45E-01 |
| Formaldehyde | d | 2.03E-04 | lb/MMBtu | 4.60E-01 | d | 2.16E-04 | lb/MMBtu | 5.09E-01 | 7.79E-01 | 7.91E-01 | 7.91E-01 | 1.58E+00 |
| Naphthalene | b | 1.30E-06 | lb/MMBtu | 2.94E-03 | f | 3.50E-05 | lb/MMBtu | 8.24E-02 | 4.99E-03 | 2.48E-02 | 2.48E-02 | 4.97E-02 |
| Polycyclic Aromatic Hydrocarbons (PAH) | b,e | 2.20E-06 | lb/MMBtu | 4.98E-03 | f,e | 4.00E-05 | lb/MMBtu | 9.41E-02 | 8.44E-03 | 3.07E-02 | 3.07E-02 | 6.15E-02 |
| Propylene Oxide | b,c | 2.90E-05 | lb/MMBtu | 6.56E-02 | | -- | -- | 0.00E+00 | 1.11E-01 | 9.48E-02 | 1.11E-01 | 2.22E-01 |
| Toluene | b | 3.30E-05 | lb/MMBtu | 7.47E-02 | | -- | -- | 0.00E+00 | 1.27E-01 | 1.08E-01 | 1.27E-01 | 2.53E-01 |
| Xylene | b | 6.40E-05 | lb/MMBtu | 1.45E-01 | | -- | -- | 0.00E+00 | 2.45E-01 | 2.09E-01 | 2.45E-01 | 4.91E-01 |
| 2-Methylnaphthalene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| 3-Methylchloranthrene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| 7,12-Dimethylbenz(a)anthracene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Acenaphthene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Acenaphthylene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Anthracene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benz(a)anthracene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo(a)pyrene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo(b)fluoranthene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo(g,h,i)perylene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Benzo(k)fluoranthene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Chrysene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Dibenzo(a,h)anthracene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Dichlorobenzene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Fluoranthene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Fluorene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Hexane | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Indeno(1,2,3-cd)pyrene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Phenanathrene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Pyrene | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Arsenic | | -- | -- | 0.00E+00 | g,c | 1.10E-05 | lb/MMBtu | 2.59E-02 | 0.00E+00 | 6.47E-03 | 6.47E-03 | 1.29E-02 |
| Beryllium | | -- | -- | 0.00E+00 | g,c | 3.10E-07 | lb/MMBtu | 7.30E-04 | 0.00E+00 | 1.82E-04 | 1.82E-04 | 3.65E-04 |
| Cadmium | | -- | -- | 0.00E+00 | g | 4.80E-06 | lb/MMBtu | 1.13E-02 | 0.00E+00 | 2.82E-03 | 2.82E-03 | 5.65E-03 |
| Chromium | | -- | -- | 0.00E+00 | g | 1.10E-05 | lb/MMBtu | 2.59E-02 | 0.00E+00 | 6.47E-03 | 6.47E-03 | 1.29E-02 |
| Cobalt | | -- | -- | 0.00E+00 | | -- | -- | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 | 0.00E+00 |
| Lead | | -- | -- | 0.00E+00 | g | 1.40E-05 | lb/MMBtu | 3.30E-02 | 0.00E+00 | 8.24E-03 | 8.24E-03 | 1.65E-02 |
| Manganese | | -- | -- | 0.00E+00 | g | 7.90E-04 | lb/MMBtu | 1.86E+00 | 0.00E+00 | 4.65E-01 | 4.65E-01 | 9.30E-01 |
| Mercury | | -- | -- | 0.00E+00 | g | 1.20E-06 | lb/MMBtu | 2.82E-03 | 0.00E+00 | 7.06E-04 | 7.06E-04 | 1.41E-03 |
| Nickel | | -- | -- | 0.00E+00 | g,c | 4.60E-06 | lb/MMBtu | 1.08E-02 | 0.00E+00 | 2.71E-03 | 2.71E-03 | 5.41E-03 |
| Selenium | | -- | -- | 0.00E+00 | g,c | 2.50E-05 | lb/MMBtu | 5.88E-02 | 0.00E+00 | 1.47E-02 | 1.47E-02 | 2.94E-02 |
| | | | **Total HAPs =** | **0.96** | | | | | **1.62** | **1.60** | **1.71** | **3.43** |
| | | | **Max. Individual HAP =** | **0.46** | | | | | **0.78** | **0.79** | **0.79** | **1.58** |

[a] Emissions based on:

| | Natural gas | Fuel oil |
|---|---|---|
| Fuel | Natural gas | Fuel oil |
| Heat input (MMBtu/hr) (HHV) (Baseload at 59 °F) | 2,262 | 2,354 |

| Fuel | Scenario 1 | Scenario 2 |
|---|---|---|
| Natural Gas | 3,390 | 2,890 |
| Fuel Oil | 0 | 500 |
| Total Hours | 3,390 | 3,390 |

[b] Emission factor from Table 3.1-3, AP-42, EPA, April 2000. For Toluene, based on EPA database.

[c] Based on the method detection limit; for the CT, based on 1/2 of the method detection limit; expected emissions are lower.

[d] Formaldehyde emission factor based on 91 ppb @15% $O_2$ equivalent to combustion turbine MACT limit (see Table GE-A-6)

[e] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

[f] Emission factor from Table 3.1-4, AP-42, EPA, April 2000.

[g] Emission factor from Table 3.1-5, AP-42, EPA, April 2000.

h Annual operating hours

**Table GE-A-6: Maximum Formaldehyde Emissions When Firing Natural Gas and ULSD Oil (GE 7F.05)**

| Parameter | CT at Baseload | | | | | |
|---|---|---|---|---|---|---|
| | Natural Gas-Firing Turbine Inlet Temperature | | | ULSD Oil-Firing Turbine Inlet Temperature | | |
| | 35° F | 59° F | 95° F | 35° F | 59° F | 95° F |
| Formaldehyde ($CH_2O$) | | | | | | |
| *$CH_2O$ (lb/hr) = $CH_2O$ (ppm actual) x Volume flow (acfm) x 30 (mole. wgt $CH_2O$) x 2116.8 lb/ft$^2$ (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/h* | | | | | | |
| *$CH_2O$ (ppm actual) = $CH_2O$ (ppmd @ 15%$O_2$) x [(20.9 - $O_2$ dry)/(20.9 - 15)] x (1- Moisture(%)/100)* | | | | | | |
| *Oxygen (%, dry)($O_2$ dry) = Oxygen (%)/[1-Moisure (%)]* | | | | | | |
| Basis, ppm actual- calculated | 0.106 | 0.107 | 0.105 | 0.121 | 0.119 | 0.117 |
| CT, ppmvd @15% $O_2$ | 0.091 | 0.091 | 0.091 | 0.091 | 0.091 | 0.091 |
| Moisture (%) | 7.96 | 8.94 | 10.69 | 10.18 | 10.83 | 12.50 |
| Oxygen (%) | 12.39 | 12.09 | 11.89 | 10.92 | 10.89 | 10.71 |
| Oxygen (%) dry | 13.46 | 13.28 | 13.31 | 12.16 | 12.21 | 12.24 |
| Exhaust Flow (acfm) | 2,869,940 | 2,866,592 | 2,911,098 | 2,885,011 | 2,874,407 | 2,903,037 |
| Exhaust Temperature (°F) | 1,102 | 1,087 | 1,131 | 1,130 | 1,106 | 1,142 |
| Molecular weight | 28.45 | 28.19 | 27.97 | 28.46 | 28.22 | 28.02 |
| CT Emission rate (lb/hr) | 0.454 | 0.460 | 0.440 | 0.514 | 0.509 | 0.488 |
| Heat Input (MMBtu/hr, HHV) | 2,223 | 2,262 | 2,321 | 2,351 | 2,354 | 2,331 |
| CT Emission rate (lb/$10^{12}$ Btu) (HHV) | 204.1 | 203.2 | 189.4 | 218.7 | 216.1 | 209.3 |
| CT Emission rate (lb/$10^6$ Btu) (HHV) | 2.04E-04 | 2.03E-04 | 1.89E-04 | 2.19E-04 | 2.16E-04 | 2.09E-04 |

Note: ppmvd= parts per million, volume dry; $O_2$= oxygen.

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015

## APPENDIX B

## BACT DETERMINATIONS FOR SIMPLE CYCLE CTs

**Table B-1: Summary of $NO_x$ BACT Determinations for Natural Gas-Fired CTs (2003-2015)**

| Facility Name | State | Permit Issued | Process Info | Heat Input | Control Method | $NO_x$ Limit | Basis |
|---|---|---|---|---|---|---|---|
| **Florida** | | | | | | | |
| Florida Power & Light Lauderdlae Plant | FL | 4/22/2014 | Turbine, Simple Cycle, Natural Gas (5) | 200 MW | DLN | 9 PPMVD @ 15% O2 | BACT-PSD |
| JEA Greenland Energy Center | FL | 3/10/2009 | Turbine, Simple Cycle, Natural Gas | 190 MW | DLN and WI | 9 PPMVD @ 15% O2 | BACT-PSD |
| Shady Hills Generating Station | FL | 1/12/2009 | Two Simple Cycle Combustion Turbine - Model 7FA | 170 MW | DLN | 9 PPMVD @ 15% O2 | BACT-PSD |
| Progress Bartow Power Plant | FL | 1/26/2007 | Simple Cycle Combustion Turbine (1) | 1972 MMBTU/H | DLN and WI | 15 PPMVD | BACT-PSD |
| JEA- St. Johns River Park Plant | FL | 12/22/2006 | Simple Cycle Turbine 172 MW | 1804 MMBTU/H | DLN and WI | 15 PPM @ 15% O2 | OTHER CASE-BY-CASE |
| Oleander Power Project | FL | 11/17/2006 | Simple Cycle Combustion Turbine | 190 MW | DLN and WI | 9 PPM @15% O2 | BACT-PSD |
| TEC/Polk Power Energy Station | FL | 4/28/2006 | Simple Cycle Gas Turbine | 1834 MMBTU/H | DLN | 9 PPMVD @ 15% O2 | BACT-PSD |
| FPL Martin Plant | FL | 4/16/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 170 MW | DLN | 9 PPMVD @ 15% O2 | BACT-PSD |
| **EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)** | | | | | | | |
| Dahlberg Combusdtion Turbine Electric Generating Facility | GA | 5/14/2010 | Simple Cycle Combustion Turbine - Electric Generating Plant | 1530 MW | DLN And Wi | 9 PPM @ 15% O2 | BACT-PSD |
| Exxon Mobile Bay -- Northwest Gulf Field | AL | 2/1/2005 | Turbine, Simple Cycle | 6000 BHP | Solonox Combustor | 25 PPM @ 15% O2 | BACT-PSD |
| Exxon Mobile -- Mobile Bay - Bon Secure Bay Field | AL | 2/1/2005 | Turbine, Simple Cycle | 3600 BHP | Solonox Combustion | 25 PPM @ 15% O2 | BACT-PSD |
| TVA - Kemper Combustion Turbine Plant | MS | 12/10/2004 | GE Combustion Turbine (4) | 1278 MMBTU/H | | 12 PPM @ 15% O2 | BACT-PSD |
| Moselle Plant | MS | 12/10/2004 | Combustion Turbine, Gas-Fired, Simple-Cycle | 1143.3 MMBTU/H | DLN Burner With Inlet Gas Cooling. | 9 PPM VD @ 15% O2 | BACT-PSD |
| Louisville Gas And Electric Company | KY | 6/6/2003 | Turbine, Simple Cycle, Natural Gas (6) | 160 MW | DLN Combustors | 12 PPM @ 15% O2 | BACT-PSD |
| Smepa - Silver Creek Generating | MS | 5/29/2003 | Turbine, Simple Cycle (3) | 1109.3 MMBTU/H | DLN Burners | 9 PPM @ 15% O2 | BACT-PSD |
| **Other States** | | | | | | | |
| NRG Marsh Landing | CA | | Turbine, Simple Cycle, Natural Gas (4) | 190 MW | DLN and hot SCR | 2.5 PPMVD @15% O2 | BACT-PSD |
| Indeck Wharton Energy Center | TX | 2/2/2015 | Combustion Turbines (3) | 220 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| SR Bertron Electric Generation Station | TX | 12/19/2014 | Simple Cycle Turbine | 225 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Roan's Prairie Generating Station | TX | 9/22/2014 | Simple Cycle Turbines (2) | 600 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Ector County Energy Center | TX | 8/1/2014 | Simple Cycle Turbines (2) | 180 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Pueblo Airport Generating Station | CO | 4/22/2014 | Simple Cycle Turbine | 375 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Antelope Elk Energy Center | TX | 4/22/2014 | Combustion Turbine Generator | 202 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Troutdale Energy Center | OR | 3/5/2014 | Combustion Turbine Generator | 1,690 MMBTU/H | DLN and hot SCR | 2.5 PPMVD @15% O2 | BACT-PSD |
| R.M. Heskett Station | ND | 2/22/2013 | Combustion Turbine | 986 MMBTU/H | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Bosque County Power Plant | TX | 2/27/2009 | Electrical Generation | 170 MW | DLN | 9 PPMVD @15% O2 | BACT-PSD |
| Great River Energy - Elk River Station | MN | 7/1/2008 | Combustion Turbine Generator | 2169 MMBTU/H | DLN | 9 PPM | BACT-PSD |
| Rawhide Energy Station | CO | 8/31/2007 | Unit F Combustion Turbine | 1400 MMBTU/H | DLN | 9 PPMVD | BACT-PSD |
| We Energies Concord | WI | 1/26/2006 | Combustion Turbine, 100 Mw, Natural Gas | 100 MW | DLN | 25 PPMDV @ 15% O2 | BACT-PSD |
| Fairbault Energy Park | MN | 7/15/2004 | Turbine, Simple Cycle, Natural Gas (1) | 1663 MMBTU/H | DLN In Lean Premix Mode. | 25 PPMVD @ 15% 02 | BACT-PSD |
| Great River Energy Lakefield Junction Station | MN | 9/10/2003 | Turbine, Simple Cycle, Natural Gas | 109 MW | DLN and GCP | 9 PPM @ 15% O2 | BACT-PSD |
| ODEC - Louisa Facility | VA | 3/11/2003 | Turbine, Simple Cycle, (1), Natural Gas | 1624 MMBTU/H | GCP And CEM System. | 10.5 PPMVD @ 15% O2 | N/A |
| ODEC - Marsh Run Facility | VA | 2/14/2003 | Turbine, Simple Cycle, (4), Natural Gas | 1624 MMBTU/H | DLN Burners | 9 PPMVD @ 15% O2 | N/A |
| ODEC -Marsh | VA | 2/14/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 1624 MMBTU/H | DLN and WI | 10.5 PPMVD | BACT-PSD |

Source: EPA 2015 (RBLC database); Golder, 2015

Note: DLN= dry low NOx; WI= water injection; SI=Steam Injection; GCP= good combustion practices; SCR= selective catalytic reduction



Golder Associates

**Table B-2: Summary of $NO_X$ BACT Determinations for ULSD Oil-Fired CTs (2003-2015)**

| Facility Name | State | Permit Issued | Process Info | Heat Input | Fuel | Control Method | $NO_x$ Limit | Basis |
|---|---|---|---|---|---|---|---|---|
| **Florida** | | | | | | | | |
| Florida Power & Light Lauderdlae Plant | FL | 4/22/2014 | Turbine, Simple Cycle, Natural Gas (5) | 200 MW | NO.2 FUEL OIL | WI | 42 PPMVD @ 15% O2 | BACT-PSD |
| JEA Greenland Energy Center | FL | 3/10/2009 | Turbine, Simple Cycle, Natural Gas | 190 MW | NO.2 FUEL OIL | WI | 42 PPMVD @ 15% O2 | BACT-PSD |
| Shady Hills Generating Station | FL | 1/12/2009 | Two Simple Cycle Combustion Turbine - Model 7FA | 170 MW | NO.2 FUEL OIL | WI | 42 PPMVD @ 15% O2 | BACT-PSD |
| FPL MARTIN PLANT | FL | 12/22/2003 | TURBINE, SIMPLE CYCLE, FUEL OIL (4) | 170 MW | NO.2 FUEL OIL | WI | 42 PPMVD @ 15% O2 | BACT-PSD |
| **EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)** | | | | | | | | |
| TVA - KEMPER COMBUSTION TURBINE PLANT | MS | 1/25/2005 | GENERAL ELECTRIC COMBUSTION TURBINES | | NO.2 FUEL OIL | WI | 42 PPMDV @ 15% O2 | BACT-PSD |
| Talbot Energy Facility | GA | 6/9/2003 | Turbine, Simple Cycle, Fuel Oil, (2) | 108 MW | NO.2 FUEL OIL | DLN and WI | 42 PPMDV @ 15% O2 | BACT-PSD |
| Broad River Energy Center | SC | 5/22/2003 | Combustion Turbines | | NO.2 FUEL OIL | WI | 42 PPMDV @ 15% O2 | BACT-PSD |
| **Other States** | | | | | | | | |
| WE ENERGIES CONCORD | WI | 11/29/2006 | COMBUSTION TURBINE, 100 MW, #2 FUEL OIL | 100 MW | No. 2 FUEL OIL | WI | 65 PPMDV @ 15% O2 | BACT-PSD |
| FAIRBAULT ENERGY PARK | MN | 9/21/2004 | TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1) | 1576 MMBTU/H | No. 2 FUEL OIL | WI | 42 PPMDV @ 15% O2 | BACT-PSD |
| ODEC - LOUISA | VA | 6/21/2004 | TURBINE, SIMPLE CYCLE, FUEL OIL (1) | 1820 MMBTU/H | No. 2 FUEL OIL | WI | 42 PPMVD @ 15% O2 | BACT-PSD |
| ODEC - LOUISA FACILITY | VA | 4/28/2003 | TURBINE, SIMPLE CYCLE, (1), FUEL OIL | 1820 MMBTU/H | No. 2 FUEL OIL | GCP AND CEM SYSTEM. | 42 PPMVD @ 15% O2 | BACT-PSD |
| Great River Energy Lakefield Junction Station | MN | 9/10/2003 | Turbine, Simple Cycle, Fuel Oil | 109 MW | No. 2 FUEL OIL | WI and GCP | 42 PPMVD @ 15% O2 | BACT-PSD |
| ODEC - Marsh Run Facility | VA | 2/14/2003 | Turbine, Simple Cycle, (4), Fuel Oil | 1803 MMBTU/H | No. 2 FUEL OIL | DLN BURNERS, CLEAN BURNING FUEL, AND CEM SYSTEM. | 62 PPMVD @ 15% O2 | NA |

Source: EPA 2015 (RBLC database); Golder, 2015

Note: SCR= selective catalytic reduction; WI= water injection; GCP= good combustion practices

**Table B-3: Summary of GHG (CO2e) BACT Determinations for Natural Gas-Fired CTs (2003-2015)**

| Facility Name | State | Permit Issued | Process Info | Heat Input | | Control Method | $CO_2e$ Limit | | Basis |
|---|---|---|---|---|---|---|---|---|---|
| Corpus Christi Liquefaction Plant | TX | 2/27/2015 | Refrigeration Compressor Turbines | 40,000 | HP | | 146,754 | TONS/YR | BACT-PSD |
| Pueblo Airport Generating Station | CO | 5/20/2014 | Simple Cycle Turbine | 375 | MW | | 1,600 | Llb/MW-HR | BACT-PSD |
| Troutdale Energy Center | OR | 3/5/2014 | Combustion Turbine Generator | 1,690 | MMBTU/H | | 1707 | Llb/MW-HR | BACT-PSD |
| PIO PICO ENERGY CENTER | CA | 4/29/2013 | COMBUSTION TURBINES (NORMAL OPERATION) | 300 | MW | | 1,328 | LB/MW-HR | BACT-PSD |
| R.M. HESKETT STATION | ND | 5/8/2013 | Combustion Turbine | 986 | MMBtu/hr | | 413,198 | TONS/YR | BACT-PSD |
| SABINE PASS LNG TERMINAL | LA | 5/11/2012 | Simple Cycle Generation Turbines (2) | 286 | MMBTU/H | GCP and fueled by natural gas - use GE LM2500+G4 turbines | 4,872,107 | TONS/YR | BACT-PSD |

Source: EPA 2015 (RBLC database); Golder, 2015

Note: GCP= good combustion practices



Golder Associates

**Table B-4: Summary of PM BACT Determinations for Natural Gas-Fired CTs (2003-2015)**

| Facility Name | State | Permit Issued | Process Info | Heat Input | pollutant | Control Method | $PM/PM_{10}/PM_{2.5}$ Limit | $PM/PM_{10}/PM_{2.5}$ Emissions Rate | Basis |
|---|---|---|---|---|---|---|---|---|---|
| **Florida** | | | | | | | | | |
| Florida Power & Light Lauderdlae Plant | FL | 4/22/2014 | Turbine, Simple Cycle, Natural Gas (5) | 200 MW | | Clean Fuel | 10 % OPACITY | | BACT-PSD |
| Shady Hills Generating Station | FL | 1/12/2009 | Two Simple Cycle Combustion Turbine - Model 7fa | 170 MW | PM10 | | 10 % OPACITY | | BACT-PSD |
| Jacksonville Electric Authority/Jea | FL | 12/22/2006 | Simple Cycle Turbine 172 Mw | 1804 MMBTU/H | filterable PM10 | Clean Fuel | | | BACT-PSD |
| Oleander Power Project | FL | 11/17/2006 | Simple Cycle Combustion Turbine | 190 MW | filterable PM10 | Clean Fuel | 1.5 GR S/100 SCF | | BACT-PSD |
| TEC/Polk Power Energy Station | FL | 4/28/2006 | Simple Cycle Gas Turbine | 1834 MMBTU/H | filterable PM10 | Clean Fuel, GCP | 10 % OPACITY | | BACT-PSD |
| FPL Martin Plant | FL | 4/16/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 170 MW | filterable PM10 | Clean Fuel | | | BACT-PSD |
| FPL Manatee Plant - Unit 3 | FL | 4/15/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 170 MW | filterable PM10 | Clean Fuel | | | BACT-PSD |
| **EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)** | | | | | | | | | |
| Dahlberg Combusdtion Turbine Electric Generating Facility | GA | 5/14/2010 | Simple Cycle Combustion Turbine | 1530 MW | PM10 | Clean Fuel, GCP | | 0.011 LB/MMBTU | BACT-PSD |
| TVA - Kemper Combustion Turbine Plant | MS | 12/10/2004 | GE Combustion Turbine (4) | 1278 MMBTU/H | PM | | | 0.0084 LB/MMBTU | OTHER CASE-BY-CASE |
| Moselle Plant | MS | 12/10/2004 | Combustion Turbine, Gas-Fired, Simple-Cycle | 1143.3 MMBTU/H | filterable PM10 | | | 10 LB/H | BACT-PSD |
| Talbot Energy Facility | GA | 6/9/2003 | Turbine, Simple Cycle, Natural Gas, (6) | 108 MW | PM | Clean Fuel | | 7.35 LB/H | BACT-PSD |
| Louisville Gas And Electric Company | KY | 6/6/2003 | Turbine, Simple Cycle, Natural Gas (6) | 160 MW | PM | GCP | | 7.35 LB/H | BACT-PSD |
| SMEPA - Silver Creek Generating | MS | 5/29/2003 | Turbine, Simple Cycle (3) | 1109.3 MMBTU/H | filterable PM10 | Clean Fuel, GCP | | 7.35 LB/H | BACT-PSD |
| Rincon Power Plant | GA | 3/24/2003 | Combustion Turbine, (2) | 171.7 MW | PM | Clean Fuel | | 7.35 LB/H | BACT-PSD |
| Warren Peaking Power Facility (Warren Power, L | MS | 1/30/2003 | Turbines, Simple Cycle, Natural Gas (4) | 959.8 MMBTU/H | PM | Clean Fuel | | 7 LB/H | BACT-PSD |
| Warren Peaking Power Facility (Warren Power, L | MS | 1/30/2003 | Turbines, Simple Cycle, Natural Gas (4) | 959.8 MMBTU/H | filterable PM10 | Clean Fuel | | 7 LB/H | BACT-PSD |
| **Other States** | | | | | | | | | |
| Pueblo Airport Generating Station | CO | 4/22/2014 | Simple Cycle Turbine | 375 MW | | Clean Fuel | | 4.8 LB/H | BACT-PSD |
| Troutdale Energy Center | OR | 3/5/2014 | Combustion Turbine Generator | 1,690 MMBTU/H | PM10 | Clean Fuel | | 9.1 LB/H | BACT-PSD |
| R.M. Heskett Station | ND | 2/22/2013 | Combustion Turbine | 986 MMBtu/hr | PM10 | GCP | | 7.3 LB/HR | BACT-PSD |
| Pio Pico Energy Center | CA | 11/19/2012 | Combustion Turbines (Normal Operation) | 300 MW | PM10 | Clean Fuel | | 0.0065 LB/MMBTU (HI | BACT-PSD |
| Great River Energy - Elk River Station | MN | 7/1/2008 | Combustion Turbine Generator | 2169 MMBTU/H | PM10 | Clean Fuel | | | BACT-PSD |
| Great River Energy - Elk River Station | MN | 7/1/2008 | Combustion Turbine Generator | 2169 MMBTU/H | filterable PM10 | Clean Fuel | | | BACT-PSD |
| Great River Energy - Elk River Station | MN | 7/1/2008 | Combustion Turbine Generator | 2169 MMBTU/H | filterable PM10 | Clean Fuel | | | BACT-PSD |
| Western Farmers Electric Anadarko | OK | 6/13/2008 | Combustion Turbine Peaking Unit(S) | 462.7 MMBTU/H | filterable PM10 | | | 4 LB/H | BACT-PSD |
| Rawhide Energy Station | CO | 8/31/2007 | Unit F Combustion Turbine | 1400 MMBTU/H | PM | Clean Fuel | | 18 LB/H | BACT-PSD |
| Rawhide Energy Station | CO | 8/31/2007 | Unit F Combustion Turbine | 1400 MMBTU/H | filterable PM10 | Clean Fuel | | 18 LB/H | BACT-PSD |
| Dayton Power And Light Company | OH | 3/7/2006 | Combustion Turbine (1), Simple Cycle | 1115 MMBTU/H | filterable PM10 | | | 8 LB/H | OTHER CASE-BY-CASE |
| Dayton Power And Light Company | OH | 3/7/2006 | Combustion Turbines (2), Simple Cycle | 1115 MMBTU/H | filterable PM10 | | | 8 LB/H | OTHER CASE-BY-CASE |
| We Energies Concord | WI | 1/26/2006 | Combustion Turbine, 100 Mw, Natural Gas | 100 MW | PM | | | 39 LB/H | BACT-PSD |
| Rolling Hills Generating Plant | OH | 1/17/2006 | Natural Gas Fired Turbines (5) | 209 MW | PM | | | 17.3 LB/H | BAT (Non-US ONLY) |
| Rolling Hills Generating Plant | OH | 1/17/2006 | Natural Gas Fired Turbines (5) | 209 MW | filterable PM10 | | | 17.3 LB/H | BACT-PSD |
| South Harper Peaking Facility | MO | 12/29/2004 | Turbines, Simple Cycle, Natural Gas, (3) | 1455 MMBTU/H | filterable PM10 | GCP | | 15.25 LB/H | |
| Fairbault Energy Park | MN | 7/15/2004 | Turbine, Simple Cycle, Natural Gas (1) | 1663 MMBTU/H | filterable PM10 | Clean Fuel, GCP | | 0.01 LB/MMBTU | BACT-PSD |
| Fredonia Energy Station | WA | 7/18/2003 | Turbines, Simple Cycle, (2) | 108 MW | filterable PM10 | Clean Fuel, GCP | 0.01 GR/DSCF | | BACT-PSD |
| Exxon Mobil Chemical Baytown Olefins Plant | TX | 6/13/2003 | Gas Turbine-Case 1 | 164 MW | PM | | | 18 LB/H | BACT-PSD |
| ODEC - Louisa Facility | VA | 3/11/2003 | Turbine, Simple Cycle, (1), Natural Gas | 1624 MMBTU/H | filterable PM10 | GCP | | 18 LB/H | N/A |
| ODEC - Louisa | VA | 3/11/2003 | Turbine, Simple Cycle, Natural Gas (1) | 1624 MMBTU/H | filterable PM10 | Clean Fuel, GCP | | 18 LB/H | BACT-PSD |
| ODEC -Marsh | VA | 2/14/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 1624 MMBTU/H | filterable PM10 | Clean Fuel, GCP | | 18 LB/H | BACT-PSD |
| Chickahominy Power | VA | 1/10/2003 | Turbine, Simple Cycle, Natural Gas, (4) | 182.6 MW | filterable PM10 | Clean Fuel, GCP | | 27 LB/H | BACT-PSD |

**Table B-5: Summary of PM BACT Determinations for ULSD Oil-Fired CTs (2003-2015)**

| Facility Name | State | Permit Issued | Process Info | Heat Input | Fuel | Pollutant | Control Method | $PM/PM_{10}/PM_{2.5}$ Limit | $PM/PM_{10}/PM_{2.5}$ Emissions Rate | Basis |
|---|---|---|---|---|---|---|---|---|---|---|
| **Florida** | | | | | | | | | | |
| FPL Martin Plant | FL | 4/16/2003 | Turbine, Simple Cycle, Fuel Oil (4) | 170 MW | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | | BACT-PSD |
| Greenland Energy Center | FL | 3/10/2009 | Combustion Turbine | 190 MW | NO.2 FUEL OIL | PM10 | Clean Fuel | 10% OPACITY | | BACT-PSD |
| **EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)** | | | | | | | | | | |
| Talbot Energy Facility | GA | 6/9/2003 | Turbine, Simple Cycle, Fuel Oil, (2) | 108 MW | NO.2 FUEL OIL | PM | Clean Fuel | | 0.023 LB/MMBTU | BACT-PSD |
| TVA - Kemper Combustion Turbine Plant | MS | 12/10/2004 | GE Combustion Turbine (4) | 1278 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 15.8 LB/H | BACT-PSD |
| Broad River Energy Center | SC | 5/22/2003 | Combustion Turbines | | NO.2 FUEL OIL | PM | Clean Fuel | | 46 LB/H | BACT-PSD |
| **Other States** | | | | | | | | | | |
| Dayton Power And Light Company | OH | 3/7/2006 | Combustion Turbines (2), Simple Cycle | 1115 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 15 LB/H | OTHER CASE-BY-CASE |
| Dayton Power And Light Company | OH | 3/7/2006 | Combustion Turbine (1), Simple Cycle | 1115 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 15 LB/H | OTHER CASE-BY-CASE |
| Fairbault Energy Park | MN | 7/15/2004 | Turbine, Simple Cycle, Distillate Oil (1) | 1576 MMBTU/H | NO.2 FUEL OIL | PM | Clean Fuel | | 0.03 LB/MMBTU | BACT-PSD |
| ODEC - Louisa Facility | VA | 3/11/2003 | Turbine, Simple Cycle, (1), Fuel Oil | 1820 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 36 LB/H | N/A |
| ODEC - Louisa | VA | 3/11/2003 | Turbine, Simple Cycle, Fuel Oil (1) | 1820 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 36 LB/H | BACT-PSD |
| ODEC - Marsh Run Facility | VA | 2/14/2003 | Turbine, Simple Cycle, (4), Fuel Oil | 1803 MMBTU/H | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 36 LB/H | N/A |
| Chickahominy Power | VA | 1/10/2003 | Turbine, Simple Cycle, Fuel Oil, (4) | 182.6 MW | NO.2 FUEL OIL | filterable PM10 | Clean Fuel | | 27 LB/H | BACT-PSD |

Source: EPA 2015 (RBLC database); Golder, 2015

Note: GCP= good combustion practices

## APPENDIX C

## FDEP FORM NO. 62-210.900(1):
## APPLICATION FOR AIR PERMIT – LONG FORM

# Department of
# Environmental Protection

## Division of Air Resource Management

## APPLICATION FOR AIR PERMIT - LONG FORM

### I. APPLICATION INFORMATION

**Air Construction Permit** – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

**Air Operation Permit** – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

**To ensure accuracy, please see form instructions.**

**Identification of Facility**

| | |
|---|---|
| 1. Facility Owner/Company Name: **Florida Power & Light Company** | |
| 2. Site Name: **Fort Myers Plant** | |
| 3. Facility Identification Number: **0710002** | |
| 4. Facility Location...<br>Street Address or Other Locator: **Fort Myers Power Plant 10650 State Road 80**<br>City: **Fort Myers** County: **Lee** Zip Code: **33905** | |
| 5. Relocatable Facility?<br>☐ Yes ☒ No | 6. Existing Title V Permitted Facility?<br>☒ Yes ☐ No |

**Application Contact**

| |
|---|
| 1. Facility Contact Name:<br>**Matthew Raffenberg, Director of Environmental Licensing** |
| 2. Facility Contact Mailing Address...<br>Organization/Firm: **Florida Power & Light Company**<br>Street Address: **700 Universe Boulevard, JES/JB**<br>City: **Juno Beach** State: **FL** Zip Code: **33408** |
| 3. Facility Contact Telephone Numbers:<br>Telephone: **(561) 691-7518** ext. Fax: **(561) 691-7070** |
| 4. Facility Contact E-mail Address: **Matthew.Raffenberg@FPL.com** |

**Application Processing Information (DEP Use)**

| | |
|---|---|
| 1. Date of Receipt of Application: | 3. PSD Number (if applicable): |
| 2. Project Number(s): | 4. Siting Number (if applicable): |

## APPLICATION INFORMATION

### Purpose of Application

**This application for air permit is being submitted to obtain: (Check one)**

**Air Construction Permit**

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

**Air Operation Permit**

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)**

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☒ Air construction permit and Title V permit renewal, incorporating the proposed project.

**Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:**

☒ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

### Application Comment

**This application is for the construction of two simple cycle gas turbines to replace 10 existing gas turbines (GTs) at the FPL Fort Myers Plant, Lee County, Florida. FPL plans to replace the existing 10 simple cycle GTs with a gross capacity of 630 megawatts (MW) with two simple cycle General Electric (GE) 7F.05 combustion turbines (CTs) that will be rated at approximately 200 MW each (Fort Myers CT Project). The three new CTs will be designated nits 3C and 3D.**

## APPLICATION INFORMATION

**Scope of Application**

| Emissions Unit ID Number | Description of Emissions Unit | Air Permit Type | Air Permit Processing Fee |
|---|---|---|---|
| Unit 3C and 3D | Two GE 7F.05 SImple-Cycle Combustion Turbines | AC1A | |
| 2 | Circuit Breakers | AC1E | |
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Application Processing Fee

**Check one:** ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

**Owner/Authorized Representative Statement**

**Complete if applying for an air construction permit or an initial FESOP.**

| | |
|---|---|
| 1. | Owner/Authorized Representative Name : **Randall R. LaBauve, Vice President, Environmental Services** |
| 2. | Owner/Authorized Representative Mailing Address... Organization/Firm: **Florida Power & Light Company - Fort Myers Plant** Street Address: **700 Universe Boulevard, JES/JB** City: **Juno Beach** State: **FL** Zip Code: **33408** |
| 3. | Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 691-7001** ext. Fax: **(561) 691-7070** |
| 4. | Owner/Authorized Representative E-mail Address: **Randall.R.LaBauve@FPL.com** |
| 5. | Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature: [signature] Date: May 7, 2015 |

## APPLICATION INFORMATION

### Application Responsible Official Certification

**Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."**

| |
|---|
| 1. Application Responsible Official Name: |
| 2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):<br>☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.<br>☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.<br>☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.<br>☐ The designated representative at an Acid Rain source or CAIR source. |
| 3. Application Responsible Official Mailing Address...<br>Organization/Firm:<br>Street Address:<br>City: State: Zip Code: |
| 4. Application Responsible Official Telephone Numbers...<br>Telephone: ( ) ext. Fax: ( ) |
| 5. Application Responsible Official E-mail Address: |
| 6. Application Responsible Official Certification:<br>I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.<br><br>Signature Date |

## APPLICATION INFORMATION

### Professional Engineer Certification

| | |
|---|---|
| 1. | Professional Engineer Name: **Kennard F. Kosky**<br>Registration Number: **14996** |
| 2. | Professional Engineer Mailing Address...<br>Organization/Firm: **Golder Associates Inc.****<br>Street Address: **6026 NW 1st Place**<br>City: **Gainesville** State: **FL** Zip Code: **32607** |
| 3. | Professional Engineer Telephone Numbers...<br>Telephone: **(352) 336-5600** ext. **21156** Fax: **(352) 336-6603** |
| 4. | Professional Engineer E-mail Address: **Ken_Kosky@golder.com** |
| 5. | Professional Engineer Statement: |

*I, the undersigned, hereby certify, except as particularly noted herein*, that:*

*(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and*

*(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.*

*(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.*

*(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.*

*(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.*

Signature — Date: 5/1/15

(seal)

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

## II. FACILITY INFORMATION

## A. GENERAL FACILITY INFORMATION

**Facility Location and Type**

| | | | |
|---|---|---|---|
| 1. Facility UTM Coordinates...<br>Zone **17** East (km) **422.3**<br>North (km) **2952.9** | | 2. Facility Latitude/Longitude...<br>Latitude (DD/MM/SS) **26/41/49**<br>Longitude (DD/MM/SS) **81/46/55** | |
| 3. Governmental Facility Code:<br>**0** | 4. Facility Status Code:<br>**A** | 5. Facility Major Group SIC Code:<br>**49** | 6. Facility SIC(s):<br>**4911** |
| 7. Facility Comment : | | | |

**Facility Contact**

| |
|---|
| 1. Facility Contact Name:<br>**Brenda Bays, PGD Environmental Specialist** |
| 2. Facility Contact Mailing Address...<br>Organization/Firm: **Fort Myers Power Plant**<br>Street Address: **10560 State Road 80**<br>City: **Fort Myers** State: **FL** Zip Code: 33905 |
| 3. Facility Contact Telephone Numbers:<br>Telephone: (**239**) **693-4390** ext. Fax: (**239**) **693-4333** |
| 4. Facility Contact E-mail Address: |

**Facility Primary Responsible Official**

**Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."**

| |
|---|
| 1. Facility Primary Responsible Official Name: |
| 2. Facility Primary Responsible Official Mailing Address...<br>Organization/Firm:<br>Street Address:<br>City: State: Zip Code: |
| 3. Facility Primary Responsible Official Telephone Numbers...<br>Telephone: ( ) ext. Fax: ( ) |
| 4. Facility Primary Responsible Official E-mail Address: |

**Facility Regulatory Classifications**

**Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."**

| | |
|---|---|
| 1. ☐ Small Business Stationary Source | ☐ Unknown |
| 2. ☐ Synthetic Non-Title V Source | |
| 3. ☒ Title V Source | |
| 4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs) | |
| 5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs | |
| 6. ☒ Major Source of Hazardous Air Pollutants (HAPs) | |
| 7. ☐ Synthetic Minor Source of HAPs | |
| 8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60) | |
| 9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60) | |
| 10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63) | |
| 11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5)) | |
| 12. Facility Regulatory Classifications Comment:<br><br>**FPL Combustion Turbines are subject to NSPS 40 CFR 60 Subpart KKKK and 40 CFR 63 Subpart YYYY.** | |

**List of Pollutants Emitted by Facility**

| 1. Pollutant Emitted | 2. Pollutant Classification | 3. Emissions Cap [Y or N]? |
|---|---|---|
| **PM/PM10** | **A** | **N** |
| **NOx** | **A** | **N** |
| **CO** | **A** | **N** |
| **VOC** | **A** | **N** |
| **SO2** | **A** | **N** |
| **CO2** | **A** | **N** |
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## B. EMISSIONS CAPS

**Facility-Wide or Multi-Unit Emissions Caps**

| 1. Pollutant Subject to Emissions Cap | 2. Facility-Wide Cap [Y or N]? (all units) | 3. Emissions Unit ID's Under Cap (if not all units) | 4. Hourly Cap (lb/hr) | 5. Annual Cap (ton/yr) | 6. Basis for Emissions Cap |
|---|---|---|---|---|---|
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7. Facility-Wide or Multi-Unit Emissions Cap Comment:

## C. FACILITY ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

| |
|---|
| 1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date:___________ |
| 2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date:___________ |
| 3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)<br>☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date:___________ |

**Additional Requirements for Air Construction Permit Applications**

| |
|---|
| 1. Area Map Showing Facility Location:<br>☒ Attached, Document ID: **See Air Report** ☐ Not Applicable (existing permitted facility) |
| 2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):<br>☒ Attached, Document ID: **See Air Report** |
| 3. Rule Applicability Analysis:<br>☒ Attached, Document ID: **See Air Report** |
| 4. List of Exempt Emissions Units:<br>☐ Attached, Document ID:___________ ☒ Not Applicable (no exempt units at facility) |
| 5. Fugitive Emissions Identification:<br>☐ Attached, Document ID:___________ ☒ Not Applicable |
| 6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.):<br>☒ Attached, Document ID: **See Air Report** ☐ Not Applicable |
| 7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.):<br>☒ Attached, Document ID: **See Air Report** ☐ Not Applicable |
| 8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):<br>☒ Attached, Document ID: **See Air Report** ☐ Not Applicable |
| 9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):<br>☒ Attached, Document ID: **See Air Report** ☐ Not Applicable |
| 10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):<br>☐ Attached, Document ID:___________ ☒ Not Applicable |

## C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for FESOP Applications**

1. List of Exempt Emissions Units:
   ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)

**Additional Requirements for Title V Air Operation Permit Applications**

1. List of Insignificant Activities: (Required for initial/renewal applications only)
   ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)
   ☐ Attached, Document ID:__________
   ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)
   ☐ Attached, Document ID:__________
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:__________
   ☐ Equipment/Activities Onsite but Not Required to be Individually Listed
   ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:__________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit:
   ☐ Attached, Document ID:__________ ☐ Not Applicable

## C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program**

| |
|---|
| 1. Acid Rain Program Forms:<br>Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):<br>☒ Attached, Document ID: FPL-AR-1 ☐ Previously Submitted, Date:______<br>☐ Not Applicable (not an Acid Rain source)<br>Phase II $NO_X$ Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):<br>☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______<br>☒ Not Applicable<br>New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):<br>☐ Attached, Document ID:______ ☐ Previously Submitted, Date:______<br>☒ Not Applicable |
| 2. CAIR Part (DEP Form No. 62-210.900(1)(b)):<br>☒ Attached, Document ID: FPL-AR-3 ☐ Previously Submitted, Date:______<br>☐ Not Applicable (not a CAIR source) |

**Additional Requirements Comment**

| |
|---|
| |

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application -** For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application -** For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application –** Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Two GE 7F.05 Simple-Cycle CTs .**

3. Emissions Unit Identification Number: **Units 3C and 3D**

| | | | |
|---|---|---|---|
| 4. Emissions Unit Status Code: **A** | 5. Commence Construction Date: **2015** | 6. Initial Startup Date: **2016** | 7. Emissions Unit Major Group SIC Code: **49** |

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit
   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **200** MW/CT **(Nominal)**

11. Emissions Unit Comment:

**Emissions Unit Control Equipment/Method:** Control **1** of **2**

| |
|---|
| 1. Control Equipment/Method Description:<br>**Natural Gas: Low NOx combustion technology** |
| 2. Control Device or Method Code: **205** |

**Emissions Unit Control Equipment/Method:** Control **2** of **2**

| |
|---|
| 1. Control Equipment/Method Description:<br>**Distillate Fuel Oil:**<br>**Water Injection**<br>**Ultra-low Sulfur Fuel** |
| 2. Control Device or Method Code: **028, 148** |

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

## B. EMISSIONS UNIT CAPACITY INFORMATION

**(Optional for unregulated emissions units.)**

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: | |
| 2. Maximum Production Rate: | |
| 3. Maximum Heat Input Rate: | million Btu/hr |
| 4. Maximum Incineration Rate: | pounds/hr<br>tons/day |
| 5. Requested Maximum Operating Schedule: | **24** hours/day **7** days/week<br>**52** weeks/year **3,390** hours/year |
| 6. Operating Capacity/Schedule Comment:<br>**See Table GE-A-1 in Appendix A of the PSD Report for maximum heat input when firing natural gas; and Table GE-A-3 in Appendix A of the PSD Report for maximum heat input when firing ultra low sulfur oil.** | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | |
|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: | 2. Emission Point Type Code: **1** |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **The combustion gases exhaust through a 100.5-ft stack.** | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | |

| | | |
|---|---|---|
| 5. Discharge Type Code: **V** | 6. Stack Height: **100.5** feet | 7. Exit Diameter: **23** feet |
| 8. Exit Temperature: **See Air Report**°F | 9. Actual Volumetric Flow Rate: **See Air Report** acfm | 10. Water Vapor: % |

| | |
|---|---|
| 11. Maximum Dry Standard Flow Rate: dscfm | 12. Nonstack Emission Point Height: feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | 14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: **See Tables GE-A-1 and GE-A-3 for the stack paramenters associated with each CT when firing natural gas and ultra low sulfur fuel oil, respectively.** | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment **1** of **2**

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel);Turbine** | | |
| 2. Source Classification Code (SCC):<br>**2-01-001-01** | 3. SCC Units:<br>**1,000 Gallons burned** | |
| 4. Maximum Hourly Rate:<br>**33.8** | 5. Maximum Annual Rate:<br>**16,880** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur:<br>**0.0015** | 8. Maximum % Ash: | 9. Million Btu per SCC Unit:<br>**131** |
| 10. Segment Comment:<br>**Million British thermal units (Btu) per SCC unit =131. Based on 7.1 lb/gal; LHV = 18,459 Btu/lb ISO conditions and two CTs. Max hourly rate based on 59 F and 500 hours per year operation. See Table GE-A-3 in Air Permit Application Report.** | | |

**Segment Description and Rate:** Segment **2** of **2**

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type):<br>**Internal Combustion Engines; Electric Generation; Natural Gas;Turbine** | | |
| 2. Source Classification Code (SCC):<br>**2-01-002-01** | 3. SCC Units:<br>**Million Cubic Feet Burned** | |
| 4. Maximum Hourly Rate:<br>**4.5** | 5. Maximum Annual Rate:<br>**15,323** | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit:<br>**918** |
| 10. Segment Comment:<br>**Based on 918 Btu/cf (LHV). Max hourly rate based on 59 F. Max annual rate based on 59 F and 3,390 hr/yr operation. See Tables GE-A-1 in PSD Report.** | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| NOx | 205, 028 | | EL |
| CO | | | EL |
| SO2 | 148 | | EL |
| VOC | | | EL |
| PM | | | EL |
| PM10 | | | EL |
| CO2e | | | EL |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **NOx** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report**<br>Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period:<br>From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period:<br>☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**See Air Report; Appendix A; Tables GE-A-2 and GE-A-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance: **See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>**

| | |
|---|---|
| 1. Pollutant Emitted: **Carbon Monoxide- CO** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report**<br>Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Air Report; Appendix A; Tables GE-A-2 and GE-A-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance: **See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Sulfur Dioxide - SO2** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report** <br> Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Air Report; Appendix A; Tables GE-A-2 and GE-A-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance: **See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Carbon Dioxide Equivalent - CO2e** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report** Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Air Report; Table 2-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance: **See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Particulate Matter - PM** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report** Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Air Report; Appendix A; Tables GE-A-2 and GE-A-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code:<br>**OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units:<br>**See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions:<br>**See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance:<br>**See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions:<br>lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **PM10** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year | 4. Synthetically Limited? ☐ Yes ☒ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **See Air Report**<br>Reference: | 7. Emissions Method Code: |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions: **See Air Report; Appendix A; Tables GE-A-2 and GE-A-4.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment: | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **OTHER** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **See Air Report; Table 4-1** | 4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year |
| 5. Method of Compliance: **See Air Report, Table 4-1** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation 1 of 2

| | |
|---|---|
| 1. Visible Emissions Subtype: **VE20** | 2. Basis for Allowable Opacity: ☒ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: **20** % Exceptional Conditions: **100** %<br>Maximum Period of Excess Opacity Allowed: **60** min/hour | |
| 4. Method of Compliance: **EPA Method 9** | |
| 5. Visible Emissions Comment:<br>**FDEP Rule 62-296.320(4)(b)1, F.A.C., requires 20 percent opacity. Excess emissions provided by Rule 62-210.700(1).** | |

**Visible Emissions Limitation:** Visible Emissions Limitation 2 of 2

| | |
|---|---|
| 1. Visible Emissions Subtype: **VE10** | 2. Basis for Allowable Opacity: ☐ Rule ☒ Other |
| 3. Allowable Opacity:<br>Normal Conditions: **10** % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: **EPA Method 9** | |
| 5. Visible Emissions Comment:<br>**Proposed as emission limit for $PM/PM_{10}$.** | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor **1** of **2**

| | |
|---|---|
| 1. Parameter Code: **EM** | 2. Pollutant(s): **NOX** |
| 3. CMS Requirement: | ☒ Rule ☐ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75. $NO_X$ monitoring includes diluent monitor ($O_2$ or $CO_2$). $CO_2$ will be determined using 40 CFR Part 75 reporting requirements.** | |

**Continuous Monitoring System:** Continuous Monitor **2** of **2**

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☒ Other |
| 4. Monitor Information... Manufacturer: Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: See Air Reports ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: See Air Reports ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: See Air Reports ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____
   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____
   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☐ Attached, Document ID: ____ ☒ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: See Air Reports ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☒ Attached, Document ID: See Air Reports ☐ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☒ Attached, Document ID: See Air Reports ☐ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____ ☒ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____ ☒ Not Applicable |

**Additional Requirements Comment**

# III. EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Application -** For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

**Air Construction Permit or FESOP Application -** For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

**Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application –** Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

## A. GENERAL EMISSIONS UNIT INFORMATION

**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

**Emissions Unit Description and Status**

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   **Circuit breakers**

3. Emissions Unit Identification Number: **6**

| 4. Emissions Unit Status Code: | 5. Commence Construction Date: | 6. Initial Startup Date: | 7. Emissions Unit Major Group SIC Code: |
|---|---|---|---|
| **C** | **2015** | **2016** | **49** |

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit
   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **TBD** Model Number: **TBD**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    **Circuit breakers containing $SF_6$.**

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: **N/A** |

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

**Emissions Unit Control Equipment/Method:** Control _____ of _____

| |
|---|
| 1. Control Equipment/Method Description: |
| 2. Control Device or Method Code: |

## B. EMISSIONS UNIT CAPACITY INFORMATION
**(Optional for unregulated emissions units.)**

**Emissions Unit Operating Capacity and Schedule**

| | |
|---|---|
| 1. Maximum Process or Throughput Rate: | |
| 2. Maximum Production Rate: | |
| 3. Maximum Heat Input Rate: million Btu/hr | |
| 4. Maximum Incineration Rate: pounds/hr<br>tons/day | |
| 5. Requested Maximum Operating Schedule:<br>**24** hours/day **7** days/week<br>**52** weeks/year **3,390** hours/year | |
| 6. Operating Capacity/Schedule Comment: | |

## C. EMISSION POINT (STACK/VENT) INFORMATION
### (Optional for unregulated emissions units.)

**Emission Point Description and Type**

| | | |
|---|---|---|
| 1. Identification of Point on Plot Plan or Flow Diagram: | | 2. Emission Point Type Code: 1 |
| 3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: | | |
| 4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: | | |
| 5. Discharge Type Code: F | 6. Stack Height: feet | 7. Exit Diameter: Feet |
| 8. Exit Temperature: °F | 9. Actual Volumetric Flow Rate: acfm | 10. Water Vapor: % |
| 11. Maximum Dry Standard Flow Rate: dscfm | | 12. Nonstack Emission Point Height: Feet |
| 13. Emission Point UTM Coordinates... Zone: East (km): North (km): | | 14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS) |
| 15. Emission Point Comment: | | |

## D. SEGMENT (PROCESS/FUEL) INFORMATION

**Segment Description and Rate:** Segment **1** of **1**

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): **SF6** | | |
| 2. Source Classification Code (SCC): | 3. SCC Units: | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: **Circuit breakers each containing 125 pounds SF6.** | | |

**Segment Description and Rate:** Segment _____ of _____

| | | |
|---|---|---|
| 1. Segment Description (Process/Fuel Type): | | |
| 2. Source Classification Code (SCC): | 3. SCC Units: | |
| 4. Maximum Hourly Rate: | 5. Maximum Annual Rate: | 6. Estimated Annual Activity Factor: |
| 7. Maximum % Sulfur: | 8. Maximum % Ash: | 9. Million Btu per SCC Unit: |
| 10. Segment Comment: | | |

## E. EMISSIONS UNIT POLLUTANTS

**List of Pollutants Emitted by Emissions Unit**

| 1. Pollutant Emitted | 2. Primary Control Device Code | 3. Secondary Control Device Code | 4. Pollutant Regulatory Code |
|---|---|---|---|
| $CO_2e$ | | | EL |
| | | | |
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## F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

**(Optional for unregulated emissions units.)**

**Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.**

**Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

| | |
|---|---|
| 1. Pollutant Emitted: **Equivalent carbon dioxide - $CO_2$e** | 2. Total Percent Efficiency of Control: |
| 3. Potential Emissions: lb/hour **7.1** tons/year | 4. Synthetically Limited? ☒ Yes ☐ No |
| 5. Range of Estimated Fugitive Emissions (as applicable): to tons/year | |
| 6. Emission Factor: **40 CFR Part 98, Subpart C**<br>Reference: **0.05 percent/year** | 7. Emissions Method Code: **2** |
| 8.a. Baseline Actual Emissions (if required): tons/year | 8.b. Baseline 24-month Period: From: To: |
| 9.a. Projected Actual Emissions (if required): tons/year | 9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years |
| 10. Calculation of Emissions:<br>**See Air Report.** | |
| 11. Potential, Fugitive, and Actual Emissions Comment:<br>**Emissions are for circuit breakers.** | |

## F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

**Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

**Allowable Emissions** Allowable Emissions 1 of 1

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: **Other** | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: **0.005% leakage** | 4. Equivalent Allowable Emissions: lb/hour **7.1** tons/year |
| 5. Method of Compliance: **Periodic inspections and leak detection systems.** | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

**Allowable Emissions** Allowable Emissions _____ of _____

| | |
|---|---|
| 1. Basis for Allowable Emissions Code: | 2. Future Effective Date of Allowable Emissions: |
| 3. Allowable Emissions and Units: | 4. Equivalent Allowable Emissions: lb/hour tons/year |
| 5. Method of Compliance: | |
| 6. Allowable Emissions Comment (Description of Operating Method): | |

## G. VISIBLE EMISSIONS INFORMATION

**Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.**

**Visible Emissions Limitation:** Visible Emissions Limitation _____ of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

**Visible Emissions Limitation:** Visible Emissions Limitation _____ of _____

| | |
|---|---|
| 1. Visible Emissions Subtype: | 2. Basis for Allowable Opacity:<br>☐ Rule ☐ Other |
| 3. Allowable Opacity:<br>Normal Conditions: % Exceptional Conditions: %<br>Maximum Period of Excess Opacity Allowed: min/hour | |
| 4. Method of Compliance: | |
| 5. Visible Emissions Comment: | |

## H. CONTINUOUS MONITOR INFORMATION

**Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.**

**Continuous Monitoring System:** Continuous Monitor _____ of _____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

**Continuous Monitoring System:** Continuous Monitor _____ of _____

| | |
|---|---|
| 1. Parameter Code: | 2. Pollutant(s): |
| 3. CMS Requirement: | ☐ Rule ☐ Other |
| 4. Monitor Information...<br>Manufacturer:<br>Model Number: | Serial Number: |
| 5. Installation Date: | 6. Performance Specification Test Date: |
| 7. Continuous Monitor Comment: | |

## I. EMISSIONS UNIT ADDITIONAL INFORMATION

**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date __________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date __________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Air Report** ☐ Previously Submitted, Date __________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date __________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date __________
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: __________
   Test Date(s)/Pollutant(s) Tested: ____________________
   ☐ Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____________________
   ☐ To be Submitted, Date (if known): __________
   Test Date(s)/Pollutant(s) Tested: ____________________
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Air Report** ☐ Not Applicable

## I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

**Additional Requirements for Air Construction Permit Applications**

| | |
|---|---|
| 1. | Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)):<br>☒ Attached, Document ID: See Air Report ☐ Not Applicable |
| 2. | Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.):<br>☐ Attached, Document ID: ____ ☒ Not Applicable |
| 3. | Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only)<br>☐ Attached, Document ID: ____ ☒ Not Applicable |

**Additional Requirements for Title V Air Operation Permit Applications**

| | |
|---|---|
| 1. | Identification of Applicable Requirements:<br>☐ Attached, Document ID: ____ |
| 2. | Compliance Assurance Monitoring:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 3. | Alternative Methods of Operation:<br>☐ Attached, Document ID: ____ ☐ Not Applicable |
| 4. | Alternative Modes of Operation (Emissions Trading):<br>☐ Attached, Document ID: ____ ☐ Not Applicable |

**Additional Requirements Comment**

| |
|---|
| |

At Golder Associates we strive to be the most respected global group of companies specializing in ground engineering and environmental services. Employee owned since our formation in 1960, we have created a unique culture with pride in ownership, resulting in long-term organizational stability. Golder professionals take the time to build an understanding of client needs and of the specific environments in which they operate. We continue to expand our technical capabilities and have experienced steady growth with employees now operating from offices located throughout Africa, Asia, Australasia, Europe, North America and South America.


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