AIR CONSTRUCTION PERMIT APPLICATION

BIG BEND POWER STATION
FACILITY ID No.: 0570039

BB UNIT 3 BOILER IMPROVEMENT PROJECTS

Prepared For:
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March 23, 2012

TECO
TAMPA ELECTRIC

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1.0 INTRODUCTION AND BACKGROUND

1.1 Introduction

This emission unit has routinely experienced slagging issues and lower steam temperatures. The pollution reduction projects required by the Consent Final Judgment (FDEP) and the Consent Decree (EPA) have exacerbated these issues. The goal of this project is to prevent further deterioration of performance due to the slagging.

This project consists of a physical modification and routine maintenance. The physical modifications involve adding additional boiler surface area to increase the outlet steam temperatures of the High Temperature Superheater and High Temperature Reheater. The routine maintenance includes the replacement of the High Temperature Superheater (HTSH), High Temperature Reheater (HTR), Economizer, Radiant Super Heater (RSH) and nose arch.

1.2 Background

Big Bend Unit No. 3 is a wet bottom, fossil fuel fired steam boiler rated at 4,115 mmBtu per hour. The boiler was originally designed as a pressurized furnace and was subsequently converted to balanced draft system as part of the consent decree mandated SCR installation.

The boiler is equipped with three (3) Riley double ended ball tube mills for pulverizing the coal. There are a total of 24 coal pipes, 12 feeding the North and 12 feeding the South burner fronts. Each coal pipes splits into 2 “pants leg” burners for a total of 24 burners per side. Pulverized coal from these mills is pneumatically transported to twenty-four (24) burners located on the front and rear furnace walls at approximately elevation 61’-9”. These burners arranged in a single row of twenty four (24) across the width of the front and rear waterwalls at this elevation at a spacing of approximately 60” centers.

2.0 Heat Input Determination

2.1 Proposed Heat Input Metric

TEC proposes to use a specific heat metric to demonstrate unit capacity during compliance testing. The metric calculates the heat input as the product of the gross heat rate (Btu/kWh) and gross power output (MW). The gross power output (MW) will be measured on a 4-hour rolling average. The gross unit heat rate will use a 3-month rolling "seasonal" rolling average based on monthly heat rates from the Generation, Fuels & Performance Report (GFP).

This metric has shown good agreement with other well established metrics such as the ASME boiler efficiency method and coal throughput measurements. Comparisons between the boiler efficiency method and the proposed metric have shown very good agreement up to approximately 3%. Heat CEMS and the proposed metric have <u>not</u> shown good agreement. Typically, the heat CEMS has been observed in excess of 15% of the proposed metric. A simple linear correction of the heat CEMS to account these biases is <u>not</u> technically defendable since the response is highly non-linear and will provide inconsistent results. TEC believes this metric (even corrected) is not an appropriate metric for compliance purposes.

2.2 Maximum Capacity

The proposed metric was used to evaluate the current maximum heat input of Unit 3. The historical data (2002 to 2011) shows the maximum heat input rate was 4578 mmBtu per hour (10430 Btu/kWh @ 439 MW) in November 2003. Given the current limitations of the boiler, the proposed maximum heat capacity is 4370 mmBtu per hour (10400 Btu/kWh @ 420 MW). TEC suggests the DEP provide this revised heat input capacity as part of the air construction permit.

2.3 Heat Input Disparities

There are several reasons for the discrepancy between the current design heat capacity (4115 mmBtu/hr) and the aforementioned maximum heat capacity (4370 mmBtu/hr). The boiler was originally designed for a heat capacity at 4115 mmBtu per hour at a continuous rated condition. Boilers are capable of exceeding their rated capacity by over pressurizing with valves wide open (VWO). Given a typical over pressure of 5%, a maximum heat input capacity for Unit 3 is approximately 4320 mmBtu per hour. Another discrepancy is the amount of design margins in the boiler design. Historically, the design margins were typically higher to guarantee the performance of the boiler. With the advancement in computer modeling, the predicted performance is more accurate and the design margin is lower. Finally, some discrepancy can be attributed to the inherent biases of the metric and associated monitoring equipment. These biases are additive and contribute the overall deviation. Therefore, these small differences can result in appreciable difference between the design rated condition and actual operating condition.

3.0 MODELING STUDY

A detailed predictive modeling study to assess the thermal performance of the boiler was performed. The modeling scope of work included:

- Construction of a thermal model of the Big Bend Unit 3 boiler.
- Calibration of the model with the actual baseline operation data (including NO_X control excess air and balanced draft conditions) to reflect actual and current boiler operating conditions.
- Evaluation of various operating parameters to minimize fouling and slagging potentials in certain radiant and convective sections based on investigation of the following operational issues:
  - Minimizing the slagging potential in the areas of the HTSH and RSH
  - Recovery of full HTSH and HTR steam temperatures at full load
  - Impact of full HTR steam temperature if HTR still lags HTSH after above items
  - Other combinations of pressure part upgrades as may be available and warranted by initial work aiming at achieving the original unit performance and especially improving steam temperature performance and slagging potential.
  - Impact of revised convective HTSH and/or HTR surface on system pressure drop (flue gas side) and impacts to the ID fan performance.
- Identification of changes in flue gas conditions (flows and temperatures) exiting the economizer and air preheaters (APH) associated with various pressure component upgrades.

3.1 Modeling Results

The model investigated a number of conditions (Cases 1 to 20). Case 20 was selected as the most feasible option to maintain the original design conditions. The excess air was maintained at 10% consistent with the current low NO_X operation.

The model results show modifications of the boiler's surface area are required to improve the steam temperatures and decrease the slagging potential in the areas of concern. The model results show the HTSH area will be increased by approximately 15,000 ft^2. RSH double flat projected area will be increased by approximately 1,200 ft^2. HTR surface area will be increased by approximately 13,800 ft^2. Economizer surface area will be reduced by approximately 10,700 ft^2.

The boiler was originally designed to operate up to 4115 mmBtu per hour. This project targets a nominal heat input condition of around 4052 mmBtu per hour. This is within 1% of the original design heat input using the same calculation metric. A summary of the boiler performance is shown in **Table 1**.

Table1. Boiler Performance Summary

	Design Heat Input	Load	Main Steam Flow	RH Steam Flow	Excess Air	BE
Description	mmBtu/hr	%MCR	kpph	kpph	%	%
Original Design	4,115	100%	3,136	2,815	15%	87.75%
Proposed Case 20	4,052	98%	3,068	2,758	10%	88.04%

4.0 PROJECT SCOPE

4.1 Routine Maintenance

Many of the boiler components are original equipment. Despite performing good maintenance over the years and exceeding the industry average for similar boiler components, these components now need to be replaced. TEC intends to replace the High Temperature Superheater, High Temperature Reheater, Economizer, Radiant Super Heater (partial additions) and Nose Arch Replacement. This work is discussed in the following sections.

4.1.1 High Temperature Superheater Replacement

The HTSH is the final steam leg in the steam path to the turbine, consisting of a vertical assembly overhanging the furnace of the boiler. The BB3 superheater is mostly original equipment although a partial replacement was conducted in 1999. Currently, tube failure in the remaining original sections is causing extensive creep damage. Also, the assembly has heavy internal diameter oxide scaling, resulting in decreased heat transfer for the element and fouling/plugging of the turbine fine mesh screens.. This project will remove and replace the HTSH section.

4.1.2 High Temperature Reheater Replacement

The HTR is the final steam leg in the reheat path to the turbine. The component is a vertical assembly in the back pass, reheat section of the boiler. The BB3 reheater is original equipment. Currently, the reheater is experiencing extensive creep damage. The section averages two forced outage failures a year with expectations to increase. This assembly has heavy internal diameter oxide scaling, which has resulted in decreased heat transfer and is the suspected cause of internal turbine foreign object damage. This project will remove and replace the HTR section.

4.1.3 Economizer Replacement

The economizer is the first point of entry for feedwater entering the boiler. The economizer consists of an upper and lowers bundles of 2 ½" tubes, formed into horizontal loops running back and forth across the bottom of the rear pass. The economizer is original equipment. This assembly has experienced acid corrosion on the bottom of the upper bundle. This project will remove and replace the economizer section.

4.1.4 Radiant Super Heat and Nose Arch Replacement

The BB3 boiler upper furnace section experiences high load slagging. The high upper furnace gas temperatures are above the ash fusion temperatures of the fuel burned. The result is extensive slagging and fouling of the upper furnace section. The increased sootblowing frequencies are required to maintain a clean upper furnace have resulted in tube failures in the nose arch and rear waterwall screen tubes.

This project will remove and install an extended nose arch and longer radiant superheater section. The new nose arch will extend out further into the boiler, to allow gas flow to enter the increased surface area of the radiant superheater, which will absorb more heat and reduce the upper furnace temperatures.

4.2 Physical Modifications

As previously discussed, modifications to the surface areas of the HTSH, HTR, RSH and economizer are proposed. HTSH surface area will be increased by approximately 15,000 ft^2. RSH double flat projected area will be increased by approximately 1,200 ft^2. HTR surface area will be increased by approximately 13,800 ft^2. Economizer surface area will be reduced by approximately 10,700 ft^2. A summary of the surface area modifications are listed in **Table 1**. The existing and proposed surface area configurations are illustrated in **Figures 1** and **2**.

The nose arch and RSH in the boiler will be extended to control and minimize slagging and erosion in the upper furnace area and at the superheater. This modification reduces slagging by reducing the peak flue gas temperature in the furnace exit plane and at the HTSH. It is necessary to extend the nose arch if the surface modification in the high temperature superheater is performed, so the high temperature superheater surface does not extend over the nose arch and increase slagging potential. The nose arch extension is illustrated in **Figure 2**.

Table 1. Boiler Surface Area Modification Summary

Description	Existing (ft^2)	Proposed (ft^2)	Comments
High Temperature Superheater	12,900	28,000	Add approximately 15,000 ft^2
Radiant Superheater (Double Flat Area)	22,400	23,600	Add approximately 1,200 ft^2
High Temperature Reheater	19,300	33,100	Add approximately 13,800 ft^2
Economizer	69,400	58,700	Remove Add 10,700 ft^2

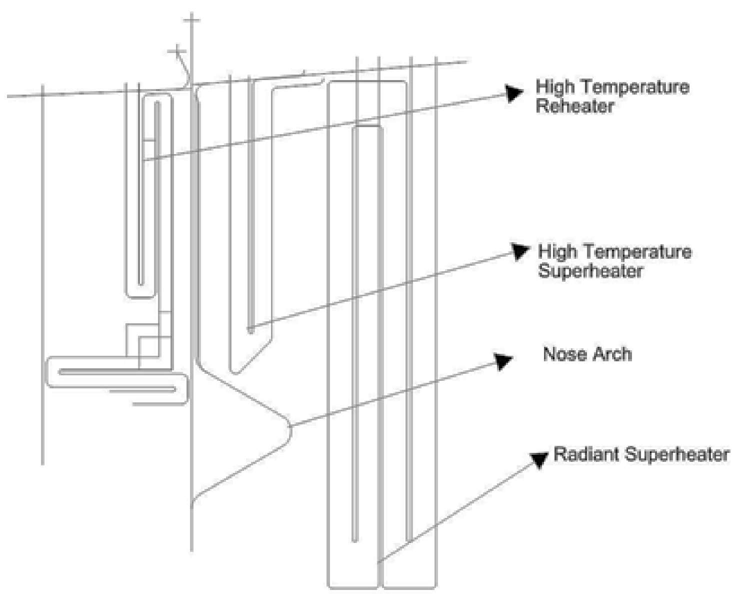

Figure 1 Existing Boiler Surface Area Configuration

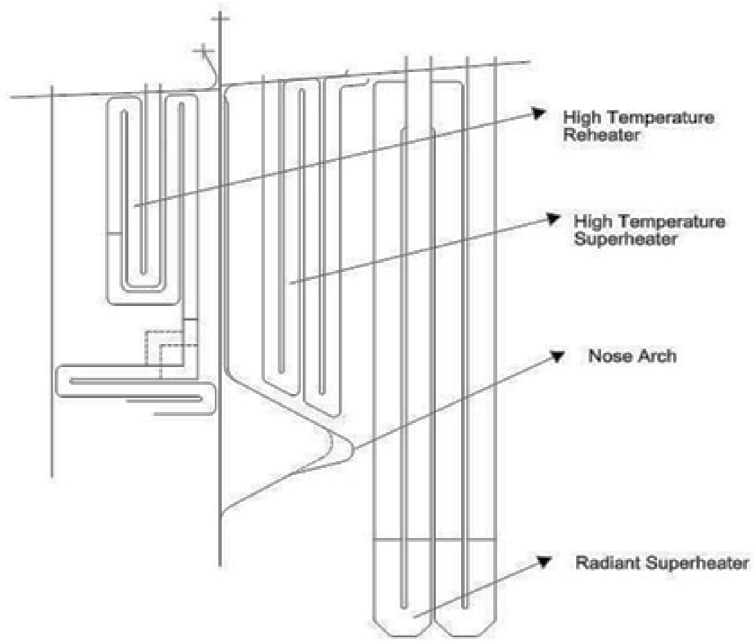

Figure 2 Proposed Boiler Surface Area Configuration

5.0 FEDERAL AND STATE RULE APPLICABILITY

5.1 Federal Rule Applicability

5.1.1 National Ambient Air Quality Standards (NAAQS)

Hillsborough County is designated attainment (for ozone, CO, and NO_2) and unclassifiable (for SO_2 , PM 10, and lead) by Section 62-204.340, F.A.C. Hillsborough County is also classified as an air quality maintenance area for ozone (entire county), for 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 for 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.

5.1.2 Nonattainment NSR Applicability

Hillsborough County is presently designated as either better than national standards or unclassifiable-attainment for all criteria pollutants. This project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

5.1.3 New Source Performance Standards (NSPS)

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA establish federal emission standards for source categories that cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. The NSPS are codified in the Code of Federal Regulations at 40 CFR 60.

Pursuant to 40 CFR 60 Part A, a Modification is any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. This project is does not increase the amount of any air pollutant and therefore does not meet the definition of Modification. Furthermore, there is no increase in hourly emission rates to the atmosphere since the project does not affect the quality/feed rate of the coal or combustion characteristics of the boiler. Therefore, this project does not trigger the requirements of the NSPS.

5.1.4 National Emission Standards for Hazardous Air Pollutants (NESHAPs)/ Mercury and Air Toxic Standards

The provisions of the CAA that address the control of HAP emissions, or air toxics, are found in Section 112. Section 112 of the CAA includes provisions for the promulgation of National Emission Standards for Hazardous Air Pollutions (NESHAPs), or Maximum Achievable Control Technology (MACT) standards, as well as several related programs to enhance and support the NESHAPs program On December 16, 2011, EPA issued the final Mercury and Air Toxic Standards Rule to reduce emissions of toxic air pollutants from power plants. Specifically, these mercury and air toxics standards (MATS) for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units (EGUs).

This project is not subject to the requirements of the NESHAP.

5.1.5 Acid Rain Program

Title IV of the CAA sets a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and mid-western states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

This unit is subject to the requirements of Title IV Acid Rain Program for Phase II SO_2 and NO_X.

5.1.6 Clean Air Interstate Rule

On March 10, 2005, EPA issued the final Clean Air Interstate Rule (CAIR). The objective of CAIR is to assist states with PM2.5 and 8-hour ozone nonattainment areas to achieve attainment by reducing precursor emissions at sources located in 28 states (including Florida) situated upwind of these nonattainment areas. Based on regional dispersion modeling, EPA determined that these 28 upwind states significantly contribute to PM2.5 and 8-hour ozone nonattainment in downwind areas. Florida emission sources are projected to significantly contribute to PM2.5 nonattainment areas located in Georgia and Alabama and to an 8-hour ozone nonattainment area in Georgia.

This unit is subject to the requirements of the CAIR.

5.1.7 Cross-State Air Pollution Rule

On July 6, 2011, the EPA issued the final Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR requires 23 states to reduce annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual PM2.5 NAAQS. Twenty-five states are required to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS. On December 30, 2011, the United States Court of Appeals for the D.C. Circuit issued its ruling to stay the CSAPR pending judicial review. Until final resolution of the stay, CAIR currently remains in effect.

This unit is subject to the requirements of the CSAPR.

5.1.8 PSD/NSR Applicability Review

This project is a physical change to an existing unit that does not increase emissions and therefore does not meet the definition of *modification* as defined in applicable regulations including 62-210.200(199), F.A.C. However, these types of physical changes have traditionally been questioned. Therefore, based on discussions with FDEP permitting engineers, TEC is applying for a minor air construction permit. Under WEPCO and the 2002 NSR revisions, instead of comparing past actual emissions to a source's potential to emit (PTE) after a change in determining if a major modification occurred triggering NSR, all sources may compare actual emissions to projected-actual emissions. This change is meant to be more representative of operating conditions in that the actual-to-PTE test is based on a source operating continuously at full capacity, while the actual-to-projected-actual test takes into consideration more realistic operations that do not operate continuously at full capacity. The following describes the basis for concluding that this project does not result in an increase in actual emissions.

5.1.8.1 Past Actual Emissions

The past actual emissions data were calculated using EPA CAMD data. The past actual emission rates for NO_X, SO_2, and CO_2 were calculated using the highest 24 month consecutive period in the preconstruction period 2007 through 2011 (NO_X emissions were conservatively determined after SCR installation). The past actual emission rate was determined as the product of the heat weighted emissions rate (lb/mmBtu) and annual heat input from the TEC's Generation, Fuels & Performance Report (GFP). This heat input data are derived from the gravimetric determination of fuel input and composite sampling. The acid rain CEMS heat input was <u>not</u> used because it over-indicates actual heat input by approximately 18%.

The past actual emission rates of the other constituents (non-CEMS) were calculated using site specific testing data or AP-42 emission factors. The past actual emission rates were determined as the product the heat input-weighted emissions rate (lb/mmBtu) and annual heat input from the TEC's Generation Fuels Report (GFP). The highest annual heat input was calculated using the highest 24 month consecutive period in the preconstruction period 2007 through 2011. A summary of the baseline emissions are shown in **Table 2**.

Table 2. Unit 3 Baseline Emissions Summary.

Parameter	Time Interval		Past Actual Emission Rate (lb/mmBtu)	Past Actual Emissions (tons/year)
NO_X	Apr-09	Mar-11	0.10	1,340
SO_2	Jun-09	May-11	0.13	1,682
CO	Oct-08	Sep-10	0.10	1,342
VOC	Oct-08	Sep-10	0.0030	40
PM	Oct-08	Sep-10	0.020	268
PM_{10}	Oct-08	Sep-10	0.015	201
$PM_{2.5}$	Oct-08	Sep-10	0.0080	107
SAM	Oct-08	Sep-10	0.019	255
N_2O	Oct-08	Sep-10	0.024	326
CH_4	Oct-08	Sep-10	0.0035	47
CO_2	Oct-08	Sep-10	205	2,752,000
CO_2e	Oct-08	Sep-10	-	2,854,000

5.1.8.2 PAR Model Projected Heat Input Calculations

TEC is required to evaluate electricity demand and resource utilization using robust modeling and report the results to the Public Service Commission. The modeling accounts for parameters relevant to evaluate whether or not a project would cause an increase in utilization and subsequently an emissions increase at a given unit. This modeling approach has been accepted by FDEP for this purpose in the past.[1] TEC uses the PROVIEW module of STRATEGIST, a computer model developed by Ventyx, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the timing and type of capacity requirements, which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit requirements, which satisfy the specified reliability criteria, and determines the schedule of additions that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module of STRATEGIST and the PLANNING & RISK (PAR) production cost model. The capital expenditures associated with each capacity requirement are obtained based on the type of generating unit, power demands, fuel type, unit heat rates, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan. One of the outputs from the PAR model is annual projected heat input. These data were used to estimate future actual emission rate.

A summary of the annual project heat input predicted by the PAR Model is shown in **Table 3**. The results show the highest annual heat input projected is 26,658,000 mmBtu per year in 2016. This heat input represents the maximum annual heat input predicted based on the type of generating unit, fuel type, unit heat rates, power demand, and economic operation.

[1] DEP File No. 0050014-005-AC; GPC Lansing Smith Generating Plant, Unit 2 Waterwall Tube Replacement Project, 9/27/02

Table 3. PAR Model Projected Heat Input Summary.

Year	PAR Model - Projected Annual Heat Input (mmBtu/year)
2013	20,663,600
2014	25,934,100
2015	26,292,380
2016	26,658,460
2017	24,162,990

5.1.8.3 Future Actual Heat Input Emissions

As mentioned earlier, the project will modify the surface area of the boiler components only. This project will <u>not</u> modify the combustion system or coal feeding system. The boiler will operate at low NO_X condition using 10% excess air. Therefore, the past actual and future projected actual heat input-weighted emissions are identical.

The future projected actual emissions data were calculated using past actual emissions data and annual heat input projections from the PAR Model. The future projected actual emission rates were calculated as the product the future heat input-weighted emissions rate (lb/mmBtu) and annual projected heat input from the PAR model. Based on the predicted heat input projections from the PAR model, the maximum annual future projected actual emissions are expected to decrease by approximately 1%. The model confirms that past actual boiler utilization is essentially equal to future projected boiler utilization as expected based on the scope of the project. Therefore, there is no net increase in projected emissions. A summary of the past actual (baseline) emissions is shown in **Table 4**. Details of the emission calculations are provided in Attachment A.

Table 4. Unit 3 Future Actual Emissions Summary.

Parameter	Time Interval		Future Actual Emission Rate (lb/mmBtu)	Future Actual Emissions (tons/year)
NO_X	Jan-13	Dec-17	0.10	1,331
SO_2	Jan-13	Dec-17	0.13	1,671
CO	Jan-13	Dec-17	0.10	1,333
VOC	Jan-13	Dec-17	0.0030	40
PM	Jan-13	Dec-17	0.020	267
PM_{10}	Jan-13	Dec-17	0.015	200
$PM_{2.5}$	Jan-13	Dec-17	0.0080	107
SAM	Jan-13	Dec-17	0.019	253
N_2O	Jan-13	Dec-17	0.024	323
CH_4	Jan-13	Dec-17	0.0035	47
CO_2	Jan-13	Dec-17	205	2,732,000
CO_2e	Jan-13	Dec-17	-	2,833,209

5.1.8.4 PSD Applicability

An assessment of PSD applicability was conducted using the procedures specified in Rule 62-212.400(2), F.A.C. The PSD emissions thresholds were calculated as the net difference between the future and past actual annual emission rates. As shown in **Table 5**, the net change in emissions for each pollutant is below the applicable PSD significant emission rate level. Accordingly, this project is not subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Details of the PSD thresholds emission calculations are shown attached.

Table 5. PSD Emissions Calculation Threshold Summary.

Parameter	Baseline Actual Emissions (Tons)	Calculated Future Actuals (Tons)	Emissions Increase or Reduction (Tons)	PSD Significance Threshold (Tons)
NO_X	1,340	1,331	(9)	40
SO_2	1,682	1,671	(12)	40
CO	1,342	1,333	(9)	100
VOC	40	40	(0)	100
PM	268	267	(2)	25
PM_{10}	201	200	(1)	15
$PM_{2.5}$	107	107	(1)	10
SAM	255	253	(2)	7
CO_2e	2,854,000	2,833,209	(20,791)	75,000

5.1.8.5 Consent Decree/Consent Final Judgment-Covenant Not to Sue

These emissions units are also regulated under a Consent Decree (U.S. vs. TECO) dated February 29, 2000, and Consent Final Judgment agreement between the FDEP and Tampa Electric Company dated December 16, 1999.

The Consent Decree paragraph 44.B. provides that EPA (United States) will not sue TEC for not getting PSD permits under the five terms described in italics below.

Paragraph 44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon

Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section 52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_X, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

TEC meets the terms of the covenant not to sue as follows:

1. The project is commencing after completing optimization of the scrubbers as described in Paragraph 31.
2. Pursuant to 40 C.F.R. Section 52.21(b)(9)(ii),the project is expected to have permits and to have "[e]ntered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time."
3. TEC is in compliance with the Consent Decree.
4. Hourly emission rates of NO_X, SO_2, and PM do not increase after the proposed change since there are no changes to coal feed rate or the combustion system that would affect these emission rates.
5. Current permit limits preclude exceedance of Total Baseline Emissions defined in Paragraph 24 of the Consent Decree (restated below).

   Paragraph 24. _ Total Baseline Emissions shall mean calendar year 1998 emissions of NO_X, SO_2, and PM comprised of the following amounts for each pollutant: A. for Gannon: 30,763 tons of NO_X, 64,620 tons of SO_2, and 1,914 tons of PM; and B. for Big Bend: 36,077 tons of NO_X , 107,334 tons of SO_2, and 3,002 tons of PM.

In addition to the demonstration that the emissions from Big Bend, Unit No. 3 will not increase as a result of the improvements proposed, language contained in the Consent Final Judgment between the FDEP and Tampa Electric Company and the Consent Decree between the United States Environmental Protection Agency and Tampa Electric Company also cover these proposed improvements.

Paragraph V.M. of the Consent Final Judgment provides that Tampa Electric Company is protected from triggering New Source Review requirements with regard to repairs, maintenance and physical or operational changes while completing the terms of the agreement. The Consent Final Judgment is still in effect although TEC intends to request closure in the near future.

5.2 State Rule Applicability

FDEP emission standards and general requirements are contained in Chapter 62-210 F.A.C., Stationary Source General Requirements (air permitting), Chapter 62-212, Stationary Source - Preconstruction Review, and Chapter 62-296 F.A.C., Stationary Sources Emission Standards.

This project is subject the Chapters 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and Chapter 62-296.700(6), F.A.C., PM RACT.

Portions of this project are not considered routine maintenance, repair or replacement of components. Therefore, this project is considered a physical modification pursuant to Chapter 62-210.200 (199)(a) F.A.C. This project does not result in a net increase in emission and is not a "Modification" in accordance with Chapter 62-210.200 (199).

This project is subject to the requirements of the Consent Final Judgment (DEP vs. TECO) dated December 16, 1999. This project is not subject to the requirements of Chapter 62-212.400.