TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Big Bend Station
Facility ID No. 0570039

PROJECT

Project No. 0570039-119-AC
Application for Minor Source Air Construction Permit
Unit 1 Modernization Project

COUNTY

Hillsborough County, Florida

PERMITTING AUTHORITY

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

May 25, 2018

1. GENERAL PROJECT INFORMATION

1.1. Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

1.2. Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

1.3. Facility Description and Location

The Big Bend Station is an existing electric generation facility, which is categorized under Standard Industrial Classification Code No. 4911. The existing Big Bend Station is in Hillsborough County (see **Figure 1**) at 13031 Wyandotte Road, Gibsonton, Florida. The location of the Big Bend Station is shown in **Figure 2**. The UTM coordinates of this existing facility are Zone 17, 363.15 kilometers (km) East, and 3074.91 km North. This site is in an area of influence for a particulate matter maintenance and a sulfur dioxide non-attainment area, pursuant to Rule 62-204.340, F.A.C. An aerial view of the Big Bend Station is shown in **Figure 3**. Situated on Tampa Bay, the Big Bend Power Station is located on nearly 1,500 acres in the southeastern region of Hillsborough County.

Figure 1. Location of Hillsborough County.

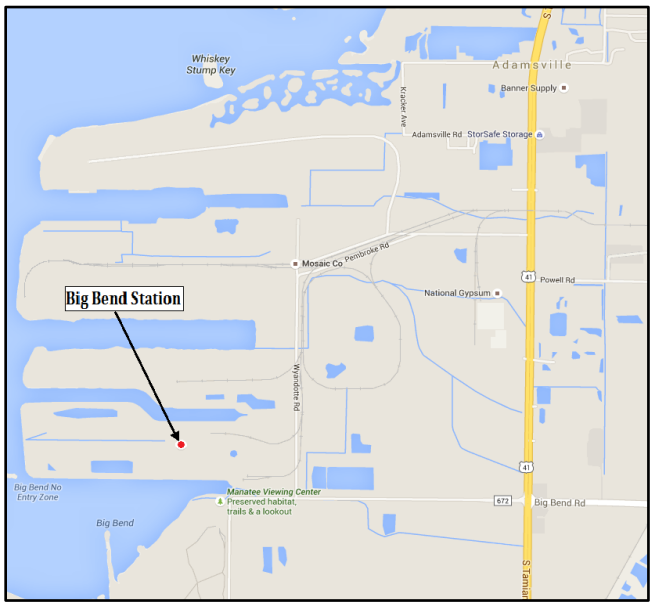

Figure 2. Location of Big Bend Station.

Figure 3. Aerial View of the Big Bend Station.

This facility consists of four fossil fuel fired steam generating Units 1 – 4 (EU 001 – EU 004); four steam turbine electrical generators; two simple-cycle combustion turbines 4A and 4B (EU 041 and EU 042) sharing a common electrical generator; solid fuels, fly ash, limestone, gypsum, slag, bottom ash storage and handling facilities; and, fuel oil storage tanks.

Units 1 through 4 have a combined electrical generation output of 1,821 megawatt (MW). Units 1 through 3 each have a design electrical generating capacity of 445 MW. Unit 4 has a design electrical generating capacity of 486 MW. Units 1 – 4 can be fired with natural gas only, coal only, or co-fired natural gas and solid fuels consisting of coal, or a coal/petroleum coke blend containing a maximum of 20% petroleum coke by weight, or coal blended with coal residual generated from the Polk Power Station, or a coal/petroleum coke blend further blended with coal residual generated from the Polk Power Station and on-site generated fly ash. In addition to the fuels allowed to be burned during normal operation, each unit burns natural gas during startup, shutdown, flame stabilization, low load operation (either alone or while co-firing solid fuels) and during the startup of an additional solid fuel mill on an already operating unit.

For each unit, nitrogen oxide (NO_X) emissions are controlled by low-NO_X burners (LNB) and a selective catalytic reduction system (SCR). Unit 4 also has a separated over fire air system to further control NO_X emissions. On each unit, particulate matter (PM) emissions are controlled by a dry electrostatic precipitator (ESP) while sulfur dioxide (SO_2) emissions are controlled by a wet flue gas desulfurization system (FGD). Units 1 through 3 are equipped with continuous emissions monitoring systems (CEMS) to measure NO_X, SO_2, PM and carbon dioxide (CO_2). Unit 4 is equipped with CEMS to measure carbon monoxide (CO), NO_X, SO_2, PM and CO_2. Units 1 – 4 began operation in 1970, 1973, 1976, and 1985, respectively.

1.4. Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act and Chapter 62-214, F.A.C.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility operates units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60.
- The facility operates units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

1.5. Project Description

The applicant proposes to retire the existing Unit 2 (EU No. 002) and to "modernize" Unit 1 (EU No. 001) by ceasing the operation of its boiler and constructing a new natural gas-fueled combined-cycle unit. The new combined-cycle unit will consist of two General Electric 7HA.02 turbines, each with a nominal generating capacity of 370 MW. Hot exhaust gases will be used to generate steam in two heat recovery steam generators (HRSGs). Steam from the HRSGs will be routed to the steam turbine of the existing Unit 1 for additional power generation. The total nominal net generating capacity for the unit, including both combustion turbine generators and the steam turbine generator, will be 1,090 MW. The combustion turbines will also be capable of operation in simple-cycle mode.

The project also includes the addition of one diesel-fueled emergency generator and one mechanical-draft cooling tower.

Table 1 list the existing emissions units (EU) that will be affected by this project.

TABLE 1 – EXISTING EU AFFECTED BY THE PROJECT.

EU No.	Description
001	Fossil Fuel Fired Steam Generator Unit No. 1 (To be permanently retired)
002	Fossil Fuel Fired Steam Generator Unit No. 2 (To be permanently retired)

Table 2 list the new EU that will be added by this project.

TABLE 2 – NEW EU ADDED BY THE PROJECT.

EU No.	Description
057	CT 5 and 6 Emergency Diesel Engine (1000 kW)
058	Combustion Turbine No. 5 (Simple-Cycle Operation)
059	Combustion Turbine No. 6 (Simple-Cycle Operation)
060	Combustion Turbine No. 5H (Combined-Cycle Operation)
061	Combustion Turbine No. 6H (Combined-Cycle Operation)
062	Mechanical Draft Cooling Tower for Combined-Cycle Unit

1.6. Processing Schedule

April 18, 2018 Department received complete application[1] for an air pollution construction permit.

May 24, 2018 Department issued Draft Permit.

2. PSD APPLICABILITY

2.1. General PSD Applicability

For areas currently in attainment with the AAQS or areas otherwise designated as unclassifiable, the Department regulates major stationary sources of air pollution in accordance with Florida's PSD preconstruction review program as defined in Rule 62-212.400, F.A.C. Under preconstruction review, the Department first must determine if a project is subject to the PSD requirements ("PSD applicability review") and, if so, must conduct a PSD preconstruction review. A PSD applicability review is required for projects at new and existing major stationary sources. In addition, proposed projects at existing minor sources are subject to a PSD applicability review to determine whether potential emissions *from the proposed project itself* will exceed the PSD major stationary source thresholds. A facility is considered a major stationary source with respect to PSD if it emits or

[1] Application available in Oculus.

has the potential to emit:

- 250 tons per year or more of any regulated air pollutant; or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the following 28 PSD-major facility categories: fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants and charcoal production plants.

For major stationary sources such as the Big Bend Station, a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(Definitions), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200(Definitions), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant". SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" (i.e. emits or has the potential-to-emit 100 or 250 TPY as applicable) for only one PSD pollutant, a project must include Best Available Control Technology (BACT) controls for any PSD pollutant that exceeds the corresponding SER given in **Table 3** below.

TABLE 3 - LIST OF SER BY PSD POLLUTANT.

Pollutant [a]	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [b]	40
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
Ozone (NO_X) [b]	40	SAM	7
SO_2	40	Pb	0.6
Hg	0.1	GHG (CO_2e) [c]	75,000

a. Excluding fluoride and those pollutants defined for Pulp and Paper, MWC, MSW landfills.

b. Ozone (O_3) is regulated by its precursors (VOC and NO_X). PSD for $PM_{2.5}$ can be triggered by its precursors (NO_X and SO_2).

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

2.2. PSD Applicability for Project

Hillsborough County is designated as attainment/unclassifiable for ozone, CO, NO_2 PM_{10}, $PM_{2.5}$, and the 1971 SO_2 standard by Section 62-204.340, F.A.C. Hillsborough County is also classified as an air quality maintenance area for ozone (entire county), PM (that portion of Hillsborough County which falls within the area of a circle having a center point at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 km), and lead (the area encompassed within a radius of 5 km centered on UTM coordinates: 364.0 km east; 3,093.5 km north; zone 17) by Section 62-204.340, F.A.C. Partial areas of Hillsborough County are designated in 40 CFR 81.310 as non-attainment for the 2010 SO_2 standard and the 2008 Pb standard. However, the facility is not located within either of these non-attainment areas. The facility was previously determined to have significant impacts within the SO_2 non-attainment area.

The first step in determining PSD applicability for this project is to determine the potential to emit (PTE) for each pollutant for each new emissions unit in the proposed modernization project. The PTE values for various pollutants are shown in **Table 4**. (The GHG PTE values for the new combined-cycle unit include an estimate of 77 tpy, CO_2e, from circuit breakers, and 12 tpy, CO_2e, from piping components. While the piping component leakage rate is likely an underestimate, this would not make a meaningful difference in the following calculations.)

TABLE 4 - PLANNED COMBINED-CYCLE UNIT POTENTIAL TO EMIT (TONS/YEAR).

Pollutant	Project Component			Total PTE for all new units
	Combined-Cycle Unit	Emergency Engine	Cooling Tower	
CO	544	2.1	-	546
NO_X	1,650	2.7	-	1,653
PM (filterable)	76.2	0.1	0.5	76.8
PM_{10} (filterable + condensable)	123	0.1	0.3	124
$PM_{2.5}$ (filterable + condensable)	123	0.1	0.3	124
SO_2	176	0.0	-	176
VOC	56	1.2	-	57.3
SAM	21.0	0.0	-	21.0
GHG (CO_2e)	3,563,230	403	-	3,563,633

The emissions estimates of NO_X and GHG for the combined-cycle unit in **Table 4** are based on the emission limits in 40 CFR 60 Subpart KKKK and TTTT, respectively. Other emissions factors are based on manufacturer guarantees or sulfur mass balance. The emissions for the emergency engine are based on 40 CFR 60 Subpart IIII and the use of ultra-low-sulfur diesel.

All the PTE values in **Table 4** exceed the respective SER values in **Table 3**. The next step in determining PSD applicability is to calculate the *net* emissions increase for the project. The net emissions increase is defined in Paragraph 62-210.200(189), F.A.C., as the "increase in emissions from a particular physical change or change in the method of operation as calculated pursuant to paragraph 62-212.400(2)(a), F.A.C., and any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are creditable." An increase or decrease is considered a contemporaneous emissions change if it occurs within the period beginning five years prior to the date on which construction on the particular change commenced and the date that the increase from the particular change occurs. Tampa Electric Company plans to commence construction on the modernization project in May 2019; therefore, for the purpose of this analysis, the beginning of the contemporaneous period has been defined as May 2014. Increases or decreases in Step 2 are based on the PTE of the unit, since "creditable" changes must be federally enforceable (unlike estimates of "projected actual emissions").

The net emissions increase therefore includes the increases in emissions associated with the combined-cycle project (**Table 4**), as well as the sum of all contemporaneous and creditable increases and decreases in actual emissions at the facility. The contemporaneous changes include the following projects, in addition to the construction of the combined-cycle unit:

- Additional of two natural gas process heaters for gas to be fired in the boilers. (Permit No. 0570039-070-AC, with subsequent permit modifications, issued May 2014)
- Removal of CO oxidation catalyst from simple-cycle combustion turbines 4A and 4B. (Permit No. 0570039-108-AC, issued September 21, 2017).

This project includes the shutdown of Unit 2 (EU No. 002) and the boiler associated with Unit 1 (EU No. 001). Credit for this shutdown can be taken in Step 2. The reduction in emissions associated with the shutdown of Units 1 and 2 was based on the five most years of operation, from April 2013 to March 2018. The baseline actual emissions for these boilers for each pollutant were based on the 24-month period during which the boilers collectively emitted the greatest amount of the particular pollutant. A new limit on SO_2 emissions from Units 1 through 4, collectively, became effective in February 2015, in Permit No. 0570039-074-AC. This permit limited combined emissions from the four units to 3,162 lb/hr on a 30-operating-day average. This corresponds to 1,138 tons per month. Weighting this by the heat input capacity of each unit, Unit 1's share of this is 279 tons per month, and Unit 2's share is 276 tons per month. Any months during the baseline period with emissions greater than these shares were adjusted downward to these levels. Further, the applicant has stated that there is no intention to increase emissions from Unit 3 or 4 after the project, even though the retirement of Units 1 and 2 would leave additional space under this emissions cap.

A review of the facility's previously reported emissions shows that the baseline actual emissions used in the applicant's analysis are in close agreement with Annual Operating Reports[2].

The PTE values for the process heaters project (Permit No. 0570039-070-AC) were based on EPA AP-42, Chapter 1.4.

For the removal of the oxidation catalyst from the existing simple-cycle combustion turbines (Permit No. 0570039-108-AC), the only affect pollutants were CO and VOC. For CO, the difference between the post-project PTE (94 tpy) and the baseline actual emissions (1.3 tpy) was 93 tpy. For VOC, the difference between the post-project PTE (6 tpy) and the baseline actual emissions (0.4 tpy) was approximately 5 tpy.

The results of this netting analysis are shown in **Table 5**. From this table, it is clear that there is a net decrease for all pollutants. Therefore, the project does not trigger PSD for any pollutant.

TABLE 5 - RESULTS OF STEP 2 (NETTING) ANALYSIS.

Pollutant	Combined-cycle project PTE (tpy) [a]	Contemporaneous Changes			Net emissions increase (decrease) (tpy)	SER (tpy)	PSD triggered?
		Units 1 & 2 Shutdown (tpy)	Process Heaters PTE (tpy)	Oxidation Catalyst Removal (tpy)			
CO	546	(5,173)	4.3	93	(4,530)	100	**No**
NO_X	1,653	(2,546)	5.2	0.0	(888)	40	**No**
PM	76.8	(245)	0.4	0.0	(168)	25	**No**
PM_{10}	124	(790)	0.4	0.0	(665)	15	**No**
$PM_{2.5}$	124	(790)	0.4	0.0	(665)	10	**No**
SO_2	176	(5,140)	0.0	0.0	(4,964)	40	**No**
VOC	57.3	(327)	0.3	5.0	(264)	40	**No**
SAM	21.0	(27)	0.0	0.0	(6)	7	**No**
GHGs	3,563,633	(5,587,583)	3,076	0.0	(2,020,874)	75,000	**No**

[a] Baseline emissions were based on the following 24-month periods:
- January 2014-December 2015 for NO_X
- April 2013-March 2015 for SO_2
- July 2013-June 2015 for CO, VOC, SAM, GHGs, PM, PM_{10}, $PM_{2.5}$

3. DEPARTMENT REVIEW

[2] AOR summary available in Oculus.

3.1. Brief Discussion of Emissions

This project entails the replacement of two boilers fueled by coal and other fuels with a 2-on-1 natural gas-fueled combined cycle unit. Units 1 and 2 each have a generating capacity of 445 MW. Unit 1 began commercial operation in 1970, and Unit 2 began commercial operation in 1973. Since the new combined-cycle unit will have a nominal capacity of 1,090 MW, the project represents an increase in capacity of approximately 200 MW. In spite of this increase in capacity, this project results in a net decrease in emissions of all pollutants.

The proposed turbines will be equipped to operate in either simple-cycle mode or combined-cycle mode. In simple-cycle mode, the burning of fuel in the combustion zone of the turbine results in the rotation of the turbine. This rotation is used to create electric power in an electric generator. The hot exhaust gases are then released to the atmosphere through a stack.

In combined-cycle mode, the exhaust gases are routed through a HRSG. In the HRSG, heat from the exhaust gases is converted to steam, which is then sent to a steam turbine generator to produce additional electric power. This project will re-purpose the existing steam turbine generator from Unit 1; however, as a non-emitting piece of equipment, this does not affect air permitting for this project.

The plan for the project includes bringing the turbines online in simple-cycle mode for the first several years of operation, while the HRSGs are constructed and connected to the steam turbine generator. Once the turbines are capable of operating in combined-cycle mode, this will be their main mode of operation. According to a GE fact sheet[3], the turbines are expected to have an efficiency of approximately 42% in simple-cycle mode and 63% in combined-cycle mode, making combined-cycle generation the more attractive option.

The applicant has proposed the use of SCR to reduce emissions of NO_X. SCR entails the injection of a nitrogen-based reagent (often ammonia) into the exhaust gases, along with a grid of catalyst, often composed of precious metals or zeolite materials. Because heat from the exhaust gases is transferred to steam in the HRSG, the exhaust gas temperatures are much more moderate under combined-cycle operation than under simple-cycle operation. The applicant estimates a combined-cycle stack exit temperature of 188 °F and a simple-cycle exit temperature of 1,093 °F. SCR is designed to work in moderate temperatures of approximately 500 to 800 °F. For this reason, the applicant does not plan to install SCR for emissions from simple-cycle operation.

Emissions from the emergency engine and the cooling tower will be minimal, as is shown in **Table 4**.

3.2. State Requirements

Existing Units 1 through 4 are subject to a cap on emissions of SO_2. This project does not change this cap, though Units 1 and 2 will no longer operate after the commencement of commercial operation of the new turbines.

The applicant will be required to cease operating the boilers associated with Units 1 and 2 once the new turbines begin commercial operation. The following condition will be included in the permit:

> Permanent Shutdown of Big Bend Units 1 and 2: The Permittee shall not commence commercial operation of either combustion turbine (exclusive of sale of test generation) until either Big Bend Unit 1 or Unit 2 has permanently ceased firing fuel. The Permittee shall not commence commercial operation of the second combustion turbine (exclusive of sale of test generation) until both Big Bend Units 1 and 2 have permanently ceased firing fuel. [Rule 62-210.200(189), F.A.C. and Avoidance of Rule 62-212.400, F.A.C.]

3.3. Federal NSPS Provisions

3.3.1. Subpart KKKK

The new turbines will be subject to limits on emissions of NO_X and SO_2 under 40 CFR 60, Subpart KKKK, which applies to stationary combustion turbines that commenced construction, reconstruction, or modification after February 18, 2005.

[3] GE Fact sheet available in Oculus

To comply with the SO_2 limit, only natural gas with a sulfur content less than 2.0 grains per 100 standard cubic feet will be fired in the turbines. This is an order of magnitude smaller than the Subpart KKKK limit of 20 grains. Compliance will be demonstrated by maintaining records of natural gas sulfur content from the gas supplier.

The subpart also limits NO_X emissions (at turbine loads greater than 75%) to 15 parts per million (ppm) at 15% O_2. Compliance will be demonstrated by CEMS. This limit applies on a 30-operating-day rolling average basis for combined-cycle operation and on a 4-hour rolling average basis for simple-cycle operation. The applicant has stated that it will be able to meet the simple-cycle limit, even without the use of SCR, through the adjustment of turbine combustion. The subpart also includes a limit of 96 ppm at 15% O_2 for hours during which operation is below 75% of peak load.

3.3.2. Subpart TTTT

The turbines will be subject to limits on emissions of CO_2 under 40 CFR 60, Subpart TTTT, which applies to stationary combustion turbines, steam generating units, and integrated gasification combined-cycle electric generating units that commence construction after January 8, 2014, or modification or reconstruction after June 18, 2014.

For a natural gas-fueled turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating-month or a 3-year rolling average basis, the applicable limit is 120 lb CO_2 per MMBtu of heat input. Alternatively, for a natural gas-fueled turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating-month and a 3-year rolling average basis, the applicable limit is 1,000 lb CO_2 per MWh of gross energy output, or 1,030 lb per MWh of net energy output.

Essentially, this means that if the capacity factor of the turbine is less than its design efficiency, then it is subject to the 120 lb per MMBtu limit. Because the combustion of natural gas yields approximately 117 lb CO_2 per MMBtu, this limit can be met simply by firing natural gas. According to the GE fact sheet referenced previously, the design efficiency for the 7HA.02 in simple-cycle mode is approximately 42%. This will likely be the limit that applies during the period when the turbines are operated only in simple-cycle mode, before the combined-cycle components of the unit are operational, as long as the capacity factor is less than 42%.

The design capacity for combined-cycle operation is approximately 63%. Therefore, once combined-cycle operation begins and the capacity factor exceeds 50%, then the turbines will be subject to the 1,000 (or 1,030) lb/MWh limit. When operating at optimal conditions, GE estimates that the 7HA.02 in a 2-on-1 configuration can achieve a heat rate of 5,377 Btu/kWh (by lower heating value). This corresponds to approximately 618 lb CO_2 per MWh, under ideal, base-load conditions. While not all operation will be at ideal conditions, this does indicate that the Subpart TTTT limit should be readily achievable.

3.3.3. Subpart IIII

The emergency diesel engine will be subject to limits for reciprocating compression-ignition internal combustion engines in Subpart IIII. These include limits on CO, PM, and non-methane hydrocarbons + NO_X. Compliance will be demonstrated through the use and proper maintenance of a certified engine.

3.4. Federal NESHAP Provisions

3.4.1. Subpart YYYY

Both turbines are subject to the NESHAP in 40 CFR 63, Subpart YYYY, for Stationary Combustion Turbines. However, this subpart includes no limits for turbines that are fueled solely with natural gas. The only requirement under this subpart is for initial notification.

3.4.2. Subpart ZZZZ

The emergency diesel engine will be subject to the NESHAP in 40 CFR 63, Subpart ZZZZ. However, this subpart imposes no requirements. Compliance is demonstrated by complying with NSPS Subpart IIII.

4. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. John Dawson is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 at 850-717-9085 or by email John.Dawson@floridadep.gov.