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DIVISION OF AIR
RESOURCE MANAGEMENT

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October 3, 2012

Ms. Cindy Mulkey, Program Administrator
Siting Coordination Office
Florida Department of Environmental Protection
3900 Commonwealth Boulevard, MS 48
Tallahassee, Florida 32399-3000

Re: Tampa Electric Company (Tampa Electric)
Site Certification Application (SCA) (No. 92-32)
Polk Power Station, Polk 2-5 Combined Cycle Conversion Project
Polk County, Florida

Dear Ms. Mulkey:

1050 233-034-AC

Tampa Electric is pleased to file this SCA for the proposed construction and operation of the Polk 2-5 Combined Cycle Conversion Project at the existing Polk Power Station (PPS) in Polk County, Florida. The Project will consist of the conversion of the existing Polk Units 2 through 5 combustion turbine generators to a 1,160-megawatt (MW) combined cycle electric generating unit and associated facilities with state-of-the-art emission and environmental control systems. Tampa Electric has determined that the proposed Polk 2-5 Conversion Project is the most cost-effective and reliable means of meeting its customers' energy needs in the 2017 time frame. The Polk 2-5 Conversion Project will be located adjacent to the existing Units 2 through 5 at the PPS Site and will be integrated with many of the existing infrastructure facilities at the Site. The addition of the Polk 2-5 Conversion Project will increase the total nominal net generating capacity at PPS to 1,420 MW. In addition, the Project will involve two associated linear facilities located in offsite corridors, an approximately 27-mile, 230-kilovolt (kV) transmission line corridor from PPS to Tampa Electric's Mines and Fishhawk substations, and approximately 5.5 miles of upgrades to the existing 230-kV transmission line from Polk to Pebbledale substation. Tampa Electric is seeking certification of the proposed electric generating facilities, the associated offsite linear corridors, and the increase in ultimate generating capacity to 1,420 MW within this certification proceeding. In addition, Tampa Electric is requesting the existing site certification be amended to remove the approximately 1,511-acre portion of the property west of SR 37 from the PPS Site, since this property has been donated to Board of Trustees of the Internal Improvement Trust Fund of the State of Florida. This will leave the 2,837-acre property east of SR 37 as the certified PPS Site.

Enclosed is an original copy of the Polk 2-5 Conversion Project SCA. The SCA includes an electronic copy on a compact disc in the front of Volume 1. Also enclosed is a check for the application fee of $66,200.

By copy of this letter, Tampa Electric is submitting the original and three copies of the Air Construction/Prevention of Significant Deterioration (PSD) permit application and a check for $7,500 for the filing fee to the Florida Department of Environmental Protection (FDEP), Office of Permitting and Compliance. Also, by copy of this letter, Tampa Electric is submitting the original and a copy of the Wastewater Facility or Activity and Industrial Wastewater Discharge permit application and a check for $7,500 for the filing fee to the FDEP Industrial Wastewater Section. The SCA includes the PSD and wastewater discharge permit applications as appendices. In addition, concurrently with this filing, copies of the SCA are being sent to agencies, groups, and the local public library identified in the attached distribution list.

Tampa Electric looks forward to working with you and the Department during this certification proceeding. If you have any questions regarding this SCA or the Polk 2-5 Conversion Project, please contact me at 813/228-4858 or David Lukcic at 813/228-1095.

Sincerely,

Paul Carpinone

Paul Carpinone
Director
Environmental Health and Safety
Tampa Electric Company

PLC/iym/DLM191

cc: Mr. Jeff Koener, Program Administrator
Division of Air Resource Management
Florida Department of Environmental Protection

Mr. Marc Harris, Supervisor
Industrial Wastewater Section
Division of Wastewater Management
Florida Department of Environmental Protection

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POLK 2-5 COMBINED CYCLE CONVERSION PROJECT

POLK POWER STATION

AIR CONSTRUCTION/PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

Prepared by:

ECT Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606
ECT No. 110888-0100

October 2012

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LIST OF ACRONYMS AND ABBREVIATIONS

°	degree
°F	degree Fahrenheit
μg/g	microgram per gram
$\mu g/m^2/s$	microgram per square meter per second
$\mu g/m^2/yr$	microgram per square mile per year
$\mu g/m^3$	microgram per cubic meter
AAQS	ambient air quality standards
AERMIC	**A**merican Meteorological Society/U.S. **E**nvironmental Protection Agency **R**egulatory **M**odel **I**mprovement **C**ommittee
AERMOD	**A**merican Meteorological Society/U.S. **E**nvironmental Protection Agency **R**egulatory **M**odel **I**mprovement **C**ommittee model
AIRS	Aerometric Information Retrieval System
AMS	American Meteorological Society
AQRV	air quality-related value
ARM	ambient ratio method
ARP	Acid Rain Program
BACT	best available control technology
BPIP	Building Profile Input Program
BPIPRM	Building Profile Input Program for Plume Rise Model Enhancements
Btu/ft^3	British thermal unit per cubic foot
Btu/gal	British thermal unit per gallon
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CASTNet	Clean Air Status and Trends Network
CBL	convectively generated boundary layer
CC	combined cycle
$cfm\text{-}ft^2$	cubic foot per minute square foot
CFR	Code of Federal Regulations
CI	compression ignition
CMAQ	Community Multiscale Air Quality
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CTG	combustion turbine generator
DAT	deposition analysis threshold
EAB	Environmental Appeals Board
ECT	Environmental Consulting & Technology, Inc.
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization

FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
FR	Federal Register
ft	foot
ft/sec	foot per second
ft-msl	foot above mean sea level
g/bhp-hr	gram per brake horsepower-hour
g/s	gram per second
GACT	generally available control technology
GAQM	Guideline on Air Quality Models
GE	General Electric
GEP	good engineering practice
GHG	greenhouse gas
gr S/100 scf	grain of sulfur per 100 standard cubic feet
gr/100 dscf	grain per 100 dry standard cubic feet
H_2O	water
H_2SO_4	sulfuric acid
ha	hectare
HAP	hazardous air pollutant
HCEPC	Hillsborough County Environmental Protection Commission
HHV	higher heating value
hp	horsepower
hr/yr	hour per year
HRSG	heat recovery steam generator
ICE	internal combustion engine
IGCC	integrated gasification combined-cycle
IWAQM	Interagency Workgroup on Air Quality Modeling
kg/ha/yr	kilogram per hectare per year
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emissions Rate
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MW	pound per megawatt
lb/MWh	pound per megawatt-hour
LCC	Lambert Conformal Conic
MACT	maximum achievable control technology
MCO	Orlando International Airport
MMBtu/hr	million British thermal units per hour
MW	megawatt

N_2	molecular nitrogen
NAAQS	national ambient air quality standards
NADP	National Atmospheric Deposition Program
NED	National Elevation Dataset
NESHAP	national emissions standard for hazardous air pollutant
NH_3	ammonia
NMHC	nonmethane hydrocarbon
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NP	National Park
NPS	National Park Service
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NWA	National Wilderness Area
O_2	oxygen
OAQPS	EPA's Office of Air Quality Planning and Standards
PM	particulate matter
PM_{10}	particulate matter less than or equal to 10 microns
$PM_{2.5}$	particulate matter less than or equal to 2.5 microns
ppb	part per billion
ppm	part per million
ppmv	part per million by volume
ppmvd	part per million by volume dry
PPS	Polk Power Station
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	reciprocating internal combustion engine
SBL	stable boundary layer
SCR	selective catalytic reduction
SER	significant emissions rate
SIL	significant impact level
SIP	state implement plan
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SR	State Road
STG	steam turbine generator

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued, Page 4 of 4)

Tampa Electric	Tampa Electric Company
TPA	Tampa International Airport
tpy	ton per year
tpy/km	ton per year per kilometer
TSP	total suspended particulates
ULSD	ultra low-sulfur diesel
USGS	U.S. Geological Survey
VOC	volatile organic compound
WHO	World Health Organization

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The Tampa Electric Company (Tampa Electric) Polk Power Station (PPS), located in southwest Polk County approximately 13 miles southwest of the city of Bartow, currently includes four simple cycle combustion turbine generators (CTGs) designated as Units 2 through 5. Tampa Electric plans to convert these existing CTGs from simple cycle operation to combined cycle (CC) operation, increasing the nominal net capacity of the existing four units from 660 to 1,160 megawatts (MW). Key directly associated facilities for the proposed Project include four heat recovery steam generators (HRSGs) equipped with duct burners, a steam turbine generator (STG), a six-cell mechanical draft cooling tower, an emergency generator diesel engine, and a new transmission line and existing line upgrades. After completion of the proposed Project, the new CC unit will be known as the Polk 2 Combined Cycle. The proposed Project will result in a total generating capacity of 1,420 MW (nominal net) at the PPS Site.

The CTG/HRSG units will use pipeline-quality natural gas as their primary fuel with ultra low-sulfur diesel (ULSD) fuel oil serving as a backup fuel source. The CTG/HRSG units may operate up to 8,760 hours per year (hr/yr) per unit when firing natural gas, including up to 4,000 hr/yr of natural gas-fired HRSG duct burner operation. Operation of the CTGs when firing ULSD fuel oil will be limited to no more than 48 hours per day and no more 3,000 hr/yr for all four units.

The Project will be designed to allow the CTGs to operate in simple cycle mode with the STG out of service or to meet peak power demands by providing a means for the CTG exhaust gas to bypass the HRSG and flow directly to the atmosphere using a diverter damper stack in combination with the existing simple cycle stack. The Project also includes the addition of fuel oil firing for existing simple cycle Units 4 and 5.

The principal Project emissions sources are the four CTG/HRSG units. Emissions from the CTG/HRSG units will be controlled using best available control technologies (BACT). Proposed BACT control technologies include:

- Dry low-nitrogen oxides (NO_x) combustion (when firing natural gas), water injection (when firing ULSD fuel oil), and selective catalytic reduction (SCR) technology for nitrogen oxides (NO_x) control.
- Good combustion practice to minimize the formation of carbon monoxide (CO) and volatile organic compounds (VOCs).
- Use of low-sulfur, pipeline-quality natural gas (primary fuel) and ULSD fuel oil (backup fuel) for control of particulate matter (PM)/particulate matter less than or equal to 10 microns (PM_{10})/particulate matter less than or equal to 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and sulfuric acid (H_2SO_4) mist emissions.

Operation of the proposed Project will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This submittal, including the required permit application forms and supporting documentation included in the appendices, constitutes Tampa Electric's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, *et. seq.*, F.A.C.

Under federal Prevention of Significant Deterioration (PSD) review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and approved by the U.S. Environmental Protection Agency (EPA) or by the state agency if PSD review authority has been delegated. A *major* stationary source is defined as any 1 of 28 named source categories that have the potential to emit 100 tons per year (tpy) or more, or any other stationary source 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. The existing PPS is an existing major stationary source, since it falls into one of the named source categories and has the potential to emit 100 tpy of at least one regulated pollutant.

The Project will be located at the existing PPS and will have potential emissions greater than one or more of the PSD significant emissions rates (SERs) listed in Section 62-210.200(282), F.A.C. Accordingly, the Project constitutes a major modification to an existing major source and is subject to the PSD New Source Review (NSR) requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD SER levels. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes NSR requirements and discusses applicability of these requirements to the proposed Project.
- Section 4.0 describes applicable state and federal emissions standards.
- Section 5.0 provides an analysis of BACT.
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the Project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on Class I areas located within 300 kilometers (km) of the Project site.

Appendices A and B provide the FDEP Application for Air Permit—Long Form and emissions rate calculations, respectively. Appendix C contains the dispersion modeling input and output files for the ambient impact analyses. Appendix D presents information regarding EPA Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emissions Rate (LAER) Clearinghouse (RBLC) control technology determinations. Appendix E contains the offsite emissions inventories used for the nitrogen dioxide (NO_2), SO_2, and $PM_{2.5}$ cumulative air quality impact modeling assessments.

1.2 SUMMARY

The primary source of emissions from the Project will result from the combustion of natural gas in the four CC CTG/HRSG units. Principal air contaminants that will be emitted from the CTG/HRSG units include NO_x, SO_2, CO, VOC, $PM/PM_{10}/PM_{2.5}$, and H_2SO_4 mist. The CTG/HRSG units will also emit trace amounts of metallic and organic compounds. Ancillary Project emissions sources include a six-cell mechanical draft cooling tower and emergency generator diesel engine.

Construction of the Project is scheduled to start in February 2014 with commercial operation planned for January 2017.

Based on an evaluation of anticipated worst-case annual operating scenarios, the Project will have the potential to emit 744.9 tpy of NO_x, 935.0 tpy of CO, 137.6 tpy of VOCs, 192.3 tpy of SO_2, 188.3 tpy of PM, 309.0 tpy of PM_{10}, 308.6 tpy of $PM_{2.5}$, 0.018 tpy of lead, 42.7 tpy of H_2SO_4 mist, 0.0032 tpy of mercury, and 4,307,862 tpy of carbon dioxide equivalent (CO_2e). Based on these potential annual emissions rates, NO_x, CO, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, and CO_2e are each projected to exceed the applicable PSD SER threshold and are, therefore, subject to PSD review.

The analyses required for this permit application have resulted in the following conclusions. Since the primary Project emissions sources are the four CTG/HRSG units, the conclusions primarily address these emissions units:

- Dry low-NO_x combustion (for natural gas firing), water injection (for ULSD fuel oil-firing), and SCR represent NO_x BACT. The proposed NO_x BACT emissions limit for all natural gas-firing operating scenarios (i.e., with or without duct burner firing) is 2.0 parts per million by volume dry (ppmvd) corrected to 15-percent oxygen on a 24-hour block average basis. The proposed NO_x BACT emissions limit for all ULSD fuel oil operating scenarios is 8.0 ppmvd corrected to 15-percent oxygen on a 24-hour block average basis. The emergency generator diesel engine will achieve a NO_x plus nonmethane hydrocarbons (NMHC) emissions rate of 4.8 grams per brake-horsepower-hour (g/bhp-hr), which complies with the applicable Chapter 40, Part 60, Code of Federal Regulations (CFR), Subpart IIII, New Source Performance Standards (NSPS).

- Use of low-sulfur, pipeline-quality natural gas as the primary fuel and ULSD fuel oil as the backup fuel represents BACT for SO_2 and H_2SO_4 mist. Proposed SO_2 BACT is the use of pipeline-quality natural gas containing no more than 2.0 grains of sulfur per one hundred standard cubic feet (gr S/100 scf) and ULSD fuel oil containing no more than 0.0015 weight percent sulfur. In addition, operation of the CTGs when firing ULSD fuel oil will be limited to no more than 48 hours per day and no more 3,000 hr/yr for all four units. The emergency generator diesel engine will be fired exclusively with ULSD fuel oil.
- Good combustion design and operation represent BACT for CO. CTG combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO. The proposed CO BACT emissions limit for all operating scenarios is 8.0 ppmvd corrected to 15-percent oxygen on a 24-hour block average basis. The emergency generator diesel engine will achieve a CO emissions rate of 2.6 g/hp-hr, which complies with the applicable 40 CFR 60, Subpart IIII NSPS.
- Good combustion design and operation represent BACT for VOC. As with CO, CTG combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and VOC. The proposed VOC BACT emissions limits for natural gas firing are 3.5 and 1.4 ppmvd corrected to 15-percent oxygen with and without duct burner-firing, respectively, based on stack testing. The proposed VOC BACT emissions limit for ULSD fuel oil firing is 3.0 ppmvd corrected to 15-percent oxygen based on stack testing.
- Use of low-ash natural gas as the primary fuel and ULSD fuel oil as the backup fuel represents BACT for PM (filterable) and $PM_{10}/PM_{2.5}$ (filterable and condensable). Proposed total (filterable and condensable) $PM_{10}/PM_{2.5}$ BACT is the use of pipeline-quality natural gas containing no more than

2.0 gr S/100 scf and ULSD fuel oil containing no more than 0.0015 weight percent sulfur. As previously mentioned, operation of the CTGs when firing ULSD fuel oil will be limited to no more than 48 hours per day and no more 3,000 hr/yr for all four units. The emergency generator diesel engine will be fired exclusively with ULSD fuel oil and will achieve a $PM/PM_{10}/PM_{2.5}$ emissions rate of 0.15 g/hp-hr, which complies with the applicable 40 CFR 60, Subpart IIII NSPS. The mechanical draft cooling tower will employ high-efficiency drift eliminators to achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow, which will result in low $PM_{10}/PM_{2.5}$ emissions rates of 0.31 and 0.0021 tpy, respectively.

- The Project is projected to emit NO_x, CO, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that Project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants with the exception of VOC. Accordingly, the Project qualifies for the Rule 62-212.400(3)(e), F.A.C., exemption from PSD preconstruction ambient air quality monitoring for all PSD pollutants except for VOC. Preconstruction monitoring for ozone is required if potential NO_x and/or VOC emissions from a project subject to PSD review exceeds 100 tpy. Two ozone monitoring sites located in Lakeland approximately 35 km north of the Project site provide background monitored values that are representative of the Project site.
- The ambient impact analysis indicates that Project operations will result in ambient air quality impacts that exceed the EPA and Rule 62-210.200(283), F.A.C., PSD Class II significant impact levels (SILs) for NO_2 and SO_2 1-hour average and $PM_{2.5}$ 24-hour average. Project impacts were below the PSD Class II SILs for all other pollutants and averaging periods. Accordingly, additional cumulative modeling was required for NO_2 and SO_2 1-hour national ambient air quality standards (NAAQS) and $PM_{2.5}$ 24-hour PSD Class II increment and NAAQS.
- Cumulative modeling demonstrates that the total impact from all PSD sources will be below the 24-hour $PM_{2.5}$ Class II increment.

- Cumulative modeling shows potential exceedances of the 1-hour NO_2 and SO_2 and 24-hour $PM_{2.5}$ NAAQS. However, the Project did not have a significant contribution to any of these potential exceedances. With respect to the 1-hour NO_2 and SO_2 NAAQS, the Project only contributed 0.0059 and 0.00030 percent to the highest potential exceedances, respectively. Regarding the 24-hour $PM_{2.5}$ NAAQS, the Project only contributed 0.0091 percent to the highest potential exceedance.
- Class I areas located within 300 km of the Project include Chassahowitzka National Wilderness Area (NWA) and Everglades National Park (NP) in Florida. Application of the Federal Land Manager (FLM) initial screening criteria for air quality-related value (AQRV) review indicates that the Project will be well below the screening criteria threshold for Everglades NP. Accordingly, Class I AQRV analyses were only required for Chassahowitzka NWA in accordance with the FLM guidance. Assessments of PSD Class I increments were conducted for both Chassahowitzka NWA and Everglades NP.
- Analyses of PSD Class I area AQRVs for Chassahowitzka NWA indicates that Project impacts will be below levels that are detrimental to soils and vegetation and will not impair visibility.
- The ambient impact analysis demonstrates that Project impacts will be below the EPA-proposed PSD Class I SILs for Chassahowitzka NWA and Everglades NP. Accordingly, a multisource cumulative assessment of PSD Class I increment consumption was not required.
- Based on refined dispersion modeling, the Project will not cause nor contribute to an exceedance of any NAAQS or PSD increment for Class I or Class II areas.

2.0 PROJECT DESCRIPTION

2.1 PROJECT LOCATION, AREA MAP, AND PLOT PLAN

The originally certified PPS Site consisted of approximately 4,348 acres in southwest Polk County. Prior to development of PPS, the Site consisted primarily of previously mined phosphate lands that have subsequently been reclaimed and released under applicable FDEP and Polk County reclamation requirements. The portion of the Site containing the existing PPS power plant facilities is unmined land except for the approximately 755-acre cooling reservoir, which was developed in a previously mined area. Tampa Electric has recently donated the approximately 1,511-acre portion of the Site on the west side of State Road (SR) 37 to FDEP for use as a wildlife management/recreation area. Tampa Electric is requesting that the existing certification for the PPS Site be amended to remove this western portion from the certified Site area. The new certified PPS Site will consist of the approximately 2,837-acre portion of the PPS Site east of SR 37.

Figure 2-1 presents the overall layout of the existing facilities (shown in red) and new facilities for the Polk 2-5 Conversion Project (shown in purple) on a recent site aerial photograph. As shown in this figure, the proposed Project facilities will be located adjacent to the existing Polk Units 2 through 5 facilities.

Figure 2-2 provides a layout of the existing and proposed facilities for the Project, and Figure 2-3 presents the similar detailed facility layout on a recent (i.e., 2011) aerial photograph. As shown in these figures, the new HRSGs and STG will be constructed immediately west of and between existing simple cycle Units 2 through 5. Figure 2-4 provides a detailed site arrangement for the proposed Project facilities, including a facilities legend. The new mechanical draft cooling tower will be located west of the new generating facilities. Construction laydown and parking areas will be temporarily provided in the previously cleared and used upland areas south and west of the proposed Project facilities. Figure 2-5 presents a conceptual rendering of the proposed Project with the existing facilities on the Site.

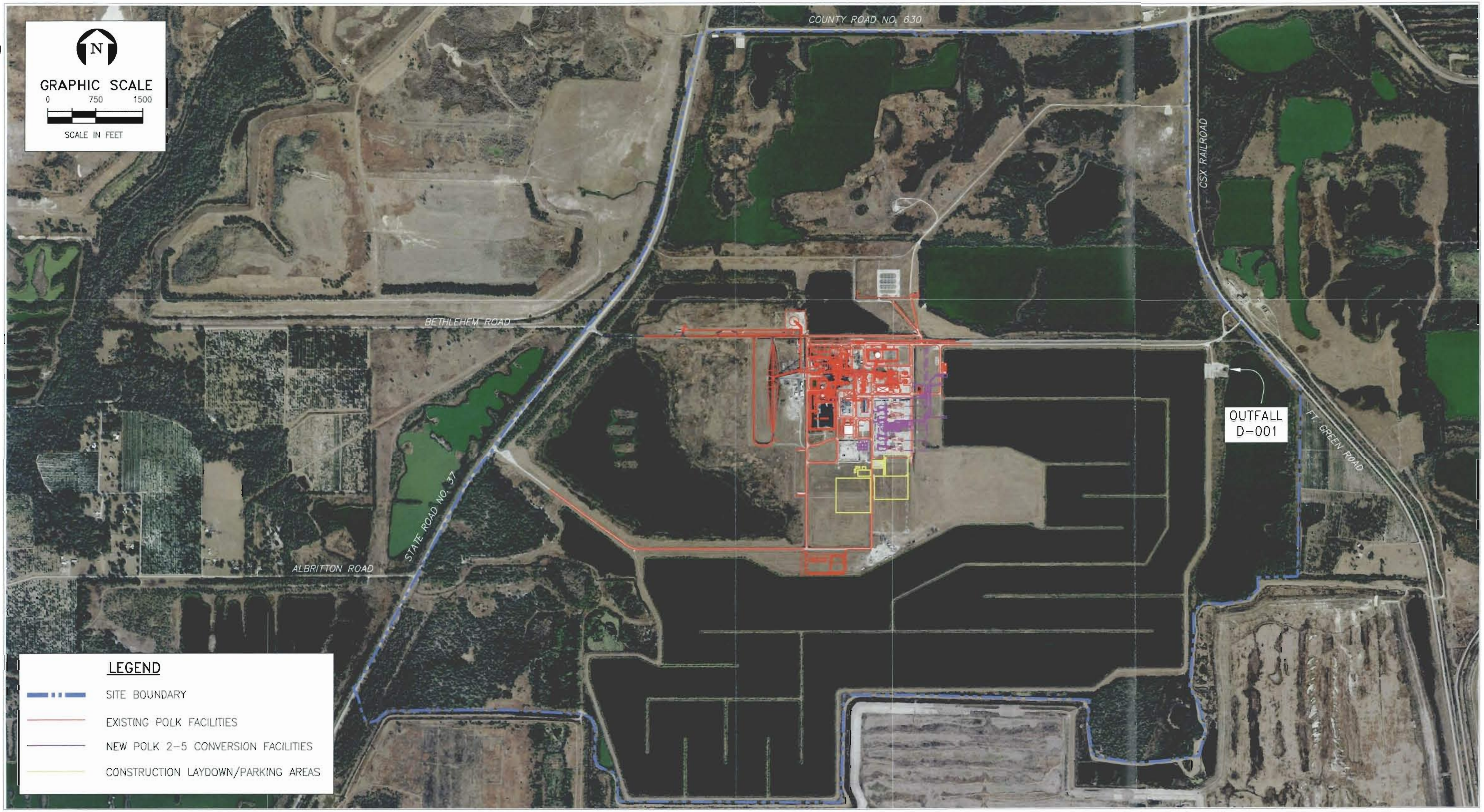

FIGURE 2-1.

GENERAL LAYOUT OF PPS EXISTING AND PROPOSED POLK 2-5 CONVERSION FACILITIES

Sources: 2011 Dept. of Revenue Aerials; Black & Veatch, 2012; Tampa Electric, 2012; ECT, 2012.

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M:\acad\110888\Site Layout Existing Proposed Unit2 Facilities NBD.dwg Sep 25, 2012 - 3:11pm by mcruz

FIGURE 2-2.

LAYOUT OF EXISTING AND PROPOSED POLK 2-5 CONVERSION FACILITIES

Sources: Black & Veatch, 2012; Tampa Electric, 2012; ECT, 2012.

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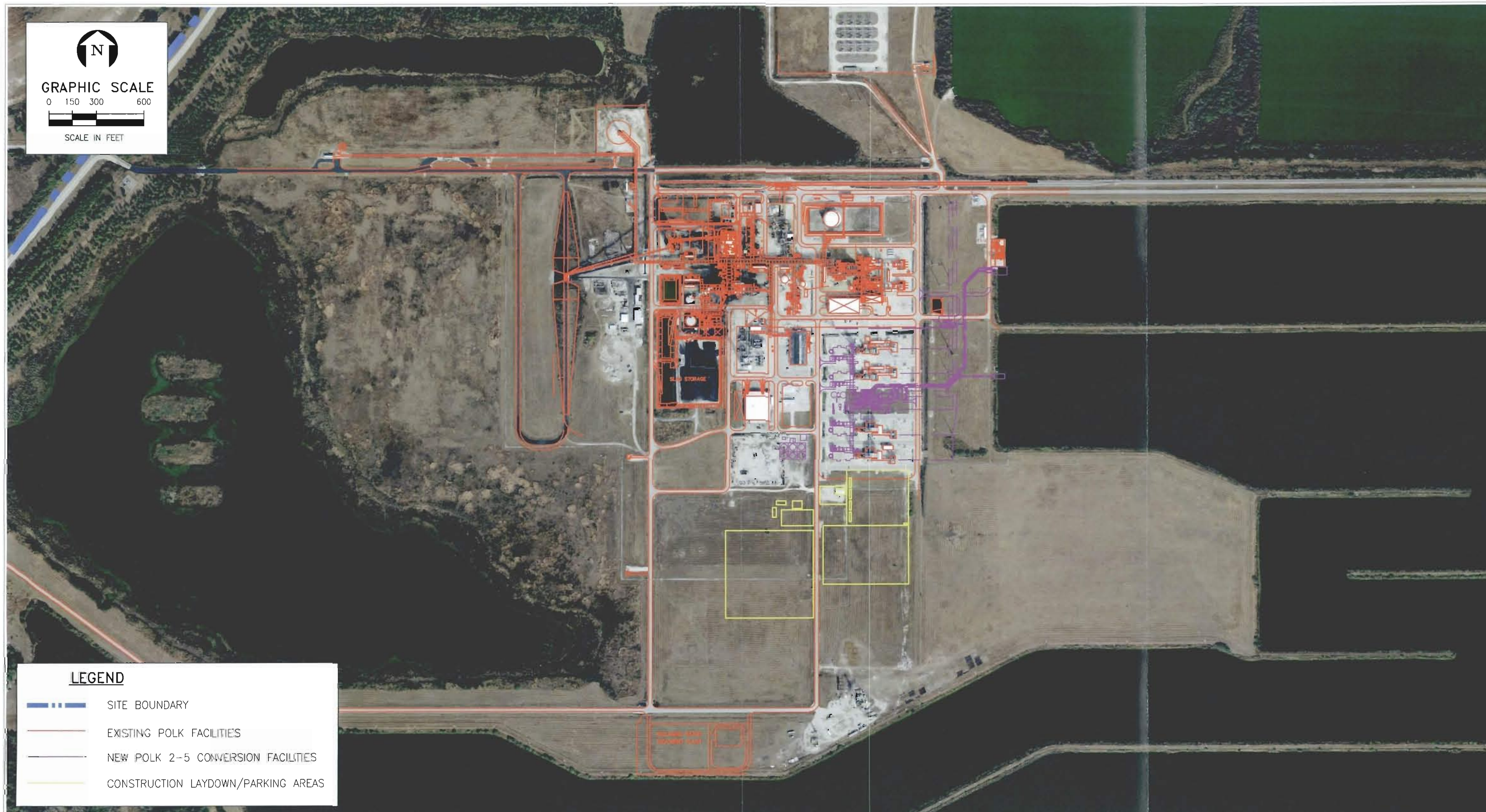

FIGURE 2-3.

LAYOUT OF EXISTING AND PROPOSED POLK 2-5 CONVERSION FACILITIES ON AERAIL PHOTOGRAPH

Sources: 2011 Dept. of Revenue Aerials; Black & Veatch, 2012; Tampa Electric, 2012; ECT, 2012.

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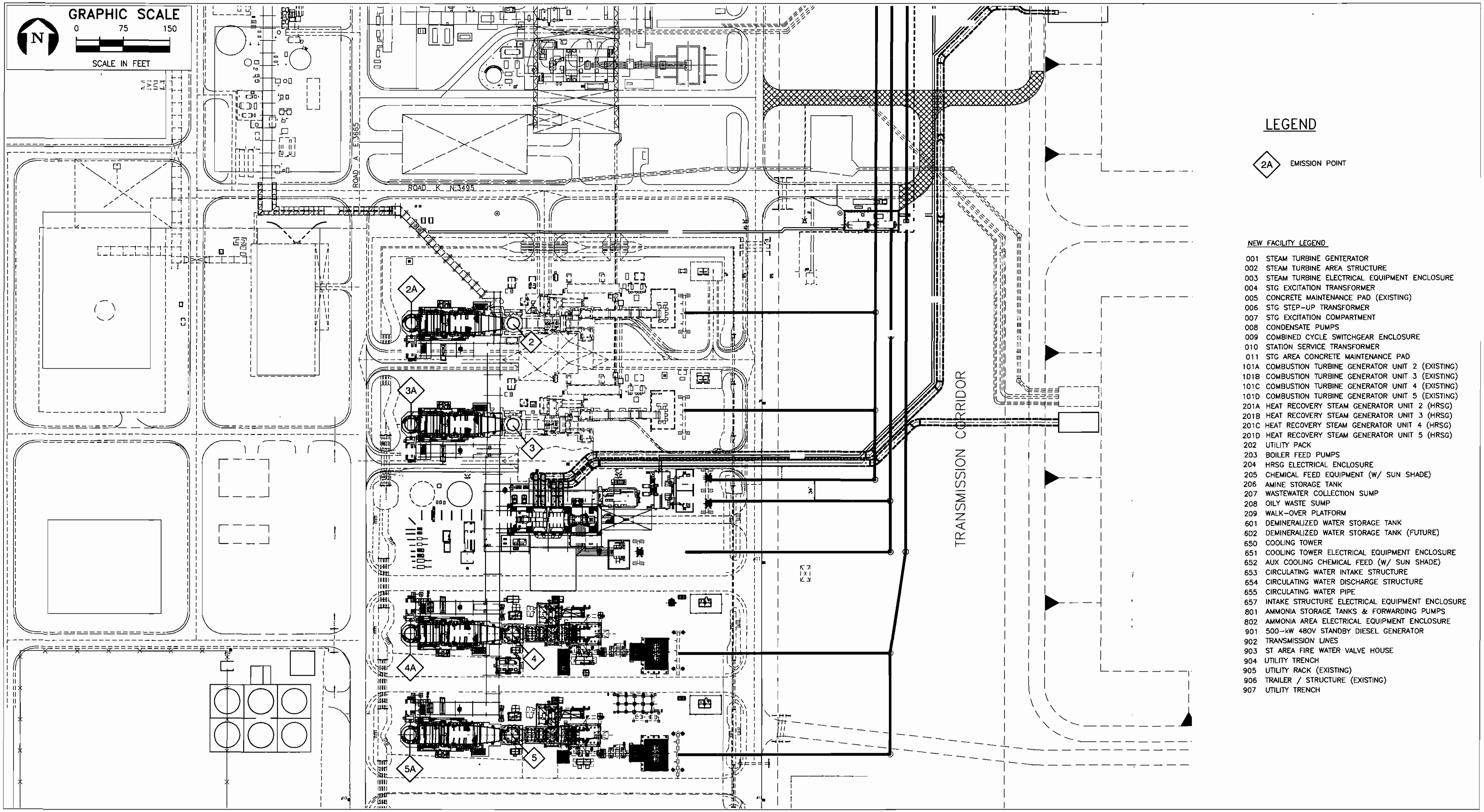

FIGURE 2-4.

DETAILED SITE ARRANGEMENT FOR POLK 2-5 CONVERSION PROJECT

Source: Black & Veatch, 2012; Tampa Electric, 2012; ECT, 2012.

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FIGURE 2-5.
CONCEPTUAL RENDERING OF PROPOSED POLK 2-5 CONVERSION PROJECT FACILITIES

Source: Black & Veatch, 2012.

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2.2 PROJECT DESCRIPTION AND FLOW DIAGRAM

The proposed Project will convert the existing Polk Units 2 through 5 from simple cycle operation to CC operation, increasing the nominal net capacity of the existing four units from 660 to 1,160 MW. Key directly associated facilities for the proposed Project include four HRSGs, an STG, a mechanical draft cooling tower, and a new transmission line and existing line upgrades. After completion of the proposed Project, the new CC unit will be known as the Polk 2 Combined Cycle. The proposed Project will result in a total generating capacity of 1,420 MW (nominal net) at the PPS Site. Construction activities for the Project are scheduled to begin in February 2014; commercial operation is scheduled for January 2017. Tampa Electric is seeking an increase in the certified ultimate site capacity from 1,150 to 1,420 MW at the PPS Site and certification of the proposed Project and directly associated facilities.

The HRSGs will use waste heat from the existing Polk Units 2 through 5 CTGs to produce steam to be directed to a new STG, which will produce additional electrical power. The steam from the STG discharges to a condenser, which is cooled by the existing cooling reservoir via a new circulating water system. A new mechanical draft cooling tower will be used for cooling of the auxiliary equipment for the proposed Project, as well as for the Polk Unit 1 auxiliary cooling systems.

Major facilities for the proposed Project will include:

- Four existing CTGs.
- Four new HRSGs with natural gas-fired duct burners.
- One new STG.
- New six-cell mechanical draft cooling tower.
- One new emergency diesel generator.
- New expanded circulating water intake and discharge structures from/to cooling reservoir.
- Various new associated transformers, pumps, and water and chemical storage tanks.

The new unit will be designed for cycling load operation. The STG will be selected in combination with the HRSGs to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. The HRSGs will be designed with natural gas-fired duct burners for peaking power operation. Evaporative coolers will be installed on the CTGs to increase warm weather power generation by increasing CTG inlet air density. The Project will be designed to allow the CTGs to operate in simple cycle mode with the STG out of service or to meet peak power demands by providing a means for the CTG exhaust gas to bypass the HRSG and flow directly to the atmosphere using a diverter damper stack in combination with the existing simple cycle stack. The project also includes the addition of fuel oil-firing for existing simple cycle Units 4 and 5.

The HRSGs will be installed outdoors and will convert waste heat from the CTG exhausts to steam for use in driving the STG. The HRSGs will be natural circulation, three-pressure, reheat units with supplemental duct firing to maximize unit output. Cycle operating pressure will be a nominal 2,400 pounds per square inch, gauge. SCR systems for NO_x control will be included within the HRSGs. The HRSGs will discharge through metal exhaust stacks. Stack dampers will be included to minimize heat loss during shutdowns. Two 100-percent capacity condensate pumps and one 100-percent capacity boiler feedwater pump per HRSG will be included.

The STG will be a tandem-compound, single reheat, condensing turbine operating at 3,600 revolutions per minute. Turbine suppliers' standard auxiliary equipment includes a lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems. A surface condenser will be provided for condensing steam from the turbine exhaust and will use the existing cooling water reservoir for cooling. The condenser will be designed for full steam flow bypass around the STG. A single synchronous generator will be directly coupled to the STG. Generator suppliers' standard auxiliary equipment will include supervisory, monitoring, and control systems and static excitation systems. The STG will be provided with enclosures as required for outdoor installation.

A six-cell, mechanical draft, counterflow cooling tower will be used by the Project for cooling of auxiliary equipment from the new CC plant as well as the existing Polk Unit 1 auxiliaries. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin. The cooling tower will include a pump intake structure housing two 100-percent capacity new Unit 1 auxiliary cooling water pumps and two 100-percent capacity new CC auxiliary cooling water pumps for the proposed Project. An auxiliary cooling water chemical feed system will be included. Makeup water to the cooling tower will primarily be provided from the onsite reclaimed water treatment facilities and the existing onsite wells. The cooling tower will be equipped with drift eliminators with a design drift rate of 0.0005 percent. The cooling tower will be approximately 1,270 feet (ft) from the nearest PPS property line.

The Project will be designed for control through a plant distributed control and information system. The control screens for this system will be located in the exiting main plant control room. A new control system for control of the STG will also be included.

Following the conversion, each CTG unit (existing Units 2 through 5) will continue to use natural gas from the existing onsite natural gas supply system as the startup and primary fuel and ULSD fuel oil as backup.

The proposed Project will be integrated into the existing PPS operations and designed to minimize the use of water and maximize the recycling/reuse of water. For the Project, the existing cooling reservoir will be used for condenser cooling purposes, similar to existing Unit 1 operations. As previously mentioned, a new mechanical draft cooling tower will be constructed to provide cooling for the Project auxiliary systems. Unit 1 auxiliary cooling systems will be modified to also use the new cooling tower instead of the cooling reservoir. Figure 2-6 presents a conceptual process flow block diagram of the Project.

2.3 PROJECT FUELS

Key factors in Tampa Electric's decision to select the CC technology to meet its future power needs were fuel costs and use of proven technology. Use of natural gas will enable Tampa Electric to take full advantage of competitive fuel pricing and availability opportunities and transportation options in the future marketplace to provide low-cost, reliable electricity to its customers. Natural gas delivery will be unchanged via the existing

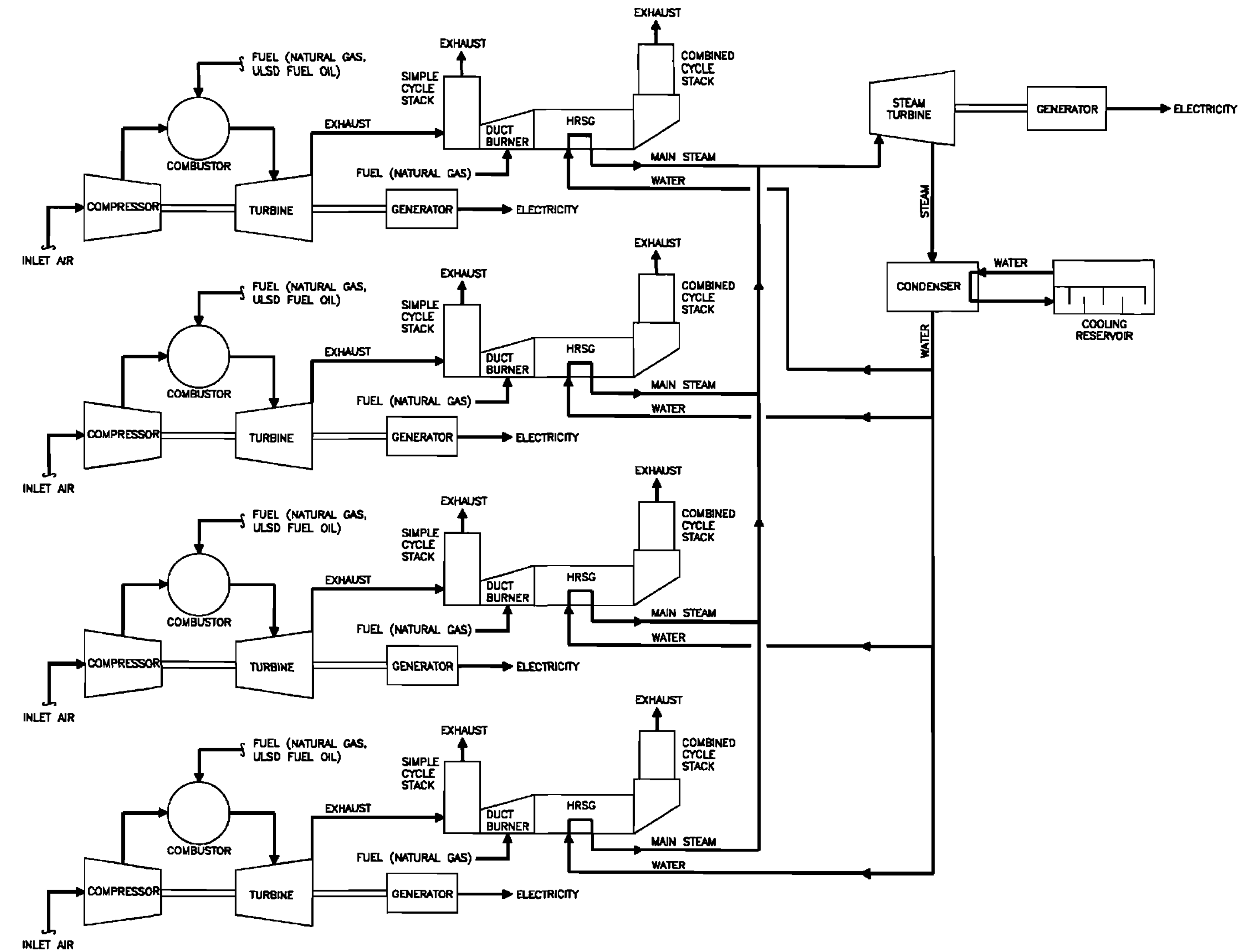

FIGURE 2-6.
CONCEPTUAL PROCESS FLOW DIAGRAM

Source: Black & Veatch, 2012.

TECO
TAMPA ELECTRIC

pipeline on the Site to Units 2 through 5. The proposed Project will be designed for operation on ULSD fuel oil as a backup fuel. ULSD fuel oil will also be fired in the new emergency generator diesel engine.

2.3.1 NATURAL GAS

The Project will fire natural gas in the CTGs and HRSG duct burners as the primary fuel. The current PPS facilities include a natural gas supply pipeline from the Florida Gas Transmission system adjacent to the Site along Fort Green Road that provides fuel to existing Units 2 through 5. This existing pipeline interconnection has adequate capacity to supply the proposed Project operational and startup fuel requirements. Modifications to the existing natural gas supply facilities required for the Project will involve the onsite extension of the pipeline to the new HRSG duct burners for supplemental firing. Table 2-1 presents the typical composition of Florida Gas Transmission pipeline system natural gas in Florida.

The hourly natural gas fuel consumption rates will depend on plant load, ambient conditions, and whether supplemental firing is used. Table 2-2 provides indicative estimates of total average fuel consumption rates for the four Unit 2 CC units.

2.3.2 ULSD FUEL OIL

ULSD fuel oil will be used as a backup fuel for the CC CTGs and for the new emergency generator diesel engine. ULSD fuel oil will be delivered to the PPS Site via tanker trucks, unloaded, and stored in day tanks near the emergency equipment. The day storage tanks will be located within appropriately designed containment areas with manually controlled drains routed to an oil-water separator. The backup fuel oil for the CTGs will be stored in the existing aboveground bulk storage tank located in an existing secondary containment area. Table 2-3 presents the typical composition of ULSD fuel oil. The ULSD fuel oil will have a maximum sulfur content of 0.0015 weight percent.

The quantity of ULSD fuel oil used for Project operations will depend on the number of hours permitted per year. Routine testing of the emergency generator will be conducted for a maximum of 100 hr/yr.

Table 2-1. Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Pentane	<0.1
Propane	0.3
I-butane	0.1
N-butane	0.1
Nitrogen	0.3
Methane	96.8
Carbon dioxide	0.8
Ethane	1.6
Other Characteristics	
Heat content (HHV)	1,020 Btu/ft^3
Sulfur content	2.0 gr/100 dscf*

*FDEP recommended value.

Note: Btu/ft^3 = British thermal unit per cubic foot.
gr/100 dscf = grain per 100 dry standard cubic feet.
HHV = higher heating value.

Sources: Tampa Electric, 2012.
Environmental Consulting & Technology, Inc. (ECT), 2012.

Table 2-2. Indicative Hourly Natural Gas Fuel Consumption Rates

Description of Operating Mode	MMBtu/hr (HHV)
59°F ambient, natural gas fuel, supplemental firing *off*, evaporative coolers *off*, full load	7,094
59°F ambient, natural gas fuel, supplemental firing *on*, evaporative coolers *on*, full load	8,113

Note: MMBtu/hr = million British thermal units per hour.
HHV = higher heating value.

Sources: Tampa Electric, 2012.
ECT, 2012.

Table 2-3. Typical ULSD Composition

Component	Maximum
Carbon residue on 10-percent bottoms	0.25 weight percent
Water and sediment	0.50 percent volume
Vanadium	1.5 ppm
Calcium	4.0 ppm
Sulfur	0.0015 weight percent
Ash	100 ppm
Lead	1.0 ppm
Heat content (HHV) (minimum)	130,000 Btu/gal

Note: Btu/gal = British thermal unit per gallon.
HHV = higher heating value.
ppm = part per million.

Source: ECT, 2012.

2.4 EMISSIONS AND STACK PARAMETERS

Project emissions sources include CTGs (2, 3, 4, and 5)/HRSGs (2A, 3A, 4A, and 5A); a mechanical draft cooling tower; and an emergency generator diesel engine. Figure 2-4 illustrates the locations of these emissions sources.

The primary source of emissions from the Project will result from the combustion of fuels in the CC CTG/HRSG units. Table 2-4 presents criteria pollutant emissions for each individual CTG/HRSG unit for both natural gas and ULSD fuel oil. Table 2-5 provides other constituents of interest (i.e., H_2SO_4 mist, PM, mercury, ammonia, and greenhouse gases [GHGs]). The CTG/HRSGs are the only significant source of hazardous air pollutant (HAP) emissions from the sources associated with the Project, with each unit emitting 3.6 and 1.1 tpy of HAPs when firing natural gas and ULSD fuel oil, respectively. Appendix B of this document contains more details regarding CTG/HRSG emissions rates.

There will be one diesel engine associated with the emergency generator. Table 2-6 shows criteria emissions and other parameters for the emergency generator diesel engine. As stated earlier, the diesel engine will be fired with ULSD fuel resulting in very low SO_2 emissions. The emissions from this engine are relatively low and were estimated assuming 500 hr/yr of operation in accordance with EPA guidance for emergency engines. HAP emissions from these units are negligible and are provided in Appendix B of this document.

The only criteria pollutants emitted from the cooling tower are PM_{10} and $PM_{2.5}$. The cooling tower will be equipped with highly efficient drift eliminators (i.e., limiting the drift loss rate to 0.0005 percent) and will use treated reclaimed water as makeup. Estimated cooling tower annual PM_{10} and $PM_{2.5}$ emissions rates are 0.31 and 0.0021 tpy, respectively.

Table 2-7 provides a summary of potential annual emissions for the Project. Table 2-8 presents stack parameters for the emissions units.

Table 2-4. CTG/HRSG—Criteria Pollutant Emissions Rates (per CTG/HRSG)

Pollutant	Unit	Value*	
		Natural Gas	ULSD Fuel Oil
NO_x	lb/MMBtu, HHV	0.0074	0.032
	ppmvd at 15-percent oxygen	2.0	8.0
	lb/hr	17.1	70.5
SO_2	lb/MMBtu, HHV	0.0053	0.0013
	ppmvd at 15-percent oxygen	1.2	0.26
	lb/hr	12.3	2.9
CO	lb/MMBtu, HHV	0.015	0.018
	ppmvd at 15-percent oxygen	8.0	8.0
	lb/hr	34.3	38.9
VOC	lb/MMBtu, HHV	0.0044	0.0041
	ppmvd at 15-percent oxygen	3.5	3.0
	lb/hr	9.7	8.7
$PM_{10}/PM_{2.5}$	lb/MMBtu, HHV	0.0091	0.031
(total)	lb/hr	18.3	38.0
Lead	lb/MMBtu, HHV	4.90E-07	4.90E-07
	lb/hr	1.15E-03	1.10E-03

Note: HHV = higher heating value.
lb/hr = pound per hour.
lb/MMBtu = pound per million British thermal units.
ppmvd = part per million by volume dry.

*Maximum rates for all operating cases.

Sources: Black & Veatch, 2012.
ECT, 2012.

Table 2-5. CTG/HRSG—H_2SO_4 Mist, PM, Mercury, Ammonia, and GHG Emissions Rates (per CTG/HRSG)

Pollutant	Unit	Value*	
		Natural Gas	ULSD Fuel Oil
H_2SO_4 mist	lb/MMBtu, HHV	0.0015	0.00016
	lb/hr	3.5	0.35
PM (filterable)	lb/MMBtu, HHV	0.0056	0.016
	lb/hr	12.4	19.3
Mercury	lb/10^{12} Btu	Negligible	1.20
	lb/hr	Negligible	0.0027
Ammonia	lb/MMBtu, HHV	0.0067	0.0073
	ppmvd at 15-percent oxygen	5.0	5.0
	lb/hr	15.6	16.2
GHG (as CO_2e)	lb/MMBtu, HHV	117.0	163.6
	lb/hr	273,959	366,261

Note: HHV = higher heating value.
lb/10^{12} Btu = pound per tera-British thermal units.
lb/hr = pound per hour.
lb/MMBtu = pound per million British thermal units.
ppmvd = part per million by volume dry.

*Maximum rates for all operating cases.

Sources: Black & Veatch, 2012.
ECT, 2012.

Table 2-6. Emergency Generator Diesel Engine-Criteria Pollutant Emissions Rates

Pollutant	Unit	Value
Operating hours	hr/yr	500
Engine output (100-percent load)	kW	568
	bhp	762
NO_x	g/bhp-hr	3.4
	lb/hr	5.6
	tpy	1.4
SO_2	g/bhp-hr	0.0046
	lb/hr	0.0078
	tpy	0.0019
CO	g/bhp-hr	2.6
	lb/hr	4.4
	tpy	1.1
VOC	g/bhp-hr	1.4
	lb/hr	2.4
	tpy	0.60
$PM/PM_{10}/PM_{2.5}$	g/bhp-hr	0.15
	lb/hr	0.25
	tpy	0.063
Lead	g/bhp-hr	Negligible
	lb/hr	Negligible
	tpy	Negligible

Note: bhp = brake horsepower.
g/bhp-hr = gram per brake-horsepower-hour.
hr/yr = hour per year.
kW = kilowatt.
lb/hr = pound per hour.
tpy = ton per hour.

Sources: Black & Veatch, 2012.
ECT, 2012.

Table 2-7. Project Potential Annual Emissions Rate Summary

Pollutant	CTG/HRSG Units 2A, 3A, 4A, and 5A* (tpy)	Cooling Tower (tpy)	Emergency Generator Engine (tpy)	Total Emissions (tpy)
Criteria pollutants				
NO_x	743.5	N/A	1.4	744.9
CO	933.9	N/A	1.1	935.0
VOC	137.0	N/A	0.60	137.6
SO_2	192.3	N/A	0.0019	192.3
PM_{10} (total)	308.6	0.31	0.063	309.0
$PM_{2.5}$ (total)	308.6	0.0021	0.063	308.6
Lead	0.018	N/A	Negligible	0.018
HAPs				
Formaldehyde	3.5	Negligible	Negligible	3.5
Total HAPs	18.2	Negligible	Negligible	18.2
Other pollutants				
H_2SO_4 mist	42.7	N/A	Negligible	42.7
PM (filterable)	187.8	0.35	0.063	188.3
Ammonia	243.4	N/A	N/A	243.4
Mercury (lb/yr)	6.5	N/A	Negligible	6.5
GHG (as CO_2e)	4,307,655	N/A	207	4,307,862

Note: N/A = not applicable.

*Maximum emissions for annual profiles Nos. 1, 2, and 3.

Source: Black & Veatch, 2012.
ECT, 2012.

Table 2-8. Stack Parameters

Parameter	Unit	CTG/HRSGs Stacks†	Generator Diesel Engine	Cooling Tower*
Height above grade	ft	130	10	51
	meter	39.6	3.0	15.5
Exit diameter	ft	19.0	0.5	31.6
	meter	5.79	0.15	9.64
Flow rate	acfm	1,020,298	3,846	1,186,000
Exit velocity	ft/sec	60.0	326.4	25.2
	m/sec	18.3	99.5	7.7
Exit temperature	°F	194.4	941.0	98.0
	K	363.4	778.2	309.8

Note: °F = degree Fahrenheit.
acfm = actual cubic foot per minute.
ft/sec = foot per second.
ft = foot.
K = Kelvin.
m/sec = meter per second.

* Per cell.
†Natural gas, Case CC-9, 100-percent load, 59°F ambient, evaporative cooling, duct burner firing.

Sources: Black & Veatch, 2012.
ECT, 2012.

3.0 NEW SOURCE REVIEW REQUIREMENTS

3.1 NATIONAL AND STATE AMBIENT AIR QUALITY STANDARDS

As a result of the 1977 CAA Amendments (1990), EPA has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has adopted the federal NAAQS by reference in Section 62-204.800(1), F.A.C. Table 3-1 presents the current NAAQS.

Areas of the country in violation of NAAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. PPS is located in southwest Polk County approximately 13 miles southwest of the city of Bartow. Polk County is presently designated in 40 CFR 81.310 as cannot be classified for total suspended particulates (TSPs); better than national standards for SO_2; cannot be classified or better than national standards for NO_2; unclassifiable/attainment for CO, 8-hour ozone, and $PM_{2.5}$; and not designated for lead. Polk County is designated attainment for ozone, SO_2, CO, and NO_2 and unclassifiable for PM_{10} and lead by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

PPS is located in Polk County. As noted previously, Polk County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the Project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The Project will have potential emissions greater than one or more of the PSD SERs listed in Rule 62-210.200(282), F.A.C. Accordingly, the Project qualifies as a major modification to an existing major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD SER levels. Table 3-2 provides comparisons of estimated potential annual emissions

Table 3-1. National Ambient Air Quality Standards

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary
SO_2 (ppb)	1-hour*	75	
	3-hour†		500
	24-hour†	140	
	Annual‡	30	20
PM_{10} (µg/m^3)	24-hour§	150	150
$PM_{2.5}$ (µg/m^3)	24-hour☼	35	35
	Annual**	15	15
CO (ppm)	1-hour†	35	
	8-hour†	9	
Ozone (ppm)	1-hour††		
	8-hour‡‡	0.075	0.075
NO_2 (ppb)	Annual‡	53	53
	1-hour§§	100	
Lead (µg/m^3)	Calendar quarter arithmetic mean	1.5	1.5
	Rolling quarterly average	0.15	0.15

Note: µg/m^3 = microgram per cubic meter.
ppb = part per billion.
ppm = part per million.
The 1971 annual and 24-hour SO_2 standards were revoked on June 2, 2010. However, these standards remain in effect until 1 year after an area is designated for the 2010 standard.

*Compliance shown with 3-year average of the 99th percentile of the annual distribution of thc daily maximum 1-hour average concentrations.
†Not to be exceeded more than once per calendar year. Federal standard has been revoked (Volume 75, Page 35580, Federal Register [FR]) for 24-hour SO_2.
‡Arithmetic mean. Federal standard has been revoked (75 FR 35580) for SO_2.
§Standards are attained when expected number of days per calendar year with a 24-hour average concentration above 150 µg/m^3, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than 1.
☼98th percentile concentration, as determined in accordance with 40 CFR 50, Appendix N.
**Arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix N.
††Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H. No longer applies to Maryland after January 15, 2005.
‡‡Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentrations over a 3-year period are less than or equal to the standard, as determined by 40 CFR 50, Appendix P.
§§Compliance shown with 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour average concentrations.

Sources: 40 CFR 50.
Section 62-204.800(1), F.A.C.

rates for the Project and the PSD SER thresholds. As shown in this table, potential emissions of NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4 mist, and GHGs are each projected to exceed the applicable PSD SER level. These pollutants are, with the exception of GHGs, which are regulated by EPA, since Florida has not requested delegation for GHG permitting, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix B contains detailed emissions rate estimates for the Project.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(4)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by the Project in amounts equal to or greater than the PSD SER levels. As defined by Rule 62-210.200(40), F.A.C., BACT is:

> "an emissions limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account: (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 emissions limiting standards or BACT determinations of Florida and any other state, determines if 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."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD SER thresholds shown in Table 3-2. All emissions units that are involved in a major modification or a new major source and emit or increase emissions of the applicable pollutants must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emissions units may undergo BACT analysis for more than one pollutant. BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal NSPS, national emissions standard for hazardous air pollutants (NESHAPs), or any other emissions limitation established by state regulations.

Table 3-2. Project Emissions Compared to PSD SERs

Pollutant	Project Potential Annual Emissions (tpy)	PSD SER (tpy)	PSD Applicability
CO	935.0	100	Yes
NO_x	744.9	40	Yes
SO_2	192.3	40	Yes
PM (filterable)	188.3	25	Yes
PM_{10} (filterable and condensable)	309.0	15	Yes
$PM_{2.5}$ (filterable and condensable)	308.6	10	Yes
Ozone/VOC	137.6	40	Yes
Lead	0.018	0.6	No
Fluorides	Not present	3	No
H_2SO_4 mist	42.7	7	Yes
Hydrogen sulfide	Not present	10	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal solid waste landfills emissions (measured as nonmethane organic compounds)	Not present	50	No
Mercury	0.0032	0.1	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 $\mu g/m^3$, 24-hour average	Not applicable	Any amount	No
GHGs (as CO_2e)	4,307,862	75,000	Yes

Sources: Rule 62-210.200(282), F.A.C.
Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

BACT analyses must be conducted using the following five step top-down approach:

1. Available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology has reached the licensing and commercial sales phase of development). An available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies determined to be technically infeasible, based on physical, chemical, and engineering principals, are eliminated from further consideration.
3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. The hierarchy is evaluated starting with the top, or most stringent, alternative to determine economic, environmental, and energy impacts and assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control alternative is not applicable due to adverse energy, environmental, or eco-

nomic impacts, it is rejected as BACT, and the next most stringent control alternative is considered.

5. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emissions level corresponding to BACT for the evaluated pollutant.

This five-step procedure for conducting a BACT analysis is described in Chapter B of EPA's Draft New Source Review Manual dated October 1990.

The BACT emissions limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. EPA's Environmental Appeals Board (EAB) has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but rather will allow permittees to achieve compliance on a consistent basis" (Three Mountain Power, PSD Appeal No. 01-05 at 21 [May 30, 2001] citing: In re Masonite Corp., 5 E.A.D. 560-61 [EAB 1994] ["There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor."]; and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to -72, slip op. at 21 [EAB, March 14, 2000] ["The inclusion of a reasonable safety factor in the emissions limitation is a legitimate method of deriving a specific emissions limitation that may not be exceeded."]).

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(7), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those that exceed the PSD SER thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year is generally 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 by EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (1987).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-3). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Section 8.2 discusses applicability of the PSD preconstruction ambient monitoring requirements to the Project.

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the SERs (see Table 3-2). FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA Guideline on Air Quality Models (GAQM) as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(283), F.A.C., SIL, as presented in Table 3-4. EPA has proposed SILs for Class I areas; Table 3-5 provides these levels.

Table 3-3. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	*De Minimis* Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	$PM_{2.5}$	4
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Total reduced sulfur	10
	Hydrogen sulfide	0.2
	Reduced sulfur compounds	10
Not applicable	Ozone	100 tpy of VOC emissions

Source: Rule 62-212.400(3)(e)1., F.A.C.

Table 3-4. FDEP SILs

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	1
	24-Hour	5
	24-Hour (Class I areas)	1
	3-Hour	25
PM_{10}	Annual	1
	24-Hour	5
	24-Hour (Class I areas)	1
$PM_{2.5}$	Annual	0.3
	Annual (Class I areas)	0.06
	24-Hour	1.2
	24-Hour (Class I areas)	0.07
NO_2	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(283), F.A.C.

Table 3-5. EPA SILs—Class I Areas

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	0.1
	24-Hour	0.2
	3-Hour	1.0
PM_{10}	Annual	0.2
	24-Hour	0.3
$PM_{2.5}$	Annual	0.06
	24-Hour	0.07
NO_2	Annual	0.1

Sources: 40 CFR 52.21 ($PM_{2.5}$).
EPA Proposed, 1996; 61 FR 38249.
40 CFR 51.166.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest short-term concentrations for comparison to ambient air quality standards (AAQS) or PSD increments. The term *highest, second-highest* 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 PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, NWAs, memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for NO_2; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO_2 increment.

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which include revised NAAQS for PM_{10} and $PM_{2.5}$, became effective on October 17, 2006. On October 20, 2010, EPA promulgated PSD $PM_{2.5}$ increments, SILs, and significant monitoring concentrations. New sources and changes at existing sources occurring after the $PM_{2.5}$ increment effective date of December 20, 2010, will consume/expand $PM_{2.5}$ increments.

Florida has adopted the federal PSD allowable increments by reference in Rule 62-204.800(3), F.A.C. Table 3-6 provides the federal PSD Class I, II, and III increments.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources that commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration but will affect the applicable maximum allowable increase(s) (i.e., allowed increment consumption):

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.

Table 3-6. PSD Allowable Increments

Pollutant	Averaging Time	Class ($\mu g/m^3$) I	II	III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
$PM_{2.5}$	Annual arithmetic mean	1	4	8
	24-Hour maximum*	2	9	18
SO_2	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

Source: 40 CFR 52.21.

- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration change attributable to emissions sources that affect increment. Major source baseline date means January 6, 1975, for PM (TSP/PM_{10}) and SO_2; February 8, 1988, for NO_2; and October 20, 2010 for $PM_{2.5}$. Minor source baseline date means the earliest date after the trigger date on which the first complete application was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2; February 8, 1988, for NO_2; and October 20, 2011, for $PM_{2.5}$.

Sections 6.0 (Methodology), 7.0 (PSD Class II areas), and 10.0 (PSD Class I areas) provide the ambient impact analyses for the Project.

3.4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(8), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emissions increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emissions estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project. Section 9.0 provides the additional impact analyses for the Project.

3.5 HAP REQUIREMENTS

Florida relies on the requirements of the CAA with respect to the regulation of HAPs (also known as toxic air pollutants). These federal requirements include a comprehensive set of technology-based emissions standards referred to as NESHAPs. These standards establish HAP emissions limitations for a wide variety of industrial source categories. Recent NESHAPs (i.e., those adopted after the 1990 amendments to the CAA) reflect maximum achievable control technology (MACT). Section 4.2 provides a discussion of the NESHAPs program and its applicability to the Project.

4.0 STATE AND FEDERAL EMISSIONS STANDARDS

4.1 NEW SOURCE PERFORMANCE STANDARDS

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA establish federal emissions 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. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Major components of the Project include the four existing CTG units, addition of HRSGs to each existing CTG, a six-cell mechanical draft cooling tower, and an emergency generator diesel engine. NSPSs that are potentially applicable to these Project emissions sources are discussed in the following subsections.

4.1.1 NSPS SUBPART KKKK—STATIONARY COMBUSTION TURBINES

Subpart KKKK establishes emissions limits for CTG/HRSG units that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input at peak load equal to greater than 10.7 gigajoules (10 million British thermal units per hour [MMBtu/hr]) based on the higher heating value (HHV) of the fuel. HRSGs and duct burners regulated under Subpart KKKK are exempt from the requirements of NSPS Subparts Da, Db, and Dc.

The affected facility under Subpart KKKK is a *stationary combustion turbine*, which is defined by Subpart KKKK as follows:

> "all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion

turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability."

The existing PPS Units 2 through 5 simple cycle CTGs are currently subject to NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines. These units will be modified by the addition of a HRSG to each CTG. In addition, Units 4 and 5 will be modified by adding fuel oil-firing capability.

NSPS requirements regarding modifications are included in the NSPS, Subpart A, General Provisions. Per Section 60.14, *modification* is defined as follows:

> "any physical or operational change to an existing facility which results in an increase in the emissions rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emissions rate to the atmosphere."

Emissions rates for the purpose of determining whether a project results in an increase in emissions are based on hourly emissions rates. NSPS Subpart KKKK includes emissions standards for NO_x and SO_2. The addition of HRSGs to the current dual-fuel-fired simple cycle Units 2 and 3 CTG will not result in an increase in hourly NO_x or SO_2 emissions rates; therefore, these CTG units will remain subject to NSPS Subpart GG. As discussed in the following regarding NSPS Subpart Da, the HRSG duct burners for CC CTG/HRSG Units 2A (simple cycle Unit 2) and 2B (simple cycle Unit 3) will be subject to the applicable requirements of NSPS Subpart Da. The addition of fuel oil-firing capability to existing simple cycle CTGs Units 4 and 5 will result in an increase in hourly SO_2 emissions rates; therefore, CC CTG/HRSG Units 2C (simple cycle Unit 4) and 2D (simple cycle Unit 5) will be subject to the applicable requirements of NSPS Subpart KKKK.

In accordance with FDEP guidance and EPA's recent proposed revisions to NSPS Subparts GG and KKKK, Tampa Electric requests that all four CC units be regulated under NSPS Subpart KKKK. Having one applicable NSPS instead of three will simplify the monitoring, recordkeeping, and reporting requirements for the CC units.

NSPS Subpart KKKK specifies emissions limitations, monitoring, reporting, and record-keeping requirements for NO_x and SO_2. Applicable NSPS Subpart KKKK emissions standards are summarized as follows:

- $\underline{NO_x}$—15 ppmvd at 15-percent oxygen, or 0.43 pound per megawatt-hour (lb/MWh) gross energy output (CTG loads greater than or equal to 75 percent of peak load).
- $\underline{NO_x}$—42 ppmvd at 15-percent oxygen, or 4.7 lb/MWh gross energy output (fuel oil and CTG loads equal to or greater than 75 percent of peak load).
- $\underline{NO_x}$—96 ppmvd at 15-percent oxygen, or 4.7 lb/MWh gross energy output (CTG loads less than 75 percent of peak load).
- $\underline{SO_2}$—0.90 lb/MWh gross energy output, or 0.060 pound per million British thermal units (lb/MMBtu).

The CC units will have NO_x and SO_2 emissions well below the NSPS Subpart KKKK emissions standards and will comply with the applicable monitoring, reporting, and performance test requirements of NSPS Subpart KKKK.

4.1.2 NSPS SUBPART GG—STATIONARY GAS TURBINES

The existing PPS Units 2 through 5 simple cycle CTGs are currently subject to NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines. These units will be modified by the addition of an HRSG to each CTG. In addition, Units 4 and 5 will be modified by adding fuel oil-firing capability.

As discussed in Section 4.1.1 for Subpart KKKK, Tampa Electric requests that all four CC units be regulated under NSPS Subpart KKKK.

4.1.3 NSPS SUBPART DA—ELECTRIC STEAM GENERATING UNITS

NSPS Subpart Da is applicable to electric utility steam generating units capable of combusting more than 250 MMBtu/hr heat input of fossil fuel that commence construction after September 18, 1978. As specified in Section 60.40Da(e)(1), HRSGs used with duct burners associated with a stationary CTG that are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel are subject to Subpart Da except in cases when the HRSG meets the applicability requirements of and is subject to subpart NSPS Subpart KKKK. For HRSG use with duct burners subject to Subpart Da, only emissions resulting from the combustion of fuels in the duct burners are subject to the standards under Subpart Da. The emissions resulting from the combustion of fuels in the stationary CTG engine are subject to NSPS Subpart GG or KKKK, as applicable.

The Project HRSG duct burners will have a maximum heat input greater than 250 MMBtu/hr and, therefore, will be subject to the requirements of NSPS Subpart Da, unless the HRSG duct burners are subject to NSPS Subpart KKKK. As discussed in Section 4.1.1 for Subpart KKKK, Tampa Electric requests that all four CC units be regulated under NSPS Subpart KKKK. Accordingly, the HRSG duct burners for the CC units will be subject to the applicable requirement of NSPS Subpart KKKK.

4.1.4 NSPS SUBPART IIII—STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006, and are not fire pump engines or after July 1, 2006, for certified National Fire Protection Association fire pump engines.

NSPS Subpart IIII specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_x, CO, NMHC, and PM. Applicable NSPS Subpart IIII emissions standards for the Project emergency generator diesel engine are summarized as follows:

- Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emissions standards for new nonroad CI engines in 40 CFR 60.4202 for all pollutants for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

- Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emissions standards in Table 4 of NSPS Subpart IIII for all pollutants.

The Project emergency generator diesel engine will comply with the applicable requirements of NSPS Subpart IIII.

4.2 NATIONAL EMISSIONS STANDARDS FOR HAPs

Section 112 of the CAA contains the provisions that address the control of HAP emissions, or air toxics. Section 112 includes provisions for the promulgation of NESHAPs, or MACT standards, as well as several related programs to enhance and support the NESHAPs program. Section 112 requires EPA to publish and regularly update (at least every 8 years) a list of all categories and subcategories of major and area sources that emit HAPs. The Section 112(c) list of source categories was initially published in the Federal Register (FR) on July 16, 1992, and has been periodically revised thereafter. EPA must promulgate regulations establishing emissions standards (NESHAPs) for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). The standards must require the maximum degree of emissions reduction that EPA determines to be achievable by each particular source category. Different criteria for MACT apply for new and existing sources. Less stringent standards, known as generally available control technology (GACT) standards, are allowed at the EPA Administrator's discretion for area sources.

4.2.1 NESHAPs SUBPART ZZZZ—RECIPROCATING INTERNAL COMBUSTION ENGINES

The source category list presently includes stationary reciprocating internal combustion engines (RICE). As required in Section 112 of the CAA, EPA promulgated a final NESHAPs for stationary RICE (40 CFR 63, Subpart ZZZZ) on June 15, 2004. Subpart ZZZZ was subsequently amended on March 3, 2010 to address CI RICE located at area HAP sources. Since PPS is an area HAP source, the Project emergency generator diesel engine will be subject to the applicable requirements of Subpart ZZZZ.

Pursuant to Section 63.6590(b)(c)(1), new stationary RICE located at an area source subject to the requirements of NSPS Subpart IIII have no further requirements under Subpart ZZZZ. As note previously, the Project emergency generator diesel engine will be subject to the applicable requirements of NSPS Subpart IIII.

4.2.2 NESHAPs SUBPART YYYY—STATIONARY COMBUSTION TURBINES

EPA promulgated a final NESHAPs for stationary combustion turbines (40 CFR 63, Subpart YYYY) on March 5, 2004. On April 7, 2004, EPA proposed to delete lean premix gas-fired stationary CTGs, diffusion flame gas-fired CTGs, emergency CTGs, and stationary CTGs located on the North Slope of Alaska from the Section 112(c) list of HAP source categories. On August 18, 2004, EPA stayed the effectiveness of two Subpart YYYY subcategories: lean premix and diffusion flame gas-fired turbines. This stay is still currently in effect.

The requirements of NESHAPs Subpart YYYY only apply to stationary CTGs located at major HAP sources. PPS is a minor or area source of HAPs. Accordingly, NESHAPs Subpart YYYY is not applicable to the Project CTG units.

4.3 ACID RAIN PROGRAM

The overall goal of EPA's Acid Rain Program (ARP) is to achieve significant environmental and public health benefits through reductions in emissions of SO_2 and NO_x, the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

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 midwestern 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.

For SO_2, the ARP introduced an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this cap-and-trade program, affected existing utility units (i.e., those in operation prior to November 15, 1990) are allocated allowances based on their historical fuel consumption and a specific emissions rate. Each allowance permits a unit to emit 1 ton of SO_2 during or after a specified year. For each ton of SO_2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold, or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the CAA to protect public health. During Phase II of the program (now in effect), the CAA set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO_2 allowance allocations to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. New utility units (i.e., those that commence operation on and after November 15, 1990) are not allocated any SO_2 allowances and must obtain such allowances annually from the ARP SO_2 allowance market in amounts equal to their actual SO_2 emissions rates.

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low NO_x burner technologies and meet new emissions standards. The ARP NO_x emissions reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

The Project CTG/HRSG units are subject to the ARP, since they are new utility units (i.e., commenced operation after November 15, 1990) and will serve a generator that produces electricity for sale. As noted previously, new utility units do not receive any SO_2

allowance allocations. Accordingly, Tampa Electric will need to annually obtain SO_2 allowances from the ARP SO_2 allowance market in amounts equal to the Project's CTG/HRSG unit's actual SO_2 emissions rates. The NO_x component of the ARP does not apply to new utility units.

4.4 CROSS-STATE AIR POLLUTION RULE

On August 8, 2011, EPA issued the final Cross-State Air Pollution Rule with an effective date of October 7, 2011. This rule is also referred to as the Transport Rule and replaced the 2005 Clean Air Interstate Rule (CAIR). The Cross-State Air Pollution Rule was stayed by the U.S. Court of Appeals, District of Columbia Circuit, on December 30, 2011. On August 21, 2012, the same court vacated the Transport Rule and required EPA to continue to administer CAIR until a replacement Transport Rule is promulgated.

4.5 CLEAN AIR INTERSTATE RULE

On March 10, 2005, EPA issued the final CAIR. The objective of CAIR is to assist states with $PM_{2.5}$ 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 $PM_{2.5}$ and 8-hour ozone nonattainment in downwind areas. Florida emissions sources are projected to significantly contribute to $PM_{2.5}$ nonattainment areas located in Georgia (Macon and Atlanta) and Alabama (Birmingham) and to an 8-hour ozone nonattainment area in Georgia (Atlanta).

The CAIR reductions of precursor emissions address annual SO_2 and NO_x emissions (for reductions in annual and daily average ambient $PM_{2.5}$ impacts) and ozone season (May through September) NO_x emissions (for reductions in 8-hour average ambient ozone impacts). The SO_2 and NO_x reductions will be implemented by means of a regional two-phase cap-and-trade program. For SO_2, the first cap begins in calendar year 2010 and extends through 2014. For NO_x, the first cap begins in calendar year 2009 and also extends through 2014. The second phase cap for both pollutants becomes effective in calendar year 2015 and thereafter. The SO_2 caps will reduce current ARP SO_2 emissions by

50 percent in Phase I and 65 percent in Phase II. The NO_x caps reflect NO_x emissions rates of 0.15 and 0.125 lb/MMBtu for the first and second phase caps, respectively.

For each phase cap, CAIR assigns SO_2 and NO_x emissions budgets (in units of tons per year and tons per ozone season) to each affected upwind state. These state emissions budgets were developed by EPA based on the application of cost-effective control technologies (i.e., flue gas desulfurization [FGD]) for SO_2 and SCR for NO_x. The affected states were required to submit revised state implementation plans (SIPs) within 18 months (i.e., by September 11, 2006) for EPA review and approval.

Following SIP approval and allocation of the state SO_2 and NO_x budgets to individual emissions sources, emissions units at these sources must possess sufficient SO_2 and NO_x allowances such that actual emissions (as measured by continuing emissions monitoring system) do not exceed the allocations for each control period beginning in 2009 for NO_x and 2010 for SO_2. Sources that have actual emissions in excess of their allocation will need to reduce actual emissions rates or purchase additional allowances on the open market. Emissions sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances on the open market.

Florida's proposed SIP revisions implementing CAIR were submitted to EPA Region 4 on March 16, 2007, for review and approval in accordance with EPA's abbreviated SIP approval process. Florida's SIP provided details as to the procedures that will be used to allocate the state NO_x and SO_2 budgets to individual sources. EPA approved Florida's SIP revision regarding CAIR on October 12, 2007.

Florida has adopted EPA's 40 CFR 96 CAIR NO_x and SO_2 trading programs for SIPs by reference in Section 62-204.800, F.A.C. Florida's implementation of the federal CAIR is set forth at Section 62-296.470, F.A.C. The Florida CAIR program includes emissions trading program requirements for annual SO_2 and NO_x and ozone season (May 1 through September 30) NO_x.

4.6 FLORIDA EMISSIONS STANDARDS

FDEP emissions standards for stationary sources are contained in Chapter 62-296, F.A.C., Stationary Sources, Emissions Standards. General pollutant emissions limit standards are included in Section 62-296.320, F.A.C. Sections 62-296.401 through 62-296.418, F.A.C., specify emissions standards for 18 categories of sources. Section 62-296.470 addresses CAIR requirements. Sections 62-296.500 through 570, F.A.C., establish RACT requirements for VOC- and NO_x-emitting facilities. RACT requirements for lead and PM are found in Sections 62-296.600 through 605 and 62-296.700 through 712, F.A.C., respectively. Section 62-204.800, F.A.C., adopts federal regulations, including NSPS, by reference.

With respect to the Project emissions sources, the general Rule 62-296.320(4)(b), F.A.C., visible emissions limitation of 20-percent opacity will apply to all point (i.e., stack) emissions sources. Reasonable precautions to prevent unconfined PM emissions (e.g., feedstock storage piles) will be required pursuant to Rule 62-296.320(4)(c), F.A.C.

Section 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 MMBtu/hr Heat Input, will apply to the CC HRSG duct burners. This section requires compliance with applicable NSPS requirements (e.g., NSPS Subpart Da or Subpart KKKK).

None of the remaining emissions standards specified in Sections 62-296.401 through 418, F.A.C., are applicable to the Project. The VOC, NO_x, lead, and PM RACT requirements do not apply to emissions units that are subject to NSR permitting and, therefore, are not applicable to the Project emissions sources.

NSPS Subparts IIII (for the emergency generator diesel engine) and KKKK (for the four CC units) will be applicable to the Project.

The Project emissions sources will comply with the applicable Florida emissions standards noted herein.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

Pursuant to 40 CFR 52.21(j)(2), an analysis of BACT is required for each pollutant that will be emitted by the proposed project in amounts equal to or greater than the PSD SER levels. The proposed Project will potentially emit NO_x, CO, VOC, SO_2, H_2SO_4, and $PM/PM_{10}/PM_{2.5}$ in amounts that exceed the PSD SER levels. These pollutants, therefore, are each subject to an assessment of BACT. Also, the proposed Project will potentially emit GHG emissions (calculated as CO_2e) in amounts greater than 75,000 tpy; therefore, GHG emissions will be subject to an assessment of BACT. The GHG BACT analysis will be submitted to EPA separately, since FDEP does not currently have PSD authority for GHGs.

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 3.4.1. The first step in the top-down BACT procedure is the identification of available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives include:

- EPA's RBLC database.
- Vendor information.
- Consultant's extensive previous experience with similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the draft EPA NSR Workshop Manual (EPA, 1990). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employs the procedures found in EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1996). The fifth and final step is the selection of a BACT emissions limitation or a design, equipment, work practice, operational standard or combination thereof corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

If the most stringent or *top* control technology is selected, an assessment of energy and economic impacts is not required. In this case, a review of collateral environmental impacts is conducted to determine if selection of a less stringent alternative control technology is warranted. If there are no issues regarding collateral environmental impacts, the top control technology is proposed as BACT, and the BACT analysis is concluded.

5.2 EVALUATION OF ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

Tampa Electric evaluated a wide range of supply-side alternative technologies to meet its generating capacity needs in the 2016 time frame. Alternative technologies considered included renewable technologies such as biomass, waste-to-energy, wind, and solar; advanced or emerging technologies such as fuel cells; nuclear technology; and solid fuel technologies. Alternative solid fuel technologies included subcritical, supercritical, and ultra supercritical pulverized coal; atmospheric circulating fluidized bed; and integrated gasification combined-cycle (IGCC). Tampa Electric first screened the technologies on the basis of technical viability and feasibility to narrow the list of alternatives, and then conducted detailed economic analyses of the most viable alternatives. The evaluations also considered noneconomic factors such as reliability, fuel flexibility, and ability to meet current and potential future environmental requirements. Based on these evaluations, Tampa Electric determined that the state-of-the-art CC technology (i.e., proposed Project) was the best option to meet its future generating need. Key advantages of the CC technology include the following:

- Cost-effective, baseload generation.
- Recognition as state-of-the-art, natural gas electric generation.
- Lower air emissions than solid fuel technologies.

- Flexibility to use ultra low-sulfur No. 2 diesel fuel oil as a backup fuel to maintain reliability.

5.3 BACT ANALYSIS FOR NO_x

NO_x emissions from combustion sources, including CTG/HRSGs and the emergency generator diesel engine, consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO_x and prompt NO_x) and conversion of FBN (fuel NO_x). Essentially all NO_x emissions originate as nitric oxide (NO). Nitric oxide generated by the CTG combustion processes is subsequently further oxidized in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x results from the oxidation of atmospheric nitrogen under high-temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism.

Prompt NO_x is formed near the combustion flame front from the oxidation of intermediate combustion products. Prompt NO_x comprises a small portion of total NO_x in conventional near-stoichiometric combustors but increases under fuel-lean conditions. Prompt NO_x, therefore, is an important consideration with respect to low-NO_x combustors that use lean fuel mixtures. Prompt NO_x levels may also become significant with ultra low-NO_x burners. Fuel NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of FBN to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion process or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the regulations typically contain an allowance for FBN directly or inherently (i.e., part of the emissions limit). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the molecular nitrogen found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.3.1 CTG/HRSG

5.3.1.1 Available NO_x Control Technologies

Available technologies for controlling NO_x emissions from CTGs and duct burners include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

- Combustion process modifications:
  - Water/steam injection and standard combustor design (CTGs).
  - Water/steam injection and advanced combustor design (CTGs).
  - Dry low-NO_x combustor design (CTGs and duct burners).
  - Catalytic combustion controls (XONON™) (CTGs).
- Postcombustion exhaust gas treatment systems:
  - Selective noncatalytic reduction (SNCR).
  - Nonselective catalytic reduction (NSCR).
  - SCR.
  - EMx™ (SCONO$_x$™).

The following subsections provide a description of each of the listed control technologies.

Combustion Process Modifications

Water or Steam Injection and Standard Combustor Design

Injection of water or steam into the primary combustion zone of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO_x.

The maximum amount of steam or water that can be injected depends on the CTG combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NO_x reduction) will occur up to the point where cold spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine.

The use of water or steam injection and standard turbine combustor design can generally achieve NO_x exhaust concentrations of 42 and 65 ppmvd for gas and oil firing, respectively.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO_x and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil firing, respectively.

Dry Low-NO_x Combustor Design

A number of CTG vendors have developed dry low-NO_x combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. This allows a lower flame temperature in the combustion zone, causing a decrease in thermal NO_x emissions.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. During oil firing, wet injection is typically employed to control NO_x emissions.

In addition to lean premixed combustion, dry low-NO_x combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All CTGs cool the high-temperature CTG combustor discharge gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the CTG turbine. By adding additional dilution air, the hot CTG combustor gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the CTG combustion gases are at a higher temperature for shorter periods of time.

Current dry low-NO_x combustor technology can typically achieve NO_x exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the CTG vendor.

Catalytic Combustion Controls (XONON™)

Another technology that is potentially capable of reducing gas turbine NO_x emissions to less than 3.5 ppmvd is catalytic combustion. Catalytica, Inc., was the first to commercially develop catalytic combustion controls for certain (mostly smaller) turbine engines and markets this system under the name XONON™. In October 2006, this technology was sold to Kawasaki Heavy Industries, Ltd. It is not commercially available for larger CTGs. Therefore, catalytic combustion does not represent an available control option for the proposed General Electric (GE) 7FA CTGs.

<u>Postcombustion Exhaust Gas Treatment Systems</u>

Selective Noncatalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research

Institute's NO_xOUT^{TM} and Exxon's Thermal $DeNO_x^{TM}$ processes. The two processes are similar in that either ammonia (Thermal $DeNO_x^{TM}$) or urea (NO_xOUT^{TM}) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal $DeNO_x^{TM}$ process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \tag{1}$$

$$4\ NH_3 + 5\ O_2 \rightarrow 4NO + 6H_2O \tag{2}$$

The NO_xOUT^{TM} process is similar with the exception that urea is used in place of ammonia. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600 degrees Fahrenheit (°F), rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1), resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Nonselective Catalytic Reduction

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen [O_2]) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed, where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \tag{3}$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \tag{4}$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 1,100°F (typically 600 to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (aluminosilicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NO_x molar ratios greater than one-to-one are necessary to achieve high NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at one-to-one or lower to prevent excessive unreacted ammonia (ammonia slip) emissions. As was the case for SNCR, reaction temperature is critical for proper SCR operation. Below this critical temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NO_x emissions. NO_x removal efficiencies for SCR systems typically range from 80 to 90 percent.

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to carbon dioxide (CO_2) and nitric oxide to NO_2. NO_2 formed by the oxidation of nitric oxide is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (5)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (6)$$

$$2\ NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (7)$$

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the CTG/HRSG exhaust stream. Water vapor and elemental nitrogen are released to the atmosphere as part of the CTG/HRSG exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of an HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the EMx™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low-temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv), resulting in an approximate 85-percent NO_x removal efficiency. This facility is no longer operating due to market factors. A high-temperature application of EMx™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW solar CTG located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTGs, there are currently no CC units larger than 43 MW that have demonstrated successful application of the EMx™ control technology.

5.3.1.2 Technical Feasibility and Ranking

Water/steam injection and standard combustor design, water/steam injection and advanced combustor, and dry low-NO_x combustor design would be feasible for the project CTGs. The GE 7FA CTGs are equipped with dry low-NO_x burner technology.

Of the postcombustion stack gas treatment technologies, SNCR is not feasible, because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that which will be found in the CTG gas streams (less than 1,000°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent oxygen) environment. The oxygen content of the proposed CTG exhaust gases is in excess of 12 percent.

EMx™ is desirable in that it, unlike SCR, does not require ammonia. However, as discussed previously, there are many complex technical issues associated with this technology. In addition, this technology has not been proven on a GE 7FA CC CTG. Furthermore, the installation of EMx™ technology would also cause an increase in back pressure, amounting to twice that of the SCR system, and consume additional water to provide steam for the regeneration process, adding to both capital and operating costs.

SCR catalyst can be subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Another consideration with the application of SCR technology is the possibility of "fouling" (i.e., formation of sticky ammonium sulfates plugging the catalyst bed surfaces over time). This is caused by the use of high sulfur fuels and is especially problematic for CC operations using HRSGs. The proposed GE 7FA CTGs will use pipeline-quality natural gas and ULSD. Furthermore, ammonia slip will be limited to 5.0 ppmvd under all conditions. Therefore, potential for poisoning or fouling the catalyst from the proposed CTG operations is expected to be minimal.

5.3.1.3 Evaluation of Control Technologies

To determine the most stringent NO_x emissions limit for the CTG/HRSGs, EPA's RBLC database was queried for large CTGs firing natural gas and fuel oil. BACT and LAER determinations were obtained for the past 10 years and are summarized in Appendix D. As shown, the lowest NO_x emissions limit is 2.0 ppmvd at 15-percent oxygen for several natural gas-fired facilities, in different states and EPA regions. The typical control system used to achieve this emissions limit for natural gas firing is dry low-NO_x combustors and an SCR system.

The lowest RBLC NO_x limits for oil-fired CC CTGs is 5 ppmvd at 15-percent oxygen for the Sam Rayburn Generating Station in Texas. It should be noted that the CTGs at this facility are rated at 45 MW, which are much smaller than the Project's GE 7FA units and not a good comparison. Five other facilities had BACT NO_x limits of 6.0 ppmvd at 15-percent oxygen, and one facility had 6.8 ppmvd at 15-percent oxygen. All other BACT limits for liquid fuel were above 8.0 ppmvd at 15-percent oxygen. The typical method to meet the limit for oil firing is water injection and SCR.

5.3.1.4 Proposed NO_x BACT

The proposed BACT NO_x emissions rate for the CTG/HRSGs for the Project for natural gas firing is 2.0 ppmvd at 15-percent oxygen based on a 24-hour block average. The proposed control system to achieve this emissions limit is dry low-NO_x combustors and SCR.

The proposed BACT NO_x emissions rate for the CTG/HRSGs for the Project for ULSD firing is 8.0 ppmvd at 15-percent oxygen based on a 24-hour block average. The proposed control system to achieve this emissions limit is water injection and SCR. Table 5-1 provides a summary of the proposed NO_x BACT emissions limits for the CTG/HRSG units.

5.3.2 EMERGENCY DIESEL ENGINE

5.3.2.1 Engine Combustion Modifications

Combustion modifications that are potentially applicable to the emergency engine include injection timing retard, air-to-fuel ratio adjustments, and several others. The application of these technologies is specific to each engine vendor and model.

5.3.2.2 Proposed NO_x BACT

The emergency generator will meet the emissions limits of 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines, effective September 11, 2006. The combined emissions limits for NO_x and NMHC specified in this NSPS are 4.8 g/bhp-hr for the emergency generator. Compliance with the Subpart IIII NO_x and NMHC emissions limit and limiting the hours of operation for routine maintenance testing to 100 hr/yr is proposed as NO_x BACT for the emergency generator diesel engine.

BACT and LAER determinations were obtained for the past 10 years for large (greater than 500 horsepower [hp]) ICE firing distillate fuel oil only and are summarized in Appendix D. There are a number of BACT determinations at 4.8 grams for NO_x and NMHC, as well as several that indicate compliance with NSPS Subpart IIII, as BACT. Several of the facilities with lower BACT determinations assume SCR for NO_x control, or have lower limits under NSPS Subpart IIII.

5.4 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

Emissions of SO_2 and H_2SO_4 from the proposed Project will occur due to the combustion of natural gas and ULSD in the CTG/HRSG and emergency generator diesel engine. SO_2 and H_2SO_4 mist emissions resulting from the combustion of natural gas and ULSD will be low due to the relatively low sulfur content of the fuels.

Table 5-1. Proposed NO_x BACT Emissions Limits

CTG/HRSG (All Operating Scenarios)	Proposed NO_x BACT Emissions Limits	
Natural gas	2 ppmvd*	17.1 lb/hr†
ULSD fuel oil	8 ppmvd*	70.5 lb/hr†

Note: lb/hr = pound per hour.
ppmvd = part per million by volume dry.

*Corrected to 15-percent oxygen, 24-hour block average.
†Maximum hourly emissions rate for CTG/HRSG based on 20°F.

Sources: Tampa Electric, 2012.
ECT, 2012.

5.4.1 CTG/HRSG

5.4.1.1 Available SO_2 and H_2SO_4 Mist Control Technologies

There are no postcombustion control systems, such as scrubbers or duct sorbent injection, for SO_2 and H_2SO_4 mist emissions that have been applied to CTGs. The use of low-sulfur fuels is the only feasible method to control SO_2 and H_2SO_4 mist emissions from the CTG/HRSGs.

5.4.1.2 Technical Feasibility and Rankings

As discussed previously, there are no postcombustion control systems that are technically feasible to control SO_2 and H_2SO_4 mist emissions from CTGs, and the only practical means to control these emissions is the use of low-sulfur fuels.

5.4.1.3 Evaluation of Control Technologies

Use of low-sulfur natural gas and ULSD fuel are the best options for reducing SO_2 and H_2SO_4 emissions from the CTG/HRSGs. RBLC determinations for the past 10 years are summarized in Appendix D. Although some SO_2 and H_2SO_4 mist BACT limits listed in the RBLC are lower than the Project's for natural gas, they can be attributed to lower natural gas sulfur content. The Project's rates for SO_2 and H_2SO_4 mist while firing ULSD are lower than the top RBLC BACT limits.

5.4.1.4 Proposed SO_2 and H_2SO_4 Mist BACT

The exclusive use of pipeline-quality natural gas as the primary fuel in the CTG/HRSG and limited hours and exclusive use of ULSD as the backup fuel in the CTG/HRSG is proposed as BACT for SO_2 and H_2SO_4. Table 5-2 provides a summary the proposed SO_2 and H_2SO_4 BACT fuel sulfur content limits.

5.4.2 EMERGENCY ENGINE

The emergency generator diesel engine will emit SO_2 and H_2SO_4 mist due to thermal oxidation of sulfur contained in the fuel oil. The only technically and economically feasible technology to control SO_2/H_2SO_4 mist from the emergency diesel engine is the use of low-sulfur fuel oil. The emergency generator diesel engine will be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. Excluding emergencies, the

Table 5-2. Proposed SO_2 and H_2SO_4 Mist BACT Emissions Limits

CTG/HRSGs	Proposed SO_2 and H_2SO_4 Mist BACT Emissions Limits Fuel Sulfur Content
SO_2	
Natural gas	2.0 gr S/100 dscf
ULSD fuel oil	0.0015 wt % S
H_2SO_4 mist	
Natural gas	2.0 gr S/100 dscf
ULSD fuel oil	0.0015 wt % S

Note: gr S/100 dscf = gram of sulfur per 100 dry standard cubic feet.
wt % S = weight percent sulfur.

Sources: Tampa Electric, 2012.
ECT, 2012.

diesel engine will operate no more than 100 hr/yr for routine testing and maintenance purposes. Potential emissions are based on 500 hr/yr. Potential SO_2 emissions rates are 0.0046 g/hp-hr, 0.0078 pound per hour (lb/hr), and 0.0019 tpy. H_2SO_4 mist emissions will be much less.

The exclusive use of ULSD fuel oil and constraints on annual operations for maintenance and testing purposes are proposed as SO_2 and H_2SO_4 mist BACT for the emergency diesel engine. The proposed BACT for the emergency diesel engine may be summarized as follows:

- Emissions Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Operating Hours—100 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.5 BACT ANALYSIS FOR CO

CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emission rates of CO will generally increase during CTG partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control should also result in an increase in CO emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO emission rates. In general, emissions of NO_x and CO are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO emissions).

CTG combustors are designed to minimize CO formation, since CO emissions are indicative of inefficient combustion and unused energy. Due to its high combustion temperatures, a CTG essentially functions as a thermal oxidizer achieving inherently low CO emissions.

5.5.1 CTG/HRSG

5.5.1.1 Available CO Control Technologies

The two technologies available for controlling CO are combustion process design and oxidation catalyst.

5.5.1.2 Technical Feasibility and Ranking

Both CTG combustor/burner design and oxidation catalyst control systems are considered technically feasible for the proposed CTGs.

5.5.1.3 Evaluation of Control Technologies

Energy and Environmental Impacts

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO emissions. However, the use of oxidation catalysts will, as previously noted, result in increased H_2SO_4 mist and salt emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will occur, on a smaller scale, from the proposed CTGs fired exclusively with natural gas and ULSD as a backup fuel.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CTG due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate. An oxidation catalyst system for the CTGs is projected to decrease CTG output due to the pressure drop across the catalyst bed, which would be 1.1 inches of water (H_2O) for this project, which would result in a 0.15-percent energy penalty per inch of water back pressure. The reduction in turbine output power (lost power generation) will result in an energy penalty of approximately 2,476,000 kilowatt-hours (kWh) at the projected typical operation and 100-percent capacity factor per CTG. The lost power generation energy penalty, based on a power cost of $0.0216 per kWh, is approximately $214,000 per year for all four CTGs.

Regarding environmental impacts, oxidation catalyst does not remove CO but simply accelerates the natural atmospheric oxidation of CO to CO_2. Project dispersion modeling shows that CO air quality impact will be insignificant without the use of oxidation catalyst.

Economic Impacts

An economic evaluation of an oxidation catalyst system was performed using guidance and methodology contained in the OAQPS EPA Air Pollution Control Cost Manual (EPA, 2002). Also, site-specific cost information supplied by Tampa Electric was used in the analysis (see Table 5-3). The resulting capital and annual operating costs for the oxidation catalyst are summarized in Tables 5-4 and 5-5.

The control costs were determined considering the base load cases at 59°F ambient temperature for natural gas firing (Case CC-8) and ULSD firing (Case CC-25). Also, Case CC-9, which is with evaporative cooling and duct burner firing at 59°F ambient temperature, was included. The annual uncontrolled CO emissions considering these cases are 137.5 tpy per CC unit. Controlling from a CO concentration of 8.0 ppmvd at 15-percent oxygen to 2.0 ppmvd at 15-percent oxygen resulted in an emissions reduction of 103.2 tpy. The cost effectiveness of oxidation catalyst for CO emissions was determined to be $4,653 per ton of CO removed. Based on the high control costs, use of oxidation catalyst to control CO emissions is not considered economically feasible for this Project. Table 5-6 summarizes the results of the oxidation catalyst economic analysis.

5.5.1.4 Proposed CO BACT

To determine the most stringent CO emissions limit for the CTG/HRSGs, EPA's RBLC database was queried for large CTGs greater than 25 MW. BACT and LAER determinations were obtained for the past 10 years and are summarized in Appendix D. The lowest numerical CO BACT emissions limits shown are 0.9 ppmvd at 15-percent oxygen for natural gas firing and 1.8 ppmvd at 15-percent oxygen for oil firing. These and similarly low limits are with oxidation catalyst control technology. Since installation of oxidation catalyst is not being proposed, facilities that are meeting the proposed limit of 8.0 ppmvd

Table 5-3. Cost Parameters for Evaluation of Oxidation Catalyst System (each CTG/HRSG Unit)

Item	Value
Equipment cost (including initial catalyst and instrumentation)	$825,000
Exhaust duct modification cost	$75,000
Interest rate	7.95 percent
Economic life of control system	25 years
Catalyst replacement cost	$675,000
Catalyst replacement frequency	3 years
Electricity cost	$0.0216/kW-hr
Labor cost	$50/manhour
Energy penalty (percent decrease in CTG output per inch of water backpressure)	0.15 percent
Control system backpressure	1.1 inch water

Source: Tampa Electric, 2012

Table 5-4. Oxidation Catalyst Capitol Cost (each CTG/HRSG Unit)

Item	Cost ($)	Calculation Using EPA Cost Factors
Total equipment cost	825,000	
Exhaust duct modification cost	75,000	
Purchased equipment cost (PEC)	**900,000**	
Foundations and supports	72,000	= PEC × 0.08
Handling and erection	126,000	= PEC × 0.14
Electrical	36,000	= PEC × 0.04
Piping	18,000	= PEC × 0.02
Insulation	9,000	= PEC × 0.01
Painting	9,000	= PEC × 0.01
Total installation costs (TIC)	**270,000**	
Total direct capital costs (DCC) (= PEC + TIC)	**1,070,000**	
Engineering	90,000	= PEC × 0.10
Construction and field expense	45,000	= PEC × 0.05
Contractor fees	90,000	= PEC × 0.10
Start-up expense	18,000	= PEC × 0.02
Performance test	9,000	= PEC × 0.01
Contingencies	27,000	= PEC × 0.03
Total indirect installation cost (IIC)	**279,000**	
Total capital investment (TCI) (= PEC+ TIC + IIC)	**1,449,000**	

Source: ECT, 2012

Table 5-5. Oxidation Catalyst Annual Operating Cost (each CTG/HRSG Unit)

Item	Cost ($/year)	Calculation Using EPA Cost Factors
Maintenance labor and materials (ML&M)	**21,735**	
Catalyst replacement cost	675,000	
Freight	0	
Capital recovery factor	0.3877	
Annualized catalyst replacement cost (ACC)	**261,686**	
Energy penalty (EP) (derate in gas turbine output due to CatOx backpressure)	**53,500**	
Total direct cost (TDC = ML&M + ACC +EP)	**336,921**	
Overhead	13,041	= ML&M × 0.60
Administrative charges	28,980	= Total capital investment (TCI) × 0.02
Property taxes	14,490	= TCI × 0.01
Insurance	14,490	= TCI × 0.01
Capitol recovery factor	0.0933	
Capitol recovery	72,198	
Total indirect costs (TIC)	**143,199**	
Total annualized cost (= TDC + TIC)	**480,120**	

Note: Energy penalty based on annual gas turbine output of 1,500,450 megawatt-hours per year for operation on natural gas and fuel oil.

Source: ECT, 2012.

Table 5-6. Cost Effectiveness of Oxidation Catalyst

Item	Value
Baseline CO emissions	138.1 tpy
Controlled CO emissions	34.5 tpy
CO emissions reduction	103.6 tpy
Total annualized cost	$480,120
Cost effectiveness	$4,633 per ton

Source: ECT, 2012.

at 15-percent oxygen and below without the use of an oxidation catalyst are of most interest. The list shows eight natural gas-fired facilities with CO BACT limits of 6.0 ppmvd at 15-percent oxygen without oxidation catalyst and one oil-fired unit facility meeting 4.0 ppmvd at 15-percent oxygen with good combustion practice only.

The proposed CO BACT emissions limit for the CTG/HRSGs for firing natural gas and ULSD for the Project is 8.0 ppmvd with or without duct burner firing at 15-percent oxygen on a 24-hour block average basis. This proposed CO BACT emissions limit is somewhat higher than the lowest emissions limits for a GE 7FA CTG, but comparable to the BACT limits for facilities without oxidation catalyst control. Compliance will be achieved through the use of good combustion practices. Table 5-7 summarizes the proposed CO BACT emissions limits for the CTG/HRSGs.

5.5.2 EMERGENCY DIESEL ENGINE

The emergency generator will meet the CO emissions limits of 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines, effective September 11, 2006. The CO emissions limit is 2.6 g/hp-hr for the emergency generator. Compliance with the Subpart IIII CO emissions limit and limiting the hours of operation for routine maintenance testing to 100 hr/yr is proposed as CO BACT for the emergency generator diesel engine.

BACT and LAER determinations were obtained for the past 10 years for large (greater than 500 hp) ICE firing distillate fuel oil only and are summarized in Appendix D. Although some of the facilities listed in the RBLC database have lower BACT emissions rates ranging from 0.3 to 2.5 g/hp-hr, compliance with NSPS Subpart IIII is widely accepted as BACT.

5.6 BACT ANALYSIS FOR VOC

VOC emissions result from the incomplete combustion of carbon and organic compounds. The general factors affecting the formation of VOC are the same as those previously discussed in Section 5.5.

Table 5-7. Proposed CO BACT Emissions Limits

CTG/HRSGs (All Operating Scenarios)	Proposed CO BACT Emissions Limits	
Natural gas	8 ppmvd*	41.5 lb/hr†
ULSD fuel oil	8 ppmvd*	42.8 lb/hr*†

Note: lb/hr = pound per hour.
ppmvd = part per million by volume dry.

*Corrected to 15-percent oxygen, 24-hour block average.
†Maximum hourly emissions rate for CTG/HRSG based on base load at 20°F.

Sources: Tampa Electric, 2012.
ECT, 2012

5.6.1 CTG/HRSG

5.6.1.1 Available VOC Control Technologies

There are two available technologies for controlling VOC from gas turbines: (1) combustion process design, and (2) oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTGs, approximately 99 percent, VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of VOC to CO_2 and water at temperatures lower than would be necessary for oxidation without a catalyst. The design operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant VOC oxidation will occur at any temperature above approximately 900°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst, which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed.

VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is in the range of 30 to 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica (typically present in fuel oil) will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also nonselective and will oxidize other compounds in addition to VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). Higher SO_3 concentrations increase the potential for formation of ammonia salt particles and H_2SO_4 mist. These substances may condense and stick to the ductwork and stack, resulting in corrosion and increased maintenance. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered appropriate for combustion devices fired with fuels containing appreciable amounts of sulfur. The CTGs will be primarily fired with low-sulfur natural gas, and ULSD will be used as the backup fuel.

5.6.1.2 Technical Feasibility and Ranking

Both combustion process design and oxidation catalysts are considered technically feasible for the proposed CTG/HRSGs, despite the potential drawbacks cited.

5.6.1.3 Evaluation of Control Technologies

To determine the most stringent VOC emissions limit for the CTG/HRSGs, EPA's RBLC database was queried for large CTGs firing natural gas only. BACT and LAER determinations were obtained for the past 10 years and are summarized in Appendix D. As shown, the lowest numerical VOC emissions limit is 0.3 ppm for Chouteau Power Plant. This specific facility has proposed Seimens V84.3A CTGs, which are not comparable to the GE 7FA CTG proposed for PPS. The Warren County facility has proposed a VOC emissions limit of 0.7 ppmvd without duct burner firing and 1.6 ppmvd with duct burner firing. However, the Warren County facility has proposed to use Mitsubishi M501 CTGs, which are not comparable to the GE 7FA CTG of the Project.

The RBLC results for CTG/HRSGs firing oil show five facilities with lower emissions; however, two of those are equipped with oxidation catalyst. The others only have rates that are marginally less than the rates of the Project.

5.6.1.4 Proposed VOC BACT

The proposed BACT VOC emissions limits for the CTG/HRSGs for the PPS Project are 1.4 ppmvd without duct burner firing and 3.5 ppmvd with duct burner firing both limits at 15-percent oxygen when fired on natural gas. The proposed limit for oil firing is 3.0 ppmvd at 15-percent oxygen. These proposed BACT VOC emissions limits are consistent with the lowest emissions limits for GE 7FA CTGs. Compliance will be achieved through good combustion practices. Table 5-8 summarizes the proposed VOC BACT emissions limits for the CTG/HRSGs.

5.6.2 EMERGENCY DIESEL ENGINE

The emergency generator will meet the emissions limits of 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines, effective September 11, 2006. NMHC emissions are included in the combined NO_x and NMHC emissions limits specified in Subsection 4.1.2.4. Therefore, compliance with the Subpart IIII NO_x and NMHC emissions limit and limiting the hours of operation for routine maintenance testing to 100 hr/yr is proposed as VOC BACT for the emergency generator diesel engine.

BACT and LAER determinations were obtained for the past 10 years for both large (greater than 500 hp) ICE firing distillate fuel oil only and are summarized in Appendix D.

5.7 BACT ANALYSIS FOR $PM/PM_{10}/PM_{2.5}$

$PM/PM_{10}/PM_{2.5}$ emissions from fuel burning equipment result when hydrocarbons are not completely combusted or when sulfur and nitrogen in the fuel are oxidized and postcombustion aerosols are formed. Formation of sulfate aerosols is common when burning high sulfur fuel oils and using ammonia injection to control NO_x with SCR technology. $PM/PM_{10}/PM_{2.5}$ emissions from natural gas combustion are typically much less

Table 5-8. Proposed VOC BACT Emissions Limits

CTG/HRSG Units	Proposed VOC BACT Emissions Limits	
Natural gas firing		
Without duct burners	1.4 ppmvd*	3.3 lb/hr†
With duct burners	3.5 ppmvd*	9.7 lb/hr†
ULSD fuel oil	3.0 ppmvd*	8.7 lb/hr†

Note: lb/hr = pound per hour.
ppmvd = part per million by volume dry.

*Corrected to 15-percent oxygen.
†Maximum hourly emissions rate for CTG/HRSG based on 20°F.

Sources: Tampa Electric, 2012.
ECT, 2012.

than emissions from fuel oil combustion, since natural gas contains less sulfur and nitrogen.

Mechanical draft cooling towers will also emit a small amount of $PM/PM_{10}/PM_{2.5}$ emissions. A small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets because of direct contact between the cooling water and ambient air. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large size water droplets (e.g., greater than 200 microns) constitute the majority of the drift released. These large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential $PM/PM_{10}/PM_{2.5}$ emissions because of the fine particles formed by crystallization of the dissolved solids contained in the droplets.

$PM/PM_{10}/PM_{2.5}$ emissions will result from the oxidation of sulfur in the fuel combusted in the emergency generator diesel engine. The exclusive use of ULSD in the emergency generator diesel engine will minimize $PM/PM_{10}/PM_{2.5}$ emissions.

5.7.1 CTG/HRSG

5.7.1.1 Available $PM/PM_{10}/PM_{2.5}$ Control Technologies

Available technologies used for controlling $PM/PM_{10}/PM_{2.5}$ include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large (greater than 10 microns) size particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field.

These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for $PM/PM_{10}/PM_{2.5}$.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute square foot ($cfm\text{-}ft^2$). Collection efficiencies are on the order of 99 percent for $PM/PM_{10}/PM_{2.5}$.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for $PM/PM_{10}/PM_{2.5}$.

5.7.1.2 Technical Feasibility and Ranking

While all of these postprocess technologies would be technically feasible for controlling $PM/PM_{10}/PM_{2.5}$ emissions from CTGs, none of the previously described control equipment has been applied to CTGs, because exhaust gas PM concentrations are inherently low. CTGs operate with a significant amount of excess air that generates large exhaust gas flow rates. The proposed CTGs will be fired primarily with natural gas. Combustion of natural gas will generate low PM emissions in comparison to other fuels due to its inherently low ash and sulfur content. The low PM emissions coupled with a large volume of exhaust gas produces low exhaust stream PM concentrations. Postcombustion PM control systems are not installed on CTG exhausts.

5.7.1.3 Evaluation of Control Technologies

$PM/PM_{10}/PM_{2.5}$ emissions from CTGs are dependent on several factors: (1) the manufacturer and model of the CTG, (2) the sulfur content of the fuel(s), and (3) the use of an SCR or oxidation catalyst. While an SCR and oxidation catalyst controls other pollutants, their use and the introduction of ammonia can increase $PM/PM_{10}/PM_{2.5}$ emissions. There are no postcombustion control systems that are technically feasible to control $PM/PM_{10}/PM_{2.5}$ emissions from CTGs. Therefore, it is difficult to make comparisons of numerical BACT emissions limits with respect to $PM/PM_{10}/PM_{2.5}$ emissions for several reasons.

First, some of the queried results represent emissions limits based on only the filterable portion of total $PM/PM_{10}/PM_{2.5}$ emissions. The condensable portion, including sulfates generated during the combustion process, are not included, resulting in a lower lb/MMBtu emissions limit.

Second, the emissions limits that do contain both the filterable and condensable portion are based on widely varying natural gas sulfur contents. Sulfur in the fuel is converted to sulfates during the combustion process, and these sulfates add to the condensable portion of the total $PM/PM_{10}/PM_{2.5}$ emissions. Facilities that have higher, short-term natural gas sulfur contents have higher $PM/PM_{10}/PM_{2.5}$ emissions solely based on the condensable portion.

In addition to the use of ULSD as a backup fuel, a natural gas sulfur content limit of 2.0 gr S/100 scf is being proposed for the Project. The calculated $PM/PM_{10}/PM_{2.5}$ emissions are based on this natural gas sulfur content, the sulfur content of ULSD fuel oil, and $PM/PM_{10}/PM_{2.5}$ emissions rates provided by GE for the 7FA CTGs.

5.7.1.4 Proposed $PM/PM_{10}/PM_{2.5}$ BACT

Consistent with recent FDEP $PM/PM_{10}/PM_{2.5}$ BACT determinations for CTG power projects, the proposed BACT $PM/PM_{10}/PM_{2.5}$ emissions limit for the CTG/HRSGs is 10-percent opacity for both natural gas and ULSD fuel oil for all operating scenarios.

EPA's RBLC database was queried for large CTGs firing natural gas and fuel oil. BACT and LAER determinations were obtained for the past 10 years and are summarized in Appendix D.

5.7.2 EMERGENCY DIESEL ENGINE

The emergency generator will meet the PM emissions limits of 40 CFR 60, Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines, effective September 11, 2006. The PM emissions limit is 0.15 g/hp-hr for the emergency generator diesel engine. Therefore, compliance with the Subpart IIII PM emissions limit and limiting the hours of operation for routine maintenance testing to 100 hr/yr is proposed as $PM/PM_{10}/PM_{2.5}$ BACT for the emergency generator diesel engine.

BACT and LAER determinations were obtained for the past 10 years for large (greater than 500 hp) ICE firing distillate fuel oil only and are summarized in Appendix D. A few facilities are shown with BACT determination below the Project's, but compliance with NSPS Subpart IIII is generally accepted as BACT.

5.7.3 COOLING TOWER

Dry cooling was not considered as a part of the design of this project and does not need to be considered in the BACT analysis. However, it should be noted that dry cooling towers are less efficient than wet cooling towers, require more energy to run the fans, and result in added emissions of all pollutants.

The following BACT analysis pertains to the wet cooling tower designed for this project.

5.7.3.1 Available $PM/PM_{10}/PM_{2.5}$ Control Technologies

The only feasible technology for controlling $PM/PM_{10}/PM_{2.5}$ from wet mechanical draft cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. Drift eliminator configurations include herringbone (blade-type), wave form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber-reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

Factors affecting cooling tower $PM/PM_{10}/PM_{2.5}$ emissions rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dissolved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

5.7.3.2 Proposed $PM/PM_{10}/PM_{2.5}$ BACT

The proposed BACT for $PM/PM_{10}/PM_{2.5}$ emissions from the cooling tower is the use of high efficiency drift eliminators (see Table 5-9). The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow. The proposed cooling tower drift loss rate is consistent with recent $PM/PM_{10}/PM_{2.5}$ BACT determinations for mechanical draft cooling towers found on the RBLC database, i.e., 0.0005 percent was the highest efficiency drift eliminator found on the RBLC. Compliance will be demonstrated by manufacturer certification.

5.8 SUMMARY OF PROPOSED BACT

Table 5-10 provides a summary of the BACT control technologies proposed for the Project. Table 5-11 presents a summary of the proposed BACT emission limits for the Project emissions sources.

Table 5-9. Proposed $PM/PM_{10}/PM_{2.5}$ BACT Emissions Limits

Emissions Source	Proposed $PM/PM_{10}/PM_{2.5}$ BACT Emissions Limits
CTG/HRSG units	
Natural gas	10-percent opacity
ULSD fuel oil	10-percent opacity
Emergency generator diesel engine	0.15 g/hp-hr
Wet mechanical draft cooling tower	0.0005-percent drift loss

Sources: Tampa Electric, 2012.
ECT, 2012.

Table 5-10. Summary of BACT Control Technologies

Pollutant	Control Technology
A. CTG/HRSG	
NO_x	• Dry low-NO_x (natural gas), water injection (ULSD fuel oil) • SCR
SO_2 and H_2SO_4 mist	• Exclusive use of pipeline-quality natural gas as primary fuel • Limited use of ULSD as backup fuel
CO	• Efficient combustion • Good combustion practices
VOC	• Efficient combustion
$PM/PM_{10}/PM_{2.5}$	• Exclusive use of pipeline-quality natural gas as primary fuel • Limited use of ULSD as backup fuel
B. Emergency Engine	
NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$	• Compliance with NSPS Subpart IIII
SO_2 and H_2SO_4 mist	• Exclusive use of ULSD fuel oil
C. Cooling Tower	
$PM/PM_{10}/PM_{2.5}$	• High-efficiency drift eliminators

Source: Tampa Electric, 2012.
ECT, 2012.

Table 5-11. Summary of Proposed BACT Emissions Limits

Pollutant	Emissions Limit	Averaging Period	Compliance Method
A. <u>CTG/HRSG Units</u>			
NO_x			
Natural gas	2.0 ppmvd at 15-percent oxygen	24-hour block	CEMS
ULSD fuel oil	8.0 ppmvd at 15-percent oxygen	24-hour block	CEMS
SO_2 and H_2SO_4 mist			
Natural gas	2.0 gr S / 100 dscf	Not applicable	Fuel analyses
ULSD fuel oil	0.0015 weight % S	Not applicable	Fuel analyses
CO			
Natural gas and ULSD fuel oil	8.0 ppmvd at 15-percent oxygen	24-hour block	CEMS
VOC			
Natural gas without duct burners	1.4 ppmvd at 15-percent oxygen	Not applicable	Stack test
Natural gas with duct burners	3.5 ppmvd at 15-percent oxygen	Not applicable	Stack test
ULSD fuel oil	3.0 ppmvd at 15-percent oxygen	Not applicable	Stack test
$PM/PM_{10}/PM_{2.5}$	10-percent opacity	6-minute	EPA RM9
B. <u>Emergency Generator Diesel Engine</u>			
NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$	Compliance with NSPS Subpart IIII	Not applicable	Not applicable
SO_2 and H_2SO_4 mist	Exclusive use of ULSD fuel oil	Not applicable	Not applicable
C. <u>Cooling Tower</u>			
$PM/PM_{10}/PM_{2.5}$	0.0005-percent drift eliminators	Not applicable	Vendor certification

Sources: Tampa Electric, 2012.
ECT, 2012.

6.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

As previously noted in Section 3.1, the Project is located in an area that is designated attainment or unclassifiable for criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. The Florida PSD Class I areas include Everglades NP and Chassahowitzka, St. Marks, and Bradwell Bay NWAs. Accordingly, PPS and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine Project air quality impacts with respect to the PSD Class II increments and NAAQS. Section 10.0 addresses Project air quality impacts with respect to the PSD Class I areas.

The approach to assessing air quality impacts for a new or modified emissions source generally begins by determining the impacts of only the proposed project. If project impacts are below the PSD SILs, then no further analysis is required. The PSD Class II SILs were previously presented in Table 3-4. If the impacts of a proposed project are found to exceed a particular PSD SIL, further analysis considering other existing sources and background pollutant concentrations is required for that SIL.

The approach used to analyze the potential impacts of the Project, as described in detail in the following subsections, was developed in accordance with current FDEP and EPA modeling guidance. Guidance contained in EPA dispersion model manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the Project will have the potential to emit 744.9 tpy of NO_x, 935.0 tpy of CO, 137.6 tpy of VOCs, 192.3 tpy of SO_2, 188.3 tpy of PM, 309.0 tpy of PM_{10}, 308.6 tpy of $PM_{2.5}$, 0.018 tpy of lead, 42.7 tpy of H_2SO_4 mist, 0.0032 tpy of mercury, and 4,307,862 tpy of CO_2e. Table 3-2 previously provided Project estimated potential annual emissions rates. As shown in that table, potential emissions of NO_x, CO, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, CO_2e are each projected to exceed the applicable PSD SER threshold. Project potential emissions are below the applicable PSD SER levels for all other PSD regulated pollutants. Accordingly, the Project is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(a), F.A.C., for NO_x, CO, VOC, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, and CO_2e.

Assessment of Project air quality impacts for PM, VOC, H_2SO_4 mist, and CO_2e were not conducted since there are no PSD increments or AAQS for these constituents. Modeling of ozone impacts were also not conducted since this pollutant is not evaluated for individual projects but rather addressed on a regional level using large-scale multisource photochemical models such as EPA's Community Multiscale Air Quality (CMAQ) model. A discussion of Project impacts on ambient ozone levels is provided in Section 7.4. Accordingly, the Project air quality impact analysis evaluated impacts for NO_x, CO, SO_2, PM_{10}, and $PM_{2.5}$.

6.3 MODEL SELECTION AND USE

Air quality models are applied at two levels: screening and refined. At the screening level, models provide conservative estimates of impacts to determine whether more detailed modeling is required. Screening modeling can also be used to identify worst-case operating scenarios for subsequent refined modeling analysis. The refined level consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides improved estimates of source impacts.

Regulatory agency-recommended procedures for conducting air quality impact assessments are contained in the EPA's GAQM. In the November 9, 2005, Federal Register, EPA approved use of American Meteorological Society (AMS)/U.S. Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model (AERMOD) as a GAQM Appendix A-preferred model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model. For the Project air quality analyses, the current version of the refined AERMOD system (Version 12060, February 29, 2012), together with 5 years of hour-by-hour National Weather Service meteorology, was used to obtain predictions of both short-term periods (i.e., periods equal to or less than 24 hours) and annual average air quality impacts.

EPA has issued modeling guidance memoranda that address the 1-hour NO_2, 1-hour SO_2, and the $PM_{2.5}$ NAAQS. The most recent EPA memoranda providing guidance concerning 1-hour SO_2 and NO_2 NAAQS modeling procedures are dated August 23, 2010, and March 1, 2011, respectively. EPA issued guidance regarding $PM_{2.5}$ modeling procedures in a memorandum dated March 23, 2010. Modeling conducted for the Project adhered to the guidance contained in these EPA documents.

6.4 MODEL OPTIONS

Procedures applicable to the AERMOD system specified in the latest version of the User's Guide for AERMOD (September 2004), AERMOD Implementation Guide (revised March 19, 2009), February 2012 Addendum to the User's Guide, and the current GAQM were followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. The Project will be located in rural Polk County. Accordingly, AERMOD options regarding pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected.

As previously mentioned, the AERMOD system was used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword.

6.5 NO_2 AMBIENT IMPACT ANALYSIS

Emissions of NO_x from combustion sources consist of nitric oxide and NO_2. At stack exit conditions, the primary species is nitric oxide, which typically comprises 90 percent or more of total NO_x.

AERMOD includes three options for estimating NO_2 impacts:

- Tier 1—Assumes complete (i.e., 100-percent) conversion of nitric oxide to NO_2.
- Tier 2—Ambient ratio method (ARM), which represents the average ambient NO_2/NO_x ratio. Current EPA guidance recommends using ratios of 0.75 (for annual averages) and 0.80 (for 1-hour averages).
- Tier 3—Uses the ozone-limiting method and plume volume molar ratio method.

The Tier 1 option is an AERMOD regulatory default option that may be used without additional regulatory agency approval. The Tier 2 option has been historically accepted for regulatory modeling applications using an average ambient NO_2/NO_x ratio of 0.75. In accordance with EPA's March 1, 2011, guidance, Tier 2 will be accepted for regulatory modeling applications if the EPA-recommended average ambient NO_2/NO_x ratio of 0.80 is used for 1-hour NO_2 assessments.

For Project annual and 1-hour NO_2 impacts, the Tier 2 ARM option was used with average ambient NO_2/NO_x ratios of 0.75 and 0.80, respectively, as recommended by EPA. As noted previously, the approach is acceptable without additional regulatory agency approval.

6.6 TERRAIN CONSIDERATION

The GAQM defines *flat* terrain as terrain equal to the elevation of the stack base, *simple* terrain as terrain lower than the height of the stack top, and *complex* terrain as terrain exceeding the height of the stack being modeled.

Site elevation for PPS is approximately 143 feet above mean sea level (ft-msl). The Polk 2-5 Conversion Project CC CTG/HRSG stacks will each have a height of 130 ft above grade elevation. The cooling tower associated with CC operation will have exhaust outlets 51 ft above grade elevation. The existing Unit 2 simple cycle CTG stacks are 114 ft above grade elevation. Accordingly, terrain elevations above approximately 273 ft-msl (for the CC CTG/HRSG units), 194 ft-msl (for the cooling tower), and 257 ft-msl (for the simple cycle CTG units) are classified as complex terrain. Terrain elevations within approximately 30 km of PPS range from 8 to 369 ft-msl. Accordingly, terrain in the vicinity of PPS is classified as ranging from flat to complex terrain.

In accordance with the GAQM recommendations for AERMOD, each modeled receptor was assigned a terrain elevation based on U.S. Geological Survey (USGS) National Elevation Dataset (NED) terrain data and the AERMAP (Version 11103, April 13, 2011) terrain preprocessing program. AERMAP was used in accordance with the latest version of the User's Guide for the AERMOD Terrain Preprocessor (AERMAP), addenda to the User's Guide, and EPA's GAQM.

6.7 BUILDING WAKE EFFECTS

The CAA Amendments require the degree of emissions limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack heights for the Project emissions sources will comply with the EPA-promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters, or 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.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require that 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. Guidelines for determining GEP stack height have been issued by EPA (1985).

The heights proposed for the Project emissions sources are all less than the regulatory GEP stack height of 213 ft. The dominant structure influencing downwash is the HRSG, which will have a height of 110 ft. Since the stack heights of the Project emissions sources will comply with the EPA-promulgated final stack height regulations, the proposed Project actual stack heights were used in the modeling analyses.

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than the calculated GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the Plume Rise Model Enhancements (PRIME) building downwash algorithms. For the Project ambient impact analysis, the complex downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (BPIPPRM) (Version 04274, September 30, 2004). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10 degrees [°] to 360°) building heights (BUILDHGT keyword), lengths (BUILDLEN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD.

Table 6-1 provides dimensions of the Project and PPS buildings/structures evaluated for wake effects. The building/structure dimensions were determined from engineering layouts and specifications. Figure 6-1 shows the buildings in three-dimension.

Table 6-1. Dimensions of Project and PPS Major Buildings and Structures

Building/Structure	Height (ft)	X Length (ft)	Y Length (ft)
Solid fuel truck unloading Area A	60.0	24.1	22.0
Solid fuel truck unloading Area B	40.0	24.1	21.1
Solid fuel truck unloading Area C	10.0	Polygon shape	
Solid fuel truck unloading Area D	20.1	Polygon shape	
Solid fuel truck unloading Area E	30.0	Polygon shape	
Solid fuel truck unloading Area F	6.0	Polygon shape	
Solid fuel truck unloading Area G	12.0	Polygon shape	
Solid fuel truck unloading Area H	18.0	Polygon shape	
Solid fuel truck unloading Area I	24.0	Polygon shape	
Solid fuel truck unloading Area J	30.0	Polygon shape	
Solid fuel Silos 1 and 2 (each)*	40.0	55.0	
Gasifier structure	252.0	60.9	65.1
Syngas cooling Wing 1	89.9	151.9	25.3
Syngas cooling Wing 2	89.9	151.9	25.3
IGCC cold box*	165.0	21.0	
IGCC hot gas cleanup unit	278.9	72.3	79.4
Fuel oil storage Tanks 1 through 3 (each)*	57.0	100.0	
Unit 1 HRSG	89.9	131.2	42.7
SC Units 2 through 4 air inlets (each)	56.4	13.6	45.6
CC Unit 2A through 5A HRSGs (each)	110.0	135.0	55.0
CC Unit 2 STG	80.0	150.0	50.0
Unit 2 cooling tower	51.0	145.0	97.0

*Length represents structure diameter.

Sources: Black & Veatch, 2012.
ECT, 2012.

FIGURE 6-2.
FENCE LINE RECEPTOR GRID

Sources: ECT, 2012.

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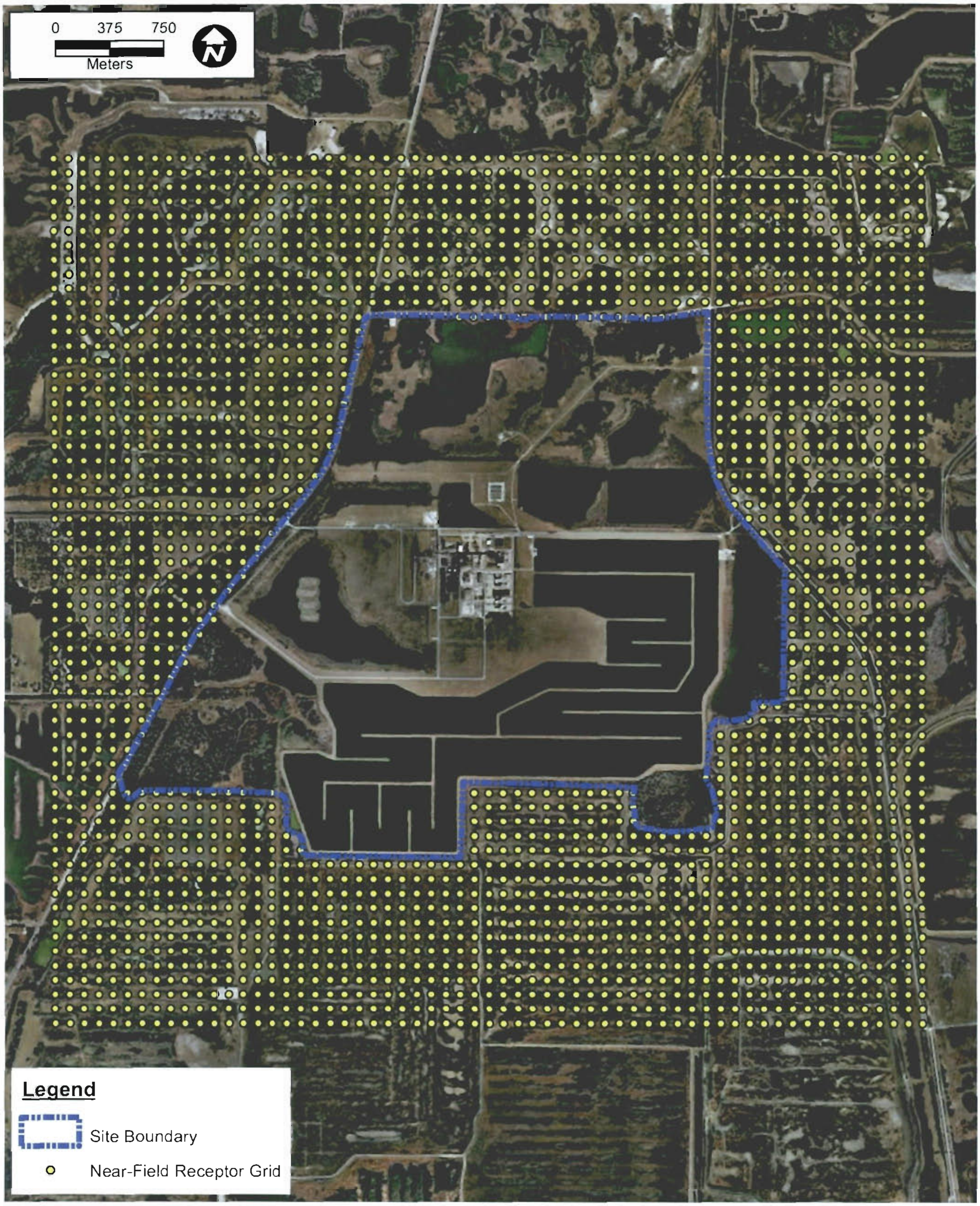

FIGURE 6-3.
NEAR-FIELD RECEPTOR GRID

Sources: ECT, 2012.

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TAMPA ELECTRIC

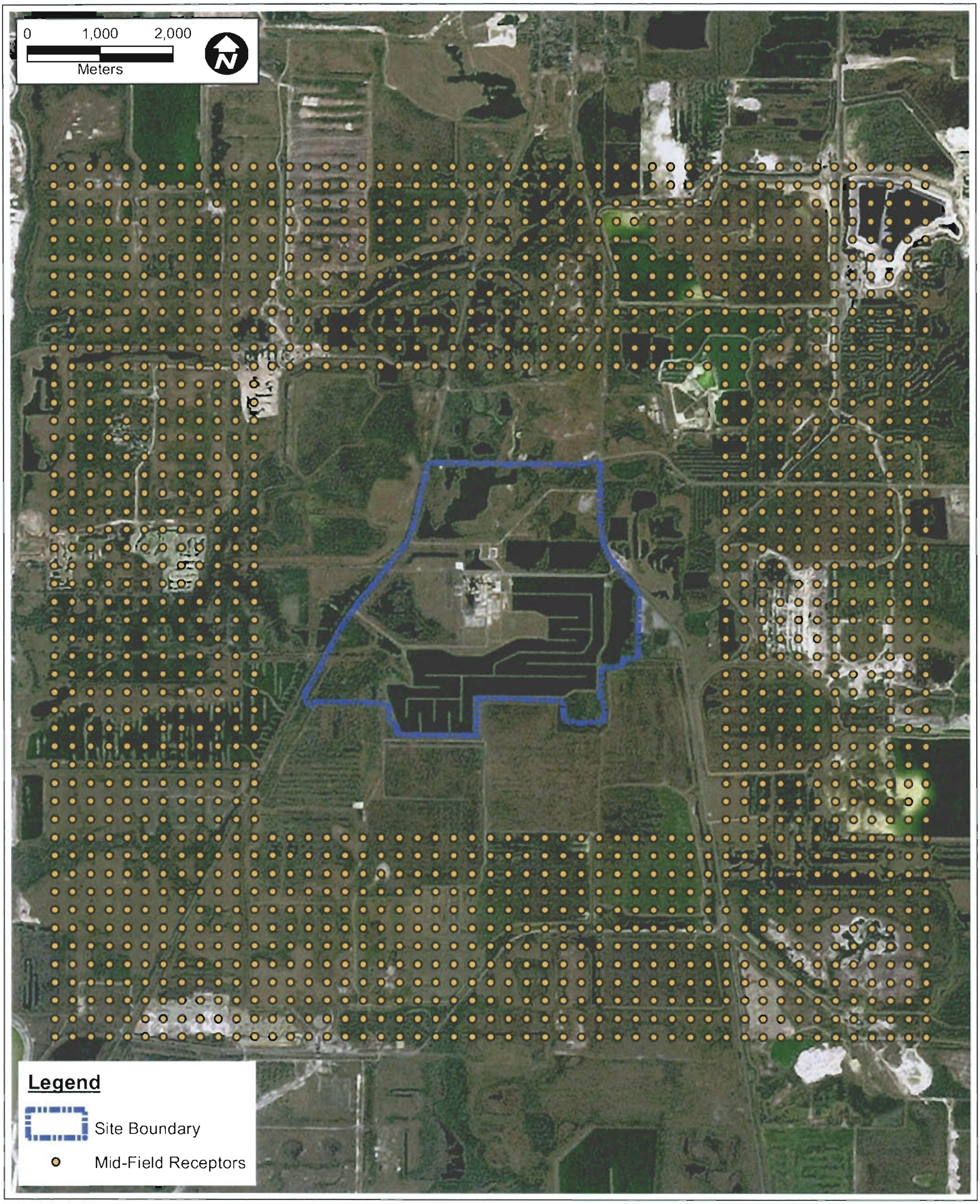


FIGURE 6-4.
MID-FIELD RECEPTOR GRID

Sources: ECT, 2012.

TECO
TAMPA ELECTRIC

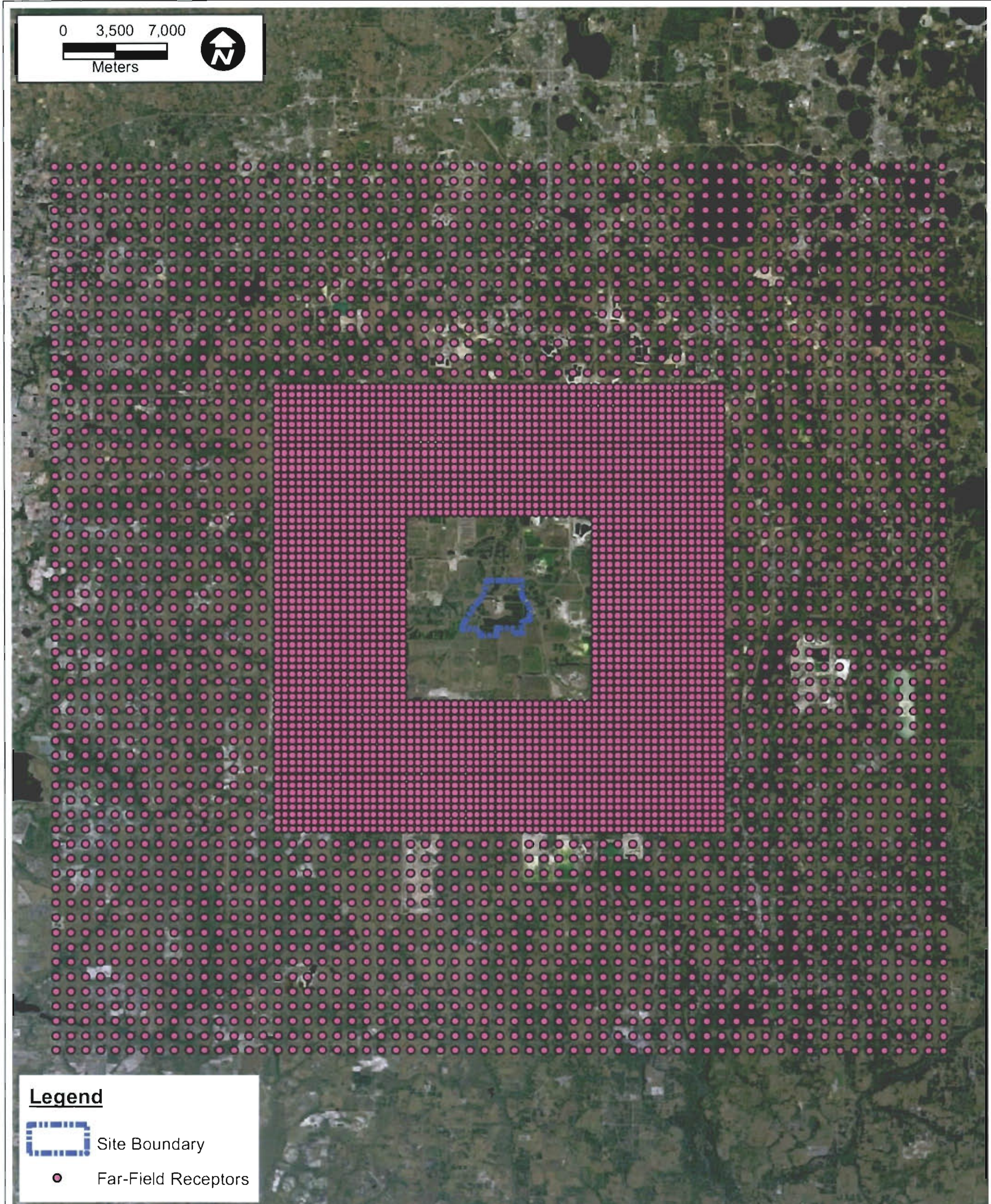


FIGURE 6-5.
FAR-FIELD RECEPTOR GRIDS

Sources: ECT, 2012.

TECO
TAMPA ELECTRIC

FIGURE 6-1.
PROJECT AND PPS BUILDINGS/STRUCTURES THREE-DIMENSIONAL VIEW

Source: Black & Veatch, 2012.

TECO
TAMPA ELECTRIC

6.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." The entire perimeter of the PPS plant Site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines. Consistent with GAQM and FDEP recommendations, the Project ambient impact analysis used the following receptor grids:

- Fence Line Receptors—Receptors placed on the site fence line spaced 25 meters apart.
- Near-Field Cartesian Receptors—Receptors at 100-meter spacing starting at 100 meters from the fence line receptors and extending to 3,000 meters from the center of the PPS Site.
- Mid-Field Cartesian Receptors—Receptors at 250-meter spacing starting at 3,250 meters and extending to 6,000 meters from the center of the PPS Site.
- Far-Field Cartesian Receptors—Receptors at 500-meter spacing starting at 6,500 meters and extending to 15,000 meters from the center of the PPS Site, and receptors at 1,000-meter spacing starting at 16,000 meters and extending to 30,000 meters from the center of the PPS Site.

As necessary, the receptor grids used for the ambient impact analysis were refined following initial modeling to ensure that the highest ambient impacts for each pollutant and averaging period have been identified using a receptor spacing of no more than 100 meters.

Figure 6-2 provides a graphical representation of the fence line receptors. Figures 6-3 and 6-4 present graphical representations of the near- and mid-field receptor grids, respectively. Figure 6-5 provides a depiction of the far-field receptor grids.

For the cumulative modeling analysis, the receptor grids consisted of only those receptors that exceeded a PSD Class II SIL for a specific pollutant and averaging period. These grids included any receptor for which an SIL was exceeded for any averaging period and any year of meteorological data.

6.9 METEOROLOGICAL DATA

The AERMET meteorological preprocessing program creates two files that are used by AERMOD: surface and profile files. The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature.

AERMET calculates the hourly boundary layer parameters for use by AERMOD, including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, CBL and SBL heights, and surface heat flux. In addition, AERMET passes all observed meteorological parameters to AERMOD including wind direction and speed (at multiple heights, if available), temperature, and if available, measured turbulence. AERMOD uses this information to calculate concentrations in a manner that accounts for a dispersion rate that is a continuous function of meteorology.

Review of the nearest meteorological surface stations with readily available meteorological data required for AERMET identified two potential stations, Tampa International Airport (TPA) and Orlando International Airport (MCO). TPA and MCO are located approximately 38 miles to the west-northwest and 64 miles to the north-northeast of PPS, respectively. Based on FDEP guidance and similarities in wind roses and surrounding surface roughness lengths between PPS and the MCO meteorological station, 5 years (2006 to 2010) of MCO surface and TPA upper air meteorological data provided by FDEP were used for the Project air quality impact analysis. The MCO/TPA meteorological dataset was prepared by FDEP using the current versions of AERMET (Version 11059, February 28, 2011) and AERMINUTE (Version 11325, November 21, 2011).

6.10 MODELED EMISSIONS INVENTORY

6.10.1 ON-PROPERTY SOURCES

The Project modeled emissions sources included the four CC CTG/HRSG units and the new mechanical draft cooling tower associated with operation of the CC STG.

The CC CTG/HRSG units will operate under a variety of operating conditions including CTG load, CTG inlet combustion air temperature, fuel types, and use of duct burners. For natural gas firing, emissions estimates were developed for 15 scenarios including three CTG loads (100, 75, and 50 percent), three ambient air temperatures (90, 59, and 20°F), and use of inlet air evaporative cooling and duct burner firing. For ULSD fuel oil firing, a total of emissions estimates were developed for 12 scenarios including three CTG loads (100, 75, and 50 percent), three ambient air temperatures (90, 59, and 20°F), and use of inlet air evaporative cooling.

The four CC CTG/HRSG units were first modeled for each operating case using a unit emissions rate of 1.0 gram per second (g/s) and assuming continuous 24/7 operation at each operating case. Model input files were developed for each of the 5 years of meteorology (i.e., 2006 through 2010) and for each fuel type (natural gas and ULSD fuel oil). This modeling approach resulted in five model input files for each fuel type (i.e., one for each year of meteorology) for a total of 10 model input files. Each model input file included all CTG/HRSG operating cases with source groups defined to obtain predicted impacts for each CTG/HRSG operating case. For example, the source group defined as CC-1 included the four CTG/HRSG units with Case CC-1 (i.e., natural gas firing, 100-percent load, 0°F ambient temperature, 4-on-1 configuration) stack parameters. Table B-2 of Appendix B, Emissions Rate Calculations provides the Project operating cases. Since model-predicted air quality impacts are directly proportional to emissions rates, the initial normalized modeling results were multiplied by the appropriate emissions rate for each operating case. As an example, the CTG/HRSG NO_x emissions rate for Case CC-1 is 15.2 lb/hr (1.91 g/s). Accordingly, the normalized NO_x impacts for Case CC-1 were multiplied by a factor of 1.91.

For NO_x impacts, the modeling results were also adjusted to reflect the Tier 2 ARM conversion of NO_x to NO_2 (i.e., using multiplier factors of 0.75 and 0.80 for annual and 1-hour average impacts, respectively) and the maximum CTG/HRSG annual hours of operation for ULSD fuel oil; i.e., 750 hr/yr per CTG/HRSG conservatively including startup/shutdown hours. The annual hour adjustment factor for ULSD fuel oil equates to

0.20 (750 ÷ 8,760). For determining 24-hour average impacts when firing ULSD fuel oil, the normalized model results were multiplied by the 24-hour average emissions rates associated with the maximum daily hours of ULSD fuel oil operation; i.e., 48 hours per day for all four CTG/HRSG units, which is equivalent to 12 hours per day per CTG/HRSG unit assuming all units are operating. No adjustment was made to the natural gas firing annual NO_x impacts, since the units are assumed to operate continuously; i.e., 8,760 hr/yr per CTG/HRSG.

The Project will include an emergency diesel engine generator, which will only operate approximately 2 hours per week for routine testing and maintenance purposes, excluding emergency conditions. As identified in EPA's March 1, 2011, 1-hour NO_2 modeling guidance memorandum, emissions sources that operate intermittently do not need to be included in the modeled emissions inventory. Due to its infrequent operation, the contribution of the emergency diesel engine to other pollutant impacts (i.e., SO_2, CO, and PM_{10}/$PM_{2.5}$) will be negligible. Accordingly, the Project emergency diesel generator was not included in the modeled emissions inventory.

The existing Units 2 through 4 CTG stacks will be retained to serve as HRSG bypass stacks to allow for simple cycle mode operation. Operation of the CTGs in simple cycle mode is expected to be infrequent and generally confined to periods when the CC HRSGs or STG are unavailable due to maintenance or equipment malfunctions or when peaking power is required. No changes are planned to simple cycle mode CTG operation with the exception of adding ULSD fuel oil firing capability to Units 4 and 5. Due to the expected infrequent operation of the CTGs in simple cycle mode (particularly when firing ULSD fuel oil), the Project modeling analysis did not evaluate air quality impacts for the previously permitted simple cycle mode operation.

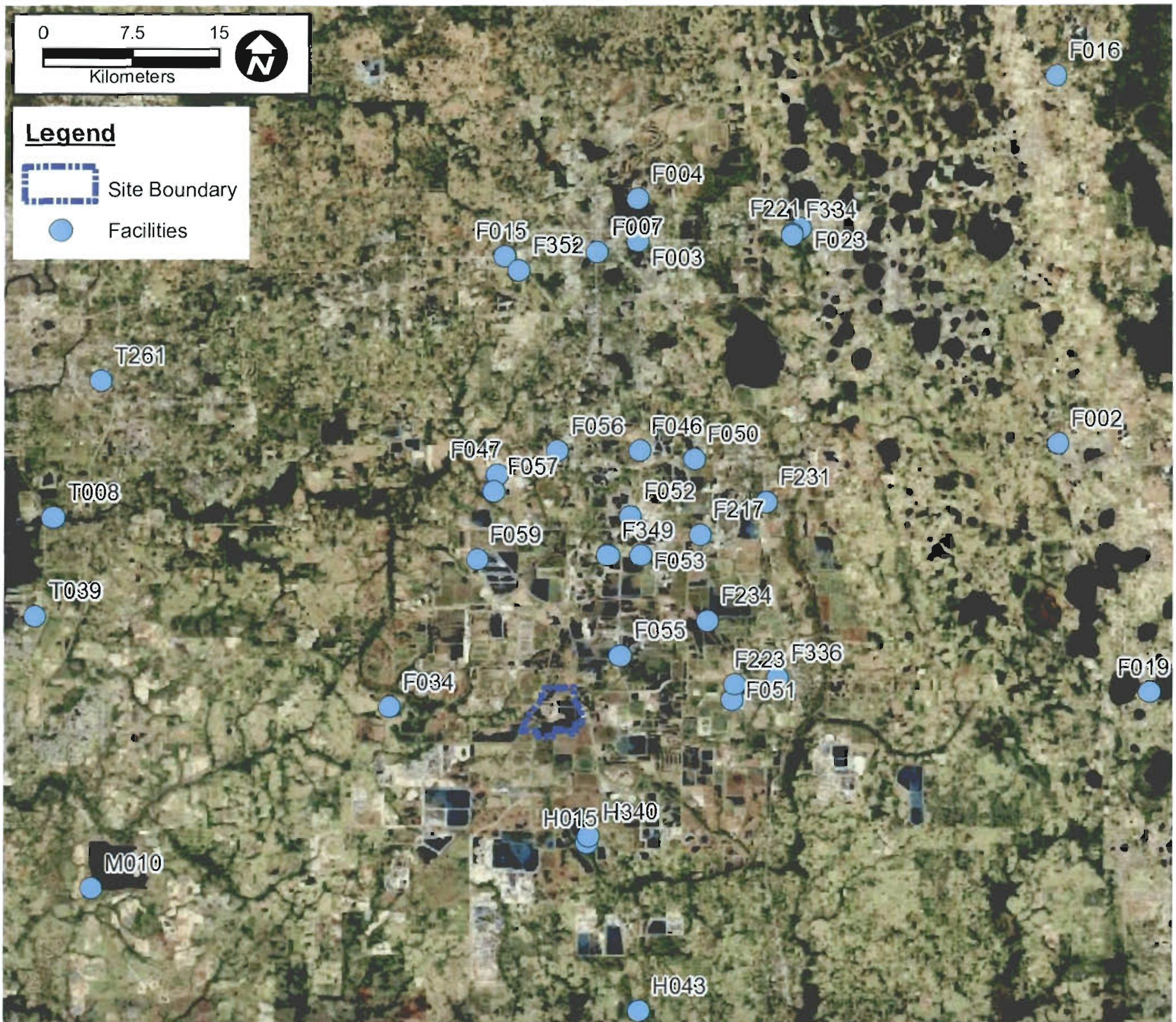
For the cumulative modeling analyses, modeled PPS emissions sources also included the IGCC Unit 1 CTG/HRSG, sulfuric acid plant, auxiliary boiler, and four baghouses associated with the IGCC solid fuel handling system.

6.10.2 OFF-PROPERTY SOURCES

The modeling analysis determined that Project impacts will exceed the PSD Class II SILs for the NO_2 and SO_2 1-hour averaging times and for the 24-hour averaging time SILs for $PM_{2.5}$. Emissions inventories for sources located in Polk, Hillsborough, Manatee, and Hardee Counties were obtained from FDEP for use in the cumulative modeling analyses. The information provided by FDEP for existing sources of NO_x, SO_2, and PM included the following facility ID, emissions unit ID, facility and emissions unit descriptions, coordinates, source parameters (e.g., stack height and diameter, exhaust temperature and flow rate, etc.), and potential, allowable, and actual emissions. PSD increment consuming sources were also indicated. This data was supplemented with permit information obtained from the Air Permit Document Search Website at http://appprod.dep.state.fl.us/air/emissions/apds/default.asp.

Only major sources (i.e., those sources having potential emissions of 100 tpy or greater), and increment consuming sources were included in the modeling of each pollutant. Inclusion of facilities was dependent on the maximum distance that a significant impact was predicted for each pollutant, and the averaging time being assessed. For assessment of the 1-hour NO_2 and SO_2 NAAQS, it is generally sufficient to include sources within 10 km, or to at least the maximum distance of significant impact, whichever is higher. To be conservative, major sources within 10 km beyond the point of maximum impact were included in the modeling. NO_2 1-hour impacts from the project were predicted to approximately 25 km, and sources within 35 km of the PPS Site were included. Although SO_2 impacts were only predicted out to approximately 3 km, all major sources within 15 km were included in the inventory, which is well beyond the furthest distance of significant impact. For the $PM_{2.5}$ cumulative modeling, which had predicted significant impacts to approximately 12 km, all major sources within 45 km of the PPS Site were included in the modeling inventory.

Figure 6-6 shows the locations of the facilities included in the cumulative modeling analyses. Table 6-2 is the list of facilities included in the modeling for each pollutant. The emissions rates used in the modeling were based on the allowable rates contained in the information received from FDEP and the Title V permits. Sources expected to operate



ID	Facility Name	ID	Facility Name
F002	CITRUS WORLD, INC.	F059	MOSAIC FERTILIZER - NEW WALES FACILITY
F003	LAKELAND, CHARLES LARSEN MEMORIAL POWER PLANT	F217	POLK POWER PARTNERS, MULBERRY COGEN FAC
F004	LAKELAND ELEC, C.D. MCINTOSH, JR. POWER PLANT	F221	AUBURNDALE POWER PARTNERS, LP
F007	OWENS-BROCKWAY GLASS CONTAINER INC.	F223	FPC, TIGER BAY COGENERATION FACILITY
F015	US BEVERAGE LAKELAND PLANT	F231	ORANGE COGENERATION FACILITY
F016	HOLLY HILL FRUIT PRODUCTS	F234	FPC, HINES ENERGY COMPLEX
F019	CARGILL, FROSTPROOF CITRUS PROCESSING FAC	F334	CALPINE, OSPREY ENERGY CENTER
F023	CUTRALE CITRUS JUICES USA, INC	F336	PEACE RIVER STATION, LLC
F034	MOSAIC FERTILIZER, CENTRAL FLORIDA MINERAL OPERATIONS	F349	CPV PIERCE POWER GENERATING FACILITY
F046	MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F352	LAKELAND ELEC, WINSTON PEAKING STATION
F047	AGRIFOS MINING, L.L.C. - NICHOLS	H015	HARDEE POWER PARTNERS LTD, HARDEE POWER STATION
F050	U S AGRI-CHEMICALS - BARTOW	H043	VANDOLAH POWER CO LLC, VANDOLAH POWER PROJECT
F051	U.S. AGRI-CHEMICALS - FT. MEADE	H340	SEMINOLE ELECTRIC COOP, INC, MIDULLA GENERATING STN
F052	CF INDUSTRIES - BARTOW PHOSPHATE COMPLEX	M010	FLORIDA POWER & LIGHT, MANATEE POWER PLANT
F053	MOSAIC FERTILIZER - GREEN BAY FACILITY	T008	MOSAIC FERTILIZER LLC, RIVERVIEW FACILITY
F055	MOSAIC FERTILIZER - SOUTH PIERCE FACILITY	T039	TAMPA ELECTRIC CO, BIG BEND STATION
F056	CD GLOBAL, PRAIRIE MINE	T261	HILLSBOROUGH CTY. RESOURCE RECOVERY FAC.
F057	IMC PHOSPAHTES COMPANY (NICHOLS)		

FIGURE 6-6.
FACILITIES INCLUDED IN THE CUMULATIVE MODELING ANALYSES

Sources: Bing, 2012; ECT, 2012.

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Table 6-2. Existing Facilities Included in the Modeling Analysis

Map ID	Facility Name	Distance from PPS (km)	Source PM	Source NO_x	Source SO_2
F055	Mosaic Fertilizer South Pierce Facility	6.5	X	X	X
H340	Seminole Electric Midulla Generating Station	9.8	X		
H015	Hardee Power Station	10.2	X		
F349	CPV Pierce Power	12.6	X	X	X
F034	Mosaic Fertilizer Central Florida Mineral	12.7	X	X	X
F059	Mosaic Fertilizer New Wales Facility	13.1	X	X	X
F051	US Agri-Chem Fort Meade Facility	13.4	X	X	X
F234	FPC Hines Energy Complex	13.5	X	X	X
F053	Mosaic Fertilizer Green Bay	13.5	X	X	X
F223	FPC Tiger Bay Cogeneration	13.7	X	X	X
F052	CF Industries Bartow Phosphate	15.9			X
F336	Peace River Station	17.1	X	X	
F217	Polk Power Station Mulberry Cogeneration	17.3	X	X	
F057	IMC Phosphates Nichols Plant	17.4	X	X	
F047	Agrifos Mining Nichols Plant	18.6	X	X	
F056	CD Global Prairie Mine	19.8	X		
F046	Mosaic Fertilizer Bartow Facility	20.8	X	X	
F050	US Agri-Chem Bartow Facility	21.8	X		
F231	Orange Cogeneration Facility	22.6	X	X	
H043	Vandolah Power Project	23.5	X		
F352	Lakeland Electric Winston Peaking Station	33.6	X		
F015	US Beverage Lakeland Plant	34.8	X	X	
F007	Owens-Brockway Glass Container	35.0	X	X	
F003	Lakeland Charles Larson Mem Plant	36.2	X		
M010	FPL Manatee Power Plant	37.8	X		
F004	Lakeland Electric McIntosh Power Plant	39.3	X		
T039	Tampa Electric Big Bend Station	40.2	X		
F334	Calpine Osprey Energy Center	40.3	X		
F221	Auburndale Power Partners	40.4	X		
T008	Mosaic Fertilizer Riverview Facility	40.9	X		
F023	Cutrale Citrus Juices USA	41.0	X		
T261	Hillsborough County Resource Recovery	42.8	X		
F002	Citrus World, Inc.	43.3	X		
F019	Cargill Frostproof Citrus Processing	45.3	X		
F016	Holly Hill Fruit Products	61.3	X		

Source: ECT, 2012.

infrequently, such as emergency engines for electrical generation or firewater pumps, were not included in the modeling.

In several cases one or more stack parameters were missing. To be able to include the emissions, missing stack parameters were substituted with value(s) that were considered to be representative of a similar source or were based on engineering judgment. In all cases, the values were also chosen to be conservative, i.e., the substituted values were selected in a manner that would result in higher predicted air quality impacts than would actually be expected to occur. In some cases, emissions rates for combustion sources (e.g., boilers, dryers, and furnaces) were missing. In these instances, the emissions were estimated based on heat input, fuel(s), and emissions factors from AP-42. If more than one fuel was listed, then the higher resulting emissions rate was chosen. Appendix E contains the unit emissions rates and stack parameters, along with more detailed information on the emissions rate calculations and stack parameter substitutions.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive dispersion modeling was conducted to assess the air quality impacts resulting from Project operations in accordance with the methodology described in Section 6.0. This section provides the results of the Project Class II air quality assessment for NO_2, CO, SO_2, PM_{10}, and $PM_{2.5}$ Project air quality impacts at distant PSD Class I areas resulting from long-range transport are addressed in Section 10.0.

The AERMOD dispersion model was used to assess Project impacts in the surrounding Class II areas for each of the 15 CC CTG/HRSG natural gas-firing operating cases and for each of the 12 CC CTG/HRSG ULSD fuel oil-operating cases for each modeled pollutant (i.e., NO_x as NO_2, CO, SO_2, PM_{10}, and $PM_{2.5}$) and averaging period (i.e., annual, 24-, 8-, 3-, and 1-hour) subject to PSD review. For each fuel type, each of the CTG/HRSG operating cases was assessed for each year of the 5 years of meteorological data sets (2006 to 2010). For each modeled operating case, the specific emissions rate, stack exit temperature, and exhaust gas velocity appropriate for each case was used.

For each fuel type and year of meteorological data, model input files were created to include all 27 CTG/HRSG operating cases for each pollutant and averaging period. For modeling purposes only, the HRSG stacks were identified as 2A through 2D labeled from north to south starting with the northernmost unit. The AERMOD emissions source nomenclature used is as follows: CC2A1 through CC2D1 were used to identify CGT/HRSG Units 2A through 2D for operating case CC-1; CC2A2 through CC2D2 were used to identify CGT/HRSG Units 2A through 2D for operating case CC-2; etc.

The following pollutants and averaging periods were analyzed:

- <u>NO_2</u>: 1-hour and annual averages.
- <u>CO</u>: 1- and 8-hour averages.
- <u>SO_2</u>: 1-, 3-, and 24-hour and annual averages.
- <u>PM_{10}</u>: 24-hour and annual averages.
- <u>$PM_{2.5}$</u>: 24-hour and annual averages.

As previously described in Section 6.0, a unit 1.0-g/s emissions rate for each operating case was used to develop normalized impacts for the four CC CTG/HRSG units. Normalized predicted impacts were subsequently multiplied by the proposed emissions rates for each pollutant and operating case.

In addition to the 27 steady-state operating scenarios, assessment of air quality impacts during CTG/HRSG startups and shutdowns was evaluated. The evaluation of startup impacts was confined to 1-hour NO_2 and CO impacts during CTG/HRSG warm startups firing natural gas. Emissions of fuel related pollutants (i.e., SO_2 and $PM_{10}/PM_{2.5}$) will be lower during startups due to lower fuel flow rates. The frequency of CTG/HRSG natural gas cold startups will be low—approximately 10 per year per CTG/HRSG unit. Although occurring more frequently, the duration of a CTG/HRSG natural gas hot startup event is brief—approximately 20 minutes per event. ULSD fuel oil will serve as a backup fuel source; therefore, the frequency of startups using ULSD fuel oil will be low for all types of startups. The duration of a shutdown event for both natural gas and ULSD fuel oil will also be low—approximately 8 minutes per shutdown event.

7.2 PSD CLASS II SIL ANALYSIS RESULTS

The EPA AERMOD dispersion model results indicate that Project operations will result in ambient air quality impacts that exceed the PSD Class II SILs for NO_2 and SO_2 1-hour average and $PM_{2.5}$ 24-hour average. Project impacts were below the PSD Class II SILs for all other pollutants and averaging periods. Accordingly, additional cumulative modeling with respect to the PSD Class II increments and NAAQS was required for NO_2 and SO_2 1-hour NAAQS and $PM_{2.5}$ 24-hour PSD Class II increment and NAAQS.

7.2.1 NATURAL GAS

Tables 7-1 through 7-13 provide results for the Project when firing natural gas. Table 7-1 provides normalized predicted impacts based on the unit emissions rate of 1.0 g/s for each operating case and pollutant averaging period.

Table 7-1. Normalized Model Results—Natural Gas

Modeled Emission Rate: 1.0 g/s per CTG/HRSG Unit

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Impacts - Four CTG/HRSG Units (μg/m³) 2006 1-Hour	2006 3-Hour	2006 8-Hour	2006 24-Hour	2006 Annual	2007 1-Hour	2007 3-Hour	2007 8-Hour	2007 24-Hour	2007 Annual	2008 1-Hour	2008 3-Hour	2008 8-Hour	2008 24-Hour	2008 Annual
CC-1	100	No	No	4 on 1	20	4.66	2.31	1.70	0.80	0.057	4.75	2.68	1.51	0.78	0.072	4.87	3.55	2.62	0.87	0.058
CC-2	100	No	Yes	4 on 1	20	5.09	2.40	1.77	0.84	0.061	5.21	2.94	1.56	0.81	0.076	5.43	3.69	2.75	0.92	0.062
CC-3	75	No	No	4 on 1	20	6.53	2.84	2.03	1.16	0.071	6.62	3.80	2.24	0.93	0.088	7.02	4.12	3.22	1.08	0.076
CC-5	100	No	Yes	1 on 1	20	4.03	1.59	0.75	0.34	0.018	4.34	2.16	0.93	0.39	0.023	4.25	1.42	0.70	0.27	0.020
CC-6	50	No	No	1 on 1	20	6.35	2.41	1.10	0.53	0.026	**8.26**	3.44	1.47	0.56	0.034	6.31	2.10	1.13	0.41	0.030
CC-7	100	No	No	4 on 1	59	5.09	2.43	1.78	0.85	0.061	5.17	2.94	1.58	0.81	0.076	5.35	3.73	2.79	0.93	0.062
CC-8	100	Yes	No	4 on 1	59	4.98	2.40	1.76	0.84	0.060	5.08	2.87	1.56	0.81	0.075	5.24	3.69	2.76	0.92	0.061
CC-9	100	Yes	Yes	4 on 1	59	5.43	2.50	1.83	0.89	0.063	5.55	3.15	1.61	0.84	0.079	5.82	3.81	2.88	0.96	0.066
CC-10	75	No	No	4 on 1	59	**6.77**	**2.91**	**2.07**	**1.25**	**0.072**	7.17	**3.94**	**2.39**	**0.98**	**0.090**	**7.26**	**4.17**	**3.28**	**1.10**	**0.078**
CC-12	100	No	No	4 on 1	90	5.32	2.52	1.84	0.89	0.062	5.42	3.08	1.62	0.84	0.078	5.60	3.83	2.90	0.97	0.065
CC-13	100	Yes	No	4 on 1	90	5.11	2.45	1.79	0.87	0.061	5.21	2.96	1.59	0.82	0.076	5.35	3.76	2.82	0.94	0.063
CC-14	100	Yes	Yes	4 on 1	90	5.57	2.56	1.86	0.91	0.064	5.69	3.23	1.64	0.85	0.080	5.95	3.87	2.95	0.98	0.067
CC-15	75	No	No	4 on 1	90	6.66	2.91	2.07	1.24	0.072	6.74	3.88	2.36	0.97	0.089	7.10	4.17	3.27	1.09	0.077
CC-17	100	Yes	Yes	1 on 1	90	4.22	1.70	0.80	0.36	0.019	4.81	2.32	0.00	0.41	0.024	4.52	1.51	0.72	0.28	0.021
CC-18	50	No	No	1 on 1	90	6.13	2.33	1.09	0.53	0.026	7.86	3.39	0.00	0.54	0.033	6.15	2.05	1.09	0.40	0.029
Maximums						6.77	2.91	2.07	**1.25**	0.072	**8.26**	3.94	2.39	0.98	**0.090**	7.26	**4.17**	**3.28**	1.10	0.078

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Impacts - Four CTG/HRSG Units (μg/m³) 2009 1-Hour	2009 3-Hour	2009 8-Hour	2009 24-Hour	2009 Annual	2010 1-Hour	2010 3-Hour	2010 8-Hour	2010 24-Hour	2010 Annual
CC-1	100	No	No	4 on 1	20	4.82	1.90	1.68	0.64	0.064	4.88	2.52	1.44	0.81	0.064
CC-2	100	No	Yes	4 on 1	20	5.39	2.03	1.77	0.67	0.068	5.38	2.74	1.53	0.88	0.068
CC-3	75	No	No	4 on 1	20	6.89	3.44	2.10	0.95	0.081	6.91	3.48	1.99	1.11	0.081
CC-5	100	No	Yes	1 on 1	20	4.35	2.06	0.77	0.35	0.021	4.20	2.06	1.14	0.56	0.027
CC-6	50	No	No	1 on 1	20	6.61	**3.87**	1.45	0.53	0.029	6.97	2.80	1.65	0.82	0.041
CC-7	100	No	No	4 on 1	59	5.29	2.04	1.79	0.67	0.068	5.34	2.74	1.51	0.88	0.068
CC-8	100	Yes	No	4 on 1	59	5.18	2.01	1.77	0.66	0.067	5.23	2.68	1.49	0.86	0.067
CC-9	100	Yes	Yes	4 on 1	59	5.77	2.15	1.85	0.73	0.072	5.76	2.93	1.65	0.94	0.071
CC-10	75	No	No	4 on 1	59	**7.11**	3.70	**2.14**	**1.00**	**0.083**	**7.15**	**3.61**	**2.07**	**1.15**	**0.083**
CC-12	100	No	No	4 on 1	90	5.54	2.11	1.86	0.73	0.071	5.59	2.86	1.58	0.92	0.070
CC-13	100	Yes	No	4 on 1	90	5.29	2.05	1.80	0.69	0.069	5.36	2.75	1.52	0.88	0.068
CC-14	100	Yes	Yes	4 on 1	90	5.89	2.25	1.90	0.77	0.073	5.89	2.99	1.69	0.96	0.073
CC-15	75	No	No	4 on 1	90	6.95	3.50	2.13	0.99	0.083	7.01	3.54	2.02	1.13	0.082
CC-17	100	Yes	Yes	1 on 1	90	4.61	2.28	0.85	0.38	0.022	4.49	2.17	1.21	0.59	0.028
CC-18	50	No	No	1 on 1	90	6.39	3.74	1.40	0.51	0.029	6.63	2.76	1.62	0.80	0.040
Maximums						7.11	3.87	2.14	1.00	0.083	7.15	3.61	2.07	1.15	0.083

Maximums - All Cases, All Years Period	μg/m³	Case	Year
1-Hour	8.26	CC-6	2007
3-Hour	4.17	CC-10	2008
8-Hour	3.28	CC-10	2008
24-Hour	1.25	CC-10	2006
Annual	0.090	CC-10	2007

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-2. 1-Hour and Annual Average NO_2 SIL Impacts—Natural Gas

Number of CTG/HRSG Units	4	
Maximum Annual Hours	8,760	hr/yr
Tier 2 NO_2/NO_x Ratio (1-Hour)	0.80	
Tier 2 NO_2/NO_x Ratio (Annual)	0.75	

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG NO_x Emissions Rates (per CTG/HRSG) 1-Hour lb/hr	1-Hour g/s	Annual lb/hr	Annual g/s	Maximum Tier 2 NO_2 Impacts (μg/m³) 2006 1-Hour	2006 Annual	2007 1-Hour	2007 Annual
CC-1	100	No	No	4 on 1	20	15.2	1.91	15.2	1.91	7.1	0.082	7.3	0.103
CC-2	100	Yes	No	4 on 1	20	**17.1**	**2.15**	**17.1**	**2.15**	8.8	**0.098**	8.9	**0.122**
CC-3	75	No	No	4 on 1	20	12.1	1.52	12.1	1.52	8.0	0.081	8.1	0.100
CC-5	100	No	No	1 on 1	20	**17.1**	**2.15**	**17.1**	**2.15**	6.9	0.030	7.5	0.037
CC-6	50	No	No	1 on 1	20	9.6	1.21	9.6	1.21	6.1	0.024	8.0	0.031
CC-7	100	No	No	4 on 1	59	14.3	1.80	14.3	1.80	7.3	0.082	7.5	0.103
CC-8	100	Yes	No	4 on 1	59	14.4	1.82	14.4	1.82	7.2	0.082	7.4	0.102
CC-9	100	No	Yes	4 on 1	59	16.3	2.05	16.3	2.05	**8.9**	0.097	**9.1**	0.121
CC-10	75	No	No	4 on 1	59	11.4	1.44	11.4	1.44	7.8	0.078	8.3	0.097
CC-12	100	No	No	4 on 1	90	13.2	1.66	13.2	1.66	7.1	0.078	7.2	0.097
CC-13	100	Yes	No	4 on 1	90	13.5	1.70	13.5	1.70	7.0	0.078	7.1	0.097
CC-14	100	Yes	Yes	4 on 1	90	15.4	1.94	15.4	1.94	8.6	0.093	8.8	0.117
CC-15	75	No	No	4 on 1	90	10.7	1.34	10.7	1.34	7.2	0.072	7.3	0.090
CC-17	100	Yes	Yes	1 on 1	90	15.4	1.94	15.4	1.94	6.5	0.028	7.5	0.035
CC-18	50	No	No	1 on 1	90	8.4	1.05	8.4	1.05	5.2	0.020	6.6	0.026
Maximums						17.1	2.148	17.1	2.148	8.9	0.098	9.1	**0.122**

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Tier 2 NO_2 Impacts (μg/m³) 2008 1-Hour	2008 Annual	2009 1-Hour	2009 Annual	2010 1-Hour	2010 Annual
CC-1	100	No	No	4 on 1	20	7.4	0.083	7.4	0.092	7.5	0.092
CC-2	100	Yes	No	4 on 1	20	9.3	0.101	9.3	0.110	9.2	0.110
CC-3	75	No	No	4 on 1	20	8.6	0.087	8.4	0.093	8.4	0.093
CC-5	100	No	No	1 on 1	20	7.3	0.032	7.5	0.034	7.2	0.043
CC-6	50	No	No	1 on 1	20	6.1	0.027	6.4	0.026	6.7	0.037
CC-7	100	No	No	4 on 1	59	7.7	0.084	7.6	0.092	7.7	0.092
CC-8	100	Yes	No	4 on 1	59	7.6	0.084	7.5	0.092	7.6	0.092
CC-9	100	No	Yes	4 on 1	59	**9.6**	**0.101**	**9.5**	**0.110**	**9.4**	**0.110**
CC-10	75	No	No	4 on 1	59	8.4	0.084	8.2	0.090	8.2	0.090
CC-12	100	No	No	4 on 1	90	7.4	0.081	7.4	0.088	7.4	0.088
CC-13	100	Yes	No	4 on 1	90	7.3	0.080	7.2	0.088	7.3	0.087
CC-14	100	Yes	Yes	4 on 1	90	9.2	0.098	9.1	0.106	9.1	0.106
CC-15	75	No	No	4 on 1	90	7.6	0.078	7.5	0.083	7.5	0.083
CC-17	100	Yes	Yes	1 on 1	90	7.0	0.030	7.2	0.032	7.0	0.041
CC-18	50	No	No	1 on 1	90	5.2	0.023	5.4	0.023	5.6	0.032
Maximums						**9.6**	0.101	9.5	0.110	9.4	0.110

Maximums - All Cases, All Years

Period	μg/m³	Case	Year
1-Hour	9.6	CC-9	2008
Annual	0.122	CC-2	2007

Highest 5-Year Average

Period	μg/m³	Case	Year
1-Hour	9.3	CC-9	2006 to 2010

PSD Class II SILs - NO_2

Period	μg/m³
1-Hour	7.5
Annual	1

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-3. 1-Hour and Annual Average NO_2 Maximum SIL Impacts—Natural Gas

Parameter	Unit	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 1-Hour Average Impacts							
CTG/HRSG operating case		CC-9	CC-9	CC-9	CC-9	CC-9	
CTG load	%	100	100	100	100	100	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	59	59	59	59	59	
Tier 2 1-Hour NO_2 Impact*	µg/m³	8.9	9.1	**9.6**	9.5	9.4	9.3
1-Hour Impact Location							
Receptor UTM Easting coordinate (X)	meters	404,137	404,089	404,328	404,354	404,137	
Receptor UTM Northing coordinate (Y)	meters	3,066,312	3,066,306	3,066,314	3,066,396	3,066,312	
Receptor elevation	meters	40.8	40.5	43.2	41.4	40.8	
Distance from stack†	meters	1,896	1,858	2,061	2,046	1,896	
Direction vector from stack‡	degrees	121	122	119	116	121	
PSD SIL	µg/m³						7.5
Exceed SIL	Yes/No						Y
Percent of SIL	%						124.0
B. Annual Average Impacts							
CTG/HRSG operating case		CC-2	CC-2	CC-9	CC-9	CC-9	
CTG load	%	100	100	100	100	100	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	20	20	59	59	59	
Tier 2 Annual NO_2 Impact§	µg/m³	0.098	**0.122**	0.101	0.110	0.110	
Annual Impact Location							
Receptor UTM Easting coordinate (X)	meters	401,008	400,927	400,995	400,995	401,022	
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,425	3,067,529	3,067,529	3,067,570	
Receptor elevation	meters	43.6	43.1	43.5	43.5	43.6	
Distance from stack†	meters	1,531	1,597	1,541	1,541	1,521	
Direction vector from stack‡	degrees	279	274	279	279	280	
PSD SIL	µg/m³	1	1	1	1	1	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	9.8	**12.2**	10.1	11.0	11.0	
PSD *de minimis* ambient impact	µg/m³	14	14	14	14	14	
Exceed PSD *de minimis* ambient impact	Yes/No	N	N	N	N	N	
Percent of PSD *de minimis* ambient impact	%	0.7	**0.9**	0.7	0.8	0.8	

Note: Maximum impacts shown in **bold** font.

*Maximum impact for all operating cases, EPA default NO_2/NO_x ratio of 0.80.

†Distance from Unit 2 CC-2A stack to the location of highest impact.

‡Direction from stack toward impact location. For example, 90° means the highest impact is located due east of the CC-2A stack.

§Maximum impact for all operating cases, EPA default NO_2/NO_x ratio of 0.75.

Source: ECT, 2012.

Table 7-4. 1- and 8-Hour Average CO SIL Impacts—Natural Gas

Number of CTG/HRSG Units 4
Maximum Annual Hours 8,760 hr/yr

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG CO Emissions Rates (Per CTG/HRSG) 1-Hour lb/hr	1-Hour g/s	8-Hour lb/hr	8-Hour g/s	CO Impacts (µg/m³) 2006 1-Hour	2006 8-Hour	2007 1-Hour	2007 8-Hour
CC-1	100	No	No	4 on 1	20	30.7	3.86	30.7	3.86	18.0	6.6	18.3	5.8
CC-2	100	Yes	No	4 on 1	20	**34.3**	**4.32**	**34.3**	**4.32**	22.0	**7.7**	22.5	6.7
CC-3	75	No	No	4 on 1	20	24.4	3.08	24.4	3.08	20.1	6.3	20.4	6.9
CC-5	100	No	No	1 on 1	20	**34.3**	**4.32**	**34.3**	**4.32**	17.4	3.3	18.8	4.0
CC-6	50	No	No	1 on 1	20	19.2	2.42	19.2	2.42	15.4	2.7	20.0	3.6
CC-7	100	No	No	4 on 1	59	28.7	3.62	28.7	3.62	18.4	6.4	18.7	5.7
CC-8	100	Yes	No	4 on 1	59	29.0	3.65	29.0	3.65	18.2	6.4	18.5	5.7
CC-9	100	No	Yes	4 on 1	59	32.7	4.12	32.7	4.12	**22.4**	7.5	**22.8**	6.6
CC-10	75	No	No	4 on 1	59	23.0	2.90	23.0	2.90	19.6	6.0	20.8	**6.9**
CC-12	100	No	No	4 on 1	90	26.4	3.33	26.4	3.33	17.7	6.1	18.0	5.4
CC-13	100	Yes	No	4 on 1	90	27.0	3.40	27.0	3.40	17.4	6.1	17.7	5.4
CC-14	100	Yes	Yes	4 on 1	90	30.7	3.87	30.7	3.87	21.6	7.2	22.0	6.4
CC-15	75	No	No	4 on 1	90	21.4	2.70	21.4	2.70	18.0	5.6	18.2	6.4
CC-17	100	Yes	Yes	1 on 1	90	30.7	3.87	30.7	3.87	16.3	3.1	18.6	0.0
CC-18	50	No	No	1 on 1	90	16.9	2.13	16.9	2.13	13.1	2.3	16.8	0.0
Maximums						34.3	4.32	34.3	4.32	22.4	7.7	22.8	6.9

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	CO Impacts (µg/m3) 2008 1-Hour	2008 8-Hour	2009 1-Hour	2009 8-Hour	2010 1-Hour	2010 8-Hour
CC-1	100	No	No	4 on 1	20	18.8	10.1	18.6	6.5	18.9	5.5
CC-2	100	Yes	No	4 on 1	20	23.5	**11.9**	23.3	**7.7**	23.2	6.6
CC-3	75	No	No	4 on 1	20	21.6	9.9	21.2	6.4	21.2	6.1
CC-5	100	No	No	1 on 1	20	18.4	3.0	18.8	3.3	18.2	4.9
CC-6	50	No	No	1 on 1	20	15.3	2.7	16.0	3.5	16.9	4.0
CC-7	100	No	No	4 on 1	59	19.3	10.1	19.1	6.5	19.3	5.5
CC-8	100	Yes	No	4 on 1	59	19.1	10.1	18.9	6.5	19.1	5.4
CC-9	100	No	Yes	4 on 1	59	**24.0**	11.9	**23.7**	7.6	**23.7**	**6.8**
CC-10	75	No	No	4 on 1	59	21.0	9.5	20.6	6.2	20.7	6.0
CC-12	100	No	No	4 on 1	90	18.6	9.6	18.4	6.2	18.6	5.3
CC-13	100	Yes	No	4 on 1	90	18.2	9.6	18.0	6.1	18.2	5.2
CC-14	100	Yes	Yes	4 on 1	90	23.0	11.4	22.8	7.3	22.8	6.5
CC-15	75	No	No	4 on 1	90	19.2	8.8	18.8	5.7	18.9	5.5
CC-17	100	Yes	Yes	1 on 1	90	17.5	2.8	17.9	3.3	17.4	4.7
CC-18	50	No	No	1 on 1	90	13.1	2.3	13.6	3.0	14.2	3.4
Maximums						**24.0**	**11.9**	23.7	7.7	23.7	6.8

Maximums - All Cases, All Years

Period	µg/m³	Case	Year
1-Hour	24.0	CC-9	2008
8-Hour	11.9	CC-2	2008

PSD Class II SILs - CO

Period	µg/m³
1-Hour	2,000
8-Hour	500

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

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Table 7-5. 1- and 8-Hour Average CO Maximum SIL Impacts—Natural Gas

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
A. 1-Hour Average Impacts						
CTG/HRSG operating case		CC-9	CC-9	CC-9	CC-9	CC-9
CTG load	%	100	100	100	100	100
Evaporative cooling	On/Off	On	On	On	On	On
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	59	59	59	59
1-Hour CO impact	µg/m³	22.4	22.8	**24.0**	23.7	23.7
1-Hour Impact Location						
Receptor UTM Easting coordinate (X)	meters	404,137	404,089	404,328	404,354	404,137
Receptor UTM Northing coordinate (Y)	meters	3,066,312	3,066,306	3,066,314	3,066,396	3,066,312
Receptor elevation	meters	40.8	40.5	43.2	41.4	40.8
Distance from stack*	meters	1,896	1,858	2,061	2,046	1,896
Direction vector from stack†	degrees	121	122	119	116	121
PSD SIL	µg/m³	2,000	2,000	2,000	2,000	2,000
Exceed SIL	Yes/No	N	N	N	N	N
Percent of SIL	%	1.1	1.1	**1.2**	1.2	1.2
B. 8-Hour Average Impacts						
CTG/HRSG operating case		CC-2	CC-10	CC-2	CC-2	CC-9
CTG load	%	100	100	100	100	100
Evaporative cooling	On/Off	Off	Off	Off	Off	On
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	20	20	20	20	59
8-Hour CO impact	µg/m³	7.7	6.9	**11.9**	7.7	6.8
8-Hour Impact Location						
Receptor UTM Easting coordinate (X)	meters	402,668	402,528	402,841	402,940	404,078
Receptor UTM Northing coordinate (Y)	meters	3,065,877	3,065,814	3,065,872	3,065,869	3,066,233
Receptor elevation	meters	41.8	45.5	41.5	41.6	40.7
Distance from stack*	meters	1,431	1,487	1,465	1,492	1,889
Direction vector from stack†	degrees	174	180	167	164	124
PSD SIL	µg/m³	500	500	500	500	500
Exceed SIL	Yes/No	N	N	N	N	N
Percent of SIL	%	1.5	1.4	**2.4**	1.5	1.4
PSD *de minimis* ambient impact	µg/m³	575	575	575	575	575
Exceed PSD *de minimis* ambient impact	Yes/No	N	N	N	N	N
Percent of PSD *de minimis* ambient impact	%	1.3	1.2	**2.1**	1.3	1.2

*Distance from Unit 2 CC2A stack to the location of highest impact.
†Direction from stack toward impact location. For example, 90° means the highest impact is located due east of the CC-2A stack

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-6. 1-, 3-, and 24-Hour Hour Annual Average SO_2 SIL Impacts---Natural Gas

Number of CTG/HRSG Units 4
Maximum Annual Hours 8,760 hr/yr

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG SO2 Emissions Rates (per CTG/HRSG) 1-, 3-, and 24-Hour lb/hr	g/s	Annual lb/hr	g/s	Maximum SO_2 Impacts (µg/m³) 2006 1-Hour	3-Hour	24-Hour	Annual	2007 1-Hour	3-Hour	24-Hour	Annual
CC-1	100	No	No	4 on 1	20	10.9	1.38	10.9	1.38	6.4	3.2	1.1	0.079	6.5	3.7	1.1	0.099
CC-2	100	Yes	No	4 on 1	20	**12.3**	**1.55**	**12.3**	**1.55**	7.9	**3.7**	1.3	**0.094**	8.1	4.6	**1.3**	**0.118**
CC-3	75	No	No	4 on 1	20	8.7	1.10	8.7	1.10	7.2	3.1	1.3	0.078	7.3	4.2	1.0	0.096
CC-5	100	No	No	1 on 1	20	**12.3**	**1.55**	**12.3**	**1.55**	6.3	2.5	0.5	0.029	6.7	3.3	0.6	0.036
CC-6	50	No	No	1 on 1	20	6.9	0.87	6.9	0.87	5.5	2.1	0.5	0.023	7.2	3.0	0.5	0.029
CC-7	100	No	No	4 on 1	59	10.3	1.29	10.3	1.29	6.6	3.1	1.1	0.078	6.7	3.8	1.1	0.098
CC-8	100	Yes	No	4 on 1	59	10.3	1.30	10.3	1.30	6.5	3.1	1.1	0.078	6.6	3.7	1.1	0.098
CC-9	100	No	Yes	4 on 1	59	11.7	1.48	11.7	1.48	**8.0**	3.7	**1.3**	0.093	**8.2**	**4.7**	1.2	0.117
CC-10	75	No	No	4 on 1	59	8.2	1.04	8.2	1.04	7.0	3.0	1.3	0.075	7.4	4.1	1.0	0.093
CC-12	100	No	No	4 on 1	90	9.4	1.19	9.4	1.19	6.3	3.0	1.1	0.074	6.4	3.7	1.0	0.093
CC-13	100	Yes	No	4 on 1	90	9.7	1.23	9.7	1.23	6.3	3.0	1.1	0.075	6.4	3.6	1.0	0.093
CC-14	100	Yes	Yes	4 on 1	90	11.1	1.40	11.1	1.40	7.8	3.6	1.3	0.090	8.0	4.5	1.2	0.112
CC-15	75	No	No	4 on 1	90	7.7	0.96	7.7	0.96	6.4	2.8	1.2	0.069	6.5	3.7	0.9	0.086
CC-17	100	Yes	Yes	1 on 1	90	11.1	1.40	11.1	1.40	5.9	2.4	0.5	0.027	6.7	3.3	0.6	0.033
CC-18	50	No	No	1 on 1	90	6.1	0.76	6.1	0.76	4.7	1.8	0.4	0.020	6.0	2.6	0.4	0.025
Maximums						12.3	1.551	12.3	1.551	8.0	3.7	1.3	0.094	8.2	4.7	1.3	**0.118**

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum SO_2 Impacts (µg/m³) 2008 1-Hour	3-Hour	24-Hour	Annual	2009 1-Hour	3-Hour	24-Hour	Annual	2010 1-Hour	3-Hour	24-Hour	Annual
CC-1	100	No	No	4 on 1	20	6.7	4.9	1.2	0.080	6.6	2.6	0.9	0.088	6.7	3.5	1.1	0.088
CC-2	100	Yes	No	4 on 1	20	8.4	**5.7**	**1.4**	0.097	8.4	3.1	1.0	**0.106**	8.3	4.3	1.4	**0.106**
CC-3	75	No	No	4 on 1	20	7.7	4.5	1.2	0.083	7.6	3.8	1.0	0.089	7.6	3.8	1.2	0.089
CC-5	100	No	No	1 on 1	20	6.6	2.2	0.4	0.031	6.7	3.2	0.5	0.033	6.5	3.2	0.9	0.041
CC-6	50	No	No	1 on 1	20	5.5	1.8	0.4	0.026	5.8	3.4	0.5	0.025	6.1	2.4	0.7	0.036
CC-7	100	No	No	4 on 1	59	6.9	4.8	1.2	0.081	6.8	2.6	0.9	0.088	6.9	3.5	1.1	0.088
CC-8	100	Yes	No	4 on 1	59	6.8	4.8	1.2	0.080	6.8	2.6	0.9	0.088	6.8	3.5	1.1	0.088
CC-9	100	No	Yes	4 on 1	59	**8.6**	5.6	1.4	**0.097**	**8.5**	3.2	**1.1**	0.106	**8.5**	**4.3**	**1.4**	0.106
CC-10	75	No	No	4 on 1	59	7.5	4.3	1.1	0.081	7.4	**3.8**	1.0	0.087	7.4	3.7	1.2	0.086
CC-12	100	No	No	4 on 1	90	6.6	4.5	1.2	0.077	6.6	2.5	0.9	0.084	6.6	3.4	1.1	0.084
CC-13	100	Yes	No	4 on 1	90	6.6	4.6	1.2	0.077	6.5	2.5	0.8	0.084	6.6	3.4	1.1	0.084
CC-14	100	Yes	Yes	4 on 1	90	8.3	5.4	1.4	0.094	8.3	3.2	1.1	0.102	8.3	4.2	1.3	0.102
CC-15	75	No	No	4 on 1	90	6.8	4.0	1.1	0.074	6.7	3.4	1.0	0.080	6.8	3.4	1.1	0.079
CC-17	100	Yes	Yes	1 on 1	90	6.3	2.1	0.4	0.029	6.5	3.2	0.5	0.031	6.3	3.0	0.8	0.040
CC-18	50	No	No	1 on 1	90	4.7	1.6	0.3	0.022	4.9	2.9	0.4	0.022	5.1	2.1	0.6	0.031
Maximums						**8.6**	**5.7**	**1.4**	0.097	8.5	3.8	1.1	0.106	8.5	4.3	1.4	0.106

Maximums - All Cases, All Years

Period	µg/m³	Case	Year
1-Hour	8.6	CC-9	2008
3-Hour	5.7	CC-2	2008
24-Hour	1.4	CC-2	2008
Annual	0.118	CC-2	2007

Highest 5-Year Average

Period	µg/m³	Case	Year
1-Hour	8.4	CC-9	2006 to 2010

PSD Class II SILs - SO_2

Period	µg/m³
1-Hour	7.8
3-Hour	25
24-Hour	5
Annual	1

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-7. 1- and 3-Hour Average SO_2 Maximum SIL Impacts—Natural Gas

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 1-Hour Average Impacts							
CTG/HRSG operating case		CC-6	CC-6	CC-10	CC-6	CC-6	
CTG load	%	50	50	75	50	50	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Duct burner firing	Yes/No	No	No	No	No	No	
Configuration	—	1 on 1	1 on 1	4 on 1	1 on 1	1 on 1	
Ambient air temperature	°F	20	20	59	20	20	
1-Hour SO_2 Impact*	µg/m³	8.03	8.20	**8.60**	8.53	8.51	8.37
1-Hour impact location							
Receptor UTM Easting coordinate (X)	meters	404,085	404,074	404,328	404,113	404,161	
Receptor UTM Northing coordinate (Y)	meters	3,066,282	3,066,209	3,066,314	3,066,309	3,066,315	
Receptor elevation	meters	40.5	40.9	43.2	40.7	40.9	
Distance from stack†	meters	1,868	1,900	2,061	1,877	1,915	
Direction vector from stack‡	degrees	123	125	119	122	121	
PSD SIL	µg/m³						7.5
Exceed SIL	Yes/No						Yes
Percent of SIL	%						111.7
B. 3-Hour Average Impacts							
CTG/HRSG operating case		CC-2	CC-10	CC-2	CC-6	CC-10	
CTG load	%	100	75	100	50	75	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Duct burner firing	Yes/No	Yes	No	Yes	No	No	
Configuration	—	4 on 1	4 on 1	4 on 1	1 on 1	4 on 1	
Ambient air temperature	°F	20	59	20	20	59	
3-Hour SO_2 Impact*	µg/m³	3.7	4.7	**5.7**	3.8	4.3	
3-Hour impact location							
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,981	401,090	401,035	
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,508	3,067,673	3,067,591	
Receptor elevation	meters	43.6	43.2	43.5	43.7	43.7	
Distance from stack†	meters	1,531	1,586	1,552	1,477	1,512	
Direction vector from stack‡	degrees	279	275	278	285	281	
PSD SIL	µg/m³	25	25	25	25	25	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	14.9	18.6	**22.9**	15.4	17.3	

Note: Maximum impacts shown in **bold** font.

*Maximum impact for all operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-8. 24-Hour and Annual Average SO_2 Maximum SIL Impacts—Natural Gas

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
A. 24-Hour Average Impacts						
CTG/HRSG operating case		CC-10	CC-2	CC-2	CC-10	CC-2
CTG load	%	75	100	100	75	100
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Duct burner firing	Yes/No	No	Yes	Yes	No	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	20	20	59	20
24-Hour SO_2 Impact[1]	µg/m³	1.31	1.25	**1.43**	1.08	1.39
24-Hour impact location						
Receptor UTM Easting coordinate (X)	meters	402,446	402,347	402,841	403,359	404,137
Receptor UTM Northing coordinate (Y)	meters	3,065,884	3,065,887	3,065,872	3,065,856	3,066,312
Receptor elevation	meters	41.5	42.1	41.5	41.0	40.8
Distance from stack†	meters	1,419	1,424	1,465	1,671	1,896
Direction vector from stack‡	degrees	183	187	167	150	121
PSD SIL	µg/m³	5	5	5	5	5
Exceed SIL	Y/N	No	No	No	No	No
Percent of SIL	%	26.2	25.0	**28.6**	21.7	27.8
PSD *de minimis* ambient impact	µg/m³	13	13	13	13	13
Exceed PSD *de minimis* ambient impact	Y/N	N	N	N	N	N
Percent of PSD *de minimis* ambient impact	%	10.1	9.6	**11.0**	8.3	10.7
B. Annual Average Impacts						
CTG/HRSG operating case		CC-2	CC-2	CC-2	CC-2	CC-2
CTG load	%	100	100	100	100	100
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	20	20	20	20	20
Annual SO_2 Impact[1]	µg/m³	0.094	**0.118**	0.097	0.106	0.106
Annual impact location						
Receptor UTM Easting coordinate (X)	meters	401,008	400,927	400,981	400,995	401,022
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,425	3,067,508	3,067,529	3,067,570
Receptor elevation	meters	43.6	43.1	43.5	43.5	43.6
Distance from stack†	meters	1,531	1,597	1,552	1,541	1,521
Direction vector from stack‡	degrees	279	274	278	279	280
PSD SIL	µg/m³	1	1	**1**	1	1
Exceed SIL	Yes/No	No	No	**No**	No	No
Percent of SIL	%	9.4	**11.8**	9.7	10.6	10.6

Note: Maximum impacts shown in **bold** font.

*Maximum impact for all operating cases.

†Distance from Unit 2 CC-2A stack to the location of highest impact.

‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-9. 24-Hour and Annual Average $PM_{10}/PM_{2.5}$ SIL Impacts—Natural Gas

Number of CTG/HRSG Units 4
Maximum Annual Hours 8,760 hr/yr

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG $PM_{10}/PM_{2.5}$ Emissions Rates (Per CTG/HRSG) 24-Hour lb/hr	24-Hour g/s	Annual lb/hr	Annual g/s	$PM_{10}/PM_{2.5}$ Impacts (ug/m^3) 2006 24-Hour	2006 Annual	2007 24-Hour	2007 Annual
CC-1	100	No	No	4 on 1	20	11.7	1.47	11.7	1.47	1.2	0.084	1.1	0.106
CC-2	100	Yes	No	4 on 1	20	**18.3**	**2.30**	**18.3**	**2.30**	1.9	0.140	1.9	0.175
CC-3	75	No	No	4 on 1	20	11.1	1.40	11.1	1.40	1.6	0.099	1.3	0.123
CC-5	100	No	No	1 on 1	20	**18.3**	**2.30**	**18.3**	**2.30**	0.8	0.043	0.9	0.053
CC-6	50	No	No	1 on 1	20	10.7	1.34	10.7	1.34	0.7	0.035	0.7	0.045
CC-7	100	No	No	4 on 1	59	11.4	1.44	11.4	1.44	1.2	0.087	1.2	0.109
CC-8	100	Yes	No	4 on 1	59	11.4	1.44	11.4	1.44	1.2	0.086	1.2	0.108
CC-9	100	No	Yes	4 on 1	59	17.9	2.26	17.9	2.26	2.0	0.143	1.9	0.178
CC-10	75	No	No	4 on 1	59	11.0	1.39	11.0	1.39	1.7	0.100	1.4	0.124
CC-12	100	No	No	4 on 1	90	11.2	1.41	11.2	1.41	1.3	0.088	1.2	0.110
CC-13	100	Yes	No	4 on 1	90	11.3	1.43	11.3	1.43	1.2	0.087	1.2	0.109
CC-14	100	Yes	Yes	4 on 1	90	17.7	2.23	17.7	2.23	**2.0**	**0.143**	**1.9**	**0.179**
CC-15	75	No	No	4 on 1	90	10.9	1.37	10.9	1.37	1.7	0.098	1.3	0.122
CC-17	100	Yes	Yes	1 on 1	90	17.7	2.23	17.7	2.23	0.8	0.043	0.9	0.053
CC-18	50	No	No	1 on 1	90	10.5	1.32	10.5	1.32	0.7	0.034	0.7	0.044
Maximums						18.3	2.301	18.3	2.301	2.0	0.143	1.9	**0.179**

Case	Load (%)	Evaporative Cooling (Yes/No)	Duct Burners (Yes/No)	Configuration	Ambient Temperature (°F)	$PM_{10}/PM_{2.5}$ Impacts (μg/m3) 2008 24-Hour	2008 Annual	2009 24-Hour	2009 Annual	2010 24-Hour	2010 Annual
CC-1	100	No	No	4 on 1	20	1.3	0.085	0.9	0.094	1.2	0.094
CC-2	100	Yes	No	4 on 1	20	2.1	0.144	1.5	0.157	2.0	0.157
CC-3	75	No	No	4 on 1	20	1.5	0.106	1.3	0.114	1.6	0.113
CC-5	100	No	No	1 on 1	20	0.6	0.045	0.8	0.049	1.3	0.061
CC-6	50	No	No	1 on 1	20	0.6	0.040	0.7	0.039	1.1	0.055
CC-7	100	No	No	4 on 1	59	1.3	0.090	1.0	0.098	1.3	0.098
CC-8	100	Yes	No	4 on 1	59	1.3	0.089	1.0	0.097	1.2	0.097
CC-9	100	No	Yes	4 on 1	59	2.2	0.149	1.7	0.162	2.1	0.161
CC-10	75	No	No	4 on 1	59	1.5	0.108	1.4	0.116	1.6	0.115
CC-12	100	No	No	4 on 1	90	1.4	0.092	1.0	0.100	1.3	0.100
CC-13	100	Yes	No	4 on 1	90	1.3	0.090	1.0	0.098	1.3	0.098
CC-14	100	Yes	Yes	4 on 1	90	**2.2**	**0.150**	**1.7**	**0.162**	**2.1**	**0.162**
CC-15	75	No	No	4 on 1	90	1.5	0.106	1.4	0.113	1.6	0.113
CC-17	100	Yes	Yes	1 on 1	90	0.6	0.046	0.8	0.050	1.3	0.063
CC-18	50	No	No	1 on 1	90	0.5	0.038	0.7	0.038	1.1	0.053
Maximums						**2.2**	0.150	1.7	0.16	2.1	0.16

Maximums - All Cases, All Years

Period	μg/m^3	Case	Year
24-Hour	2.2	CC-14	2008
Annual	0.179	CC-14	2007

PSD Class II SILs PM_{10} / $PM_{2.5}$

PM_{10} Period	μg/m^3	$PM_{2.5}$ Period	μg/m^3
24-Hour	5	24-Hour	1.2
Annual	1	Annual	0.3

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-10. 24-Hour and Annual Average PM_{10} Maximum SIL Impacts—Natural Gas

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
A. 24-Hour Average Impacts						
CTG/HRSG operating case		CC-14	CC-14	CC-14	CC-14	CC-14
CTG load	%	100	100	100	100	100
Evaporative cooling	On/Off	On	On	On	On	On
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	90	90	90	90	90
24-Hour PM_{10} Impact	μg/m³	2.03	1.90	**2.20**	1.71	2.14
24-Hour impact location						
Receptor UTM Easting coordinate (X)	meters	404,563	402,347	402,841	403,359	404,089
Receptor UTM Northing coordinate (Y)	meters	3,066,625	3,065,887	3,065,872	3,065,856	3,066,306
Receptor elevation	meters	41.4	42.1	41.5	41.0	40.5
Distance from stack*	meters	2,153	1,424	1,465	1,671	1,858
Direction vector from stack†	degrees	108	187	167	150	122
PSD SIL	μg/m³	5	5	5	5	5
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	40.7	38.0	44.0	34.2	42.9
PSD *de minimis* ambient impact	μg/m³	10	10	10	10	10
Exceed PSD *de minimis* ambient impact	Yes/No	N	N	N	N	N
Percent of PSD *de minimis* ambient impact	%	20.3	19.0	**22.0**	17.1	21.4
B. Annual Average Impacts						
CTG/HRSG operating case		CC-14	CC-14	CC-14	CC-14	CC-14
CTG load	%	100	100	100	100	100
Evaporative cooling	On/Off	On	On	On	On	On
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	90	90	90	90	90
Annual PM_{10} Impact	μg/m³	0.143	**0.179**	0.150	0.162	0.162
Annual impact location						
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,995	400,995	401,022
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,529	3,067,570
Receptor elevation	meters	43.6	43.2	43.5	43.5	43.6
Distance from stack*	meters	1,531	1,586	1,541	1,541	1,521
Direction vector from stack†	degrees	279	275	279	279	280
PSD SIL	μg/m³	1	1	1	1	1
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	14.3	**17.9**	15.0	16.2	16.2

Note: Maximum impacts shown in **bold** font.

*Distance from Unit 2 CC-2A stack to the location of highest impact.
†Direction from stack toward impact location. For example, 90° means the highest impact is located due east of the CC-2A stack.

Source: ECT, 2012.

Table 7-11. 24-Hour and Annual Average $PM_{2.5}$ Maximum SIL Impacts—Natural Gas

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 24-Hour Average Impacts							
CTG/HRSG operating case		CC-14	CC-14	CC-14	CC-14	CC-14	
CTG load	%	100	100	100	100	100	
Evaporative cooling	On/Off	On	On	On	On	On	
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	90	90	90	90	90	
24-Hour $PM_{2.5}$ Impact	µg/m³	2.03	1.90	**2.20**	1.71	2.14	2.00
24-Hour Impact Location							
Receptor UTM Easting coordinate (X)	meters	404,563	402,347	402,841	403,359	404,089	
Receptor UTM Northing coordinate (Y)	meters	3,066,625	3,065,887	3,065,872	3,065,856	3,066,306	
Receptor elevation	meters	41.4	42.1	41.5	41.0	40.5	
Distance from stack*	meters	2,153	1,424	1,465	1,671	1,858	
Direction vector from stack†	degrees	108	187	167	150	122	
PSD SIL	µg/m³						1.2
Exceed SIL	Yes/No						Yes
Percent of SIL	%						166.5
B. Annual Average Impacts							
CTG/HRSG operating case		CC-14	CC-14	CC-14	CC-14	CC-14	
CTG load	%	100	100	100	100	100	
Evaporative cooling	On/Off	On	On	On	On	On	
Duct burner firing	Yes/No	Yes	Yes	Yes	Yes	Yes	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	90	90	90	90	90	
Annual $PM_{2.5}$ Impact	µg/m³	0.143	**0.179**	0.150	0.162	0.162	
Annual Impact Location							
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,995	400,995	401,022	
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,529	3,067,570	
Receptor elevation	meters	43.6	43.2	43.5	43.5	43.6	
Distance from stack*	meters	1,531	1,586	1,541	1,541	1,521	
Direction vector from stack†	degrees	279	275	279	279	280	
PSD SIL	µg/m³	0.3	0.3	0.3	0.3	0.3	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	47.7	**59.6**	49.9	54.1	54.1	
PSD *de minimis* ambient impact	µg/m³	10	10	10	10	10	
Exceed PSD *de minimis* ambient impact	Y/N	No	No	No	No	No	
Percent of PSD *de minimis* ambient impact	%	1.4	**1.8**	1.5	1.6	1.6	

Note: Maximum impacts shown in **bold** font.

*Distance from Unit 2 CC2A stack to the location of highest impact.
†Direction from stack toward impact location. For example, 90° means the highest impact is located due east of the CC-2A stack

Source: ECT, 2012.

Table 7-12. 1-Hour NO_2 SIL Results—Warm Startup Natural Gas

A. Model Input

Parameter	Unit	Value				
		CC-2A	CC-2B	CC-2C	CC-2D	Totals
NO_x emissions rate	lb/hr	14.3	14.3	14.3	105.0	147.9
	g/s	1.8	1.8	1.8	13.2	18.6
Stack temperature	°F	207.6	207.6	207.6	162.0	
	K	370.7	370.7	370.7	345.4	
Stack velocity	ft/s	60	60	60	30	
	m/s	18.3	18.3	18.3	9.1	

B. Model Results

Parameter	Unit	Value
1-Hour NO_2 impact (5-year 2006-2010 maximum), Tier 1	μg/m^3	59.1
1-Hour NO_2 impact (5-year 2006-2010 maximum), Tier 2	μg/m^3	47.3
Receptor UTM Easting (meter)	meters	401,553
Receptor UTM Northing (meter)	meters	3,068,584
Receptor elevation (meter, amsl)	meters	42.3
Distance from stack (meter)*	meters	1,607
Direction from stack (degrees)*	°	323.0
1-Hour NO_2 SIL	μg/m^3	7.5
1-Hour NO_2 NAAQS	μg/m^3	188
Number of receptors > 1-hour NO_2 SIL	—	5,933
Farthest distance to receptor > 1-hour NO_2 SIL	meters	21,463

*Distance from CC-2A HRSG stack.

Source: ECT, 2012.

Table 7-13. 1-Hour CO SIL Results—Natural Gas Warm Startup

A. Model Input

Parameter	Unit	Value				
		CC-2A	CC-2B	CC-2C	CC-2D	Totals
CO emissions rate	lb/hr	31.7	31.7	31.7	170.0	265.1
	g/s	4.0	4.0	4.0	21.4	33.4
Stack temperature	°F	207.6	207.6	207.6	162.0	
	K	370.7	370.7	370.7	345.4	
Stack velocity	ft/s	60	60	60	30	
	m/s	18.3	18.3	18.3	9.1	

B. Model Results

Parameter	Unit	Value
1-Hour CO impact (5-year 2006-2010 maximum)	μg/m³	97.3
Receptor UTM Easting (meter)	meters	401,552.7
Receptor UTM Northing (meter)	meters	3,068,584
Receptor elevation (meter, amsl)	meters	42
Distance from stack (meter)*	meters	1,606.7
Direction from stack (degrees)*	°	323
1-Hour CO SIL	μg/m³	2,000.0
1-Hour CO NAAQS	μg/m³	40,000.0
Number of receptors > 1-hour CO SIL	—	0
Farthest distance to receptor > 1-hour CO SIL	meters	Not applicable

*Distance from CC-2A HRSG stack.

Source: ECT, 2012.

Table 7-2 presents the 1-hour and annual average NO_2 impacts for each operating case. Table 7-3 provides details of the maximum 1-hour and annual average NO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-4 provides maximum 1- and 8-hour average CO impacts for each operating case. Table 7-5 presents details of the maximum 1- and 8-hour average CO impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-6 provides maximum 1- , 3-, and 24-hour and annual average SO_2 impacts for each operating case. Table 7-7 presents details of the maximum 1- and 3-hour average SO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs. Table 7-8 contains details of the maximum 24-hour and annual average SO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-9 presents maximum 24-hour and annual average $PM_{10}/PM_{2.5}$ impacts for each operating case. Table 7-10 provides details of the maximum 24-hour and annual average PM_{10} impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels. Table 7-11 contains details of the maximum 24-hour and annual average $PM_{2.5}$ impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Tables 7-12 and 7-13 provide modeling results for CTG/HRSG warm startups during natural gas firing for NO_2 and CO, respectively. These tables show the worst-case warm startup NO_2 and CO emissions rates and corresponding stack temperatures and velocities.

7.2.2 ULSD FUEL OIL

Tables 7-14 through 7-24 provide results for the Project when firing ULSD fuel oil. Table 7-14 provides normalized predicted impacts based on the unit emissions rate of 1.0 g/s for each operating case and pollutant averaging period.

Table 7-15 presents the 1-hour and annual average NO_2 impacts for each operating case. Table 7-16 presents details of the maximum 1-hour and annual and average NO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-17 presents maximum 1- and 8-hour average CO impacts for each operating case. Table 7-18 contain details of the maximum 1- and 8-hour average CO impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-19 provides maximum 1- , 3-, and 24-hour and annual average SO_2 impacts for each operating case. Table 7-20 presents details of the maximum 1- and 3-hour average SO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs. Table 7-21 supplies details of the maximum 24-hour and annual average SO_2 impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-22 provides maximum 24-hour and annual average $PM_{10}/PM_{2.5}$ impacts for each operating case. Table 7-23 supplies details of the maximum 24-hour and annual average PM_{10} impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels. Table 7-24 presents details of the maximum 24-hour and annual average $PM_{2.5}$ impacts, including locations of the maximum impacts and comparisons to the PSD Class II SILs and ambient monitoring *de minimis* levels.

Table 7-14. Normalized Model Results—ULSD Fuel Oil

Modeled Emissions Rate 1.0 g/s per CTG/HRSG unit

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Impacts - Four CTG/HRSG Units (μg/m³) 2006 1-Hour	2006 3-Hour	2006 8-Hour	2006 24-Hour	2006 Annual	2007 1-Hour	2007 3-Hour	2007 8-Hour	2007 24-Hour	2007 Annual	2008 1-Hour	2008 3-Hour	2008 8-Hour	2008 24-Hour	2008 Annual
CC-19	100	No	4 on 1	20	4.31	2.21	1.62	0.75	0.054	4.40	2.46	1.45	0.75	0.069	4.47	3.40	2.46	0.83	0.054
CC-20	75	No	4 on 1	20	6.27	2.76	1.99	1.08	0.069	6.37	3.63	2.07	0.91	0.086	6.72	4.06	3.15	1.05	0.073
CC-22	100	No	1 on 1	20	3.32	1.28	0.62	0.28	0.016	3.29	1.75	0.75	0.31	0.020	3.36	1.18	0.64	0.24	0.017
CC-23	50	No	1 on 1	20	6.17	2.37	1.08	0.51	0.026	**8.05**	3.36	1.44	0.55	0.033	6.20	2.07	1.07	0.39	0.028
CC-24	100	No	4 on 1	59	4.69	2.32	1.71	0.80	0.058	4.79	2.70	1.51	0.78	0.072	4.90	3.57	2.64	0.88	0.059
CC-25	100	Yes	4 on 1	59	4.68	2.32	1.70	0.80	0.057	4.76	2.69	1.51	0.78	0.072	4.87	3.57	2.63	0.88	0.058
CC-26	75	No	4 on 1	59	**6.59**	**2.87**	**2.05**	**1.19**	**0.071**	6.69	**3.84**	**2.29**	**0.95**	**0.088**	**7.06**	**4.14**	**3.24**	**1.08**	**0.076**
CC-28	100	No	4 on 1	90	5.00	2.42	1.77	0.85	0.060	5.09	2.89	1.57	0.81	0.075	5.24	3.72	2.78	0.93	0.062
CC-29	100	Yes	4 on 1	90	4.82	2.37	1.73	0.82	0.059	4.90	2.78	1.54	0.79	0.074	5.01	3.64	2.71	0.90	0.060
CC-30	75	No	4 on 1	90	6.37	2.83	2.02	1.14	0.070	6.46	3.70	2.17	0.93	0.087	6.78	4.11	3.20	1.07	0.074
CC-32	100	Yes	1 on 1	90	3.67	1.42	0.70	0.32	0.018	3.71	1.98	0.85	0.35	0.022	3.81	1.30	0.68	0.26	0.018
CC-33	50	No	1 on 1	90	5.94	2.29	1.06	0.51	0.025	7.67	3.30	1.41	0.53	0.032	6.03	2.01	1.04	0.38	0.028
Maximums					6.59	2.87	2.05	**1.19**	0.071	**8.05**	3.84	2.29	0.95	**0.088**	7.06	**4.14**	**3.24**	1.08	0.076

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Impacts - Four CTG/HRSG Units (μg/m³) 2009 1-Hour	2009 3-Hour	2009 8-Hour	2009 24-Hour	2009 Annual	2010 1-Hour	2010 3-Hour	2010 8-Hour	2010 24-Hour	2010 Annual
CC-19	100	No	4 on 1	20	4.43	1.80	1.59	0.62	0.060	4.51	2.33	1.37	0.74	0.060
CC-20	75	No	4 on 1	20	6.61	3.11	2.05	0.90	0.079	6.63	3.35	1.91	1.07	0.079
CC-22	100	No	1 on 1	20	3.47	1.33	0.53	0.29	0.018	3.38	1.72	0.93	0.46	0.022
CC-23	50	No	1 on 1	20	6.45	**3.77**	1.41	0.52	0.029	6.79	2.76	1.62	0.80	0.040
CC-24	100	No	4 on 1	59	4.85	1.91	1.69	0.65	0.064	4.92	2.53	1.44	0.81	0.064
CC-25	100	Yes	4 on 1	59	4.82	1.91	1.69	0.64	0.064	4.90	2.52	1.44	0.81	0.064
CC-26	75	No	4 on 1	59	**6.93**	3.50	**2.11**	**0.97**	**0.082**	**6.97**	**3.50**	**2.01**	**1.13**	**0.082**
CC-28	100	No	4 on 1	90	5.18	2.02	1.78	0.67	0.067	5.25	2.69	1.49	0.86	0.067
CC-29	100	Yes	4 on 1	90	4.97	1.97	1.74	0.65	0.066	5.04	2.60	1.46	0.83	0.066
CC-30	75	No	4 on 1	90	6.64	3.14	2.08	0.93	0.080	6.71	3.39	1.92	1.08	0.080
CC-32	100	Yes	1 on 1	90	3.91	1.51	0.61	0.32	0.020	3.83	1.91	1.04	0.51	0.024
CC-33	50	No	1 on 1	90	6.20	3.63	1.36	0.50	0.028	6.31	2.72	1.57	0.79	0.039
Maximums					6.93	3.77	2.11	0.97	0.082	6.97	3.50	2.01	1.13	0.082

Maximums - All Cases, All Years

Period	μg/m³	Case	Year
1-Hour	8.05	CC-23	2007
3-Hour	4.14	CC-26	2008
8-Hour	3.24	CC-26	2008
24-Hour	1.19	CC-26	2006
Annual	0.088	CC-26	2007

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-15. 1-Hour and Annual Average NO_2 SIL Impacts—ULSD Fuel Oil

Number of CTG/HRSG units	4	Tier 2 NO_2/NO_x ratio (1-hour)	0.80
Maximum annual hours	750 hr/yr	Tier 2 NO_2/NO_x ratio (annual)	0.75

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG NO_x Emissions Rates (Per CTG/HRSG) 1-Hour lb/hr	1-Hour g/s	Annual lb/hr	Annual g/s	Maximum Tier 2 NO_2 Impacts (μg/m³) 2006 1-Hour	2006 Annual	2007 1-Hour	2007 Annual
CC-19	100	No	4 on 1	20	**70.5**	**8.88**	**6.0**	**0.76**	30.6	0.031	31.2	0.039
CC-20	75	No	4 on 1	20	55.9	7.04	4.8	0.60	**35.3**	0.031	**35.9**	0.039
CC-22	100	No	1 on 1	20	**70.5**	**8.88**	**6.0**	**0.76**	23.6	0.009	23.4	0.012
CC-23	50	No	1 on 1	20	43.7	5.50	3.7	0.47	27.1	0.009	35.4	0.011
CC-24	100	No	4 on 1	59	66.7	8.40	5.7	0.72	31.5	0.031	32.2	0.039
CC-25	100	Yes	4 on 1	59	67.1	8.45	5.7	0.72	31.6	**0.031**	32.2	**0.039**
CC-26	75	No	4 on 1	59	52.8	6.65	4.5	0.57	35.1	0.030	35.6	0.038
CC-28	100	No	4 on 1	90	61.6	7.76	5.3	0.66	31.0	0.030	31.6	0.037
CC-29	100	No	4 on 1	90	63.1	7.96	5.4	0.68	30.7	0.030	31.2	0.038
CC-30	75	No	4 on 1	90	49.1	6.18	4.2	0.53	31.5	0.028	31.9	0.034
CC-32	100	Yes	1 on 1	90	63.1	7.96	5.4	0.68	23.3	0.009	23.6	0.011
CC-33	50	No	1 on 1	90	38.5	4.85	3.3	0.42	23.0	0.008	29.7	0.010
Maximums					70.5	8.884	6.0	0.761	35.3	0.031	35.9	**0.039**

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum Tier 2 NO_2 Impacts (μg/m³) 2008 1-Hour	2008 Annual	2009 1-Hour	2009 Annual	2010 1-Hour	2010 Annual
CC-19	100	No	4 on 1	20	31.8	0.031	31.5	0.034	32.0	0.034
CC-20	75	No	4 on 1	20	**37.9**	**0.033**	**37.3**	**0.036**	**37.3**	**0.036**
CC-22	100	No	1 on 1	20	23.9	0.010	24.7	0.011	24.1	0.012
CC-23	50	No	1 on 1	20	27.3	0.010	28.4	0.010	29.9	0.014
CC-24	100	No	4 on 1	59	33.0	0.032	32.6	0.035	33.1	0.035
CC-25	100	Yes	4 on 1	59	33.0	0.032	32.6	0.035	33.1	0.035
CC-26	75	No	4 on 1	59	37.6	0.033	36.9	0.035	37.1	0.035
CC-28	100	No	4 on 1	90	32.5	0.031	32.1	0.034	32.6	0.034
CC-29	100	No	4 on 1	90	31.9	0.031	31.6	0.034	32.1	0.033
CC-30	75	No	4 on 1	90	33.5	0.030	32.8	0.032	33.2	0.032
CC-32	100	Yes	1 on 1	90	24.3	0.009	24.9	0.010	24.4	0.012
CC-33	50	No	1 on 1	90	23.4	0.009	24.1	0.009	24.5	0.012
Maximums					**37.9**	0.033	37.3	0.036	37.3	0.036

Maximums - All Cases, All Years

Period	μg/m³	Case	Year
1-Hour	37.9	CC-20	2008
Annual	0.039	CC-25	2007

Highest 5-Year Average

Period	μg/m³	Case	Year
1-Hour	36.7	CC-20	2006-2010

PSD Class II SILs - NO_2

Period	μg/m³
1-Hour	7.5
Annual	1

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

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Table 7-16. 1-Hour and Annual Average NO_2 Maximum SIL Impacts—ULSD Fuel Oil

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 1-Hour Average Impacts							
CTG/HRSG operating case		CC-20	CC-20	CC-20	CC-20	CC-20	
CTG load	%	75	75	75	75	75	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	20	20	20	20	20	
Tier 2 1-Hour NO_2 impact*	µg/m³	35.3	35.9	**37.9**	37.3	37.3	36.7
1-Hour Impact Location							
Receptor UTM Easting coordinate (X)	meters	404,089	404,089	404,328	404,354	404,137	
Receptor UTM Northing coordinate (Y)	meters	3,066,306	3,066,306	3,066,314	3,066,396	3,066,312	
Receptor elevation	meters	40.5	40.5	43.2	41.4	40.8	
Distance from stack†	meters	1,858	1,858	2,061	2,046	1,896	
Direction Vector from stack‡	degrees	122	122	119	116	121	
PSD SIL	µg/m³						7.5
Exceed SIL	Yes/No						Yes
Percent of SIL	%						489.8
B. Annual Average Impacts							
CTG/HRSG operating case		CC-25	CC-25	CC-20	CC-20	CC-20	
CTG load	%	100	100	75	75	75	
Evaporative cooling	On/Off	On	On	Off	Off	Off	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	59	59	20	20	20	
Tier 2 Annual NO_2 Impact§	µg/m³	0.031	**0.039**	0.033	0.036	0.036	
Annual Impact Location							
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,995	400,995	401,022	
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,529	3,067,570	
Receptor elevation	meters	43.6	43.2	43.5	43.5	43.6	
Distance from stack†	meters	1,531	1,586	1,541	1,541	1,521	
Direction Vector from stack‡	degrees	279	275	279	279	280	
PSD SIL	µg/m³	1	1	1	1	1	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	3.1	**3.9**	3.3	3.6	3.6	
PSD *de minimis* ambient impact	µg/m³	14	14	14	14	14	
Exceed PSD *de minimis* ambient impact	Yes/No	No	No	No	No	No	
Percent of PSD *de minimis* ambient impact	%	0.2	**0.3**	0.2	0.3	0.3	

Note: Maximum impacts shown in **bold** font.

*Maximum impact for all operating cases, EPA default NO_2/NO_x ratio of 0.80.

†Distance from Unit 2 CC-2A stack to the location of highest impact.

‡Direction from stack <u>toward</u> impact location. For example, 90° means the highest impact is located due east of the CC-2A stack

§Maximum impact for all operating cases, EPA default NO_2/NO_x ratio of 0.75.

Source: ECT, 2012.

Table 7-17. 1- and 8-Hour Average CO SIL Impacts—ULSD Fuel Oil

Number of CTG/HRSG units 4

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	CTG/HRSG CO Emissions Rates (Per CTG/HRSG) 1-Hour lb/hr	1-Hour g/s	Annual lb/hr	Annual g/s	Maximum CO Impacts (μg/m³) 2006 1-Hour	2006 8-Hour	2007 1-Hour	2007 8-Hour
CC-19	100	No	4 on 1	20	**38.9**	**4.91**	**38.9**	**4.91**	21.1	7.9	21.6	7.1
CC-20	75	No	4 on 1	20	30.9	3.89	30.9	3.89	**24.4**	7.7	**24.8**	8.0
CC-22	100	No	1 on 1	20	**38.9**	**4.91**	**38.9**	**4.91**	16.3	3.1	16.1	3.7
CC-23	50	No	1 on 1	20	24.2	3.04	24.2	3.04	18.8	3.3	24.5	4.4
CC-24	100	No	4 on 1	59	37.0	4.66	37.0	4.66	21.8	8.0	22.3	7.0
CC-25	100	Yes	4 on 1	59	37.3	4.69	37.3	4.69	21.9	**8.0**	22.4	7.1
CC-26	75	No	4 on 1	59	29.1	3.67	29.1	3.67	24.2	7.5	24.5	**8.4**
CC-28	100	No	4 on 1	90	34.2	4.31	34.2	4.31	21.5	7.6	21.9	6.8
CC-29	100	No	4 on 1	90	35.0	4.41	35.0	4.41	21.2	7.6	21.6	6.8
CC-30	75	No	4 on 1	90	27.1	3.42	27.1	3.42	21.8	6.9	22.1	7.4
CC-32	100	Yes	1 on 1	90	35.0	4.41	35.0	4.41	16.2	3.1	16.4	3.7
CC-33	50	No	1 on 1	90	21.3	2.68	21.3	2.68	15.9	2.8	20.5	3.8
Maximums					38.9	4.91	38.9	4.91	24.4	8.0	24.8	8.4

Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	Maximum CT CO Impacts (μg/m³) 2008 1-Hour	2008 8-Hour	2009 1-Hour	2009 8-Hour	2010 1-Hour	2010 8-Hour
CC-19	100	No	4 on 1	20	21.9	12.0	21.7	7.8	22.1	6.7
CC-20	75	No	4 on 1	20	**26.2**	12.3	**25.8**	**8.0**	**25.8**	**7.4**
CC-22	100	No	1 on 1	20	16.5	3.1	17.0	2.6	16.6	4.6
CC-23	50	No	1 on 1	20	18.9	3.3	19.6	4.3	20.7	4.9
CC-24	100	No	4 on 1	59	22.8	12.3	22.6	7.9	22.9	6.7
CC-25	100	Yes	4 on 1	59	22.9	**12.3**	22.6	7.9	23.0	6.8
CC-26	75	No	4 on 1	59	25.9	11.9	25.4	7.7	25.6	7.4
CC-28	100	No	4 on 1	90	22.6	12.0	22.3	7.7	22.6	6.4
CC-29	100	No	4 on 1	90	22.1	11.9	21.9	7.7	22.2	6.4
CC-30	75	No	4 on 1	90	23.2	10.9	22.7	7.1	22.9	6.6
CC-32	100	Yes	1 on 1	90	16.8	3.0	17.3	2.7	16.9	4.6
CC-33	50	No	1 on 1	90	16.1	2.8	16.6	3.6	16.9	4.2
Maximums					**26.2**	**12.3**	25.8	8.0	25.8	7.4

Maximums - All Cases, All Years

Period	μg/m³	Case	Year
1-Hour	26.2	CC-20	2008
8-Hour	12.3	CC-25	2008

PSD Class II SILs - CO

Period	μg/m³
1-Hour	2,000
8-Hour	500

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

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Table 7-18. 1- and 8-Hour Average CO Maximum SIL Impacts—ULSD Fuel Oil

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
A. 1-Hour Average Impacts						
CTG/HRSG operating case		CC-20	CC-20	CC-20	CC-20	CC-20
CTG load	%	75	75	75	75	75
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	20	20	20	20	20
1-Hour CO Impact*	µg/m³	24.4	24.8	**26.2**	25.8	25.8
1-Hour impact location						
Receptor UTM Easting coordinate (X)	meters	404,354	404,089	404,328	404,354	404,137
Receptor UTM Northing coordinate (Y)	meters	3,066,396	3,066,306	3,066,314	3,066,396	3,066,312
Receptor elevation	meters	41.4	40.5	43.2	41.4	40.8
Distance from stack†	meters	2,046	1,858	2,061	2,046	1,896
Direction Vector from stack‡	degrees	116	122	119	116	121
PSD SIL	µg/m³	2,000	2,000	2,000	2,000	2,000
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	1.2	1.2	**1.3**	1.3	1.3
B. 8-Hour Average Impacts						
CTG/HRSG operating case		CC-25	CC-26	CC-25	CC-20	CC-20
CTG load	%	100	75	100	75	75
Evaporative cooling	On/Off	On	Off	On	Off	Off
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	59	59	20	20
8-Hour CO Impact*	µg/m³	8.0	8.4	**12.3**	8.0	7.4
8-Hour impact location						
Receptor UTM Easting coordinate (X)	meters	402,940	402,528	402,841	402,940	404,078
Receptor UTM Northing coordinate (Y)	meters	3,065,869	3,065,814	3,065,872	3,065,869	3,066,233
Receptor elevation	meters	41.6	45.5	41.5	41.6	40.7
Distance from stack†	meters	1,492	1,487	1,465	1,492	1,889
Direction Vector from stack‡	degrees	164	180	167	164	124
PSD SIL	µg/m³	500	500	500	500	500
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	1.6	1.7	**2.5**	1.6	1.5
PSD *de minimis* ambient impact	µg/m³	575	575	575	575	575
Exceed PSD *de minimis* ambient impact	Yes/No	N	N	N	N	N
Percent of PSD *de minimis* ambient impact	%	1.4	1.5	**2.1**	1.4	1.3

Note: Maximum impacts shown in **bold** font.

*Maximum impact for operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-19. 1-, 3-, and 24-Hour Hour Annual Average SO_2 SIL Impacts—ULSD Fuel Oil

Number of CTG/HRSG uni	4
Maximum daily hours	12 hr/day
Maximum annual hours	750 hr/yr

					CTG/HRSG SO_2 Emissions Rates (Per CTG/HRSG)						Maximum SO_2 Impacts (ug/m^3)							
		Evaporative		Ambient	1- and 3-Hour		24-Hour		Annual		2006				2007			
Case	Load (%)	Cooling (Yes/No)	Configuration	Temperature (°F)	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	1-Hour	3-Hour	24-Hour	Annual	1-Hour	3-Hour	24-Hour	Annual
CC-19	100	No	4 on 1	20	**2.9**	**0.36**	**1.44**	**0.18**	**0.25**	**0.031**	1.6	**0.80**	0.135	0.0017	1.6	0.89	**0.135**	0.0017
CC-20	75	No	4 on 1	20	2.3	0.29	1.14	0.14	0.20	0.025	**1.8**	0.79	0.155	**0.0017**	**1.8**	**1.04**	0.131	**0.0017**
CC-22	100	No	1 on 1	20	**2.9**	**0.36**	**1.44**	**0.18**	**0.25**	**0.031**	1.2	0.46	0.051	0.0005	1.2	0.64	0.056	0.0005
CC-23	50	No	1 on 1	20	1.8	0.22	0.89	0.11	0.15	0.019	1.4	0.53	0.057	0.0005	1.8	0.75	0.061	0.0005
CC-24	100	No	4 on 1	59	2.7	0.34	1.36	0.17	0.23	0.029	1.6	0.79	0.137	0.0017	1.6	0.92	0.133	0.0017
CC-25	100	Yes	4 on 1	59	2.7	0.34	1.37	0.17	0.23	0.029	1.6	0.80	0.138	0.0017	1.6	0.92	0.134	0.0017
CC-26	75	No	4 on 1	59	2.2	0.27	1.08	0.14	0.18	0.023	1.8	0.78	**0.162**	0.0016	1.8	1.04	0.129	0.0016
CC-28	100	No	4 on 1	90	2.5	0.32	1.25	0.16	0.21	0.027	1.6	0.76	0.134	0.0016	1.6	0.91	0.128	0.0016
CC-29	100	No	4 on 1	90	2.6	0.32	1.29	0.16	0.22	0.028	1.6	0.77	0.134	0.0016	1.6	0.90	0.129	0.0016
CC-30	75	No	4 on 1	90	2.0	0.25	1.01	0.13	0.17	0.022	1.6	0.72	0.144	0.0015	1.6	0.94	0.118	0.0015
CC-32	100	Yes	1 on 1	90	2.6	0.32	1.29	0.16	0.22	0.028	1.2	0.46	0.051	0.0005	1.2	0.64	0.056	0.0005
CC-33	50	No	1 on 1	90	1.6	0.20	0.79	0.10	0.13	0.017	1.2	0.45	0.051	0.0004	1.5	0.65	0.053	0.0004
laximums					2.9	0.363	1.44	0.18	0.25	0.031	1.8	0.80	**0.162**	0.0017	1.8	1.04	0.135	0.0017

					Maximum SO_2 Impacts (ug/m^3)											
					2008				2009				2010			
					1-Hour	3-Hour	24-Hour	Annual	1-Hour	3-Hour	24-Hour	Annual	1-Hour	3-Hour	24-Hour	Annual
CC-19	100	No	4 on 1	20	1.6	**1.23**	0.150	0.0017	1.6	0.65	0.112	0.0019	1.6	0.84	0.135	0.0019
CC-20	75	No	4 on 1	20	**1.9**	1.17	**0.151**	**0.0018**	**1.9**	0.89	0.129	**0.0019**	**1.9**	**0.96**	**0.153**	**0.0019**
CC-22	100	No	1 on 1	20	1.2	0.43	0.044	0.0005	1.3	0.48	0.053	0.0006	1.2	0.63	0.083	0.0007
CC-23	50	No	1 on 1	20	1.4	0.46	0.044	0.0005	1.4	0.85	0.058	0.0006	1.5	0.62	0.090	0.0008
CC-24	100	No	4 on 1	59	1.7	1.22	0.150	0.0017	1.7	0.65	0.110	0.0019	1.7	0.86	0.139	0.0019
CC-25	100	Yes	4 on 1	59	1.7	1.23	0.151	0.0017	1.7	0.66	0.111	0.0019	1.7	0.87	0.139	0.0019
CC-26	75	No	4 on 1	59	1.9	1.12	0.147	0.0018	1.9	**0.95**	**0.131**	0.0019	1.9	0.95	0.152	0.0019
CC-28	100	No	4 on 1	90	1.6	1.17	0.146	0.0017	1.6	0.64	0.105	0.0018	1.7	0.85	0.136	0.0018
CC-29	100	No	4 on 1	90	1.6	1.18	0.146	0.0017	1.6	0.64	0.106	0.0018	1.6	0.84	0.135	0.0018
CC-30	75	No	4 on 1	90	1.7	1.04	0.136	0.0016	1.7	0.80	0.118	0.0017	1.7	0.86	0.137	0.0017
CC-32	100	Yes	1 on 1	90	1.2	0.42	0.042	0.0005	1.3	0.49	0.052	0.0006	1.2	0.62	0.083	0.0007
CC-33	50	No	1 on 1	90	1.2	0.40	0.038	0.0005	1.2	0.72	0.050	0.0005	1.2	0.54	0.078	0.0007
laximums					**1.9**	**1.23**	0.151	0.0018	1.9	0.95	0.131	**0.0019**	1.9	0.96	0.153	0.0019

Maximums - All Cases, All Years

Period	µg/m^3	Case	Year
1-Hour	1.9	CC-20	2008
3-Hour	1.2	CC-19	2008
24-Hour	0.16	CC-26	2006
Annual	0.0019	CC-20	2009

Highest 5-Year Average

Period	µg/m^3	Case	Year
1-Hour	1.8	CC-20	2006-2010

PSD Class II SILs - SO_2

Period	µg/m^3
1-Hour	7.8
3-Hour	25
24-Hour	5
Annual	1

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-20. 1- and 3-Hour Average SO_2 Maximum SIL Impacts—ULSD Fuel Oil

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 1-Hour Average Impacts							
CTG/HRSG operating case		CC-20	CC-20	CC-20	CC-20	CC-20	
CTG load	%	75	75	75	75	75	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	20	20	20	20	20	
1-Hour SO_2 Impact*	µg/m³	1.80	1.83	**1.93**	1.90	1.90	1.87
1-Hour impact location							
Receptor UTM Easting coordinate (X)	meters	404,089	404,089	404,328	404,354	404,137	
Receptor UTM Northing coordinate (Y)	meters	3,066,306	3,066,306	3,066,314	3,066,396	3,066,312	
Receptor elevation	meters	40.5	40.5	43.2	41.4	40.8	
Distance from stack†	meters	1,858	1,858	2,061	2,046	1,896	
Direction Vector from stack‡	degrees	122	122	119	116	121	
PSD SIL	µg/m³						7.8
Exceed SIL	Yes/No						No
Percent of SIL	%						24.0
B. 3-Hour Average Impacts							
CTG/HRSG operating case		CC-19	CC-20	CC-19	CC-26	CC-20	
CTG load	%	100	75	100	75	75	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	20	20	20	59	20	
3-Hour SO_2 Impact*	µg/m³	0.80	1.04	**1.23**	0.95	0.96	
3-Hour impact location							
Receptor UTM Easting coordinate (X)	meters	402,372	402,865	402,865	404,137	404,070	
Receptor UTM Northing coordinate (Y)	meters	3,065,886	3,065,871	3,065,871	3,066,312	3,066,185	
Receptor elevation	meters	42.0	41.5	41.5	40.8	41.1	
Distance from stack†	meters	1,422	1,471	1,471	1,896	1,910	
Direction Vector from stack‡	degrees	186	166	166	121	126	
PSD SIL	µg/m³	25	25	25	25	25	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	3.2	4.2	**4.9**	3.8	3.8	

Note: Maximum impacts shown in **bold** font.

*Maximum impact for operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-21. 24-Hour and Annual Average SO_2 Maximum SIL Impacts—ULSD Fuel Oil

Parameter	Units	Year of Meteorology				
		2006	2007	2008	2009	2010
A. 24-Hour Average Impacts						
CTG/HRSG operating case		CC-26	CC-19	CC-25	CC-26	CC-20
CTG load	%	75	100	100	75	75
Evaporative cooling	On/Off	Off	Off	On	Off	Off
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	20	59	59	20
24-Hour SO_2 Impact*	µg/m^3	**0.16**	0.14	0.15	0.13	0.15
24-Hour Impact Location						
Receptor UTM Easting coordinate (X)	meters	402,446	402,347	404,272	403,359	404,078
Receptor UTM Northing coordinate (Y)	meters	3,065,884	3,065,887	3,067,730	3,065,856	3,066,233
Receptor elevation	meters	41.5	42.1	42.7	41.0	40.7
Distance from stack†	meters	1,419	1,424	1,805	1,671	1,889
Direction Vector from stack‡	degrees	183	187	76	150	124
PSD SIL	µg/m^3	5	5	5	5	5
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	**3.2**	2.7	3.0	2.6	3.1
PSD *de minimis* Ambient Impact	µg/m^3	13	13	13	13	13
Exceed PSD *de minimis* Ambient Impact	Yes/No	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impac	%	**1.2**	1.0	1.2	1.0	1.2
B. Annual Average Impacts						
CTG/HRSG operating case		CC-20	CC-20	CC-20	CC-20	CC-20
CTG load	%	75	75	75	75	75
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	20	20	20	20	20
Annual SO_2 Impact*	µg/m^3	0.0017	0.0017	0.0018	**0.0019**	0.0019
Annual Impact Location						
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,995	400,995	401,022
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,529	3,067,570
Receptor elevation	meters	43.6	43.2	43.5	43.5	43.6
Distance from stack†	meters	1,531	1,586	1,541	1,541	1,521
Direction Vector from stack‡	degrees	279	275	279	279	280
PSD SIL	µg/m^3	1	1	1	1	1
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	0.17	0.17	0.18	**0.19**	0.19

Note: Maximum impacts shown in **bold** font.

*Maximum impact for operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-22. 24-Hour and Annual Average $PM_{10}/PM_{2.5}$ SIL Impacts—ULSD Fuel Oil

Number of CTG/HRSG Units	4	
Maximum Daily Hours	12	hr/day
Maximum Annual Hours	750	hr/yr

		Evaporative		Ambient	CTG/HRSG $PM_{10}/PM_{2.5}$ Emissions Rates (Per CTG/HRSG)				Maximum $PM_{10}/PM_{2.5}$ Impacts ($\mu g/m^3$)			
	Load	Cooling		Temperature	24-Hour		Annual		2006		2007	
Case	(%)	(Yes/No)	Configuration	(°F)	lb/hr	g/s	lb/hr	g/s	24-Hour	Annual	24-Hour	Annual
CC-19	100	No	4 on 1	20	**19.0**	**2.39**	**1.6**	**0.20**	1.8	0.011	1.8	0.014
CC-20	75	No	4 on 1	20	18.9	2.38	1.6	0.20	2.6	0.014	2.2	0.017
CC-22	100	No	1 on 1	20	**19.0**	**2.39**	**1.6**	**0.20**	0.7	0.003	0.7	0.004
CC-23	50	No	1 on 1	20	18.9	2.38	1.6	0.20	1.2	0.005	1.3	0.007
CC-24	100	No	4 on 1	59	18.9	2.38	1.6	0.20	1.9	0.012	1.9	0.015
CC-25	100	Yes	4 on 1	59	**19.0**	**2.39**	**1.6**	**0.20**	1.9	0.012	1.9	0.015
CC-26	75	No	4 on 1	59	18.9	2.38	1.6	0.20	**2.8**	**0.015**	**2.3**	**0.018**
CC-28	100	No	4 on 1	90	18.9	2.38	1.6	0.20	2.0	0.012	1.9	0.015
CC-29	100	No	4 on 1	90	18.9	2.38	1.6	0.20	2.0	0.012	1.9	0.015
CC-30	75	No	4 on 1	90	18.9	2.38	1.6	0.20	2.7	0.014	2.2	0.018
CC-32	100	Yes	1 on 1	90	18.9	2.38	1.6	0.20	0.8	0.004	0.8	0.004
CC-33	50	No	1 on 1	90	18.9	2.38	1.6	0.20	1.2	0.005	1.3	0.006
Maximums					19.0	2.39	1.6	0.20	**2.8**	0.015	2.3	**0.018**

					Maximum $PM_{10}/PM_{2.5}$ Impacts ($\mu g/m^3$)					
					2008		2009		2010	
Case	Load (%)	Evaporative Cooling (Yes/No)	Configuration	Ambient Temperature (°F)	24-Hour	Annual	24-Hour	Annual	24-Hour	Annual
CC-19	100	No	4 on 1	20	2.0	0.011	1.5	0.012	1.8	0.012
CC-20	75	No	4 on 1	20	2.5	0.015	2.1	0.016	2.5	0.016
CC-22	100	No	1 on 1	20	0.6	0.003	0.7	0.004	1.1	0.004
CC-23	50	No	1 on 1	20	0.9	0.006	1.2	0.006	1.9	0.008
CC-24	100	No	4 on 1	59	2.1	0.012	1.5	0.013	1.9	0.013
CC-25	100	Yes	4 on 1	59	2.1	0.012	1.5	0.013	1.9	0.013
CC-26	75	No	4 on 1	59	**2.6**	**0.016**	**2.3**	**0.017**	**2.7**	**0.017**
CC-28	100	No	4 on 1	90	2.2	0.013	1.6	0.014	2.1	0.014
CC-29	100	No	4 on 1	90	2.2	0.012	1.6	0.013	2.0	0.013
CC-30	75	No	4 on 1	90	2.5	0.015	2.2	0.016	2.6	0.016
CC-32	100	Yes	1 on 1	90	0.6	0.004	0.8	0.004	1.2	0.005
CC-33	50	No	1 on 1	90	0.9	0.006	1.2	0.006	1.9	0.008
Maximums					2.6	0.016	2.3	0.017	2.7	0.017

Maximums - All Cases, All Years

Period	$\mu g/m^3$	Case	Year
24-Hour	2.8	CC-26	2006
Annual	0.018	CC-26	2007

Highest 5-Year Average

Period	$\mu g/m^3$	Case	Year
24-Hour	2.5	CC-26	2006-2010

PSD Class II SILs PM_{10} / $PM_{2.5}$

PM_{10}		$PM_{2.5}$	
Period	$\mu g/m^3$	Period	$\mu g/m^3$
24-Hour	5	24-Hour	1.2
Annual	1	Annual	0.3

Note: Maximum impacts shown in **bold** font.

Source: ECT, 2012.

Table 7-23. 24-Hour and Annual Average PM_{10} Maximum SIL Impacts - ULSD Fuel Oil

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
A. 24-Hour Average Impacts						
CTG/HRSG operating case		CC-26	CC-26	CC-26	CC-26	CC-26
CTG load	%	75	75	75	75	75
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	59	59	59	59
24-Hour PM_{10} Impact*	µg/m^3	**2.8**	2.3	2.6	2.3	2.7
24-Hour impact location						
Receptor UTM Easting coordinate (X)	meters	402,446	403,236	402,841	403,359	404,089
Receptor UTM Northing coordinate (Y)	meters	3,065,884	3,065,860	3,065,872	3,065,856	3,066,306
Receptor elevation	meters	41.5	41.5	41.5	41.0	40.5
Distance from stack†	meters	1,419	1,609	1,465	1,671	1,858
Direction Vector from stack‡	degrees	183	154	167	150	122
PSD SIL	µg/m^3	5	5	5	5	5
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	**56.9**	45.3	51.7	46.1	53.7
PSD *de minimis* ambient impact	µg/m^3	10	10	10	10	10
Exceed PSD *de minimis* ambient impact	Yes/No	No	No	No	No	No
Percent of PSD *de minimis* ambient impact	%	28.4	22.6	25.8	23.0	26.8
B. Annual Average Impacts						
CTG/HRSG operating case		CC-26	CC-26	CC-26	CC-26	CC-26
CTG load	%	75	75	75	75	75
Evaporative cooling	On/Off	Off	Off	Off	Off	Off
Configuration		4 on 1	4 on 1	4 on 1	4 on 1	4 on 1
Ambient air temperature	°F	59	59	59	59	59
Annual PM_{10} Impact[1]	µg/m^3	0.0145	**0.0180**	0.0156	0.0167	0.0166
Annual impact location						
Receptor UTM Easting coordinate (X)	meters	401,008	400,940	400,995	401,008	401,035
Receptor UTM Northing coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,549	3,067,591
Receptor elevation	meters	43.6	43.2	43.5	43.6	43.7
Distance from stack†	meters	1,531	1,586	1,541	1,531	1,512
Direction Vector from stack‡	degrees	279	275	279	279	281
PSD SIL	µg/m^3	1	1	1	1	1
Exceed SIL	Yes/No	No	No	No	No	No
Percent of SIL	%	1.5	**1.8**	1.6	1.7	1.7

Note: Maximum impacts shown in **bold** font.

*Maximum impact for operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-24. 24-Hour and Annual Average $PM_{2.5}$ Maximum SIL Impacts - ULSD Fuel Oil

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010	Average
A. 24-Hour Average Impacts							
CTG/HRSG operating case		CC-26	CC-26	CC-26	CC-26	CC-26	
CTG load	%	75	75	75	75	75	
Evaporative cooling	On/Off	Off	Off	Off	Off	Off	
Configuration	—	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient air temperature	°F	59	59	59	59	59	
24-Hour $PM_{2.5}$ Impact*	μg/m³	**2.8**	2.3	2.6	2.3	2.7	2.5
24-Hour Impact Location							
Receptor UTM Easting coordinate (X)	meters	402,446	403,236	402,841	403,359	404,089	
Receptor UTM Northing coordinate (Y)	meters	3,065,884	3,065,860	3,065,872	3,065,856	3,066,306	
Receptor elevation	meters	41.5	41.5	41.5	41.0	40.5	
Distance from stack†	meters	1,419	1,609	1,465	1,671	1,858	
Direction Vector from stack‡	degrees	183	154	167	150	122	
PSD SIL	μg/m³						1.2
Exceed SIL	Yes/No						Yes
Percent of SIL	%						211.3
PSD *de minimis* ambient impact	μg/m³	4	4	4	4	4	
Exceed PSD *de minimis* ambient impact	Yes/No	No	No	No	No	No	
Percent of PSD *de minimis* ambient impact	%	**71.1**	56.6	64.6	57.6	67.1	
B. Annual Average Impacts							
CTG/HRSG Operating Case		CC-26	CC-26	CC-26	CC-26	CC-26	
CTG Load	%	75	75	75	75	75	
Evaporative Cooling	On/Off	Off	Off	Off	Off	Off	
Configuration		4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	
Ambient Air Temperature	°F	59	59	59	59	59	
Annual PM_{10} Impact*	μg/m³	0.0145	**0.0180**	0.0156	0.0167	0.0166	
Annual Impact Location							
Receptor UTM Easting Coordinate (X)	meters	401,008	400,940	400,995	401,008	401,035	
Receptor UTM Northing Coordinate (Y)	meters	3,067,549	3,067,446	3,067,529	3,067,549	3,067,591	
Receptor Elevation	meters	43.6	43.2	43.5	43.6	43.7	
Distance from Stack[2]	meters	1,531	1,586	1,541	1,531	1,512	
Direction Vector from Stack[3]	degrees	279	275	279	279	281	
PSD SIL	μg/m³	0.3	0.3	0.3	0.3	0.3	
Exceed SIL	Yes/No	No	No	No	No	No	
Percent of SIL	%	4.8	**6.0**	5.2	5.6	5.5	

Note: Maximum impacts shown in **bold** font.

*Maximum impact for operating cases.
†Distance from Unit 2 CC-2A stack to the location of highest impact.
‡Direction from stack toward impact location.

Source: ECT, 2012.

7.3 CUMULATIVE IMPACT ANALYSIS RESULTS

Since Project 1-hour NO_2 and SO_2 and 24-hour $PM_{2.5}$ impacts are predicted to exceed the PSD Class II SILs, multisource cumulative analyses of air quality impacts with respect to these pollutants and averaging periods were conducted.

The SIL modeling analysis indicates that the following Project operating scenarios will have the maximum impacts:

- 1-Hour NO_2: Natural gas warm startup and ULSD fuel oil Case CC-20 (four CTG/HRSG units operating at 75-percent load and 20°F ambient air temperature).
- 1-Hour SO_2: Natural gas Case CC-9 (four CTG/HRSG units operating at 100-percent load, inlet air evaporative cooling, duct burner firing, and 59°F ambient air temperature).
- 24-Hour $PM_{2.5}$: ULSD fuel oil Case CC-26 (four CTG/HRSG units operating at 75-percent load and 59°F ambient air temperature).

Cumulative modeling was therefore conducted for these Project operating scenarios to assess air quality impacts with respect to the PSD Class II increments and NAAQS.

As previously discussed in Section 6.2, only those receptors that were predicted to have an impact above the PSD Class II SILs for any averaging period and year of meteorological data were assessed in the cumulative analysis. Figures 7-1 and 7-2 depict the cumulative 1-hour NO_2 NAAQS modeling receptor grids for the natural gas warm startup and ULSD fuel oil Case CC-20 scenarios, respectively. Figure 7-3 illustrates the 1-hour SO_2 cumulative NAAQS modeling receptor grid. Figure 7-4 presents the 24-hour $PM_{2.5}$ cumulative NAAQS modeling receptor grid.

In accordance with agency modeling guidance, background concentrations were determined by reviewing available ambient air data collected for the latest three years (2009 through 2011) at agency monitoring stations. For 1-hour NO_2, the 3-year average of the 8^{th} highest daily maximum ambient air values (69.0 micrograms per cubic meter [$\mu g/m^3$]) from the Hillsborough County Environmental Protection Commission (HCEPC)

FIGURE 7-1.

POLK 2-5 CONVERSION PROJECT

1-HOUR NO_2 SIL, RECEPTORS, NATURAL GAS WARM START

Sources: ECT, 2012.

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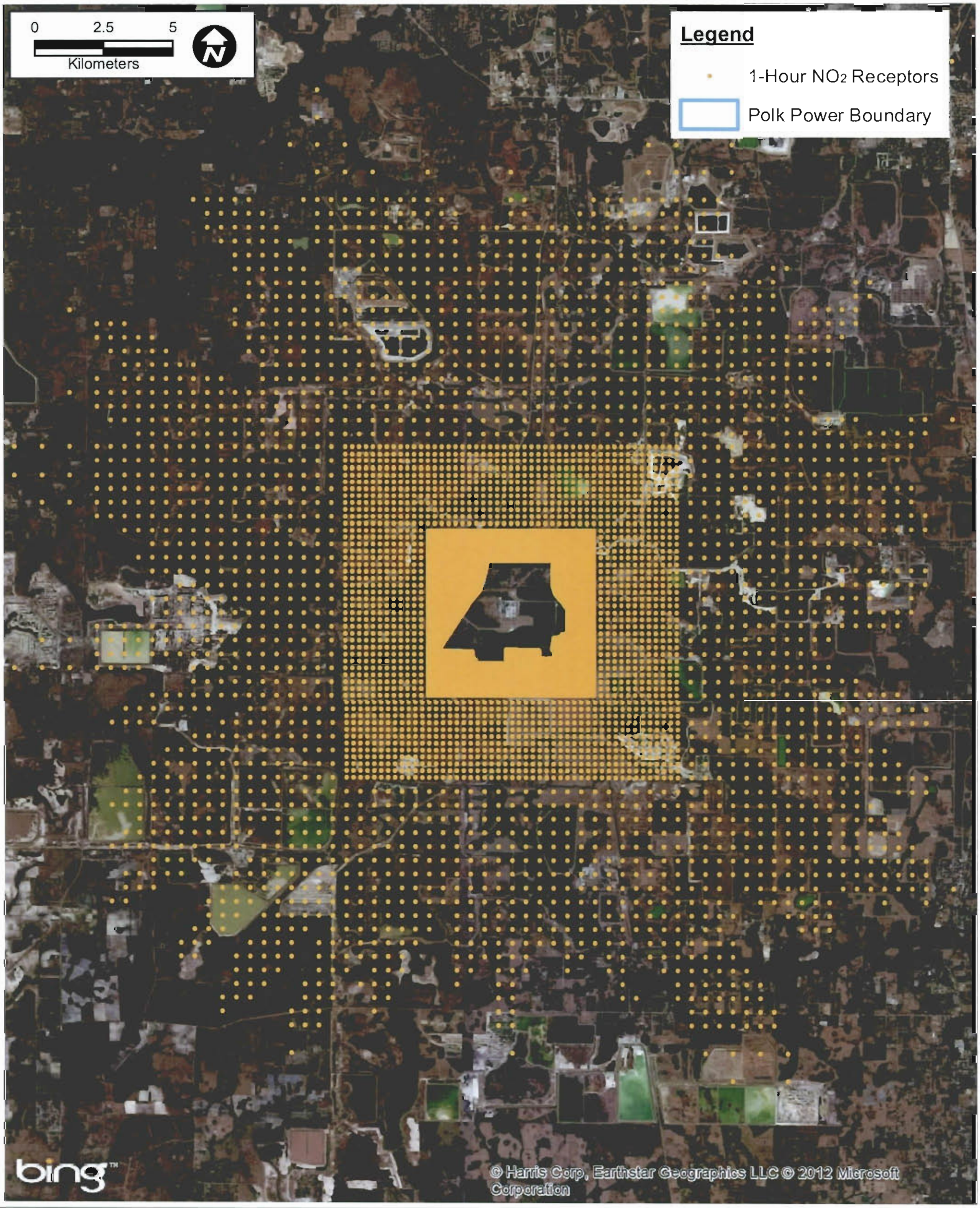

FIGURE 7-2.
POLK 2-5 CONVERSION PROJECT
1-HOUR NO_2 SIL RECEPTORS, CASE CC-20

Sources: ECT, 2012.

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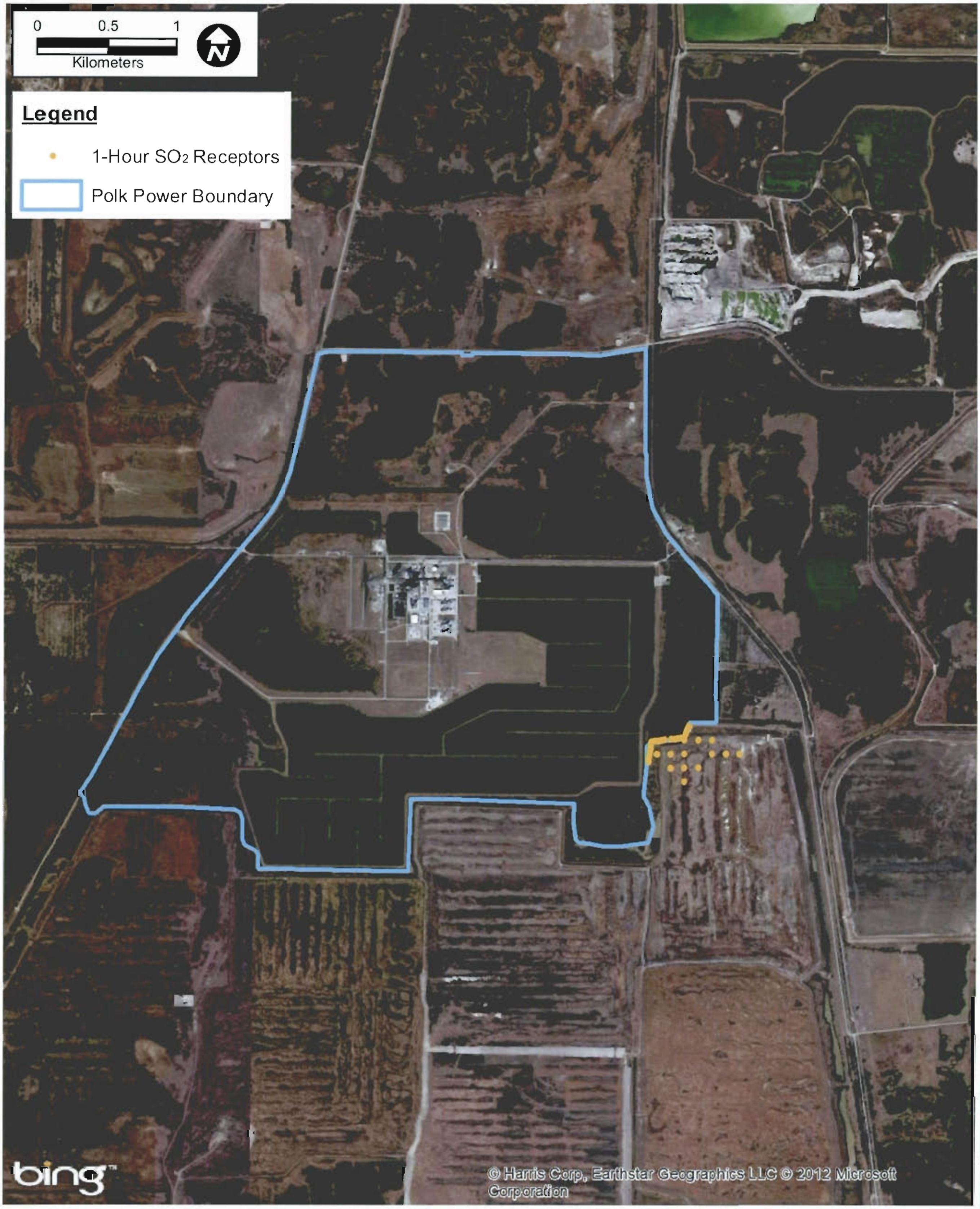

FIGURE 7-3.
POLK 2-5 CONVERSION PROJECT
1-HOUR SO_2 SIL, RECEPTORS

Sources: ECT, 2012.

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FIGURE 7-4.
POLK 2-5 CONVERSION PROJECT
24-HOUR $PM_{2.5}$ SIL, RECEPTORS

Sources: ECT, 2012.

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monitoring station located at 5121 Grandy Boulevard in Tampa (ID 12-057-1065) was used as background for the Project. For 1-hour SO_2, the 3-year average of the 4th highest daily maximum ambient air values (39.3 $\mu g/m^3$) from the HCEPC monitoring station located at 1167 North Dover Road in Tampa (ID 12-057-3002) was used as background. Data from these urban monitoring stations, which are the closest NO_2 and SO_2 stations to the PPS Site, will provide conservative estimates (i.e., over-estimates) of background NO_2 and SO_2 concentrations at the rural PPS Site.

For $PM_{2.5}$, the 3-year average of the 4th highest 24-hour average values (15.4 $\mu g/m^3$) collected at the FDEP monitoring station located at 1015 Sikes Boulevard in Lakeland (ID 12-105-6006) was used as background.

Cumulative NAAQS modeling that included the Project emissions sources, other PPS emissions sources, and the offsite emissions inventories was conducted to obtain 1-hour NO_2 and SO_2 and 24-hour $PM_{2.5}$ air quality impacts for these emissions sources. The modeling results were then added to the representative background concentrations to obtain a total impact for comparison to the NAAQS for pollutant and averaging period.

For modeling purposes, the 1-hour NO_2 NAAQS is evaluated based on the 5-year average of the 98th percentile (i.e., highest, 8th highest) of the 1-hour daily maximum NO_2 impacts. The 1-hour SO_2 NAAQS is evaluated based on the 5-year average of the 99th percentile (i.e., highest, 4th highest) of the 1-hour daily maximum SO_2 impacts. In accordance with EPA guidance, modeling demonstrations for the $PM_{2.5}$ NAAQS are based on the average of the 1st highest 24-hour average concentrations over 5 years of meteorological data. Modeling demonstrations for the $PM_{2.5}$ PSD Class II 24-hour average increments are based on the highest, 2nd highest 24-hour average values for the 5 years of meteorological data evaluated.

Tables 7-25 and 7-26 provide the results of the 1-hour NO_2 NAAQS analysis for the natural gas warm startup and ULSD fuel oil Case CC-20 operating scenarios, respectively. As shown on these tables, the model results indicate potential exceedances of the 1-hour NO_2 NAAQS. However, the Project did not have a significant contribution to any of the

Table 7-25. Cumulative 1-Hour Average NO_2 NAAQS Impact—Natural Gas Warm Start

Parameter	2006 through 2010 5-Year Average All Sources
Highest 98th percentile of 1-hour daily maximum NO_2 impacts ($\mu g/m^3$)	182.0
Receptor UTM Easting (meter)	410,528
Receptor UTM Northing (meter)	3,087,214
Receptor elevation (meter, amsl)	112.5
Distance from Polk Unit 2 stack (meter)*	21,463
Direction from Polk Unit 2 stack (degrees)*	22
Background 1-hour NO_2 concentration ($\mu g/m^3$)†	69.0
Total 1-hour NO_2 concentration ($\mu g/m^3$)	251.0
Polk Unit 2 contribution ($\mu g/m^3$)	0.015
Polk Unit 2 contribution (%)	0.0059
1-Hour NO_2 NAAQS ($\mu g/m^3$)	188
Exceed 1-hour NO_2 NAAQS? (Yes/No)	Y
Percent of 1-hour NO_2 NAAQS (%)	134
Number of modeled exceedances of the 1-hour NO_2 NAAQS ($\mu g/m^3$)‡	18
Number of Polk Unit 2 significant impacts to modeled exceedances	0
EPA 1-hour NO_2 recommended interim SIL ($\mu g/m^3$)	7.5
Maximum Polk Unit 2 contribution to an exceedance ($\mu g/m^3$)	0.022
Exceedance concentration, including background ($\mu g/m^3$)	229.0
Receptor UTM Easting (meter)	410,528
Receptor UTM Northing (meter)	3,087,214
Receptor elevation (meter, amsl)	112.5
Distance from Polk Unit 2 stack (meter)*	21,463
Direction from Polk Unit 2 stack (degrees)*	22

*Distance and direction measured from Polk Unit 2 CC-2A stack located at UTM 402,519 meters easting, and 3,067,301 meters northing.

†Three-year average of 1-hour 98th percentile NO_2 values for 2009, 2010, and 2011 from Station ID: 12-057-1065 (5121 Grandy Boulevard, Tampa, Hillsborough County).

‡Including all ranks and background concentration.

Source: ECT, 2012.

Table 7-26. Cumulative 1-Hour Average NO_2 NAAQS Impact—ULSD Fuel Oil Gas Case CC-20

Parameter	2006 through 2010 5-Year Average All Sources
Highest 98th percentile of 1-hour daily maximum NO_2 impacts ($\mu g/m^3$)	227.3
Receptor UTM Easting (meter)	408,028
Receptor UTM Northing (meter)	3,071,964
Receptor elevation (meter, amsl)	86.6
Distance from Polk Unit 2 stack (meter)*	7,217
Direction from Polk Unit 2 stack (degrees)*	50
Background 1-hour NO_2 concentration ($\mu g/m^3$)†	69.0
Total 1-hour NO_2 concentration ($\mu g/m^3$)	296.3
Polk Unit 2 contribution ($\mu g/m^3$)	0.00075
Polk Unit 2 contribution (%)	0.00025
1-Hour NO_2 NAAQS ($\mu g/m^3$)	188
Exceed 1-hour NO_2 NAAQS? (Yes/No)	Y
Percent of 1-hour NO_2 NAAQS (%)	158
Number of modeled exceedances of the 1-hour NO_2 NAAQS ($\mu g/m^3$)‡	162
Number of Polk Unit 2 significant impacts to modeled exceedances	0
EPA 1-hour NO_2 recommended interim SIL ($\mu g/m^3$)	7.5
Maximum Polk Unit 2 contribution to an exceedance ($\mu g/m^3$)	0.057
Exceedance concentration, including background ($\mu g/m^3$)	198.4
Receptor UTM Easting (meter)	404,028
Receptor UTM Northing (meter)	3,057,214
Receptor elevation (meter, amsl)	32.5
Distance from Polk Unit 2 stack (meter)*	10,199
Direction from Polk Unit 2 stack (degrees)*	171

*Distance and direction measured from Polk Unit 2 CC-2A stack located at UTM 402,519 meters easting, and 3,067,301 meters northing.

†Three-year average of 1-hour 98th percentile NO_2 values for 2009, 2010, and 2011 from Station ID: 12-057-1065 (5121 Grandy Boulevard, Tampa, Hillsborough County).

‡Including all ranks and background concentration.

Source: ECT, 2012.

modeled NO_2 NAAQS exceedances. The AERMOD assessment of Project facility contributions to the modeled exceedances was conducted by: (a) specifying NO_2 on the AERMOD COPOLLUTID keyword, (b) selecting 1-hour averaging using the AVERTIME keyword, and (c) using the MAXDCONT keyword with defined source groups of ALL and CC. The ALL source group includes all (offsite and onsite) modeled emissions sources. CC is the NO_x emissions source code used in AERMOD for the Project emissions sources.

Table 7-27 provides the results of the 1-hour SO_2 NAAQS analysis for natural gas Case CC-9. Similar to the 1-hour NO_2 NAAQS analysis, the model results indicate potential exceedances of the 1-hour SO_2 NAAQS. However, the Project did not have a significant contribution to any of the modeled SO_2 NAAQS exceedances. The AERMOD assessment of Project facility contributions to the modeled exceedances was conducted as described previously for the 1-hour NO_2 NAAQS.

Table 7-28 presents cumulative model results with respect to the $PM_{2.5}$ PSD Class II increments. The model results indicate that cumulative impacts will be below the PSD Class II increments for $PM_{2.5}$.

Table 7-29 provides the results of the 24-hour $PM_{2.5}$ NAAQS analysis for ULSD fuel oil Case CC-26. For $PM_{2.5}$, potential exceedances of the $PM_{2.5}$ 24-hour NAAQS are predicted. However, the Project did not have a significant contribution to any of the modeled $PM_{2.5}$ NAAQS exceedances.

7.4 OZONE IMPACTS

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and VOCs during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models such as the EPA CMAQ model. Currently, all areas of Florida are attaining the 8-hour ozone AAQS.

Table 7-27. Cumulative 1-Hour Average SO_2 NAAQS Impacts—Natural Gas Case CC-9

Parameter	2006 through 2010 5-Year Average All Sources
Highest 99th percentile of 1-hour daily maximum SO_2 impacts ($\mu g/m^3$)	205.0
Receptor UTM Easting (meter)	404,089
Receptor UTM Northing (meter)	3,066,306
Receptor elevation (meter, amsl)	40.5
Distance from Polk Unit 2 stack (meter)*	1,858
Direction from Polk Unit 2 stack (degrees)*	122
Background 1-hour SO_2 concentration ($\mu g/m^3$)†	39.3
Total 1-hour SO_2 concentration ($\mu g/m^3$)	244.3
Polk Unit 2 contribution ($\mu g/m^3$)	0.00073
Polk Unit 2 contribution (%)	0.00030
1-Hour SO_2 NAAQS ($\mu g/m^3$)	198
Exceed 1-hour SO_2 NAAQS? (Yes/No)	Y
Percent of 1-hour SO_2 NAAQS (%)	123
Number of modeled exceedances of the 1-hour SO_2 NAAQS ($\mu g/m^3$)‡	198
Number of Polk Unit 2 significant impacts to modeled exceedances	0
EPA 1-hour SO_2 recommended interim SIL ($\mu g/m^3$)	7.8
Maximum Polk Unit 2 contribution to an exceedance ($\mu g/m^3$)	0.034
Exceedance concentration, including background ($\mu g/m^3$)	212.3
Receptor UTM Easting (meter)	404,081
Receptor UTM Northing (meter)	3,066,258
Receptor elevation (meter, amsl)	40.6
Distance from Polk Unit 2 stack (meter)*	1,878
Direction from Polk Unit 2 stack (degrees)*	124

*Distance and direction measured from Polk Unit 2 CC-2A stack located at UTM 402,519 meters easting, and 3,067,301 meters northing.

†Three-year average of 1-hour 99th percentile SO_2 values for 2009, 2010, and 2011 from Station ID: 12-057-3002 (1167 North Dover Road, Tampa, Hillsborough County).

‡Including all ranks and background concentration.

Source: ECT, 2012.

Table 7-28. Cumulative 24-Hour Average $PM_{2.5}$ PSD Class II Increment Impacts—ULSD Fuel Oil Case CC-26

Parameter	Units	Year of Meteorology 2006	2007	2008	2009	2010
Highest, 2nd highest impact	µg/m³	5.49	5.31	6.38	6.30	**7.29**
Impact location						
Receptor UTM Easting coordinate (X)	meters	400,981	401,518	400,981	400,913	404,241
Receptor UTM Northing coordinate (Y)	meters	3,067,508	3,068,468	3,067,508	3,067,405	3,067,769
Receptor elevation	meters	43.5	41.9	43.5	43.1	43.1
Distance from stack*	meters	1,552	1,538	1,552	1,609	1,785
Direction vector from ctack†	degrees	278	319	278	274	75
PSD Class II increment	µg/m³	9	9	9	9	9
Exceed PSD Class II increment	Yes/No	No	No	No	No	No
Percent of PSD Class II increment	%	61.0	59.0	70.9	70.0	**81.0**

Note: Maximum impacts shown in **bold** font.

*Distance from Unit 2 CC2A stack to the location of highest impact.
†Direction from stack toward impact location.

Source: ECT, 2012.

Table 7-29. Cumulative 24-Hour Average $PM_{2.5}$ NAAQS Impact—ULSD Fuel Oil Case CC-26

Parameter	2006 through 2010 5-Year Average All Sources
Highest aveage of maximum 24-hour $PM_{2.5}$ impacts ($\mu g/m^3$)	27.1
Receptor UTM Easting (meter)	399,628
Receptor UTM Northing (meter)	3,064,214
Receptor elevation (meter, amsl)	44.7
Distance from Polk Unit 2 stack (meter)*	4,229
Direction from Polk Unit 2 stack (degrees)*	223
Background 24-hour $PM_{2.5}$ concentration ($\mu g/m^3$)†	15.4
Total 24-hour $PM_{2.5}$ concentration ($\mu g/m^3$)	42.5
Polk Unit 2 contribution ($\mu g/m^3$)	0.026
Polk Unit 2 contribution (%)	0.060
24-Hour $PM_{2.5}$ NAAQS ($\mu g/m^3$)	35
Exceed 24-hour $PM_{2.5}$ NAAQS? (Yes/No)	Y
Percent of 24-hour $PM_{2.5}$ NAAQS (%)	121
Number of modeled exceedances of the 24-hour $PM_{2.5}$ NAAQS ($\mu g/m^3$)‡	683
Number of Polk Unit 2 significant impacts to modeled exceedances	0
24-hour $PM_{2.5}$ SIL ($\mu g/m^3$)	1.2
Maximum Polk Unit 2 contribution to an exceedance ($\mu g/m^3$)	0.38
Exceedance concentration, including background ($\mu g/m^3$)	42.5
Receptor UTM Easting (meter)	402,693
Receptor UTM Northing (meter)	3,065,876
Receptor elevation (meter, amsl)	41.9
Distance from Polk Unit 2 stack (meter)*	1,435
Direction from Polk Unit 2 stack (degrees)*	173

*Distance and direction measured from Polk Unit 2 CC-2A stack located at UTM 402,519 meters easting, and 3,067,301 meters northing.

†Three-year average of highest, 2nd highest 24-hour $PM_{2.5}$ values for 2009, 2010, and 2011 from Station ID: 12-056-006 (1051 Sikes Boulevard, Lakeland, Polk County).

‡Including all ranks and background concentration.

Source: ECT, 2012.

Project estimated potential NO_x and VOC emissions are 744.9 and 137.6 tpy, respectively. These annual emissions rates are relatively minor in comparison to regional emissions. For example, Hillsborough County NO_x and VOC emissions in 2008 were 56,368 and 35,785 tons, respectively, based on data obtained from EPA's National Emissions Inventory database. NO_x and VOC emissions for Polk County in 2008 were 21,862 and 26,163 tons, respectively. Hillsborough County, which has a higher population density and greater NO_x and VOC emissions compared to Polk County, currently has monitored ambient ozone levels below the ozone AAQS.

Ambient ozone levels in Polk County are primarily due to ozone transport from upwind areas. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emissions rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, implementation of CAIR has resulted in significant actual reductions in existing power plant NO_x emissions throughout Florida.

In summary, the relatively minor NO_x and VOC emissions associated with the Project will not significantly impact ambient ozone levels in Polk County or other areas in Florida. Polk County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

7.5 SUMMARY OF MODEL RESULTS

Table 7-30 provides an overall summary of the Project modeling analyses. Conclusions regarding the modeling analyses are as follows:

- Project impacts are predicted to exceed the PSD Class II SILs for NO_2 and SO_2 1-hour average and $PM_{2.5}$ 24-hour average. Project impacts were below the PSD Class II SILs for all other all pollutants and averaging periods.
- Cumulative modeling shows potential exceedances of the 1-hour NO_2 and SO_2 NAAQS. However, the Project did not have a significant contribution to any of the modeled 1-hour NO_2 or SO_2 NAAQS exceedances.

Table 7-30. Summary of Modeling Results

Standard	Averaging Period	NO_2 (μg/m³)	CO (μg/m³)	SO_2 (μg/m³)	PM_{10} (μg/m³)	$PM_{2.5}$ (μg/m³)
A. Maximum SIL and *de minimis* Impacts						
Natural gas (Cases CC-1 through CC-18): SIL	1-Hour	9.3 *	24.0	8.4 *		
	3-Hour			5.7		
	8-Hour		11.9			
	24-hour			1.4	2.2	2.2 *
	Annual	0.12		0.12	0.18	0.18
ULSD fuel oil (Cases CC-19 through CC-33): SIL	1-Hour	36.7 *	26.2	1.9		
	3-Hour			1.2		
	8-Hour		12.3			
	24-hour			0.16	2.8	2.5 *
	Annual	0.039		0.0019	0.018	0.018
Natural case (Cases CC-1 through CC-18): *de minimis* impact	8-Hour		11.9			
	24-hour			1.4	2.2	2.2
	Annual	0.12				
ULSD fuel oil (Cases CC-19 through CC-33): *de minimis* impact	8-Hour		12.3			
	24-hour			0.16	2.8	2.5
	Annual	0.039				
B. Cumulative Impacts						
1-Hour NO_2 NAAQS						
All emissions sources + background	1-Hour	251.0 †				
Polk Unit 2 contribution - natural gas warm start	1-Hour	0.015				
All emissions sources + background	1-Hour	296.3 †				
Polk Unit 2 contribution - ULSD fuel oil Case CC-20	1-Hour	0.00075				
1-Hour SO_2 NAAQS						
All emissions sources + background	1-Hour			244.3 †		
Polk Unit 2 contribution - natural gas Case CC-9	1-Hour			0.00073		
24-Hour $PM_{2.5}$ PSD Class II Increment						
All emissions sources	24-Hour					7.3
24-Hour $PM_{2.5}$ NAAQS						
All emissions sources + background	24-Hour					42.5 †
Polk Unit 2 contribution - ULSD fuel oil Case CC-26						0.026

*Exceed PSD Class II SIL.
†Potential NAAQS exceedance.

Source: ECT, 2012.

- The cumulative model results show that impacts will be below the PSD Class II increments for $PM_{2.5}$.
- Cumulative modeling shows potential exceedances of the 24-hour $PM_{2.5}$ NAAQS. However, the Project did not have a significant contribution to any of the modeled 24-hour $PM_{2.5}$ NAAQS exceedances.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

There are several ambient air quality monitoring stations shown in Figure 8-1 that can be used to represent air quality at the PPS site. Figure 8-1 shows the pollutants monitored at each site. Table 8-1 presents a summary of the ambient air quality data for these monitoring stations. The monitored values are based on the most recent available quality assured data. Several of the pollutants, including NO_2, SO_2, ozone, and $PM_{2.5}$, are based on the 3-year average (i.e., 2008 through 2011).

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 3.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several PSD pollutants will be emitted from the Project in excess of their respective SERs, preconstruction monitoring is required. However, Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. Table 3-1 previously presented the *de minimis* ambient impact levels. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from Project. In cases where the predicted ambient impacts exceed the *de minimis* levels, regulatory agencies have the authority to allow data from existing monitoring stations to substitute for preconstruction monitoring.

Section 7.0 discusses in detail the results of ambient impact analyses. The following paragraphs summarize the dispersion modeling results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM_{10}/$PM_{2.5}$

The maximum 24-hour PM_{10} impact from the Project was predicted to be 2.8 $\mu g/m^3$. This concentration is below the 24-hour average PM_{10} *de minimis* ambient impact level of

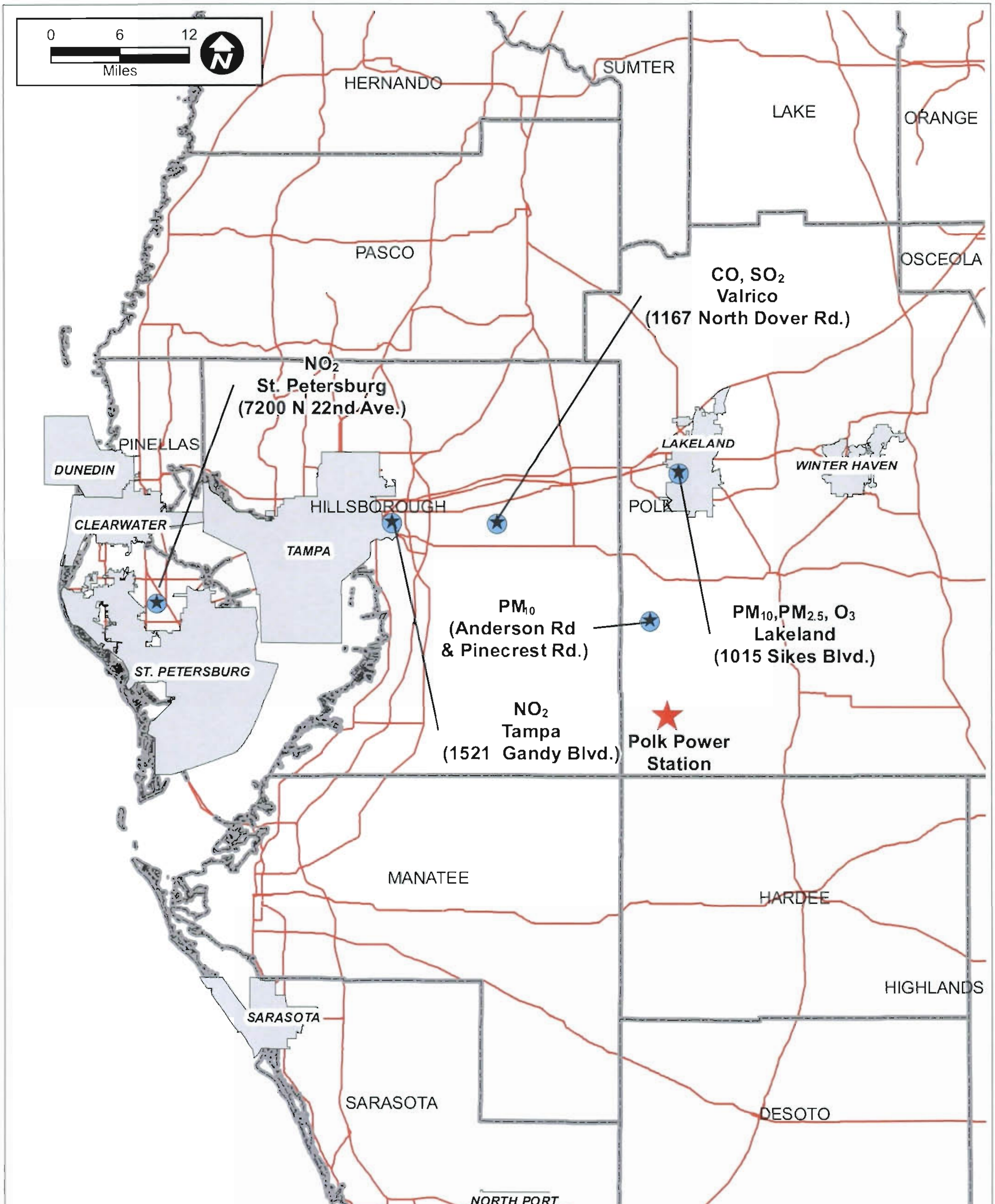

FIGURE 8-1.
LOCATION OF AMBIENT AIR QUALITY
MONITORS NEAR THE PROJECT SITE

Sources: FGDL, 2006; ECT, 2012.

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TAMPA ELECTRIC

Table 8-1. NAAQS and Monitored Air Quality Concentrations

Pollutant and Averaging Time	Primary NAAQS*	2008 Monitored Data†		Location of Monitor	
				City	County
CO					
8-hour ‡	9 ppm	0.5 ppm	2nd maximum	Valrico	Hillsborough
1-hour ‡	35 ppm	0.9 ppm	2nd maximum	Valrico	Hillsborough
NO_2					
Annual §	53 ppb	N/A	Arithmetic mean	N/A	N/A
1-hour ◊	100 ppb	37 ppb	98th percentile	Tampa	Hillsborough
	100 ppb	37 ppb	98th percentile	St. Petersburg	Pinellas
PM_{10}					
24-hour ‡	150 $\mu g/m^3$	32 $\mu g/m^3$	2nd maximum	(Not in a city)	Polk
	150 $\mu g/m^3$	31 $\mu g/m^3$	2nd maximum	Lakeland	Polk
$PM_{2.5}$					
Annual §	15 $\mu g/m^3$	8.66 $\mu g/m^3$	Arithmetic mean	Lakeland	Polk
24-hour ◊	35 $\mu g/m^3$	17.6 $\mu g/m^3$	98th percentile	Lakeland	Polk
Ozone					
8-hour £ ¥	0.075 ppm	0.068 ppm	4th maximum	Lakeland	Polk
SO_2					
24-hour ‡	0.14 ppm	0.003 ppm	2nd maximum	Valrico	Hillsborough
1-hour «	75 ppb	15 ppb	99th percentile	Valrico	Hillsborough

‡Not to be exceeded more than once per year.
§Arithmetic mean.
◊The 3-year average of the 98th percentile of the daily maximum 1-hour average.
£2008 standard.
¥Standard attained when the 3-year average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard.
«The 3-year average of the 99th percentile of the daily maximum 1-hour average.

Sources: *40 CFR 50.1-50.12.
†EPA AirData Website, http://www.epa.gov/air/data/index.html.
ECT, 2012.

10 μg/m^3. Therefore, the Project qualifies for a preconstruction monitoring exemption for PM_{10} in accordance with the FDEP PSD regulations.

The maximum 24-hour $PM_{2.5}$ impact was predicted to be 2.8 μg/m^3. This concentration is below the 24-hour average $PM_{2.5}$ *de minimis* ambient impact level of 4 μg/m^3. Therefore, the Project qualifies for a preconstruction monitoring exemption for $PM_{2.5}$ in accordance with FDEP PSD regulations.

8.2.2 SO_2

The maximum 24-hour SO_2 impact was predicted to be 1.5 μg/m^3. This concentration is below the 24-hour average SO_2 *de minimis* ambient impact level of 13 μg/m^3. Therefore, the Project qualifies for a preconstruction monitoring exemption for SO_2 in accordance with the FDEP PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.12 μg/m^3. This concentration is below the annual average NO_2 *de minimis* ambient impact level of 14 μg/m^3. Therefore, the Project qualifies for a preconstruction monitoring exemption for NO_2 in accordance with the FDEP PSD regulations.

8.2.4 CO

The maximum 8-hour CO impact was predicted to be 12.3 μg/m^3. This concentration is below the 8-hour average CO *de minimis* ambient impact level of 575 μg/m^3. Therefore, the Project qualifies for a preconstruction monitoring exemption for CO in accordance with the FDEP PSD regulations.

8.2.5 OZONE

Preconstruction monitoring for ozone is required if potential NO_x and/or VOC emissions from a project subject to PSD review exceeds 100 tpy. Since the Project's potential annual NO_x and VOC emissions each exceed the 100-tpy *de minimis* threshold, the Project does not qualify for a preconstruction monitoring exemption under this test. However, there are two ozone monitoring sites located in Lakeland approximately 35 km north of the Project site. It is believed that the data from these sites provide monitored values that are representative of the Project site.

9.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following subsections. Based on a thorough review of emissions expected as a result of this project, it is concluded that the Project will not cause any adverse impacts to the soils, vegetation, or wildlife of relevant Class I and II areas.

9.1 <u>GROWTH IMPACTS ANALYSIS</u>

9.1.1 PROJECT GROWTH IMPACTS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and assess air quality impacts that would result from that growth.

Impacts associated with construction of the Project will be minor. During the approximate 32-month construction period, Tampa Electric will employ an average of 250 workers. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Project is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the Project will not require any additional fulltime workers. The increase in natural gas and ULSD fuel oil due to the operation of the Project will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected at this time.

9.1.2 AREA GROWTH SINCE 1977

U.S. Census data shows that the population of the Polk County has increased by approximately 24.4 percent between 2000 and 2010. The 2010 estimated population of Polk County is 602,095. In 2004, Polk County was ranked as the eighth most populous county with a population density of 334.9 persons per square mile, which is within 5 percent of the average population density of Florida. Population growth in Polk County had been increasing at a rate of approximately 7 percent higher than the rate for the rest of Florida from 2000 to 2010. Major Polk County population areas are Lakeland and Bartow.

Although there has been significant population growth in Polk County and Florida over the past 25 years, improvements in motor vehicle emissions controls, use of clean transportation fuels, reductions in electric utility emissions due to the ARP, and well-controlled stationary sources have resulted in air quality in Polk County that is currently below the national and Florida AAQS for all pollutants. As evidenced by the Polk County air quality index data, air quality in Polk County has been steadily improving over the past 10 years. The number of days per year with good air quality in Polk County increased from 281 in 2001 to 317 in 2011.

Accordingly, it is concluded that air quality in Polk County has not deteriorated since 1977. As discussed previously in Section 7.0, the emissions associated with the Project will result in air quality impacts that are well below the national and Florida AAQS.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Potential impacts to soils, vegetation, and wildlife resources resulting from the Project operation include the effects of air emissions. Table 9-1 summarizes the modeled air quality impacts due to the Project for all relevant Class I and II areas. In addition, Table 9-2 provides predicted maximum annual nitrogen and sulfur deposition values at the Class I areas of concern. As previously discussed, the Project will employ state-of-the-art CC technology and emissions controls. Maximum air quality impacts in the vicinity of the Project will be well below the applicable national and Florida AAQS.

Given the resulting low emissions rates and low air quality impacts, potential detrimental effects on soils, vegetation, and wildlife will be insignificant.

Table 9-1. Polk 2-5 Conversion Project Maximum Pollutant Concentration Impacts

Pollutant	Averaging Period	CClass I ($\mu g/m^3$)	Class II ($\mu g/m^3$)
NO_2	Annual	0.0031	0.039
	1-Hour	Not applicable	36.7
SO_2	Annual	0.0018	0.12
	24-Hour	0.039	1.4
	3-Hour	0.17	5.7
	1-Hour	Not applicable	8.4
PM_{10}	Annual	Not applicable	0.18
	24-Hour	Not applicable	2.5
$PM_{2.5}$	Annual	0.0034	0.18
	24-Hour	0.07	2.5
CO	1-Hour	Not applicable	26.2
	8-Hour	Not applicable	12.3

Source: ECT, 2012.

Table 9-2. Projected Maximum Annual Wet and Dry Atmospheric Deposition Impacts

Pollutant	Averaging Period	Chassahowitzka NWA Class I Area Impact (kg/ha/yr)
Total nitrogen deposition	Annual	0.0024
Total sulfur deposition	Annual	0.0029

Note: kg/ha/yr = kilogram per hectare per year.

Source: ECT, 2012.

A general discussion of air emissions impacts on soils, vegetation, and wildlife is provided in the following subsection. Following this general discussion, specific analyses of impacts in the vicinity of the Project as well as the two Class I areas located within 300 km (i.e., Chassahowitzka NWA and Everglades NP) are provided. Because of the Project's emissions, analysis of the AQRVs were only required for Chassahowitzka NWA.

9.2.1 GENERAL AIR EMISSIONS IMPACTS ON SOILS

Sulfur and nitrogen can be added to soil as a result of atmospheric deposition. Sulfur and nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emissions impacts on soils can cause acidic conditions to develop. Acidic conditions in the soil can cause the leaching of basic cations essential for plant life and in extreme circumstances can transform aluminum to a more soluble form where toxicity can occur (Goldstein *et al.*, 1985).

Nitrogen deficiency is common in nonagricultural areas; therefore, much of the atmospherically deposited NO_x is biologically assimilated. There is a limited soil adsorption mechanism for nitrate, so unutilized nitrate will be leached through the soil (Johnson and Reuss, 1984). Both of these factors indicate that nitrate does not play a significant role in soil acidification and that sulfate is more of a concern. Atmospheric deposition of nitrogen can facilitate eutrophication of the soil and vegetative community. Critical loads of nitrogen above which eutrophication caused a change in vegetative species present in calcareous forests was found to be 15 to 20 kilograms per hectare per year (kg/ha/yr) (Thimonier *et al.*, 1994).

Sulfur deposition can facilitate soil acidification. Sulfur exists in the soil predominantly in the form of sulfate. The maintenance of sulfate in soil solution facilitates the loss of cations. Therefore, the more sulfate that is adsorbed to soil particles, the more buffered the soils will be (Johnson and Reuss, 1984). The soil is a much larger sink for sulfate than vegetation (Johnson and Reuss, 1984). Sulfate can be adsorbed on the surface of reactive clays and iron/aluminum oxides within the soil, which often releases hydroxide, further buffering the soil (Johnson and Reuss, 1984). Soils found in Florida and Georgia that have high adsorption rates for sulfates include ultisols and certain suborders of inceptisols and entisols (Psamments) (Johnson and Reuss, 1984). The high iron and aluminum content of the subsurface spodic horizon of spodosols likely adsorbs the sulfate anion to a large extent as is shown to occur with the anion of phosphate. The development of acidic conditions in the Southeast are thought to be well buffered by the high amount of sulfate adsorption (USGS, 1999).

Dissolution of sulfate and nitrate can also facilitate the formation of nitric acid and H_2SO_4 in rainwater, which increases acidic hydrogen ion composition within the soil. Soils that are well buffered to the addition of acid causing hydrogen ions have a high cation exchange capacity, often imparted by surface or subsurface clays and a high base saturation. Barton *et al.* (2002) found soils with a base saturation of 12 to 19 percent and reactive clays to be buffered to acidic inputs, whereas soils with a base saturation of 3 to 7 percent by depth show the effects of soil acidification. In addition, organic horizons of wetland histosols buffer acidic inputs protecting the depletion of cations from the mineral horizons (Koptsik *et al.*, 1998).

9.2.2 GENERAL AIR EMISSIONS IMPACTS ON VEGETATION

It is difficult to predict site-specific ecological impacts due to air emissions based on data and conclusions in available literature because of significant variations in experimental designs relating dose, duration, and vegetation species. Minor variations in experimental design and the conditions under which the various vegetation species have been fumigated can result in large differences in the tolerance limits of tested species.

Table 9-3 presents a summary of the thresholds for the most sensitive vegetation and the air-pollution induced effects, for important air pollution constituents. To demonstrate the range of tolerances for relevant vegetation, Table 9-4 lists literature results for injury threshold concentrations and characteristic injury symptoms of plants found in the southeastern United States. The species listed are likely to occur in all or many of the Class I areas addressed herein. As a result, all listed vegetation will be used as bioindicators for impacts to all the Class I and II areas relevant to the Project.

Table 9-3. Estimated Maximum Facility Impacts Compared to General Plant Injury Symptoms and Threshold Concentrations for Important Air Pollutants

Pollutant	Symptoms	Injury Threshold $\mu g/m^3$	Injury Threshold Sustainable Exposure	Estimated Maximum Facility Impact ($\mu g/m^3$)
SO_2	Bleached spots, intercostal chlorosis	131*	8 hours	5.7†† (3-hour)
SO_2	Absence of the most sensitive lichen	13 to 26†	Chronic	0.118 (annual)
NO_2	Increase in Nitrate Reductase activity in sensitive bryophytes	65‡	24 hours	37.9†† (1-hour)
Mercury	Chlorosis and abscission; brown spotting; yellowing of veins	0.08**	5 weeks	<0.0001†† (annual)

Note: Conservative (worst-case) impact estimated based on modeling results presented in Section 7.0.

Sources: *Jones *et al.,* 1974.
†Wetmore, 1983.
‡World Health Organization, 2000.
**Hindawi, 1970.
††ECT 2012.

Table 9-4. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast

Common Name	Scientific Name	SO_2	NO_x
Red maple	*Acer rubrum*	786[a] (5 hours)	
Maple	*Acer* sp.	524 to 6,550[b] (8 hours)	
Bald Cypress	*Taxodium distichum*	2,620[c] (48 hours)	
Bracken fern	*Pteridium aquilinum*	131 to 1,310[b] (8 hours)	
Blackberry	*Rubus* sp.	131 to 1,310[b] (8 hours)	
Ragweeds	*Ambrosia* sp.	1,310 to 2,620[h] (1 hour) 790 1,570 (3 hours)	
Southern red oak	*Quercus falcata*	1,310 to 2,620[h] (1 hour) 790 to 1,570 (3 hours)	
Black oak	*Quercus velutina*	1,310 to 2,620[h] (1 hour) 790 to 1,570 (3 hours)	
Legumes		1,310 to 2,620[h] (1 hour) 790 to 1,570 (3 hours)	
Locust	*Gleditsia* sp.	2,620 to 5,240[h] (1 hour) 1,570 to 2,100 (3 hours)	
Many crop and garden species		2,620 to 5,240[h] (1 hour) 1,570 to 2,100 (3 hours)	
American elm	*Ulmus americana*	131 to 1,310[b] (8 hours)	
White ash	*Fraxinus americana*	131 to 1,310[b] (8 hours)	
Sumacs	*Rhus* spp.	131 to 1,310[b] (8 hours)	
Tulip poplar	*Liriodendron tulipifera*	524 to 6,550[b] (8 hours)	
Sweetgum	*Liquidambar styraciflua*	524 to 6,550[b] (8 hours)	
Slash pine	*Pinus elliottii*	149[f] (chronic)	
Basswood	*Tilia glabra=T. americana*	524 to 6,550[b] (8 hours)	
Pin oak	*Quercus palustris*	524 to 6,550[b] (8 hours)	
Red cedar	*Juniperus virginiana*	>5,240[b] (8 hours)	
Potato		2,620 to 5,240[h] (1 hour) 1,570 to 2,100 (3 hours)	
Upland cotton	*Gossypium hirsutum*	>5,240[h] (1 hour) >2,100 (3 hours)	

Table 9-4. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast (Continued, Page 2 of 2)

Common Name	Scientific Name	SO_2	NO_x
Corn	*Zea mays*	>5,240[h] (1 hour) >2,100 (3 hours)	
Lichen	*Ramalina americana*	13 to 26[d] (chronic)	
Lichens	Sensitive species of *Usnea, Lobaria, Cladonia*	>30[e] (chronic)	
White oak	*Quercus alba*	>5,240[b] (8 hours)	
Dogwood	*Cornus florida*	>5,240[b] (8 hours)	
Bryophyte	*Several Bryophyte species*		65[g] (24 hours)
Birch	*Betula* sp.		120[g] (chronic)
Common sunflower	*Helianthus annuus*		375[g] (chronic)
Alfalfa	*Medicago sativa*		1,000[g] (5 hours)
Peach	*Prunus persica*		>5,240 (1 hour) >2,100 (3 hours)
Garden pea	*Pisum sativum*		850[g] (7 hours)
Cultivated tobacco	*Nicotiana tabacum*		2,000 to 3,000[g] (3.5 hours)
Perennial ryegrass	*Lolium perenne*		125[g] (chronic)
Southern pine	*Pinus* spp.	1572[b] (3 hours)	

Note: Concentrations in $\mu g/m^3$ (exposure times shown in parentheses).

Sources: [a]Davis and Shelly, 1992.
[b]Jones *et al.*, 1974.
[c]Shanklin and Kozlowski, 1985.
[d]Wetmore, 1983.
[e]Treshow and Anderson, 1989.
[f]Hogsett *et al.*, 1985.
[g]World Health Organization, 2000.
[h]EPA, 1982.

Vegetation damage is described as impacts resulting in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage, as well as changes in secondary metabolites such as tannins and phenolic compounds. Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses over relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages, which have both functional and visible consequences, are usually manifested by internal physical damage to foliar tissues. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the potential effects upon vegetation associated with the relevant pollutants.

9.2.2.1 Nitrogen Oxides

During combustion, atmospheric nitrogen is oxidized to NO_x and small amounts of NO_2 (Taylor *et al.*, 1975). Impacts to vegetation from NO_2 result from high concentrations occurring during short time periods (Taylor and MacLean, 1970). Acute exposures of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Nonvascular bryophytes are sensitive to NO_x, exhibiting reductions in nitrate reductase activity at concentrations of 65 $\mu g/m^3$ with an exposure duration of 24 hours (World Health Organization [WHO], 2000). Bald cypress (*Taxodium distichum*), a common tree species in wetlands of this geographical area, shows no adverse impacts below 2,620 $\mu g/m^3$ with an exposure time of 48 hours (Shanklin and Kozlowski, 1985).

9.2.2.2 Sulfur Dioxide

Natural (ambient) background concentrations of SO_2 range between 0.28 and 2.8 $\mu g/m^3$ on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO_2 is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO_2 primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO_2 may also be absorbed through the protective cuticle. At low concentrations SO_2 byproducts are effectively detoxified by the plant and can become a sulfur source to the plant, while elevated concentrations can be toxic (Zeiger, 2002). Adverse effects on plants from SO_2 are primarily due to impacts to photosynthetic processes.

SO_2 can react with chlorophyll by bleaching or phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due to SO_2 appears as marginal or intercostal areas of dead tissue that at first cause leaves to appear water-soaked (Barett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO_2 exposure, there is some bleaching of the chlorophyll that appears as a mild chlorosis or yellowing of the leaf and/or a silvering or bronzing of the undersurface. Species that are categorized as sensitive to SO_2 emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 $\mu g/m^3$ SO_2 for a period of 8 hours (Jones *et al.*, 1974).

Researchers have conducted numerous studies to determine the effects of SO_2 exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, tulip poplar, goldenrods [*Solidago* spp.], legumes, blackberry [*Rubus* spp.], black oak [*Quercus velutina*], and ragweeds [*Ambrosia* spp.]) exhibit visible injury to short-term (3 hours) exposure to SO_2 concentrations ranging from 790 to 1,570 $\mu g/m^3$. Tolerant plants native to the southeast region are dogwood (*Cornus florida*), red cedar (*Juniperus virginiana*), and white oak (*Quercus alba*) with injury thresholds greater than 5,240 $\mu g/m^3$ for a 3-hour exposure period (Jones *et al.*, 1974). Plants with intermediate tolerance (131 to 1,310 $\mu g/m^3$ for an 8-hour period) are maples (*Acer* spp.), tulip poplar (*Liriodendron tulipifera*), and sweetgum (*Liquidambar styraciflua*). Vascular plant species found in this region of the southeast, which are sensitive or moderately sensitive to SO_2, include bracken fern (*Pteridium aquilinum*), blackberry, sumacs (*Rhus* spp.), and tulip poplar. Complicating generalizations regarding SO_2 injury is the observation that the genetic variability of native annual plants can result in the selection of SO_2 resistant strains in as little as 25 years (Westman *et al.*, 1985).

Due to their rather diminutive and inconspicuous nature, lichens and bryophytes are often not considered as important biological components of the ecosystem. However, these nonvascular plants do play a valid role in the environment by functioning as habitat for invertebrates, containing blue-green bacteria that fix nitrogen, participating in mineral cycling, and providing a food source for various fauna, among others.

Nonvascular plants such as lichens and bryophytes are especially important as bioindicators due to well-documented air pollution sensitivity. Because of relatively low chlorophyll content and the absence of the protective covering of a cuticle (common in the leaves of higher plants), nonvascular plants are more sensitive to SO_2 injury. Hart *et al.* (1988) showed that *Ramalina* sp., a lichen genus, exhibited a reduction of CO_2 uptake and biomass gain at SO_2 exposures of 400 μg/m^3 for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 μg/m^3; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975). A mean annual concentration of 30 μg/m^3 of SO_2 may injure sensitive individuals of some lichen species such as *Usnea*, *Lobaria*, *Ramalina*, and *Cladonia* (Treshow and Anderson, 1989). One lichen species, *Ramalina americana*, is known to be absent where SO_2 concentration mean annual values range from 13 to 26 μg/m^3 (LeBlanc and Rao, 1972; Wetmore, 1983).

9.2.2.3 <u>Particulate Matter</u>

In addition to gaseous emissions, PM will be emitted by the proposed Project. Included among the PM may be low concentrations of mercury, beryllium, arsenic, and lead, to the extent present at low levels in the fuels. The mercury may occur as both mercury vapors and particulates. The mechanism of mercury phytotoxicity is currently under investigation. Past investigations indicate that mercury vapors will cause chlorosis, abscission of older leaves, growth reduction, and poor development. Most investigations have been restricted to greenhouse crops where air quality monitoring was not conducted. One investigation indicates that vegetation exposed to 50 μg/m^3 mercury for 7 days experienced leaf abscission (Siegel *et al.*, 1984). Plants found in the region showing injury at this concentration and period of exposure to mercury are willow (*Salix* spp.) and red maple (*Acer rubrum*).

The literature regarding effects on vegetation from beryllium, arsenic, and lead is scarce. One investigation indicates that vegetation growth was reduced by beryllium concentrations in excess of 735 μg/m^3 (Gough *et al.*, 1979). Arsenic uptake by vegetation to a concentration of 5 micrograms per gram (μg/g) is considered harmful. Lead retards plant growth above a concentration of 30 μg/g in the soil.

9.2.2.4 Carbon Monoxide

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO.

9.2.3 GENERAL AIR EMISSIONS IMPACTS ON WILDLIFE

Impacts to wildlife can occur due to direct uptake of pollutants through ingestion or via the skin and more indirectly as a result of air pollution induced changes to wildlife habitat and food source. Studies have shown direct air pollution induced injury and death in wildlife as a result of fluoride, cadmium, SO_2, particulates, NO_x, arsenic, mercury, and oxidants like ozone (Newman, 1980; Newman & Schreiber, 1985). These impacts are mostly the result of extreme incidences due to acute toxicity. This acute toxicity occurs most severely in circumstances where air pollutants were likely elevated far above the AAQS, or where significantly elevated concentrations of pollutants occurred on vegetation that was subsequently consumed. The NAAQS were previously shown in Section 3.0 on Table 3-1. Physiological and behavioral effects have not been observed at concentrations at or below the AAQS. No observed impacts upon wildlife are expected at concentrations below the values reported in Table 9-5.

Studies have shown damage to the tracheal epithelium of bird species at extreme concentrations of NO_x and SO_2 of 2,500 $\mu g/m^3$ and 1,221 $\mu g/m^3$, respectively (Llacuna *et al.* 1993). These values are far elevated above concentrations that are expected.

Ambient air quality concentrations as a result of the Project will not exceed the national and Florida AAQS or the values listed in Table 9-5. Pollutant deposition on vegetation at levels harmful to wildlife will likely be lower than plant injury thresholds previously shown in Tables 9-3 and 9-4. Absent any site-specific studies on baseline levels of pollutants, it is assumed that wildlife impacts will be insignificant if pollutant effects on vegetation are also expected to be insignificant.

Table 9-5. Examples of Reported Stresses to Animals at Air Pollutant Concentrations Below National Secondary AAQS

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
SO_2*	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 days/week for 10 weeks continually for 5 months
	Decreased abundance in deer mice	13 to 157	
NO_x†‡	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days continually for 2 months
Particulates*	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	2 hours
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	

Sources: *Newman and Schreiber, 1988.
†Gardner and Graham, 1976.
‡Trzeciak *et al.*, 1977.

Persistent pollutants such as mercury have the potential to collect in the environment and bioaccumulate to elevated concentrations in upper-trophic level wildlife. Mercury is a persistent pollutant that accumulates in the sediments. Mercury methylation, whereby inorganic forms of mercury are biologically converted to a bioavailable organic form, occurs most predominantly in the anaerobic conditions found in ponds, lakes, and wetlands (St. Louis *et al.*, 1994; Krabbenhoft *et al.*, 1995; Driscoll *et al.*, 1998). As a result, species living and feeding within these aquatic systems are the most sensitive to mercury bioaccumulation.

Most impacts to wildlife due to emissions from power plants are indirect, predominantly as a result of effects on habitat quality. One such indirect effect is increased acidification. Amphibians are particularly sensitive to increased acidification in vernal pools and ponds as a result of the permeability of their skin. The highest potential for acidification to impact amphibian egg-laying habitat occurs in snow-melt water pools, which do not occur in the Project area (Newman and Schreiber, 1988). Loss of fish, amphibians, algae, invertebrates, and vegetative habitat as a result of acidification can impact species further up the food chain such as fish-eating feral mink (Bevanger and Albu, 1986) and wetland waterfowl (Rattner *et al.*, 1987). These studies indicate that the greatest possible impact to wildlife as a whole is degradation of the composition, structure, and habitat value due to increased acidification of the soils and aquatic systems caused by elevated SO_x and NO_x. As discussed in subsequent sections, the atmospheric concentrations of SO_x and NO_x and deposition of sulfur and nitrogenous compounds as a result of the Project are unlikely to cause soil and water acidification.

9.2.4 SPECIFIC AIR EMISSIONS IMPACTS IN THE VICINITY OF THE PROJECT

The Project's air quality impacts on soils, vegetation, and wildlife in the vicinity of PPS will be insignificant. Maximum Project Class II impacts are projected to be well below the NAAQS. Maximum Project annual average NO_2, SO_2, and $PM_{2.5}$ impacts are only 0.04, 0.15, and 1.1 percent of the annual average AAQS, respectively. Maximum Project 24-hour average SO_2, PM_{10}, and $PM_{2.5}$ impacts are only 4.1, 3.8, and 16.3 percent of the

24-hour average AAQS, respectively. Maximum project 1-hour average NO_2 and SO_2 impacts are 20.1 and 5.4 percent of the AAQS, respectively.

9.2.5 SPECIFIC AIR EMISSIONS IMPACTS—CLASS I AREAS

The following describes environmental features and a discussion of potential impacts to Class I areas located within 300 km of the proposed Project Site as a result of the Project emissions. The two Class I areas within this range are Chassahowitzka NWA and Everglades NP. Because of the Project's emissions and distance to Everglades NP, analysis of AQRV was not required for this Class I area. This portion of the analysis will focus on the potential impacts to AQRVs within Chassahowitzka NWA. AQRVs are defined as:

> "All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. The 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 assets that are to be preserved if the area is to achieve the purposes for which it was set aside" (Federal Register, 1978).

The following sections address the Project's air quality impacts on vegetation, wildlife, and soils at Chassahowitzka NWA. The Project is located 117 km from Chassahowitzka NWA.

9.2.5.1 Vegetation Types

The predominant vegetative communities that are represented in Chassahowitzka NWA include hardwood swamps, cypress ponds, flatwoods, saltmarsh, sandhill, scrub, and wet prairies (FWC, 2001).

Hardwood Swamp

The hardwood swamp is the most prevalent vegetative community in Chassahowitzka NWA. This community is a palustrine wetland community characterized by the diverse mixture of trees, shrubs, and vines that vary with the differences in elevation. Dominant tree species include bald cypress (*Taxodium distichum*), red maple (*Acer rubrum),* sweet gum (*Liquidambar styraciflua*), winged elm (*Ulmus alata*), southern magnolia (*Magnolia* *grandiflora*), ashes (*Fraxinus* spp.), and southern red cedar (*Juniperus silicicola*). The subcanopy includes redbud (*Cercis canadensis*) and basswood (*Tilia* spp.) in higher elevation sites and red bay (*Persea borbonia*), swamp dogwood (*Cornus foemina*), and dahoon holly (*Ilex cassine*) in lower elevations. The understory vegetation consists of dwarf palmetto (*Sabal minor*), American beautyberry (*Callicarpa americana*), and grape vines (*Vitis* spp.) in higher elevations, while wax myrtle (*Myrica cerifera*), dewberry (*Rubus* spp.), and various ferns are found in lower elevations. The vegetative community provides a good source of mast for numerous wildlife species and plentiful habitat.

Cypress Pond

Cypress ponds are found in depressions throughout the uplands. The vegetative community consists of pond cypress (*Taxodium ascendens*), bald cypress, red maple, sweet gum, Virginia willow (*Itea virginica*), and buttonbush (*Cephalanthus occidentalis).*

Flatwoods

Flatwoods are often located in regions with unproductive soils with low water available to the vegetation. The plant community consists largely of longleaf pine (*Pinus palustris*) or slash pine (*P. elliottii*) with an understory consisting of saw palmetto (*Serenoa repens*) wax myrtle, and gallberry (*Ilex glabra*). The quality of this community for wildlife utilization appears to be poor as a result of historic fire suppression.

Sandhills

Xeric conditions brought on by sandy soils define the sparse vegetative community of the sandhills. The tree canopy consists of longleaf pine, sand pine (*Pinus clausa*), blackjack oak (*Q. incana*), and turkey oak (*Quercus laevis*) with wiregrass (*Aristida stricta*), palmettos, and various herbs in the understory.

Saltmarsh

The saltmarsh community occurs from the Gulf of Mexico in to the tidal creeks with the vegetative community transitioning from black needle rush (*Juncus roemerianus*) and smooth cordgrass (*Spartina alterniflora*) in the high salinity portions to sawgrass

(*Cladium jamaicense*) in the fresher portions. Upland islands consist of red cedar, cabbage palm, and live oaks.

Scrub

The scrub community occurs on north-south strands occurring along prehistoric dunes. Scrub communities consist of sand pine, myrtle oak (*Q. myrtifolia*), and scrub live oak (*Q. geminata*).

Wet Prairie

Wet prairies occur scattered throughout the sandhills. They are dominated by marsh species including white-tops (*Dichromena colorata*), spikerushes (*Eleocharis* spp.), bog buttons (*Lachnocaulon anceps*), dahoon holly, American lotus (*Nelumbo lutea*), and spatterdock (*Nuphar lutea*).

9.2.5.2 Vegetation Impact Analysis

Monitoring stations are spread throughout the region at different distances from Chassahowitzka NWA. Nonetheless, these measurements can be illustrative of baseline conditions at Chassahowitzka NWA. The NO_2 concentration at St. Petersburg remains stable at approximately 20 percent of the national 1-hour standard of 100 parts per billion (ppb) (188 $\mu g/m^3$). As a result of the Project's, maximum annual NO_2 impact, concentrations are projected to increase annually by only 0.0031 $\mu g/m^3$, as shown in Table 9-1. This increase is a small fraction of levels known to cause harm to the most sensitive vegetation (65 $\mu g/m^3$ for 24 hours), as shown in Table 9-3. Currently, SO_2 at the Tampa-St. Petersburg-Clearwater sites are well below the annual AAQS of 80 $\mu g/m^3$. A maximum SO_2 increase in 3-hour, 24-hour, and annual concentrations of 0.17, 0.039, and 0.0018 $\mu g/m^3$, respectively, as a result of the Project's operations will not impact the most sensitive vegetation with tolerances of 131 $\mu g/m^3$ for 8 hours and 13 $\mu g/m^3$ for chronic exposures, as indicated in Table 9-4. The SO_2 concentration increase as a result of the Project will produce a negligible increase in concentrations with respect to vegetative impacts.

$PM_{2.5}$ concentrations in the St. Petersburg-Tampa-Clearwater area remain well below the annual average AAQS of 15 µg/m^3 and the 24-hour AAQS of 35 µg/m^3. The impact from the small maximum annual and 24-hour $PM_{2.5}$ increases of 0.0034 and 0.067 µg/m^3, respectively, as a result of the Project, are negligible with regard to ecosystem impacts within Chassahowitzka NWA.

9.2.5.3 Typical Wildlife

The diverse array of communities and the close association between wetlands and uplands allows for a wide array of wildlife species. Many species of wildlife that are endangered, threatened, or species of special concern are present in Chassahowitzka NWA including the Florida black bear, Florida mouse, gopher tortoise, Eastern indigo snake, Florida gopher frog, American alligator, Florida pine snake, and potentially bald eagles. The heterogeneous composition of the aquatic communities and range of salinities allows for a large diversity of fish species typical of this region of Florida.

Whooping crane populations have recently been established to winter in Chassahowitzka NWA. In addition, along their migratory pathway, they have been known to occur near the Tampa electric Site. This is a sensitive species brought back from the brink of extinction. On their wintering grounds, the whooping crane prefers a habitat within estuarine marshes, shallow bays, and salt tidal flats and can be found within freshwater wetlands along their migration path. They prefer to feed on crabs, shrimps, clams, snails, frogs, snakes, grasshoppers, larval and nymph forms of flies, beetles, water bugs, birds, and small mammals. In addition, they have been known to eat more than 58 species of fish.

9.2.5.4 Wildlife Impact Evaluation

Air pollutant concentrations in the vicinity of Unit 6 are projected to be well below national and Florida AAQS and the minimum threshold concentrations shown in Table 9-5, below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed above, minimal impacts to vegetation are expected to occur as a result of the low air impacts from the Project in Chassahowitzka NWA. Therefore, no adverse impacts to wildlife are expected due to the Project.

Due to the fact that the cranes are a carnivorous species, predominantly feeding in wetlands, (where mercury methylation is accelerated) there is a potential for biomagnification of mercury. Mercury deposition is monitored at Chassahowitzka NWR as part of the Mercury Deposition Program (MDP). Annual average wet deposition values of mercury at the MDP monitoring station range from 0.006 to 2.9 micrograms per square mile per year ($\mu g/m^2/yr$) reported for 2011. These values are within the lower end of the range of reported background mercury deposition rates of 0.5 and 1 $\mu g/m^{-2}/yr^{-1}$ (Bindler, 2003). No studies have been found that determine the impact of mercury deposition on Chassahowitzka NWA ecosystem, but these deposition levels are roughly equivalent to deposition occurring in Okeefenokee NWA, where mercury has been found at high levels in fish tissue, as discussed previously.

Given the extremely low emissions and air quality impacts from expected from the Project, it is safe to assume that mercury deposition at the distant Chassahowitzka NWA will be insignificant. Therefore, it is unlikely that whooping cranes will be significantly affected by mercury along their migratory pathway or in their wintering grounds in Chassahowitzka NWA as a result of the Project.

Migratory birds spending time in freshwater wetlands can be affected by acidification (Longcore, Ross, and Fischer, 1987). Reproductive success of birds with a variety of feeding habits has declined as a result of acidification-induced reductions in food abundance (Blancher and McAuley, 1987). Due to the low emissions discussed throughout these sections, which have been shown to be below levels causing significant acidity, it is unlikely that the whooping crane will be affected.

9.2.5.5 Soil Characteristics

Soil types within Chassahowitzka NWA are listed in the conceptual management plan (FWS, 2001). NRCS/USDA soil surveys were utilized to compile the soil pH data provided in Table 9-6, and the relevant soil chemical properties for all the soils shown in Table 9-7. Soils found in Chassahowitzka NWA range from very poorly drained organic soils (Aripeka-Okeelanta-Lauderhill and Okeelanta-Terra Ceia) in the freshwater wet

Table 9-6. Soil pHs for the Soils Found in Chassahowitzka NWA

Soil	Depth (inches)	Soil Reaction (pH)
Adamsville-fine sand	0 to 80	4.5 to 7.8
Anclote fine sand	0 to 80	5.1 to 8.4
Aripeka fine sand	0 to 13	5.6 to 7.8
	13 to 21	6.6 to 8.4
Aripeka - Okeelanta - Lauderhill		
Okeelanta	0 to 27	5.1 to 6.5
	27 to 60	5.1 to 7.3
Lauderhill	0 to 80	6.1 to 8.4
Astatula fine sand	0 to 80	4.5 to 6.5
Basinger fine sand	0 to 8	3.6 to 8.4
	8 to 60	3.6 to 7.3
Basinger fine sand, depressional	0 to 80	3.6 to 7.3
Candler fine sand	0 to 80	4.5 to 6.0
EauGallie fine sand	0 to 25	4.5 to 6.0
	25 to 33	4.5 to 6.5
	33 to 57	5.1 to 7.8
	57 to 63	5.1 to 7.8
Homosassa mucky fine sandy loam	0 to 80	6.1 to 7.8
Lacoochee fine sandy loam	0 to 8	7.9 to 8.4
	8 to 13	6.6 to 8.4
Myakka fine sand	0 to 80	3.6 to 6.5
Okeelanta - Terra Ceia		
Okeelanta	0 to 27	4.5 to 7.8
	27 to 60	5.1 to 7.8
Terra Ceia	0 to 80	5.6 to 8.4
Paola fine sand	0 to 80	3.6 to 7.3
Pomello fine sand	0 to 80	4.5 to 6.0
Tavares fine sand	0 to 80	4.5 to 6.0
Weekiwachee muck	0 to 80	6.1 to 7.8
Weekiwachee – Homosassa	0 to 80	6.1 to 7.8

Source: USDA, NRCS soil surveys of Citrus County, 1988 and Hernando County, 1977.

Table 9-7. Chemical Properties of the Soils within Chassahowitzka NWA

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
Adamsville-fine sand	0 to 18	Ap	1.19	0.27	0.02	0.13	5.04	32
	18 to 51	C1	0.2	0.07	0.01	0.03	1.36	23
	51 to 99	C2	0.12	0.05	0.01	0.01	0.72	26
	99 to 152	C3	0.04	0.04	0.02	0	0.4	25
	152 to 203	C3	0.06	0.02	0.01	0	0.24	38
Aripeka fine sand	0 to 8	A1	3.1	1.6	0	0.1	7.8	62
	8 to 13	A2	1.2	0.6	0	0.1	4	48
	13 to 25	B21	0.4	0.3	0.1	0	1.8	44
	25 to 33	B22	1.4	0.5	0.1	0	3	67
	33 to 38	B23t	7.7	1.5	0.8	0.2	14.1	72
	38 to 53	B24t	10.8	1	1.6	0.2	15.8	86
Astatula fine sand	0 to 13	A	0.11	0.04	0.02	0.02	2.4	8
	13 to 46	C1	0.03	0.01	0.02	0.01	1.74	4
	46 to 119	C2	0.02	0.01	0.01	0	0.78	5
	119 to 203	C3	0.02	0.01	0.01	0	0.68	6
Candler fine sand	0 to 10	A	0.18	0.05	0.01	0.01	3.02	8
	10 to 36	E1	0.03	0.02	0.01	0.01	1.5	5
	36 to 89	E2	0.03	0.02	0.01	0	0.61	10
	89 to 132	E3	0.01	0.02	0.01	0	0.45	9
	132 to 183	E4	0.02	0.02	0.01	0	0.24	21
	183 to 203	E/Bt	0.02	0.03	0.01	0	0.4	15

Table 9-7. Chemical Properties of the Soils within Chassahowitzka NWA (Continued, Page 2 of 2)

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
EauGallie fine sand	0 to 8	A1	4.8	3.36	0.12	0.13	19.91	42
	8 to 25	A2	0.51	0.56	0.04	0.03	4.19	27
	25 to 56	E	0.05	0.03	0.02	0	0.55	18
	56 to 114	Bh1	0.15	0.18	0.07	0	19.3	2
	114 to 135	Bh2	0.24	0.05	0.05	0	9.57	4
	135 to 173	Btg1	2.53	0.48	0.11	0.14	12.66	26
	173 to 203	Btg2	3.8	0.48	0.09	0.14	11.87	38
Myakka fine sand	0 to 10	A	2.46	2.33	0.11	0.05	14.64	34
	10 to 25	E1	1.13	0.89	0.08	0.02	6.75	31
	25 to 68	E2	0.05	0.03	0.02	0	0.18	56
	68 to 107	Bh1	0.12	0.04	0.05	0	14.46	1
	107 to 140	Bh2	0.24	0.04	0.05	0	10.99	3
	140 to 170	BC	0.49	0.05	0.03	0	5.94	10
	170 to 203	Bh'	4.35	0.08	0.08	0.01	9.23	49
Tavares fine sand	0 to 8	A	0.64	0.16	0.01	0.03	3.16	27
	8 to 56	C1	0.04	0.02	0.01	0.01	1.35	6
	56 to 104	C1	0.02	0.01	0	0	0.96	3
	104 to 160	C2	0.03	0.02	0.02	0	0.37	19
	160 to 203	C3	0.02	0.01	0.01	0	0.14	29

Source: USDA, NRCS soil surveys of Citrus County, 1988 and Hernando County, 1977.

lands and saltwater marshes to excessively drained sandy soils in the sandhills (Candler fine sand). The dominant soils are histosols and the psamment subgroup of the series entisols.

9.2.5.6 Soils Impacts Evaluation

Dominant soil types (histosols, psamment entisols) have a high sulfate adsorption capacity, increasing buffering to changes in pH (Johnson and Reuss, 1984). Base saturation of the soils of Chassahowitzka NWA tends to be high, even in surface horizons, further indicating a strong buffering capacity. The Astatula soil has a low base saturation, but it comprises only 0.15 percent of the refuge.

Soil acidification and eutrophication and other effects can occur as a result of atmospheric deposition of NO_x and SO_x. Atmospheric deposition is monitored at Chassahowitzka NWA as part of the National Atmospheric Deposition Program (NADP). Annual averages for wet deposition of nitrate and sulfate were available from 1997 through 2011. NADP monitoring of average annual nitrate wet deposition values range between approximately 6 to 14 kg/ha/yr but appear to have stabilized to approximately 6 to 9 kg/ha/yr from 2006 through 2011. These deposition values are below the threshold (15 to 20 hg/ha/yr) where eutrophication has been observed in calcareous forests (Thimonier *et al.*, 1994). Maximum atmospheric total deposition of nitrogen is projected to increase by 0.0024 kg/ha/yr as a result of the Project, which would cause no measurable eutrophication of Chassahowitzka NWA. The average annual sulfite wet deposition values range between approximately 8 to 18 kg/ha/yr over the same period but have generally been decreasing since 2006 and appear to be stable at approximately 10 kg/ha/yr. The dominant soil types of the refuge are well buffered to sulfate deposition. Regardless, sulfur total atmospheric deposition will only increase at a maximum of 0.0029 kg/ha/yr within Chassahowitzka NWA as a result of the Project.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions associated with the Project. Visible emissions from the CT/HRSG stacks, the primary Project emissions source, will be 10 percent or less, excluding water. Emissions of primary particulates and SO_x from the Project will be low due to the use of ULSD fuel oil and pipeline-quality natural gas. The Project will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACT RESULTS

10.1 OVERVIEW

Comprehensive refined modeling was conducted to assess Project Class I area air quality impacts in accordance with EPA, FLMs, and FDEP modeling guidance. This section provides the results of the Project air quality assessment with respect to long-range transport impacts at Chassahowitzka NWA and Everglades NP Class I areas. Section 7.0 previously addressed Project air quality impacts in the vicinity of the project Site.

PSD Class I areas located within 300 km of the Project include Chassahowitzka NWA and Everglades NP in Florida. The nearest PSD Class I area is Chassahowitzka NWA situated approximately 117 km (73 miles) to the northwest of the Project. Everglades NP is situated approximately 211 km (310 miles) southeast of the Project. Figure 10-1 provides the locations of the Class I areas located within 300 km of the Project.

For new sources that will be located at a distance of 50 km or greater from a Class I area, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report, Revised (2010), guidance on initial screening criteria recommends using the ratio of potential project emissions rates divided by the project's distance from a Class I area (i.e., Q/D or 10D Rule) to determine whether an assessment of Class I area AQRVs is necessary. Potential project emissions (i.e., Q) include SO_2, NO_2, PM_{10}, and H_2SO_4 mist annual emissions in tpy, based on 24-hour maximum allowable emissions. The distance (i.e., D) is the distance in kilometers from the Class I area. For cases in which the source is located more than 50 km and has a calculated Q/D ratio of 10 or less, the FLM will consider the source to have negligible impacts with respect to Class I AQRVs and would not request any further Class I AQRV impact analyses for such sources.

The Q/D ratios were calculated for the Project using annual emissions based on 24-hour maximum allowable emissions as required by the FLM screening guidance and the nearest distance to each of the two Class I areas located within 300 km of the Project.

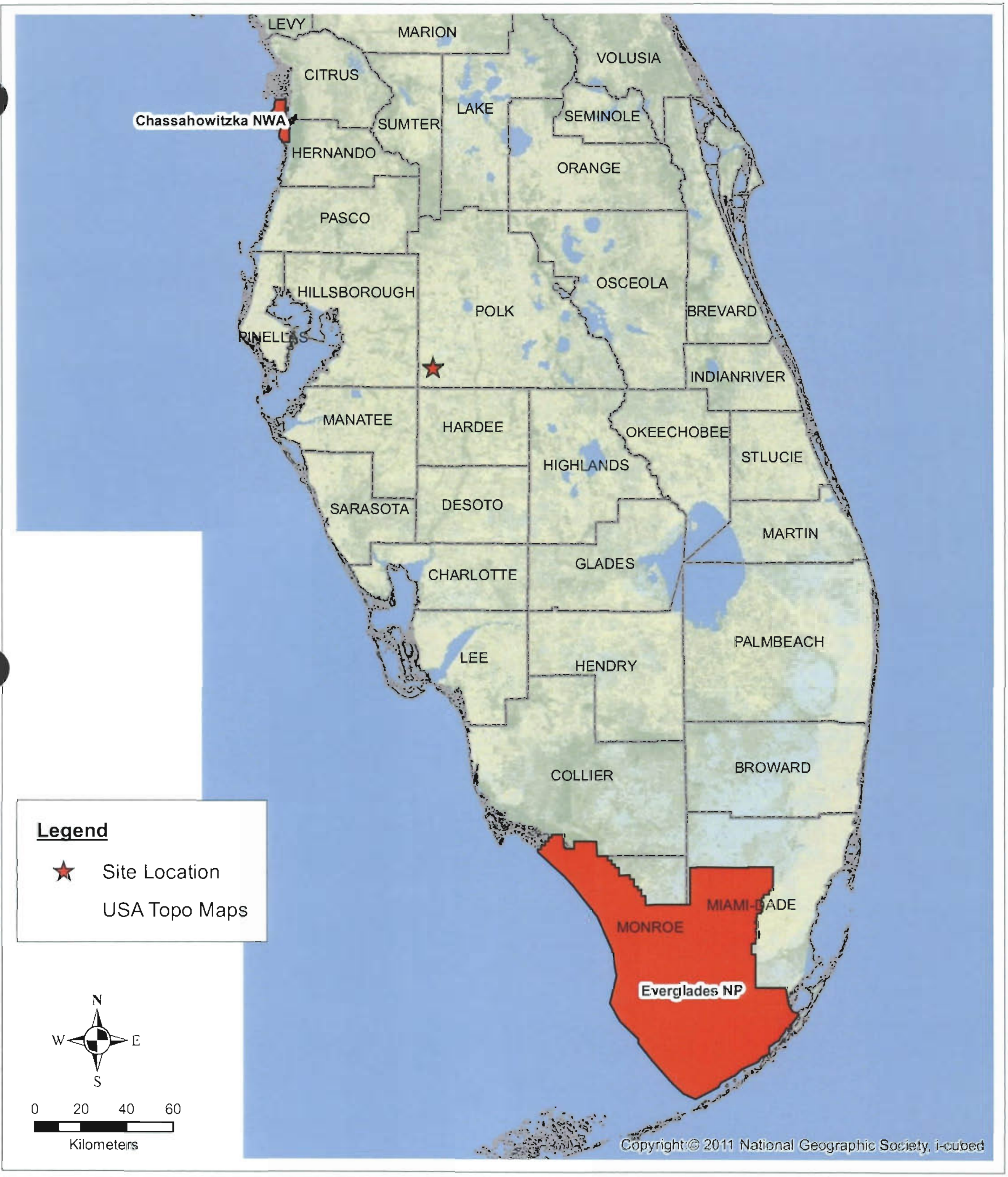

FIGURE 10-1.
LOCATION OF CLASS 1 AREAS

Sources: NPS, 2007; FWC, 2007; ECT, 2012.

TECO
TAMPA ELECTRIC

Table 10-1 summarizes the combustor stack's NO_2, SO_2, H_2SO_4 mist, and PM_{10} potential annual emissions in tpy, the distance to each Class I area (km), and the calculated Q/D ratio for each Class I area. The calculated Q/D ratio for Everglades NP is well below the FLM threshold of 10. Accordingly, Class I AQRV analyses were only required for Chassahowitzka NWA in accordance with the FLAG guidance.

10.2 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the Project will have insignificant air quality impacts for all modeled PSD pollutants and all averaging periods. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2, SO_2, and $PM_{2.5}$ was not required.

Based on the results of the AQRV analyses, it is concluded that the Project will not adversely affect visibility at any Class I area and that nitrogen and sulfur deposition impacts will not adversely affect the ecology of any Class I area.

10.3 GENERAL APPROACH

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts, the FLAG Phase I Report, Revised (2010), and EPA's GAQM.

The CALPUFF model was employed in a refined mode using 3 years (2001 through 2003) of 4-km resolution CALMET data and Class I area receptor grids as recommended by the National Park Service (NPS). The CALPUFF suite of programs, including the POSTUTIL and CALPOST postprocessing programs, was employed to develop estimates of Project impacts at Chassahowitzka NWA for the PSD Class I increments, regional haze, and deposition, and at Everglades NP for the PSD Class I increments.

Table 10-1. PSD Class I Initial Screening Analysis

	NO_x	SO_2	H_2SO_4 Mist	PM_{10} (total)*	Totals
Potential emissions (Q) (tpy)	618.5	215.5	61.3	332.9	1,228.2

	Chassahowitzka NWA	Everglades NP
Distance from the Project (D) (km)	116.9	211.8
FLAG screening ratio (Q/D) (tpy/km)	10.5	5.8

Note: tpy/km = ton per year per kilometer.

*Filterable and condensable PM.

Source: ECT, 2012.

10.4 MODEL SELECTION AND USE

Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction, nor do they limit the downwind transport of a pollutant as a function of windspeed and travel time. Due to these limitations, conventional steady-state dispersion models, such as AERMOD, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emissions source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emissions sources of interest, EPA and the FLMs initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The IWAQM was formed to coordinate the model development efforts of EPA and the FLMs.

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase 1, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase 2, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments. The Phase 2 recommendations, issued in December 1998, are contained in the IWAQM Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I report dated December 2000. The Phase 2 IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emissions source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendices A through W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants.

The EPA GAQM indicates that the CALPUFF modeling system is appropriate for long-range transport (source-receptor distances of 50 to several hundred kilometers) of emissions from point, volume, area, and line sources. All the receptors at the Class I areas evaluated are situated greater than 50 km from the Project.

The EPA-approved version of the CALPUFF modeling suite was used for the Project Class I area impact assessments. The EPA-approved CALPUFF modeling suite is comprised of the following programs:

- CALMET Version 5.8 Level: 070623
- CALPUFF Version: 5.8 Level: 070623
- POSTUTIL Version: 1.56 Level: 070627
- CALPOST Version: 6.221 Level: 080724

These programs were used to assess PSD Class I increments, regional haze, and nitrogen and sulfur deposition impacts.

The CALPUFF modeling system consists of three main components: CALMET, CALPUFF, and CALPOST. Each of these components is described in the following subsections.

10.4.1 CALMET

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file used by CALPUFF. The specific meteorological data used by the CALMET program include:

- Penn State/National Center for Atmospheric Research mesoscale model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and windspeed).

- Surface station weather data (windspeed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and windspeed at each sounding).
- Surface station precipitation data (precipitation rates).
- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, windspeed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, vegetation leaf area index, and anthropogenic heat flux).

Further technical discussion of the CALMET model can be found in Section 2 of the User's Guide for the CALMET meteorological model dated January 2000.

VISTAS developed a 3-year (2001 through 2003) CALMET dataset for a fine, 4-km, subregional domain that covers all of Florida and the adjacent Class I areas of interest to Florida. The VISTAS 2001 through 2003 meteorological data was reprocessed by the U.S. Fish and Wildlife Service (USFWS) using the current EPA regulatory version of CALMET; i.e., Version 5.8, Level 70623. This reprocessed fine-grid CALMET dataset (containing more than 250 gigabytes of data) was obtained from FDEP and was used in the Project Class I impact assessments.

10.4.2 CALPUFF

CALPUFF is a transport and puff model that advects puffs of material from an emissions source. These puffs undergo various dispersion and transformation simulation processes as they are advected from an emissions source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also use nongridded meteorological data similar to that used by a steady-state dispersion model such as AERMOD. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models. Further technical discussion of the CALPUFF model can be found in Section 2 of the User's Guide for the CALPUFF Model dated January 2000.

There are a number of optional CALPUFF input files that were not used for the Project Class I area impact assessments. These include time-varying emissions rates, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest.

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Project Class I area impact assessments conform to the recommendations contained in the IWAQM Phase 2 report and EPA's GAQM. Key CALPUFF model options selected for the Project Class I impact assessments are as follows:

- CALPUFF domain configured to include the Project emissions sources and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.
- Class I receptors as defined by NPS.
- Modeling of 11 species (SO_2, sulfate, NO_x, nitric acid, nitrate, and PM less than or equal to 1.0, 0.25, 0.20, 0.15, 0.10, and 0.05 micrometers).
- Use of the MESOPUFF II chemical mechanism module.
- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.

- 2001 through 2003 ozone data from EPA's Clean Air Status and Trends Network (CASTNet) and Aerometric Information Retrieval System (AIRS) stations.
- Background ammonia concentration of 0.5 ppb.
- Integrated puff sampling methodology.
- No consideration of building downwash.

The PM fractions shown address the PM size distribution expected for the Project CTG/HRSG units when firing fuel oil.

10.4.3 POSTUTIL

POSTUTIL is a postprocessing program used to process the concentrations generated by CALPUFF. POSTUTIL was used to recompute the nitric acid/nitrate concentration partition, develop visibility PM component emissions rates (i.e., elemental and organic carbon PM fractions), consolidate the $PM_{2.5}$ impacts (i.e., impacts due to $PM_{2.5}$ fractions), consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes.

10.4.4 CALPOST

CALPOST is a postprocessing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., regional haze), CALPOST uses the CALPUFF generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility.

For visibility assessments, background conditions were estimated using natural background data (i.e., absent anthropogenic influences). The CALPOST program was then used to compute background extinction coefficients using the natural background data and the IWAQM-recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the Project Class I impact assessments conform to the recommendations contained in the FLAG Phase I report.

10.5 RECEPTOR GRIDS

As noted previously, Chassahowitzka NWA and Everglades NP in Florida are both located within 300 km from the Project. The receptor grids developed for the Project Class I area impacts therefore addressed each of these Class I areas.

The Project Class I area receptor grids included Chassahowitzka NWA (113 discrete receptors) and Everglades NP (901 discrete receptors) receptors identified by NPS for these two Class I areas. The Class I receptor locations, which are provided by NPS in geographic (latitude and longitude) coordinates, were converted to Lambert Conformal Conic (LCC) coordinates consistent with the VISTAS fine 4-km CALMET grid parameters (i.e., two matching parallels, latitude/longitude of the projection origin, and coordinate datum) using the NPS Class I Areas Conversion program.

10.6 MODELED EMISSION SOURCES

Project modeled emissions sources included the four CC CTG/HRSG units. The Project cooling tower emissions source will have low PM_{10}/$PM_{2.5}$ emissions and a relatively low release height of 51 ft above grade. Accordingly, this emissions source will have negligible impacts at the distant Chassahowitzka NWA and Everglades NP Class I areas. The emergency generator diesel engine (which will operate approximately 2 hours per week for routine testing and maintenance, excluding emergencies) will have relatively minor emissions rates and will operate infrequently. Accordingly, this Project emissions source will also have negligible impacts at the two Class I areas evaluated.

Maximum 24-hour average emissions rates were used for each modeled Project emissions source. Table 10-2 summarizes the Project emissions source stack parameters and emissions rates used in the CALPUFF modeling assessments.

Table 10-2. Project CALPUFF Modeling Data

Parameter	Units	Value
CTG/HRSG Units (per unit)		
Stack height	ft	130
Stack diameter	ft	19.0
Stack velocity	ft/sec	60.0
Stack temperature	°F	194
SO_2 emissions	lb/hr	12.3
H_2SO_4 emissions	lb/hr	3.5
NO_x emissions	lb/hr	35.3
$PM_{2.5}$ emissions	lb/hr	19.0

Note: °F = degree Fahrenheit.
ft = foot.
ft/sec = foot per second.
lb/hr = pound per hour.

Source: ECT, 2012.

10.7 MODEL RESULTS

The following subsections discuss Project CALPUFF modeling results for Class I PSD increments, deposition impacts, and regional haze (i.e., visibility) at Chassahowitzka NWA and for Class I PSD increments at Everglades NP.

10.7.1 PSD CLASS I SIGNIFICANT IMPACT LEVEL ANALYSIS

Table 10-3 summarizes Project NO_2, SO_2, and $PM_{2.5}$ impacts with respect to the PSD Class I SILs. This table provides the highest annual average impacts for NO_2, SO_2, and $PM_{2.5}$; highest 3-hour average impacts for SO_2; and highest 24-hour average impacts for SO_2 and $PM_{2.5}$ for the two Class I areas evaluated.

All impacts are below the PSD Class I SILs for all pollutants and all averaging periods. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2, SO_2, and $PM_{2.5}$ was not required.

10.7.2 SULFUR AND NITROGEN DEPOSITION

Table 10-4 summarizes the Project total wet and dry annual sulfur and nitrogen deposition rates at Chassahowitzka NWA. As shown, Project sulfur and nitrogen deposition impacts will be below the FLM sulfur and nitrogen deposition analysis threshold (DAT) of 0.01 kg/ha/yr.

10.7.3 REGIONAL HAZE

Assessment of Project regional haze impacts was conducted for Chassahowitzka NWA using the current EPA-approved CALPOST program, background light extinction Method 8, sub-mode 5 monthly relative humidity data for Chassahowitzka NWA in accordance with current FLM modeling guidance.

The Project regional haze assessment evaluated the 98th percentile of the 24-hour average impacts (equivalent to the 8th highest 24-hour average impact at any receptor). The 24-hour average 98th percentile impact is the metric recommended by the FLMs for the assessment of regional haze impacts under the PSD NSR permitting program. The FLM visibility threshold for concern is not exceeded if the 98th percentile in light extinction is

Table 10-3. Summary of PSD Class I Air Quality Impacts: NO_x, SO_2, and PM_{10}

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact (µg/m³) Chassahowitzka NWA	Everglades NP
NO_x	2001	Annual	0.0030	0.00040
	2002		0.0031	0.00067
	2003		0.0026	0.00050
	Maximum		0.0031	0.00067
PSD SIL			0.1	0.1
% of PSD SIL			3.1	0.7
Exceed PSD SIL			No	No
SO_2	2001	Annual	0.0017	0.00036
	2002		0.0018	0.00058
	2003		0.0016	0.00048
	Maximum		0.0018	0.00058
PSD SIL			0.1	0.1
% of PSD SIL			1.8	0.6
Exceed PSD SIL			No	No
	2001	24-Hour	0.039	0.013
	2002		0.022	0.015
	2003		0.035	0.017
	Maximum		0.039	0.017
PSD SIL			0.2	0.2
% of PSD SIL			19.7	8.5
Exceed PSD SIL			No	No
	2001	3-Hour	0.17	0.037
	2002		0.12	0.046
	2003		0.11	0.057
	Maximum		0.17	0.057
PSD SIL			1.0	1.0
% of PSD SIL			16.8	5.7
Exceed PSD SIL			No	No
$PM_{2.5}$	2001	Annual	0.0030	0.00079
	2002		0.0034	0.00122
	2003		0.0028	0.00112
	Maximum		0.0034	0.00122
PSD SIL			0.06	0.06
% of PSD SIL			5.7	2.0
Exceed PSD SIL			No	No
	2001	24-Hour	0.067	0.026
	2002		0.037	0.035
	2003		0.065	0.037
	Maximum		0.067	0.037
PSD SIL			0.07	0.07
% of PSD SIL			95.4	52.7
Exceed PSD SIL			No	No

Source: ECT, 2012.

Table 10-4. Summary of PSD Class I Air Quality Impacts—Nitrogen and Sulfur Deposition

Pollutant	Year of Meteorology	Averaging Period	Chassahowitzka NWA	
			μg/m²/s	kg/ha/yr
Total wet and dry Nitrogen deposition	2001	Annual	0.0000077	0.0024
	2002		0.0000064	0.0020
	2003		0.0000070	0.0022
	Maximum		**0.0000077**	**0.0024**
FLM DAT				0.01
Percent of FLM DAT SIL				24.4
Exceed FLM DAT				No
Total wet and dry Sulfur deposition	2001	Annual	0.0000093	0.0029
	2002		0.0000083	0.0026
	2003		0.0000079	0.0025
	Maximum		**0.0000093**	**0.0029**
FLM DAT				0.01
Percent of FLM DAT SIL				29.5
Exceed FLM DAT				No

Note: μg/m²/s = microgram per square meter per second.
kg/ha/yr = kilogram per hectare per year.

Source: ECT, 2012.

less than 5 percent for each year of meteorology modeled when compared to the annual average natural visibility condition for a particular Class I area.

Table 10-5 provides Project regional haze impacts at Chassahowitzka NWA. As shown in this table, the increases in 24-hour average 98th percentile natural visibility due to Project emissions are all less than the 5-percent FLM visibility threshold for concern.

Table 10-5. Summary of Chassahowitzka NWA Regional Haze Impacts

Maximum 24-Hour Average 98th Percentile Impacts	Unit	2001	2002	2003	Maximum
B_{ext-s} – sulfate	Mm^{-1}	0.084	0.072	0.076	0.084
B_{ext-s} – nitrate	Mm^{-1}	0.093	0.091	0.024	0.093
B_{ext-s} – organic carbon	Mm^{-1}	0.059	0.045	0.059	0.059
B_{ext}-s – elemental carbon	Mm^{-1}	0.051	0.039	0.051	0.051
B_{ext-s} – fine particulate matter	Mm^{-1}	0.005	0.004	0.005	0.005
B_{ext-s} – NO_2	Mm^{-1}	0.005	0.002	0.002	0.005
B_{ext-s} – total	Mm^{-1}	0.297	0.253	0.217	0.297
B_{ext-b} – background	Mm^{-1}	22.914	22.9	22.3	22.9
Visual range, background	km mile deciview	170.7 106.1 8.3	170.7 106.0 8.3	175.2 108.8 8.0	175.2 108.8 8.3
Number of days with B_{ext} >5.0 percent	—	0	0	0	0
B_{ext} change	%	1.30	1.10	0.97	1.30
NPS significant impact, B_{ext} change	%	5.00	5.00	5.00	5.00
Exceed NPS significant impact	Yes/No	No	No	No	Yes
Percent of NPS significant impact	%	26.0	22.0	19.4	26.0
Receptor LCC easting	km	1,410.8	1,410.8	1,408.3	
Receptor LCC northing	km	-1,153.7	-1,153.7	-1,154.0	
Distance from CC-2A	km	118.1	118.1	119.6	
Direction from CC-2A	Vector °	316	316	315	

Source: ECT, 2012.

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APPENDIX A

FDEP APPLICATION FOR AIR PERMIT
LONG FORM

Leigh-Ann

Module AC015

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).

RECEIVED

OCT 04 2012

DIVISION OF AIR RESOURCE MANAGEMENT

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: **Tampa Electric Company**	
2. Site Name: **Polk Power Station**	
3. Facility Identification Number: **1050233**	
4. Facility Location... Street Address or Other Locator: **9895 State Road 37 South** City: **Mulberry** County: **Polk** Zip Code: **33860-0775**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Paul L. Carpinone** **Director, Environmental, Health & Safety**
2. Application Contact Mailing Address Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3. Application Contact Telephone Numbers... Telephone: **(813) 228-4858** ext. Fax: **(813) 228-1308**
4. Application Contact Email Address: **plcarpinone@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 10-4-12	3. PSD Number (if applicable):
2. Project Number(s): 1050233-034-AC	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

PSD air construction permit application to convert existing Units 2 through 5 at the Tampa Electric Company Polk Power Station (PPS) located in southwest Polk County from simple to combined cycle (CC) operation, increasing the nominal net capacity of the existing four units from 660 to 1,160 MW. Key directly associated facilities for the proposed Project include four heat recovery steam generators, one steam turbine generator, a mechanical draft cooling tower, and an emergency generator diesel engine. After completion of the proposed Project, the new CC unit will be known as the Polk 2 Combined Cycle. A detailed description of the Project is provided in Section 2.0.

Polk 2 Combined Cycle being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
-013	Nominal 290-MW Combined Cycle Unit No. 2A	N/A	N/A
-014	Nominal 290-MW Combined Cycle Unit No. 2B	N/A	N/A
-015	Nominal 290-MW Combined Cycle Unit No. 2C	N/A	N/A
-016	Nominal 290-MW Combined Cycle Unit No. 2D	N/A	N/A
-017	6-Cell Mechanical Draft Cooling Tower	N/A	N/A
-018	Nominal 760-HP Emergency Generator Diesel Engine	N/A	N/A

Application Processing Fee

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

Application processing fee of $7,500 for PSD review is required pursuant to Rule 62-4.050(a)2., F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name: **Paul L. Carpinone, Director, Environmental, Health & Safety**
2.	Owner/Authorized Representative Mailing Address Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3.	Owner/Authorized Representative Telephone Numbers Telephone: Telephone: **(813) 228-4858** ext. Fax: **(813) 228-1308**
4.	Owner/Authorized Representative Email Address: **plcarpinone@tecoenergy.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.* Paul Carpinone 9-25-2012 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification NOT APPLICABLE

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):
   - ☐ 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.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

   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.

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **Florida** Zip Code: **32606-5004**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332 – 0444** ext. Fax: **(352) 332 - 6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.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 10/1/12

(seal)

THOMAS W. DAVIS No. 36777 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **402.45** North (km) **3,067.35**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/43/43** Longitude (DD/MM/SS) **81/59/23**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Mike Perkins, Environmental Coordinator**
2. Facility Contact Mailing Address Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3. Facility Contact Telephone Numbers: Telephone: **(813) 228-1111** ext. **39109** Fax: **(863) 428-5927**
4. Facility Contact Email Address: **mrperkins@tecoenergy.com**

Facility Primary Responsible Official **NOT APPLICABLE**

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... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

FACILITY INFORMATION

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: **Applicable State and Federal emission standards are discussed in Section 4.0.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NO_x	**A**	**N**
SO_2	**A**	**N**
PM	**A**	**N**
PM_{10}	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SAM	**A**	**N**
PB	**B**	**N**
Arsenic Compounds (H015)	**B**	**N**
Beryllium Compounds (H021)	**B**	**N**
Mercury Compounds (H114)	**B**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps NOT APPLICABLE

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

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) ☒ Attached, Document ID: **Section 2.0** ☐ 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) ☒ Attached, Document ID: **Section 2.0** ☐ 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) ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date:_______

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Section 2.0** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **Section 2.0**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Section 4.0**
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☒ Attached, Document ID: **Section 2.0** ☐ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **Section 8.0** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **Sections 7.0 and 10.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **Section 9.0** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **Section 9.0** ☐ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

NOT APPLICABLE

Additional Requirements for FESOP Applications

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

NOT APPLICABLE

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)

NOT APPLICABLE

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

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

Additional Requirements Comment

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:

   Nominal 290-MW combined cycle (CC) unit comprised of a GE 7FA combustion turbine generator (CTG) and fired recovery steam generator (HRSG). The CTG will be fired with natural gas as the primary fuel and ULSD fuel oil as a backup fuel. The HRSG duck burner will be fired with natural gas. CTG/HRSG Unit 2A shares a common steam turbine with CC Units 2B, 2C, and 2D; i.e., a 4 x 1 configuration.

3. Emissions Unit Identification Number: **013 (Unit 2A)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**N/A**	**N/A**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241FA**

10. Generator Nameplate Rating: **165** MW

11. Emissions Unit Comment:

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

1.	Control Equipment/Method Description: **Dry low-NO_x combustors (natural gas)**
2.	Control Device or Method Code: **205**

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

1.	Control Equipment/Method Description: **Water injection (ULSD fuel oil)**
2.	Control Device or Method Code: **028**

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:	**2,239** million Btu/hr **(HHV, CTG Only)**
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	**24** hours/day **7** days/week **52** weeks/year **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input is higher heating value (HHV) at 100 percent load, 20°F, ULSD fuel oil operating conditions (Case CC-19).** **Maximum heat input at 100 percent load, 20°F, natural gas operating conditions (Case CC-1) is 2,078 x 10^6 Btu/hr (HHV), CTG only.** **HRSG duct burner maximum heat input is 264 x 10^6 Btu/hr, HHV.** **Heat inputs will vary with load, fuel type, and ambient temperature. See Tables B-23 and B-24 of Appendix B.** **Maximum of 8,760 hours per year (natural gas), up to 4,000 hours per year duct burner firing (natural gas) , and 12 hours per day and 750 hours per year (ULSD fuel 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: **Unit 2A**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **130** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **210**°F	9. Actual Volumetric Flow Rate: **1,027,900** acfm	10. Water Vapor: **N/A** %

11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

Fields 8 and 9 for natural gas, 100% load, 59°F, without evaporative cooling and duct burner firing operating conditions (Case CC-7).

Stack exit temperature and actual volumetric flow rate will vary with CTG load, ambient temperature, and use of evaporative cooling and duct burner firing. See Tables B-27 and B-28 of Appendix B.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **3**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **2.0**	5. Maximum Annual Rate: **17,520**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,040 (HHV)**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment **2** of **3**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with ULSD fuel oil.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand gallons Burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **12,075**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **139 (HHV)**
10. Segment Comment (limit to 200 characters): **Field 5 annual rate based on 750 hours per year.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **3** of **3**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **HRSG duct burner fired with pipeline quality natural gas.**			
2. Source Classification Code (SCC): **1-01-006-01**		3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.25**	5. Maximum Annual Rate: **1,000**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit: **1,040 (HHV)**
10. Segment Comment (limit to 200 characters): **Field 5 annual rate based on 4,000 hours per year.**			

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type) (limit to 500 characters):			
3. Source Classification Code (SCC):		3. SCC Units:	
6. Maximum Hourly Rate:	7. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		10. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):			

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
NO_x	**N/A**	**N/A**	**EL**
CO	**N/A**	**N/A**	**EL**
VOC	**N/A**	**N/A**	**EL**
PM	**N/A**	**N/A**	**WP**
$PM_{10}/PM_{2.5}$	**N/A**	**N/A**	**WP**
SO_2	**N/A**	**N/A**	**WP**

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: **70.5** lb/hour **119.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Hourly (Case CC-19) and Annual (Profile No. 2).
See Table B5 (hourly) and Table B-11 (annual).

11. Potential, Fugitive, and Actual Emissions Comment:

ULSD fuel oil-firing limited to no more than 750 hours per year.

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.

<u>**Allowable Emissions**</u> Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 ppmvd @ 15% O_2 (Natural Gas)**	4. Equivalent Allowable Emissions: **17.1** lb/hour **66.9** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

<u>**Allowable Emissions**</u> Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **8.0 ppmvd @ 15% O_2 (ULSD Fuel Oil)**	4. Equivalent Allowable Emissions: **70.5** lb/hour **26.4** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.9** lb/hour **226.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Hourly (Case CC-19) and Annual (Profile No. 2).
See Table B5 (hourly) and Table B-11 (annual).

11. Potential, Fugitive, and Actual Emissions Comment:

ULSD fuel oil-firing limited to no more than 750 hours per year.

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 **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **8.0 ppmvd @ 15% O_2 (Natural Gas)**	4. Equivalent Allowable Emissions: **34.3** lb/hour **134.3** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **8.0 ppmvd @ 15% O_2 (ULSD Fuel Oil)**	4. Equivalent Allowable Emissions: **38.9** lb/hour **14.6** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.7** lb/hour **32.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Hourly (Case CC-19) and Annual (Profile No. 2).
See Table B5 (hourly) and Table B-11 (annual).

11. Potential, Fugitive, and Actual Emissions Comment:

ULSD fuel oil-firing limited to no more than 750 hours per year.

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 **3**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **3.5 ppmvd @ 15% O_2 (Natural Gas With Duct Burner Firing)**	4. Equivalent Allowable Emissions: **9.7** lb/hour **26.3** tons/year
5. Method of Compliance: **EPA Reference Methods 18 and 25 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **1.4 ppmvd @ 15% O_2 (Natural Gas Without Duct Burner Firing)**	4. Equivalent Allowable Emissions: **3.3** lb/hour **14.5** tons/year
5. Method of Compliance: **EPA Reference Methods 18 and 25 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-1. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 8,760 hrs/yr.**	

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 **3** of **3**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **3.0 ppmvd @ 15% O_2 (ULSD Fuel Oil)**	4. Equivalent Allowable Emissions: **8.7** lb/hour **3.3** tons/year
5. Method of Compliance: **EPA Reference Methods 18 and 25 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **19.3** lb/hour **43.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Hourly (Case CC-19) and Annual (Profile No. 2).
See Table B5 (hourly) and Table B-11 (annual).

11. Potential, Fugitive, and Actual Emissions Comment:

ULSD fuel oil-firing limited to no more than 750 hours per year.

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 **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **12.4** lb/hour **40.7** tons/year
5. Method of Compliance: **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **19.3** lb/hour **7.2** tons/year
5. Method of Compliance: **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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: **$PM_{10}/PM_{2.5}$**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.0** lb/hour **70.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**
10. Calculation of Emissions: **Hourly (Case CC-19) and Annual (Profile No. 2). See Table B5 (hourly) and Table B-11 (annual).**	
11. Potential, Fugitive, and Actual Emissions Comment: **ULSD fuel oil-firing limited to no more than 750 hours per year.**	

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 **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **18.3** lb/hour **63.1** tons/year
5. Method of Compliance: **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **38.0** lb/hour **14.3** tons/year
5. Method of Compliance: **EPA Reference Method 9 (initial only)**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.3** lb/hour **42.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**
10. Calculation of Emissions: **Hourly (Case CC-2) and Annual (Profile No. 2).** **See Table B3 (hourly) and Table B-11 (annual).**	
11. Potential, Fugitive, and Actual Emissions Comment: **ULSD fuel oil-firing limited to no more than 750 hours per year.**	

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.

<u>**Allowable Emissions**</u> Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 gr S / 100 dscf natural gas**	4. Equivalent Allowable Emissions: **12.3** lb/hour **48.1** tons/year
5. Method of Compliance: **40 CFR Part 75, Appendix D**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for natural gas firing – Case CC-2. See Appendix B, Table B-3.** **Equivalent allowable annual rates based on 4,760 hrs/yr (Case CC-8) and 4,000 hrs/yr (Case CC-9). See Appendix B, Table B-11.**	

<u>**Allowable Emissions**</u> Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0015 weight % S ULSD Fuel Oil**	4. Equivalent Allowable Emissions: **2.9** lb/hour **1.1** tons/year
5. Method of Compliance: **40 CFR Part 75, Appendix D**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT** **Equivalent allowable hourly emission rate for ULSD fuel oil firing – Case CC-19. See Appendix B, Table B-5.** **Equivalent allowable annual rates based on 750 hrs/yr.**	

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 1

1. Visible Emissions Subtype: **VE 10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(10)(b), F.A.C. - BACT**	

Visible Emissions Limitation: Visible Emissions Limitation __ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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 **1** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Part 96 (CAIR). Specific CEMS will be provided to the FDEP when available.**	

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **CO_2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
9. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program) and 40 CFR Part 96 (CAIR). Specific CEMS will be provided to the FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
10. Continuous Monitor Comment: **Rule 62-212.400(10)(b), F.A.C. – BACT.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

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: **Section 2.0** ☐ 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: **Section 2.0** ☐ 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: **Section 5.0** ☐ 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)): ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date:__________
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **Section 6.0** ☐ Previously Submitted, Date:__________
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

1.	Identification of Applicable Requirements: ☐ Attached, Document ID:
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements Comment

NOTE:

Emission Unit ID No. -013 (Nominal 290-MWCombined Cycle Unit No. 2A), Emission Unit ID No. -014 (Nominal 290-MWCombined Cycle Unit No. 2B), Emission Unit ID No. -015 (Nominal 290-MWCombined Cycle Unit No. 2C), and Emission Unit ID No. -016 (Nominal 290-MWCombined Cycle Unit No. 2D) are identical emission units.

The information provided in Section III. Emissions Unit Information, Section 1 for Emission Unit ID No. -013 is also applicable to Sections 2 and 3 for EU ID Nos. -014, -015, and -016 with the exception of identification numbers.

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:

   One, 6-cell mechanical draft cooling tower

3. Emissions Unit Identification Number: **-018**

4. Emissions Unit Status Code: **C**	5. Commence Construction Date: **N/A**	6. Initial Startup Date: **N/A**	7. Emissions Unit Major Group SIC Code: **49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit: **N/A**
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **N/A** MW

11. Emissions Unit Comment:

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

1. Control Equipment/Method Description: **Mist (Drift) Eliminators – High Velocity (V > 250 ft/min)**	
2. Control Device or Method Code: **015**	

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: **62,450 gal/min**
2.	Maximum Production Rate:
3.	Maximum Heat Input Rate: million Btu/hr
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8,760** hours/year
6.	Operating Capacity/Schedule Comment: **Field 1 maximum process rate is the cooling tower water recirculation rate.**

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: **Cooling Tower**	2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Cooling tower consists of 6 cells.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **51** feet	7. Exit Diameter: **31.6** feet
8. Exit Temperature: **100°F**	9. Actual Volumetric Flow Rate: **1,186,000** acfm	10. Water Vapor: **N/A** %

11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** 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:

Cooling tower consists of 6 cells with 6 individual exhaust fans. Stack height and diameter data provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient conditions.

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Cooling Tower, Process Cooling, Mechanical Draft. Cooling tower water recirculation rate.**		
2. Source Classification Code (SCC): **3-85-001-01**	3. SCC Units: **Million gallons**	
4. Maximum Hourly Rate: **3.75**	5. Maximum Annual Rate: **32,824**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

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
PM	**014**	**N/A**	**EL**
PM_{10}	**014**	**N/A**	**EL**
$PM_{2.5}$	**014**	**N/A**	**EL**

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: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.080** lb/hour **0.35** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.0005 % drift loss rate** Reference: **Proposed BACT**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**
10. Calculation of Emissions: **See Appendix B, Table B-20 for detailed emission rate calculations.**	
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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0005 % drift loss rate**	4. Equivalent Allowable Emissions: **0.080** lb/hour **0.35** tons/year
5. Method of Compliance: **Cooling tower vendor certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT**	

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: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.072** lb/hour **0.31** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.0005 % drift loss rate** Reference: **Proposed BACT**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

See Appendix B, Table B-20 for detailed emission rate calculations.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0005 % drift loss rate**	4. Equivalent Allowable Emissions: **0.072** lb/hour **0.31** tons/year
5. Method of Compliance: **Cooling tower vendor certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT**	

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: **$PM_{2.5}$**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.00047** lb/hour **0.0021** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.0005 % drift loss rate** Reference: **Proposed BACT**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

See Appendix B, Table B-20 for detailed emission rate calculations.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0005 % drift loss rate**	4. Equivalent Allowable Emissions: **0.00047** lb/hour **0.0021** tons/year
5. Method of Compliance: **Cooling tower vendor certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. - BACT**	

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 1

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation_

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % 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.

NOT APPLICABLE

Continuous Monitoring System: Continuous Monitor ___ of ___

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:	

Continuous Monitoring System: Continuous Monitor ___ of ___

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: **Section 2.0** ☐ 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: __________ ☒ Not Applicable

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: **Section 5.0** ☐ 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)): ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date:______
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **Section 6.0** ☐ Previously Submitted, Date:______
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ______ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

1.	Identification of Applicable Requirements: ☐ Attached, Document ID:
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ______ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: ______ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ______ ☐ Not Applicable

Additional Requirements Comment

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:

   One, 500-kW Caterpillar internal combustion (IC) reciprocating engine/generator set; or equivalent.

3. Emissions Unit Identification Number: **-017**

4. Emissions Unit Status Code: **C**	5. Commence Construction Date: **N/A**	6. Initial Startup Date: **N/A**	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: **Caterpillar** Model Number: **C15 ATAAC**

10. Generator Nameplate Rating: **0.5** MW

11. Emissions Unit Comment:

    Emergency generator diesel engine. Diesel engine will be fired with ULSD fuel oil.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Engine Combustion Design – NOx Pollution Prevention**	
2. Control Device or Method Code: **024**	

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: **5.1** million Btu/hr **(HHV)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **100** hours/year
6. Operating Capacity/Schedule Comment: **Other than emergencies, the emergency generator will be operated approximately two hours per week for routine testing and maintenance.**	

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: **Emergency Generator**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **10** feet	7. Exit Diameter: **0.5** feet
8. Exit Temperature: **940**°F	9. Actual Volumetric Flow Rate: **3,900** acfm	10. Water Vapor: N/A %
11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: N/A 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): **Ultra Low Sulfur Diesel (ULSD) fuel oil burned in IC reciprocating engine.**		
2. Source Classification Code (SCC): **2-02-001-02**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **0.0366**	5. Maximum Annual Rate: **18.3**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **139 (HHV)**
10. Segment Comment: **Maximum annual rate based on 500 hours per year operation.**		

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
NOx			**EL**
CO			**EL**
VOC			**EL**
PM			**EL**

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: **5.6** lb/hour **1.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **3.4 grams per horsepower hour (g/hp-hr)** Reference: **NSPS Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 500 hours per year operation.

See Appendix B.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **6.4 g/kWh (4.8 g/hp-hr)**	4. Equivalent Allowable Emissions: **5.6** lb/hour **1.4** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit is for NO_x + NMHC per 40 CFR §89.112, Table 1.**	

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: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.4** lb/hour **1.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **2.6 grams per horsepower hour (g/hp-hr)** Reference: **NSPS Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 500 hours per year operation.

See Appendix B.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **3.5 g/kWh (2.6 g/hp-hr)**	4. Equivalent Allowable Emissions: **2.6** lb/hour **1.1** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit per 40 CFR §89.112, Table 1.**	

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: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.4** lb/hour **0.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **1.4 grams per horsepower hour (g/hp-hr)** Reference: **NSPS Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 500 hours per year operation.

See Appendix B.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **6.4 g/kWh (4.8 g/hp-hr)**	4. Equivalent Allowable Emissions: **1.4** lb/hour **0.6** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit is for NO_x + NMHC per 40 CFR §89.112, Table 1.**	

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: **$PM/PM_{10}/PM_{2.5}$**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.25** lb/hour **0.063** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.15 grams per horsepower hour (g/hp-hr)** Reference: **NSPS Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 500 hours per year operation.

See Appendix B.

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: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.20 g/kWh (0.15 g/hp-hr)**	4. Equivalent Allowable Emissions: **0.25** lb/hour **0.063** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit per 40 CFR §89.112, Table 1.**	

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: **VE 20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **Multiple Limits**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **N/A** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **40 CFR Part 86, Subpart I**	
5. Visible Emissions Comment: **40 CFR §89.113 opacity limits.**	

H. CONTINUOUS MONITOR INFORMATION

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

NOT APPLICABLE

Continuous Monitoring System: Continuous Monitor ___ of ___

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:	

Continuous Monitoring System: Continuous Monitor ___ of ___

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: **Section 2.0** ☐ 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: **Section 2.0** ☐ 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: **Section 5.0** ☐ 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)): ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date:__________
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **Section 6.0** ☐ Previously Submitted, Date:__________
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

1.	Identification of Applicable Requirements: ☐ Attached, Document ID:
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements Comment

APPENDIX B

EMISSIONS RATE CALCULATIONS

Appendix B Polk 2-5 Conversion Project
Emissions Rate Calculations—List of Tables

Table Number	Description

Operation Sources

Y:\GDP-12\TEC\PPS\UNT2\PSD\PSD-APPB.XLSX\Table List—9/18/2012

Source: ECT, 2012.

Table B-1. Operating Mode Scenarios

Case	Ambient Temperature (°F)	Load (%)	Operating Mode (SC, CC, SU, SD)	CC Configuration (CTG/HRSG × STG)	Fuel Type (NG or ULSD FO)	CTG Inlet Air Evaporative Cooling	HRSG Duct Burner Firing	Annual Number of SU/SD Events (Per CTG)	Annual Profile No. 1 (hr/yr/CTG)	Annual Profile No. 2 (hr/yr/CTG)	Annual Profile No. 3* (hr/yr/CTG)
CC-1	20	100	CC	4 on 1	NG						
CC-2	20	100	CC	4 on 1	NG		✔				
CC-3	20	75	CC	4 on 1	NG						
CC-5	20	100	CC	1 on 1	NG		✔				
CC-6	20	50	CC	1 on 1	NG						
CC-7	59	100	CC	4 on 1	NG						
CC-8	59	100	CC	4 on 1	NG	✔			4,760	3,432	3,432
CC-9	59	100	CC	4 on 1	NG	✔	✔		4,000	4,000	4,000
CC-10	59	75	CC	4 on 1	NG						
CC-12	90	100	CC	4 on 1	NG						
CC-13	90	100	CC	4 on 1	NG	✔					
CC-14	90	100	CC	4 on 1	NG	✔	✔				
CC-15	90	75	CC	4 on 1	NG						
CC-17	90	100	CC	1 on 1	NG	✔	✔				
CC-18	90	50	CC	1 on 1	NG						
CC-19	20	100	CC	4 on 1	ULSD FO						
CC-20	20	75	CC	4 on 1	ULSD FO						
CC-22	20	100	CC	1 on 1	ULSD FO						
CC-23	20	50	CC	1 on 1	ULSD FO						
CC-24	59	100	CC	4 on 1	ULSD FO						
CC-25	59	100	CC	4 on 1	ULSD FO	✔				634	259
CC-26	59	75	CC	4 on 1	ULSD FO						
CC-28	90	100	CC	4 on 1	ULSD FO						
CC-29	90	100	CC	4 on 1	ULSD FO	✔					
CC-30	90	75	CC	4 on 1	ULSD FO						
CC-32	90	100	CC	1 on 1	ULSD FO	✔					
CC-33	90	50	CC	1 on 1	ULSD FO						
CC-34	59	0 to 50	CCSU - cold start	4 on 1	NG			10		74	74
CC-35	59	0 to 50	CCSU - warm start	4 on 1	NG			40		137	137
CC-36	59	0 to 50	CCSU - hot start	4 on 1	NG			200		293	293
CC-37	59	50 to 0	CCSD	4 on 1	NG			250		75	75
CC-38	59	0 to 50	CCSU - cold start	4 on 1	ULSD FO			2		15	15
CC-39	59	0 to 50	CCSU - warm start	4 on 1	ULSD FO			8		27	27
CC-40	59	0 to 50	CCSU - hot start	4 on 1	ULSD FO			40		59	59
CC-41	59	50 to 0	CCSD	4 on 1	ULSD FO			50		15	15

Table B-1. Operating Mode Scenarios (Continued, Page 2 of 2)

Case	Ambient Temperature (°F)	Load (%)	Operating Mode (SC, CC, SU, SD)	CC Configuration (CTG/HRSG × STG)	Fuel Type (NG or ULSD FO)	CTG Inlet Air Evaporative Cooling	HRSG Duct Burner Firing	Annual Number of SU/SD Events (Per CTG)	Annual Profile No. 1 (hr/yr/CTG)	Annual Profile No. 2 (hr/yr/CTG)	Annual Profile No. 3* (hr/yr/CTG)
SC-1	20	100	SC	4	NG						
SC-2	20	75	SC	4	NG						
SC-3	20	50	SC	1	NG						
SC-4	59	100	SC	4	NG						
SC-5	59	100	SC	4	NG	✔					
SC-6	59	75	SC	4	NG						
SC-7	59	50	SC	1	NG						
SC-8	90	100	SC	4	NG						
SC-9	90	100	SC	4	NG	✔					
SC-10	90	75	SC	4	NG						
SC-11	90	50	SC	1	NG						
SC-12	20	100	SC	4	ULSD FO						
SC-13	20	75	SC	4	ULSD FO						
SC-14	20	50	SC	1	ULSD FO						
SC-15	59	100	SC	4	ULSD FO						
SC-16	59	100	SC	4	ULSD FO	✔					375
SC-17	59	75	SC	4	ULSD FO						
SC-18	59	50	SC	1	ULSD FO						
SC-19	90	100	SC	4	ULSD FO						
SC-20	90	100	SC	4	ULSD FO	✔					
SC-21	90	75	SC	4	ULSD FO						
SC-22	90	50	SC	1	ULSD FO						
								Total Hours	**8,760**	**8,760**	**8,760**

*SC Units 2 and 3 are currently authorized to burn ULSD fuel oil up to 750 hr/yr each. Profile 3 SC-16 hours based on only Units 4 and 5 (ULSD fuel oil) at 750 hr/yr each; i.e., average of 375 hr/yr for four CTGs.

Note: SC = simple cycle.
SU = startup.
STG = steam turbine generator.
CC = combined cycle.
SD = shutdown.
CTG = combustion turbine generator.
HRSG = heat recovery steam generator.
ULSD = ultra low sulfur diesel fuel oil.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-2. Potential Annual Emissions Rate Summary

Pollutant	Potential Annual Emissions (tpy)†					
	CTG/HRSG Units					
	Annual Profile No. 1	Annual Profile No. 2	Annual Profile No. 3	Cooling Tower	Emergency Generator Diesel Engine	Unit 2 Increase*
Criteria Pollutants						
NO_x	267.4	479.2	743.5	N/A	1.4	744.9
CO	537.3	906.0	933.9	N/A	1.1	935.0
VOC	105.0	130.9	137.0	N/A	0.60	137.6
SO_2	192.3	170.9	173.1	N/A	0.0019	192.3
PM_{10} (filterable + condensable)	162.8	280.5	308.6	0.31	0.063	309.0
$PM_{2.5}$ (filterable + condensable)	162.8	280.5	308.6	0.0021	0.063	308.6
Lead	0.018	0.017	0.017	Not applicable	Negligible	0.018
Other Pollutants						
Formaldehyde	2.4	3.1	3.5	Not applicable	Negligible	3.5
Total HAPs	12.8	16.3	18.2	Not applicable	Negligible	18.2
H_2SO_4 Mist	42.7	38.7	38.9	Not applicable	Negligible	42.7
PM (filterable)	162.8	173.8	187.8	0.35	0.063	188.3
Ammonia	243.4	228.0	228.0	Not applicable	Not applicable	243.4
CO_2e	4,279,434	4,157,876	4,307,655	Not applicable	207	4,307,862
Mercury (lb/yr)	Negligible	6.5	6.5	Not applicable	Negligible	6.5

*Maximum emissions for Profiles Nos. 1 , 2, and 3.
†Unless otherwise indicated.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-3. Natural Gas CC Modes—NO_x, SO_2, CO, VOC, $PM_{10}/PM_{2.5}$, and Lead Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case																
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9	CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,077.6	2,077.6	1,656.5	2,077.6	1,314.3	1,951.0	1,967.1	1,967.1	1,566.7	1,790.8	1,852.1	1,852.1	1,454.3	1,852.1	1,152.9	2,077.6	1,152.9
HRSG duct burner	MMBtu/hr, HHV	0.0	263.9	0.0	263.9	0.0	0.0	0.0	263.9	0.0	0.0	0.0	263.9	0.0	263.9	0.0	263.9	0.0
CTG/HRSG heat input	MMBtu/hr, HHV	2,077.6	2,341.5	1,656.5	2,341.5	1,314.3	1,951.0	1,967.1	2,231.0	1,566.7	1,790.8	1,852.1	2,116.0	1,454.3	2,116.0	1,152.9	2,341.5	1,152.9
NO_x	ppmvd @ 15% oxygen	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/hr, as NO_2	15.2	17.1	12.1	17.1	9.6	14.3	14.4	16.3	11.4	13.2	13.5	15.4	10.7	15.4	8.4	17.1	8.4
	g/s, as NO_2	1.91	2.15	1.52	2.15	1.21	1.80	1.82	2.05	1.44	1.66	1.70	1.94	1.34	1.94	1.05	2.15	1.05
	lb/MMBtu, HHV	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0074	0.0073	0.0073	0.0073	0.0073	0.0073	0.0074	0.0073
CO	ppmvd @ 15% oxygen	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
	lb/hr	30.7	34.3	24.4	34.3	19.2	28.7	29.0	32.7	23.0	26.4	27.0	30.7	21.4	30.7	16.9	34.3	16.9
	g/s	3.86	4.32	3.08	4.32	2.42	3.62	3.65	4.12	2.90	3.33	3.40	3.87	2.70	3.87	2.13	4.32	2.13
	lb/MMBtu, HHV	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
VOC	ppmvd @ 15% oxygen	1.2	3.3	1.2	3.3	1.3	1.2	1.2	3.4	1.3	1.3	1.3	3.5	1.3	3.5	1.4	3.5	1.2
	lb/hr, as methane	3.3	9.7	2.6	9.7	2.1	3.1	3.1	9.5	2.5	2.9	3.0	9.2	2.4	9.2	2.0	9.7	2.0
	g/s, as methane	0.42	1.22	0.33	1.22	0.26	0.39	0.39	1.19	0.32	0.36	0.37	1.16	0.30	1.16	0.25	1.22	0.25
	lb/MMBtu, HHV	0.0016	0.0041	0.0016	0.0041	0.0016	0.0016	0.0016	0.0042	0.0016	0.0016	0.0016	0.0044	0.0017	0.0044	0.0017	0.0044	0.0016
SO_2	ppmvd @ 15% oxygen	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	lb/hr	10.9	12.3	8.7	12.3	6.9	10.3	10.3	11.7	8.2	9.4	9.7	11.1	7.7	11.1	6.1	12.3	6.1
	g/s	1.38	1.55	1.10	1.55	0.87	1.29	1.30	1.48	1.04	1.19	1.23	1.40	0.96	1.40	0.76	1.55	0.76
	lb/MMBtu, HHV	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053
$PM_{10}/PM_{2.5}$ (total)	lb/hr	11.7	18.3	11.1	18.3	10.7	11.4	11.4	17.9	11.0	11.2	11.3	17.7	10.9	17.7	10.5	18.3	10.5
	g/s	1.47	2.30	1.40	2.30	1.34	1.44	1.44	2.26	1.39	1.41	1.43	2.23	1.37	2.23	1.32	2.30	1.32
	lb/MMBtu, HHV	0.0056	0.0078	0.0067	0.0078	0.0081	0.0059	0.0058	0.0080	0.0070	0.0063	0.0061	0.0084	0.0075	0.0084	0.0091	0.0091	0.0056
PM (filterable)	lb/hr	7.2	12.4	6.6	12.4	6.2	6.9	6.9	12.1	6.5	6.7	6.8	11.9	6.4	11.9	5.9	12.4	5.9
	g/s	0.90	1.57	0.83	1.57	0.78	0.87	0.87	1.52	0.82	0.85	0.86	1.50	0.80	1.50	0.75	1.57	0.75
	lb/MMBtu, HHV	0.0034	0.0053	0.0040	0.0053	0.0047	0.0036	0.0035	0.0054	0.0041	0.0037	0.0037	0.0056	0.0044	0.0056	0.0052	0.0056	0.0034
Lead	lb/hr	1.02E-03	1.15E-03	8.12E-04	1.15E-03	6.44E-04	9.56E-04	9.64E-04	1.09E-03	7.68E-04	8.78E-04	9.08E-04	1.04E-03	7.13E-04	1.04E-03	5.65E-04	1.15E-03	5.65E-04
	g/s	1.28E-04	1.45E-04	1.02E-04	1.45E-04	8.12E-05	1.20E-04	1.21E-04	1.38E-04	9.68E-05	1.11E-04	1.14E-04	1.31E-04	8.98E-05	1.31E-04	7.12E-05	1.45E-04	7.12E-05
	lb/MMBtu, HHV	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07

Note: Heat input and mass emission rates (except CO and SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-4. Natural Gas CC Modes—H_2SO_4 Mist, Mercury, Ammonia, and CO_2e Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case																
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9	CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	Yes	Yes	Yes	No	No	No	Yes	No	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,077.6	2,077.6	1,656.5	2,077.6	1,314.3	1,951.0	1,967.1	1,967.1	1,566.7	1,790.8	1,852.1	1,852.1	1,454.3	1,852.1	1,152.9	2,077.6	1,152.9
HRSG duct Burner	MMBtu/hr, HHV	0.0	263.9	0.0	263.9	0.0	0.0	0.0	263.9	0.0	0.0	0.0	263.9	0.0	263.9	0.0	263.9	0.0
CTG/HRSG heat input	MMBtu/hr, HHV	2,077.6	2,341.5	1,656.5	2,341.5	1,314.3	1,951.0	1,967.1	2,231.0	1,566.7	1,790.8	1,852.1	2,116.0	1,454.3	2,116.0	1,152.9	2,341.5	1,152.9
H_2SO_4 mist	lb/MMBtu	0.00085	0.00151	0.00085	0.00151	0.00084	0.00085	0.00085	0.00150	0.00085	0.00085	0.00085	0.00150	0.00085	0.00150	0.00085	0.00151	0.00084
	lb/hr	1.76	3.53	1.40	3.53	1.11	1.65	1.67	3.35	1.33	1.52	1.57	3.17	1.23	3.17	0.98	3.53	0.98
Mercury	lb/MMBtu, HHV	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
	lb/hr	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
Ammonia	ppmvd @ 15% oxygen	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu, HHV	0.0067	0.0067	0.0066	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0066	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	0.0066
	lb/hr	13.9	15.6	11.0	15.6	8.8	13.0	13.1	14.9	10.5	11.9	12.3	14.1	9.7	14.1	7.7	15.6	7.7
CO_2	kg/MMBtu	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02		
	lb/MMBtu	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89		
	lb/hr	242,845	273,691	193,625	273,691	153,625	228,046	229,936	260,782	183,133	209,325	216,487	247,332	169,993	247,332	134,762	273,691	134,762
	GWP	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		
	lb/hr, as CO_2e	242,845	273,691	193,625	273,691	153,625	228,046	229,936	260,782	183,133	209,325	216,487	247,332	169,993	247,332	134,762	273,691	134,762
Methane	kg/MMBtu	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022		
	lb/hr	4.6	5.2	3.7	5.2	2.9	4.3	4.3	4.9	3.5	3.9	4.1	4.7	3.2	4.7	2.5	5.2	2.5
	GWP	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21		
	lb/hr, as CO_2e	96	108	77	108	61	90	91	103	73	83	86	98	67	98	53	108	53
Nitrous oxide	kg/MMBtu	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
	lb/MMBtu	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022		
	lb/hr	0.46	0.52	0.37	0.52	0.29	0.43	0.43	0.49	0.35	0.39	0.41	0.47	0.32	0.47	0.25	0.52	0.25
	GWP	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310		
	lb/hr, as CO_2e	142	160	113	160	90	133	134	152	107	122	127	145	99	145	79	160	79
CO_2e	lb/MMBtu	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
	lb/hr	243,083	273,959	193,815	273,959	153,775	228,269	230,161	261,037	183,313	209,530	216,699	247,575	170,159	247,575	134,895	273,959	134,895

Note: Heat input and mass emission rates (except CO and SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-5. ULSD Fuel Oil CC Modes—NO_x, SO_2, CO, VOC, $PM_{10}/PM_{2.5}$, and Lead Hourly Emissions Rates Gas (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case													
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26	CC-28	CC-29	CC-30	CC-32	CC-33	Maximums	Minimums
Ambient temperature	°F	20.0	20.0	20.0	20.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	100.0	50.0	100.0	100.0	75.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	Yes	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,238.7	1,770.7	2,238.7	1,388.8	2,109.7	2,122.0	1,671.3	1,948.4	2,002.8	1,560.5	2,002.8	1,225.6	2,238.7	1,225.6
NO_x	ppmvd @ 15% oxygen	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
	lb/hr, as NO_2	70.5	55.9	70.5	43.7	66.7	67.1	52.8	61.6	63.1	49.1	63.1	38.5	70.5	38.5
	g/s, as NO_2	8.88	7.04	8.88	5.50	8.40	8.45	6.65	7.76	7.96	6.18	7.96	4.85	8.88	4.85
	lb/MMBtu, HHV	0.0315	0.0316	0.0315	0.0314	0.0316	0.0316	0.0316	0.0316	0.0315	0.0314	0.0315	0.0314	0.0316	0.0314
CO	ppmvd @ 15% O_2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
	lb/hr	38.9	30.9	38.9	24.2	37.0	37.3	29.1	34.2	35.0	27.1	35.0	21.3	38.9	21.3
	g/s	4.91	3.89	4.91	3.04	4.66	4.69	3.67	4.31	4.41	3.42	4.41	2.68	4.91	2.68
	lb/MMBtu, HHV	0.017	0.017	0.017	0.017	0.018	0.018	0.017	0.018	0.017	0.017	0.017	0.017	0.018	0.017
VOC	ppmvd @ 15% oxygen	2.8	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.8	3.0	3.0	2.7
	lb/hr, as methane	8.7	6.6	8.7	5.4	8.0	8.1	6.4	7.5	7.7	6.2	7.7	5.1	8.7	5.1
	g/s, as methane	1.09	0.83	1.09	0.68	1.01	1.03	0.80	0.94	0.97	0.78	0.97	0.64	1.09	0.64
	lb/MMBtu, HHV	0.0039	0.0037	0.0039	0.0039	0.0038	0.0038	0.0038	0.0038	0.0038	0.0039	0.0038	0.0041	0.0041	0.0037
SO_2	ppmvd @ 15% oxygen	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.3	0.3
	lb/hr	2.9	2.3	2.9	1.8	2.7	2.7	2.2	2.5	2.6	2.0	2.6	1.6	2.9	1.6
	g/s	0.36	0.29	0.36	0.22	0.34	0.34	0.27	0.31	0.32	0.25	0.32	0.20	0.36	0.20
	lb/MMBtu, HHV	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
														0.00	0.00
$PM_{10}/PM_{2.5}$ (total)	lb/hr	38.0	37.8	38.0	37.7	37.8	38.0	37.8	37.8	37.8	37.7	37.8	37.7	38.0	37.7
	g/s	4.78	4.77	4.78	4.75	4.77	4.78	4.77	4.77	4.77	4.75	4.77	4.75	4.78	4.75
	lb/MMBtu, HHV	0.0170	0.0214	0.0170	0.0272	0.0179	0.0179	0.0226	0.0194	0.0189	0.0242	0.0189	0.0308	0.0308	0.0170
PM (filterable)	lb/hr	19.3	19.1	19.3	19.0	19.1	19.3	19.1	19.1	19.1	19.0	19.1	19.0	19.3	19.0
	g/s	2.43	2.41	2.43	2.40	2.41	2.43	2.41	2.41	2.41	2.40	2.41	2.40	2.43	2.40
	lb/MMBtu, HHV	0.0086	0.0108	0.0086	0.0137	0.0091	0.0091	0.0115	0.0098	0.0096	0.0122	0.0096	0.0155	0.0155	0.0086
Lead	lb/hr	1.10E-03	8.68E-04	1.10E-03	6.81E-04	1.03E-03	1.04E-03	8.19E-04	9.55E-04	9.82E-04	7.65E-04	9.82E-04	6.01E-04	1.10E-03	6.01E-04
	g/s	1.38E-04	1.09E-04	1.38E-04	8.58E-05	1.30E-04	1.31E-04	1.03E-04	1.20E-04	1.24E-04	9.64E-05	1.24E-04	7.57E-05	1.38E-04	7.57E-05
	lb/MMBtu, HHV	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07

Note: Heat input and mass emissions rates (except CO and SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-6. ULSD Fuel Oil CC Modes—H_2SO_4 Mist, Mercury, Ammonia, and CO_2e Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case												Maximum	Minimum
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26	CC-28	CC-29	CC-30	CC-32	CC-33		
Ambient temperature	°F	20.0	20.0	20.0	20.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	100.0	50.0	100.0	100.0	75.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	Yes	No	No	Yes	No	Yesq	No		
CTG heat input	MMBtu/hr, HHV	2,238.7	1,770.7	2,238.7	1,388.8	2,109.7	2,122.0	1,671.3	1,948.4	2,002.8	1,560.5	2,002.8	1,225.6	2,238.7	1,225.6
H_2SO_4 Mist	lb/MMBtu, HHV	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016	0.00016
	lb/hr	0.35	0.28	0.35	0.22	0.33	0.33	0.26	0.31	0.32	0.25	0.32	0.19	0.35	0.19
Mercury	lb/10^{12} Btu, HHV	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ammonia	ppmvd @ 15% oxygen	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu, HHV	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0073	0.0072	0.0073	0.0073	0.0072
	lb/hr	16.2	12.8	16.2	10.0	15.3	15.3	12.1	14.1	14.5	11.3	14.5	8.9	16.2	8.9
CO_2	kg/MMBtu	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96	73.96		
	lb/MMBtu	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05	163.05		
	lb/hr	365,032	288,714	365,032	226,441	343,993	346,002	272,518	317,699	326,559	254,439	326,559	199,842	365,032	199,842
	GWP	1	1	1	1	1	1	1	1	1	1	1	1		
	lb/hr, as CO_2e	365,032	288,714	365,032	226,441	343,993	346,002	272,518	317,699	326,559	254,439	326,559	199,842	365,032	199,842
Methane	kg/MMBtu	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030		
	lb/MMBtu	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066		
	lb/hr	15	12	15	9	14	14	11	13	13	10	13	8	15	8
	GWP	21	21	21	21	21	21	21	21	21	21	21	21		
	lb/hr, as CO_2e	311	246	311	193	293	295	232	271	278	217	278	170	311	170
Nitrous oxide	kg/MMBtu	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060		
	lb/MMBtu	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132	0.00132		
	lb/hr	3	2	3	2	3	3	2	3	3	2	3	2	3	2
	GWP	310	310	310	310	310	310	310	310	310	310	310	310		
	lb/hr, as CO_2e	918	726	918	569	865	870	685	799	821	640	821	503	918	503
CO_2e	lb/MMBtu	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6	163.6
	lb/hr	366,261	289,686	366,261	227,203	345,151	347,166	273,436	318,768	327,658	255,295	327,658	200,515	366,261	200,515

Note: Heat input and ammonia mass emissions rates include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-7. Natural Gas Simple Cycle Modes—NO_x, SO_2, CO, VOC, $PM_{10}/PM_{2.5}$, and Lead Emissions Rates (Per CTG Unit)

Parameter	Unit	Operating Case												
		SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11	Maximum	Minimum
Ambient temperature	°F	20	20	20	59	59	59	59	90	90	90	90	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,078.1	1,648.5	1,306.9	1,950.9	1,968.6	1,560.9	1,239.4	1,787.9	1,849.4	1,449.5	1,150.8	2,078.1	1,150.8
NO_x	ppmvd @ 15% oxygen	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/hr, as NO_2	68.4	54.6	43.2	64.4	64.9	51.7	40.8	59.2	60.6	47.9	37.8	68.4	37.8
	g/s, as NO_2	8.62	6.87	5.45	8.11	8.18	6.51	5.14	7.46	7.64	6.03	4.77	8.62	4.77
	MMBtu/hr, HHV	0.0329	0.0331	0.0331	0.0330	0.0330	0.0331	0.0329	0.0331	0.0328	0.0330	0.0329	0.0331	0.0328
CO	ppmvd @ 15% O_2	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
	lb/hr	33.7	26.8	21.2	31.6	31.9	25.3	20.1	29.0	29.7	23.6	18.6	33.7	18.6
	g/s	4.25	3.38	2.67	3.98	4.02	3.19	2.53	3.66	3.74	2.97	2.35	4.25	2.35
	MMBtu/hr, HHV	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
VOC	ppmvd @ 15% O_2	1.2	1.2	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.2
	lb/hr, as methane	3.3	2.6	2.1	3.1	3.1	2.5	2.1	2.9	3.0	2.4	2.0	3.3	2.0
	g/s, as methane	0.42	0.33	0.26	0.39	0.39	0.32	0.26	0.36	0.37	0.30	0.25	0.42	0.25
	MMBtu/hr, HHV	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0017	0.0016	0.0016	0.0017	0.0017	0.0017	0.0016
SO_2	ppmvd @ 15% O_2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	lb/hr	10.9	8.7	6.9	10.3	10.4	8.2	6.5	9.4	9.7	7.6	6.1	10.9	6.1
	g/s	1.38	1.09	0.87	1.29	1.30	1.03	0.82	1.18	1.23	0.96	0.76	1.38	0.76
	MMBtu/hr, HHV	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053	0.0053
													0.00	0.00
$PM_{10}/PM_{2.5}$ (total)	lb/hr	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	g/s	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
	MMBtu/hr, HHV	0.0043	0.0055	0.0069	0.0046	0.0046	0.0058	0.0073	0.0050	0.0049	0.0062	0.0078	0.0078	0.0043
PM (filterable)	lb/hr	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
	g/s	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
	MMBtu/hr, HHV	0.0022	0.0027	0.0035	0.0023	0.0023	0.0029	0.0036	0.0025	0.0024	0.0031	0.0039	0.0039	0.0022
													0.00	0.00
Lead	lb/hr	1.02E-03	8.08E-04	6.41E-04	9.56E-04	9.65E-04	7.65E-04	6.08E-04	8.76E-04	9.07E-04	7.11E-04	5.64E-04	1.02E-03	5.64E-04
	g/s	1.28E-04	1.02E-04	8.07E-05	1.20E-04	1.22E-04	9.64E-05	7.65E-05	1.10E-04	1.14E-04	8.95E-05	7.11E-05	1.28E-04	7.11E-05
	MMBtu/hr, HHV	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07

Note: Heat input and mass emissiosn rates (except CO and SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-8. Natural Gas Simple Cycle Modes—H_2SO_4 Mist, Mercury, and CO_2e Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case											Maximums	Minimums
		SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11		
Ambient temperature	°F	20	20	20	59	59	59	59	90	90	90	90	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	YesNo	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,078.1	1,648.5	1,306.9	1,950.9	1,968.6	1,560.9	1,239.4	1,787.9	1,849.4	1,449.5	1,150.8	2,078.1	1,150.8
H_2SO_4 mist	MMBtu/hr, HHV	0.00069	0.00069	0.00069	0.00069	0.00069	0.00068	0.00068	0.00069	0.00069	0.00069	0.00069	0.00069	0.00068
	lb/hr	1.43	1.13	0.90	1.34	1.35	1.07	0.85	1.23	1.28	1.00	0.79	1.43	0.79
													0.00	0.00
Mercury	MMBtu/hr, HHV	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
	lb/hr	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible
CO_2	kg/MMBtu	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02		
	lb/MMBtu	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89		
	lb/hr	242,909	192,687	152,763	228,033	230,103	182,452	144,869	208,990	216,178	169,427	134,518	242,909.27	134,518.14
	GWP	1	1	1	1	1	1	1	1	1	1	1		
	lb/hr, as CO_2e	242,909	192,687	152,763	228,033	230,103	182,452	144,869	208,990	216,178	169,427	134,518	242,909.27	134,518.14
Methane	kg/MMBtu	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022		
	lb/hr	5	4	3	4	4	3	3	4	4	3	3	4.5815	2.5371
	GWP	21	21	21	21	21	21	21	21	21	21	21		
	lb/hr, as CO_2e	96	76	61	90	91	72	57	83	86	67	53	96.2	53.3
Nitrous oxide	kg/MMBtu	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
	lb/MMBtu	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022		
	lb/hr	0.46	0.36	0.29	0.43	0.43	0.34	0.27	0.39	0.41	0.32	0.25	0.46	0.25
	GWP	310	310	310	310	310	310	310	310	310	310	310		
	lb/hr, as CO_2e	142	113	89	133	135	107	85	122	126	99	79	142	79
CO_2e	lb/MMBtu	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
	lb/hr	243,148	192,876	152,913	228,256	230,329	182,631	145,011	209,195	216,390	169,593	134,650	243,148	134,650

Note: Heat input and H_2SO_4 mist mass emission rates include a 10% margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-9. ULSD Fuel Oil Simple Cycle Modes—NO_x, SO_2, CO, VOC, $PM_{10}/PM_{2.5}$, and Lead Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Cases											Maximum	Minimum
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22		
Ambient temperature	°F	20	20	20	59	59	59	59	90	90	90	90	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	NO	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,235.5	1,755.3	1,374.9	2,110.8	2,123.7	1,666.0	1,311.5	1,943.6	1,998.8	1,550.7	1,219.4	2,235.5	1,219.4
NO_x	ppmvd @ 15% oxygen	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
	lb/hr, as NO_2	370.7	290.2	227.6	349.8	352.4	274.0	216.5	322.5	330.8	255.6	201.1	370.7	201.1
	g/s, as NO_2	46.71	36.56	28.68	44.07	44.41	34.52	27.28	40.64	41.68	32.21	25.34	46.71	25.34
	lb/MMBtu, HHV	0.1658	0.1653	0.1655	0.1657	0.1660	0.1645	0.1651	0.1659	0.1655	0.1649	0.1649	0.1660	0.1645
CO	ppmvd @ 15% oxygen	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
	lb/hr	39.0	30.6	24.0	37.0	37.3	28.8	22.9	34.1	34.9	26.9	21.2	39.0	21.2
	g/s	4.91	3.85	3.02	4.66	4.69	3.62	2.88	4.29	4.40	3.39	2.67	4.91	2.67
	lb/MMBtu, HHV	0.017	0.017	0.017	0.018	0.018	0.017	0.017	0.018	0.017	0.017	0.017	0.018	0.017
VOC	ppmvd @ 15% oxygen	2.8	2.7	2.8	2.8	2.8	2.8	2.9	2.8	2.8	2.9	3.0	3.0	2.7
	lb/hr, as methane	8.7	6.6	5.4	8.0	8.1	6.3	5.3	7.5	7.7	6.2	5.1	8.7	5.1
	g/s, as methane	1.09	0.83	0.68	1.01	1.03	0.79	0.67	0.94	0.97	0.78	0.64	1.09	0.64
	lb/MMBtu, HHV	0.0039	0.0038	0.0039	0.0038	0.0038	0.0038	0.0040	0.0038	0.0039	0.0040	0.0041	0.0041	0.0038
SO_2	ppmvd @ 15% oxygen	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	lb/hr	3.1	2.4	1.9	2.9	3.0	2.3	1.8	2.7	2.8	2.2	1.7	3.1	1.7
	g/s	0.39	0.31	0.24	0.37	0.37	0.29	0.23	0.34	0.35	0.27	0.21	0.39	0.21
	lb/MMBtu, HHV	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
													0.00	0.00
$PM_{10}/PM_{2.5}$ (total)	lb/hr	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4	37.4
	g/s	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
	lb/MMBtu, HHV	0.0167	0.0213	0.0272	0.0177	0.0176	0.0224	0.0285	0.0192	0.0187	0.0241	0.0307	0.0307	0.0167
PM (filterable)	lb/hr	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
	g/s	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36
	lb/MMBtu, HHV	0.0084	0.0107	0.0136	0.0089	0.0088	0.0112	0.0143	0.0096	0.0094	0.0121	0.0153	0.0153	0.0084
													0.00	0.00
Lead	lb/hr	1.10E-03	8.60E-04	6.74E-04	1.03E-03	1.04E-03	8.17E-04	6.43E-04	9.53E-04	9.80E-04	7.60E-04	5.98E-04	1.10E-03	5.98E-04
	g/s	1.38E-04	1.08E-04	8.49E-05	1.30E-04	1.31E-04	1.03E-04	8.10E-05	1.20E-04	1.23E-04	9.58E-05	7.53E-05	1.38E-04	7.53E-05
	lb/MMBtu, HHV	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07	4.90E-07

Note: Heat input and mass emissions rates (except CO and SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-10. ULSD Fuel Oil Simple Cycle Modes—H_2SO_4 Mist, Mercury, and CO_2e Hourly Emissions Rates (Per CTG Unit)

Parameter	Unit	Operating Cases											Maximum	Minimum
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22		
Ambient temperature	°F	20	20	20	59	59	59	59	90	90	90	90	90	20
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,235.5	1,755.3	1,374.9	2,110.8	2,123.7	1,666.0	1,311.5	1,943.6	1,998.8	1,550.7	1,219.4	2,235.5	1,219.4
H_2SO_4 Mist	lb/MMBtu, HHV	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
	lb/hr	0.24	0.19	0.14	0.22	0.23	0.18	0.14	0.21	0.21	0.17	0.13	0.24	0.13
Mercury	lb/MMBtu, HHV	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012	0.0000012
	lb/hr	0.0027	0.0021	0.0016	0.0025	0.0025	0.0020	0.0016	0.0023	0.0024	0.0019	0.0015	0.0027	0.0015
CO_2	kg/MMBtu	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02	53.02		
	lb/MMBtu	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89	116.89		
	lb/hr	261,309	205,172	160,709	246,728	248,232	194,731	153,303	227,184	233,639	181,256	142,529	261,309	142,529
	GWP	1	1	1	1	1	1	1	1	1	1	1		
	lb/hr, as CO_2e	261,309	205,172	160,709	246,728	248,232	194,731	153,303	227,184	233,639	181,256	142,529	261,309	142,529
Methane	kg/MMBtu	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
	lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022		
	lb/hr	5	4	3	5	5	4	3	4	4	3	3	5	3
	GWP	21	21	21	21	21	21	21	21	21	21	21		
	lb/hr, as CO_2e	103	81	64	98	98	77	61	90	93	72	56	103	56
Nitrous oxide	kg/MMBtu	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
	lb/MMBtu	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022		
	lb/hr	0.49	0.39	0.30	0.47	0.47	0.37	0.29	0.43	0.44	0.34	0.27	0.49	0.27
	GWP	310	310	310	310	310	310	310	310	310	310	310		
	lb/hr, as CO_2e	153	120	94	144	145	114	90	133	137	106	83	153	83
CO_2e	lb/MMBtu	117	117	117	117	117	117	117	117	117	117	117	117	117
	lb/hr	261,565	205,373	160,867	246,970	248,476	194,922	153,454	227,407	233,868	181,434	142,668	261,565	142,668

Note: Heat input and mass emissions rates (except SO_2) include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Parameter	Unit	Operating Cases - Normal Operations				Operating Cases - Startup/Shutdown Operations								Totals
		CC-8	CC-9	CC-25	SC-16	CC-34	CC-35	CC-36	CC-37	CC-38	CC-39	CC-40	CC-41	
Operating Hours														
Profile No. 1	hr/yr	4,760	4,000											8,760
Profile No. 2	hr/yr	3,432	4,000	634		74	137	293	75	15	27	59	15	8,760
Profile No. 3*	hr/yr	3,432	4,000	259	375	74	137	293	75	15	27	59	15	8,760
Profile No. 1														
NO_x	lb/hr, as NO_2	14.4	16.3											
	tpy	34.3	32.6											66.9
CO	lb/hr	29.0	32.7											
	tpy	69.0	65.3											134.3
VOC	lb/hr	3.1	9.5											
	tpy	7.3	18.9											26.3
SO_2	lb/hr	10.3	11.7											
	tpy	24.6	23.5											48.1
$PM_{10}/PM_{2.5}$ (total)	lb/hr	11.4	17.9											
	tpy	27.2	35.9											63.1
PM (filterable)	lb/hr	6.9	12.1											
	tpy	16.5	24.2											40.7
Lead	lb/hr	0.0010	0.0011											
	tpy	0.0023	0.0022											0.0045
Ammonia	lb/hr	13.1	14.9											
	tpy	31.2	29.7											60.9
H_2SO_4 Mist	lb/hr	1.7	3.4											
	tpy	4.0	6.7											10.7
Mercury	lb/hr	Negligible	Negligible											
	tpy	Negligible	Negligible											Negligible
Formaldehyde	lb/hr	0.13	0.14											
	tpy	0.30	0.29											0.59
Total HAPs	lb/hr	0.69	0.78											
	tpy	1.6	1.6											3.2
CO_2e	lb/hr	230,161	261,037											
	tpy	547,784	522,075											1,069,859
Profile No. 2														
NO_x	lb/hr, as NO_2	14.4	16.3	67.1										
	tpy	24.7	32.6	21.3		3.6	7.4	12.2	4.4	1.7	3.3	6.2	2.4	119.8
CO	lb/hr	29.0	32.7	37.3										
	tpy	49.7	65.3	11.8		10.8	19.6	45.7	15.3	0.57	1.7	4.7	1.3	226.5
VOC	lb/hr	3.1	9.5	8.1										
	tpy	5.3	18.9	2.6		0.82	1.9	2.5	0.49	0.024	0.060	0.14	0.039	32.7
SO_2	lb/hr	10.3	11.7	2.7										
	tpy	17.7	23.5	0.9		0.083	0.17	0.28	0.094	0.0040	0.0080	0.015	0.0050	42.7
$PM_{10}/PM_{2.5}$ (total)	lb/hr	11.4	17.9	38.0										
	tpy	19.6	35.9	12.0		0.20	0.42	0.65	0.20	0.16	0.33	0.50	0.16	70.1
PM (filterable)	lb/hr	6.9	12.1	19.3										
	tpy	11.9	24.2	6.1		0.10	0.20	0.30	0.094	0.079	0.16	0.25	0.078	43.5
Lead	lb/hr	0.0010	0.0011	0.0010										
	tpy	0.0017	0.0022	0.0003		Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0.0042
Ammonia	lb/hr	13.1	14.9	15.3										
	tpy	22.5	29.7	4.8										57.0
H_2SO_4 Mist	lb/hr	1.7	3.4	0.33										
	tpy	2.9	6.7	0.10		Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	9.7

Parameter	Unit	Operating Cases - Normal Operations				Operating Cases - Startup/Shutdown Operations								Totals
		CC-8	CC-9	CC-25	SC-16	CC-34	CC-35	CC-36	CC-37	CC-38	CC-39	CC-40	CC-41	
Mercury	lb/hr	Negligible	Negligible	0.0025										
	tpy	Negligible	Negligible	0.00081		Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0.00081
Formaldehyde	lb/hr	0.13	0.14	0.59										
	tpy	0.30	0.29	0.19										0.78
Total HAPs	lb/hr	0.69	0.78	2.73										
	tpy	1.64	1.56	0.87										4.1
CO_2e	lb/hr	230,161	261,037	347,166										
	tpy	394,899	522,075	110,104		1,659	3,346	5,469	1,917					1,039,469
Profile No. 3*														
NO_x	lb/hr, as NO_2	14.4	16.3	67.1	352.4									
	tpy	24.7	32.6	21.3	66.1	3.6	7.4	12.2	4.4	1.7	3.3	6.2	2.4	185.9
CO	lb/hr	29.0	32.7	37.3	37.3									
	tpy	49.7	65.3	11.8	7.0	10.8	19.6	45.7	15.3	0.57	1.7	4.7	1.3	233.5
VOC	lb/hr	3.1	9.5	8.1	8.1									
	tpy	5.3	18.9	2.6	1.5	0.82	1.9	2.5	0.49	0.024	0.060	0.14	0.039	34.2
SO_2	lb/hr	10.3	11.7	2.7	3.0									
	tpy	17.7	23.5	0.87	0.55	0.083	0.17	0.28	0.094	0.0040	0.0080	0.015	0.0050	43.3
$PM_{10}/PM_{2.5}$ (total)	lb/hr	11.4	17.9	38.0	37.4									
	tpy	19.6	35.9	12.0	7.0	0.20	0.42	0.65	0.20	0.16	0.33	0.50	0.16	77.1
PM (filterable)	lb/hr	6.9	12.1	19.3	18.7									
	tpy	11.9	24.2	6.1	3.5	0.10	0.20	0.30	0.094	0.079	0.16	0.25	0.078	47.0
Lead	lb/hr	0.0010	0.00109	0.0010	0.0010	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	
	tpy	0.0017	0.0022	0.00033	0.00020	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0.0044
Ammonia	lb/hr	13.1	14.9	15.3	N/A									
	tpy	22.5	29.7	4.8	N/A									57.0
H_2SO_4 Mist	lb/hr	1.7	3.4	0.33	0.23	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	
	tpy	2.9	6.7	0.10	0.043	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	9.7
Mercury	lb/hr	Negligible	Negligible	0.0025	1.20E-06	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	
	tpy	Negligible	Negligible	0.00081	2.25E-07	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0.0008
Formaldehyde	lb/hr	0.13	0.14	0.59	0.55									
	tpy	0.30	0.29	0.19	0.10									0.89
Total HAPs	lb/hr	0.69	0.78	2.7	2.5									
	tpy	1.64	1.56	0.87	0.48									4.5
CO_2e	lb/hr	230,161	261,037	347,166	248,476									
	tpy	394,899	522,075	110,104	46,589					442	891	1,456	458	1,076,914

*SC Units 2 and 3 are currently authorized to burn ULSD fuel oil up to 750 hr/yr each.
Profile 3 SC-16 hours based on only Units 4 and 5 (ULSD fuel oil) at 750 hr/yr each; i.e., average of 375 hr/yr for four CTGs.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-12. Natural Gas CC Modes—HAP Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case																
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9	CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	Yes	Yes	Yes	No	No	No	Yes	No	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,077.6	2,077.6	1,656.5	2,077.6	1,314.3	1,951.0	1,967.1	1,967.1	1,566.7	1,790.8	1,852.1	1,852.1	1,454.3	1,852.1	1,152.9	2,077.6	1,152.9
HRSG duct burner	MMBtu/hr, HHV	0.0	263.9	0.0	263.9	0.0	0.0	0.0	263.9	0.0	0.0	0.0	263.9	0.0	263.9	0.0	263.9	0.0
CTG/HRSG heat input	MMBtu/hr, HHV	2,077.6	2,341.5	1,656.5	2,341.5	1,314.3	1,951.0	1,967.1	2,231.0	1,566.7	1,790.8	1,852.1	2,116.0	1,454.3	2,116.0	1,152.9	2,341.5	1,152.9
1,3-Butadiene	lb/MMBtu, HHV	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07		
	lb/hr	8.93E-04	1.01E-03	7.12E-04	1.01E-03	5.65E-04	8.39E-04	8.46E-04	9.59E-04	6.74E-04	7.70E-04	7.96E-04	9.10E-04	6.25E-04	9.10E-04	4.96E-04	1.01E-03	4.96E-04
Acetaldehyde	lb/MMBtu, HHV	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05		
	lb/hr	8.31E-02	9.37E-02	6.63E-02	9.37E-02	5.26E-02	7.80E-02	7.87E-02	8.92E-02	6.27E-02	7.16E-02	7.41E-02	8.46E-02	5.82E-02	8.46E-02	4.61E-02	9.37E-02	4.61E-02
Acrolein	lb/MMBtu, HHV	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06		
	lb/hr	1.33E-02	1.50E-02	1.06E-02	1.50E-02	8.41E-03	1.25E-02	1.26E-02	1.43E-02	1.00E-02	1.15E-02	1.19E-02	1.35E-02	9.31E-03	1.35E-02	7.38E-03	1.50E-02	7.38E-03
Benzene	lb/MMBtu, HHV	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05		
	lb/hr	2.49E-02	2.81E-02	1.99E-02	2.81E-02	1.58E-02	2.34E-02	2.36E-02	2.68E-02	1.88E-02	2.15E-02	2.22E-02	2.54E-02	1.75E-02	2.54E-02	1.38E-02	2.81E-02	1.38E-02
Formaldehyde	lb/MMBtu, HHV	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05	6.49E-05		
	lb/hr	1.35E-01	1.52E-01	1.08E-01	1.52E-01	8.53E-02	1.27E-01	1.28E-01	1.45E-01	1.02E-01	1.16E-01	1.20E-01	1.37E-01	9.44E-02	1.37E-01	7.48E-02	1.52E-01	7.48E-02
Naphthalene	lb/MMBtu, HHV	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06		
	lb/hr	2.70E-03	3.04E-03	2.15E-03	3.04E-03	1.71E-03	2.54E-03	2.56E-03	2.90E-03	2.04E-03	2.33E-03	2.41E-03	2.75E-03	1.89E-03	2.75E-03	1.50E-03	3.04E-03	1.50E-03
PAH	lb/MMBtu, HHV	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06		
	lb/hr	4.57E-03	5.15E-03	3.64E-03	5.15E-03	2.89E-03	4.29E-03	4.33E-03	4.91E-03	3.45E-03	3.94E-03	4.07E-03	4.66E-03	3.20E-03	4.66E-03	2.54E-03	5.15E-03	2.54E-03
Propylene oxide	lb/MMBtu, HHV	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05		
	lb/hr	6.02E-02	6.79E-02	4.80E-02	6.79E-02	3.81E-02	5.66E-02	5.70E-02	6.47E-02	4.54E-02	5.19E-02	5.37E-02	6.14E-02	4.22E-02	6.14E-02	3.34E-02	6.79E-02	3.34E-02
Toluene	lb/MMBtu, HHV	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04		
	lb/hr	2.70E-01	3.04E-01	2.15E-01	3.04E-01	1.71E-01	2.54E-01	2.56E-01	2.90E-01	2.04E-01	2.33E-01	2.41E-01	2.75E-01	1.89E-01	2.75E-01	1.50E-01	3.04E-01	1.50E-01
Xylenes	lb/MMBtu, HHV	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05		
	lb/hr	1.33E-01	1.50E-01	1.06E-01	1.50E-01	8.41E-02	1.25E-01	1.26E-01	1.43E-01	1.00E-01	1.15E-01	1.19E-01	1.35E-01	9.31E-02	1.35E-01	7.38E-02	1.50E-01	7.38E-02
Totals	lb/hr	0.73	0.82	0.58	0.82	0.46	0.68	0.69	0.78	0.55	0.63	0.65	0.74	0.51	0.74	0.40	0.82	0.40
	tpy	3.19	3.59	2.54	3.59	2.02	2.99	3.02	3.42	2.40	2.75	2.84	3.25	2.23	3.25	1.77	3.59	1.77

Note: PAH = polycyclic aromatic hydrocarbon.
Heat input rates includes a 10-percent margin for vendor data uncertainty.
HAP emissions factors (except formaldehyde) from AP-42, Table 3.1-3, April 2000.
HAP emissions factor for formaldehyde is EPA average for lean premix CTGs (EPA August 2, 2001 memorandum).

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-13. ULSD Fuel Oil CC Modes—HAP Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case													
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26	CC-28	CC-29	CC-30	CC-32	CC-33	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	0.0	0.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	No	Yes	Yes	No	No	No		
CTG heat input	MMBtu/hr, HHV	2,238.7	1,770.7	2,238.7	1,388.8	2,109.7	2,122.0	1,671.3	1,948.4	2,002.8	1,560.5	2,002.8	1,225.6	2,238.7	1,225.6
Arsenic	MMBtu/hr, HHV	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05		
	lb/hr	2.46E-02	1.95E-02	2.46E-02	1.53E-02	2.32E-02	2.33E-02	1.84E-02	2.14E-02	2.20E-02	1.72E-02	2.20E-02	1.35E-02	2.46E-02	1.35E-02
Beryllium	MMBtu/hr, HHV	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07		
	lb/hr	6.94E-04	5.49E-04	6.94E-04	4.31E-04	6.54E-04	6.58E-04	5.18E-04	6.04E-04	6.21E-04	4.84E-04	6.21E-04	3.80E-04	6.94E-04	3.80E-04
1,3 Butadiene	MMBtu/hr, HHV	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05		
	lb/hr	3.58E-02	2.83E-02	3.58E-02	2.22E-02	3.38E-02	3.40E-02	2.67E-02	3.12E-02	3.20E-02	2.50E-02	3.20E-02	1.96E-02	3.58E-02	1.96E-02
Benzene	MMBtu/hr, HHV	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05		
	lb/hr	1.23E-01	9.74E-02	1.23E-01	7.64E-02	1.16E-01	1.17E-01	9.19E-02	1.07E-01	1.10E-01	8.58E-02	1.10E-01	6.74E-02	1.23E-01	6.74E-02
Cadmium	MMBtu/hr, HHV	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06		
	lb/hr	1.07E-02	8.50E-03	1.07E-02	6.67E-03	1.01E-02	1.02E-02	8.02E-03	9.35E-03	9.61E-03	7.49E-03	9.61E-03	5.88E-03	1.07E-02	5.88E-03
Chromium	MMBtu/hr, HHV	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05		
	lb/hr	2.46E-02	1.95E-02	2.46E-02	1.53E-02	2.32E-02	2.33E-02	1.84E-02	2.14E-02	2.20E-02	1.72E-02	2.20E-02	1.35E-02	2.46E-02	1.35E-02
Formaldehyde	MMBtu/hr, HHV	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04		
	lb/hr	6.27E-01	4.96E-01	6.27E-01	3.89E-01	5.91E-01	5.94E-01	4.68E-01	5.46E-01	5.61E-01	4.37E-01	5.61E-01	3.43E-01	6.27E-01	3.43E-01
Lead	MMBtu/hr, HHV	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05		
	lb/hr	3.13E-02	2.48E-02	3.13E-02	1.94E-02	2.95E-02	2.97E-02	2.34E-02	2.73E-02	2.80E-02	2.18E-02	2.80E-02	1.72E-02	3.13E-02	1.72E-02
Manganese	MMBtu/hr, HHV	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04		
	lb/hr	1.77E+00	1.40E+00	1.77E+00	1.10E+00	1.67E+00	1.68E+00	1.32E+00	1.54E+00	1.58E+00	1.23E+00	1.58E+00	9.68E-01	1.77E+00	9.68E-01
Mercury	MMBtu/hr, HHV	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06		
	lb/hr	2.69E-03	2.12E-03	2.69E-03	1.67E-03	2.53E-03	2.55E-03	2.01E-03	2.34E-03	2.40E-03	1.87E-03	2.40E-03	1.47E-03	2.69E-03	1.47E-03
Naphthalene	MMBtu/hr, HHV	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05		
	lb/hr	7.84E-02	6.20E-02	7.84E-02	4.86E-02	7.38E-02	7.43E-02	5.85E-02	6.82E-02	7.01E-02	5.46E-02	7.01E-02	4.29E-02	7.84E-02	4.29E-02
Nickel	MMBtu/hr, HHV	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06		
	lb/hr	1.03E-02	8.15E-03	1.03E-02	6.39E-03	9.70E-03	9.76E-03	7.69E-03	8.96E-03	9.21E-03	7.18E-03	9.21E-03	5.64E-03	1.03E-02	5.64E-03
PAH	MMBtu/hr, HHV	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05		
	lb/hr	8.95E-02	7.08E-02	8.95E-02	5.56E-02	8.44E-02	8.49E-02	6.69E-02	7.79E-02	8.01E-02	6.24E-02	8.01E-02	4.90E-02	8.95E-02	4.90E-02
Selenium	MMBtu/hr, HHV	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05		
	lb/hr	5.60E-02	4.43E-02	5.60E-02	3.47E-02	5.27E-02	5.31E-02	4.18E-02	4.87E-02	5.01E-02	3.90E-02	5.01E-02	3.06E-02	5.60E-02	3.06E-02
Totals	lb/hr	2.88	2.28	2.88	1.79	2.72	2.73	2.15	2.51	2.58	2.01	2.58	1.58	2.88	1.58
	tpy	1.08	0.86	1.08	0.67	1.02	1.02	0.81	0.94	0.97	0.75	0.97	0.59	1.08	0.59

Note: PAH = polycyclic aromatic hydrocarbon.
Heat input rates includes a 10-percent margin for vendor data uncertainty.
HAP emissions factors (except formaldehyde) from AP-42, Tables 3.1-4 (organics) and 3.1-5 (metals), April 2000.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-14. Natural Gas Simple Cycle Modes—HAP Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,078.1	1,648.5	1,306.9	1,950.9	1,968.6	1,560.9	1,239.4	1,787.9	1,849.4	1,449.5	1,150.8	2,078.1	1,150.8
1,3-Butadiene	MMBtu/hr, HHV	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07	4.30E-07		
	lb/hr	8.94E-04	7.09E-04	5.62E-04	8.39E-04	8.46E-04	6.71E-04	5.33E-04	7.69E-04	7.95E-04	6.23E-04	4.95E-04	8.94E-04	4.95E-04
Acetaldehyde	MMBtu/hr, HHV	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05		
	lb/hr	8.31E-02	6.59E-02	5.23E-02	7.80E-02	7.87E-02	6.24E-02	4.96E-02	7.15E-02	7.40E-02	5.80E-02	4.60E-02	8.31E-02	4.60E-02
Acrolein	MMBtu/hr, HHV	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06	6.40E-06		
	lb/hr	1.33E-02	1.06E-02	8.36E-03	1.25E-02	1.26E-02	9.99E-03	7.93E-03	1.14E-02	1.18E-02	9.28E-03	7.37E-03	1.33E-02	7.37E-03
Benzene	MMBtu/hr, HHV	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05	1.20E-05		
	lb/hr	2.49E-02	1.98E-02	1.57E-02	2.34E-02	2.36E-02	1.87E-02	1.49E-02	2.15E-02	2.22E-02	1.74E-02	1.38E-02	2.49E-02	1.38E-02
Formaldehyde	MMBtu/hr, HHV	6.49E-05	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04	7.10E-04		
	lb/hr	1.35E-01	1.17E+00	9.28E-01	1.39E+00	1.40E+00	1.11E+00	8.80E-01	1.27E+00	1.31E+00	1.03E+00	8.17E-01	1.40E+00	1.35E-01
Naphthalene	MMBtu/hr, HHV	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06	1.30E-06		
	lb/hr	2.70E-03	2.14E-03	1.70E-03	2.54E-03	2.56E-03	2.03E-03	1.61E-03	2.32E-03	2.40E-03	1.88E-03	1.50E-03	2.70E-03	1.50E-03
PAH	MMBtu/hr, HHV	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06	2.20E-06		
	lb/hr	4.57E-03	3.63E-03	2.88E-03	4.29E-03	4.33E-03	3.43E-03	2.73E-03	3.93E-03	4.07E-03	3.19E-03	2.53E-03	4.57E-03	2.53E-03
Propylene oxide	MMBtu/hr, HHV	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05	2.90E-05		
	lb/hr	6.03E-02	4.78E-02	3.79E-02	5.66E-02	5.71E-02	4.53E-02	3.59E-02	5.19E-02	5.36E-02	4.20E-02	3.34E-02	6.03E-02	3.34E-02
Toluene	MMBtu/hr, HHV	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04		
	lb/hr	2.70E-01	2.14E-01	1.70E-01	2.54E-01	2.56E-01	2.03E-01	1.61E-01	2.32E-01	2.40E-01	1.88E-01	1.50E-01	2.70E-01	1.50E-01
Xylenes	MMBtu/hr, HHV	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05	6.40E-05		
	lb/hr	1.33E-01	1.06E-01	8.36E-02	1.25E-01	1.26E-01	9.99E-02	7.93E-02	1.14E-01	1.18E-01	9.28E-02	7.37E-02	1.33E-01	7.37E-02
Totals	lb/hr	0.73	1.64	1.30	1.94	1.96	1.55	1.23	1.78	1.84	1.44	1.15	1.96	0.73
	tpy	1.59	3.59	2.85	4.25	4.29	3.40	2.70	3.90	4.03	3.16	2.51	4.29	1.59

Note: PAH = polycyclic aromatic hydrocarbon.
Heat input rates includes a 10-percent margin for vendor data uncertainty.
HAP emissions factors (except formaldehyde) from AP-42, Table 3.1-3, April 2000.
HAP emissions factor for formaldehyde is EPA average for lean premix CTGs (EPA August 2, 2001, memorandum).

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-15. ULSD Fuel Oil Simple Cycle Modes—HAP Hourly Emissions Rates (Per CTG/HRSG Unit)

Parameter	Unit	Operating Case											Maximum	Minimum
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22		
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,078.1	1,648.5	1,306.9	1,950.9	1,968.6	1,560.9	1,239.4	1,787.9	1,849.4	1,449.5	1,150.8	2,078.1	1,150.8
Arsenic	MMBtu/hr, HHV	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05		
	lb/hr	2.29E-02	1.81E-02	1.44E-02	2.15E-02	2.17E-02	1.72E-02	1.36E-02	1.97E-02	2.03E-02	1.59E-02	1.27E-02	2.29E-02	1.27E-02
Beryllium	MMBtu/hr, HHV	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07	3.10E-07		
	lb/hr	6.44E-04	5.11E-04	4.05E-04	6.05E-04	6.10E-04	4.84E-04	3.84E-04	5.54E-04	5.73E-04	4.49E-04	3.57E-04	6.44E-04	3.57E-04
1,3 Butadiene	MMBtu/hr, HHV	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05		
	lb/hr	3.32E-02	2.64E-02	2.09E-02	3.12E-02	3.15E-02	2.50E-02	1.98E-02	2.86E-02	2.96E-02	2.32E-02	1.84E-02	3.32E-02	1.84E-02
Benzene	MMBtu/hr, HHV	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05	5.50E-05		
	lb/hr	1.14E-01	9.07E-02	7.19E-02	1.07E-01	1.08E-01	8.58E-02	6.82E-02	9.83E-02	1.02E-01	7.97E-02	6.33E-02	1.14E-01	6.33E-02
Cadmium	MMBtu/hr, HHV	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06	4.80E-06		
	lb/hr	9.97E-03	7.91E-03	6.27E-03	9.36E-03	9.45E-03	7.49E-03	5.95E-03	8.58E-03	8.88E-03	6.96E-03	5.52E-03	9.97E-03	5.52E-03
Chromium	MMBtu/hr, HHV	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05	1.10E-05		
	lb/hr	2.29E-02	1.81E-02	1.44E-02	2.15E-02	2.17E-02	1.72E-02	1.36E-02	1.97E-02	2.03E-02	1.59E-02	1.27E-02	2.29E-02	1.27E-02
Formaldehyde	MMBtu/hr, HHV	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04	2.80E-04		
	lb/hr	5.82E-01	4.62E-01	3.66E-01	5.46E-01	5.51E-01	4.37E-01	3.47E-01	5.01E-01	5.18E-01	4.06E-01	3.22E-01	5.82E-01	3.22E-01
Lead	MMBtu/hr, HHV	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05	1.40E-05		
	lb/hr	2.91E-02	2.31E-02	1.83E-02	2.73E-02	2.76E-02	2.19E-02	1.74E-02	2.50E-02	2.59E-02	2.03E-02	1.61E-02	2.91E-02	1.61E-02
Manganese	MMBtu/hr, HHV	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04	7.90E-04		
	lb/hr	1.64E+00	1.30E+00	1.03E+00	1.54E+00	1.56E+00	1.23E+00	9.79E-01	1.41E+00	1.46E+00	1.15E+00	9.09E-01	1.64E+00	9.09E-01
Mercury	MMBtu/hr, HHV	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06		
	lb/hr	2.49E-03	1.98E-03	1.57E-03	2.34E-03	2.36E-03	1.87E-03	1.49E-03	2.15E-03	2.22E-03	1.74E-03	1.38E-03	2.49E-03	1.38E-03
Naphthalene	MMBtu/hr, HHV	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05		
	lb/hr	7.27E-02	5.77E-02	4.57E-02	6.83E-02	6.89E-02	5.46E-02	4.34E-02	6.26E-02	6.47E-02	5.07E-02	4.03E-02	7.27E-02	4.03E-02
Nickel	MMBtu/hr, HHV	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06	4.60E-06		
	lb/hr	9.56E-03	7.58E-03	6.01E-03	8.97E-03	9.06E-03	7.18E-03	5.70E-03	8.22E-03	8.51E-03	6.67E-03	5.29E-03	9.56E-03	5.29E-03
PAH	MMBtu/hr, HHV	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05		
	lb/hr	8.31E-02	6.59E-02	5.23E-02	7.80E-02	7.87E-02	6.24E-02	4.96E-02	7.15E-02	7.40E-02	5.80E-02	4.60E-02	8.31E-02	4.60E-02
Selenium	MMBtu/hr, HHV	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05		
	lb/hr	5.20E-02	4.12E-02	3.27E-02	4.88E-02	4.92E-02	3.90E-02	3.10E-02	4.47E-02	4.62E-02	3.62E-02	2.88E-02	5.20E-02	2.88E-02
Totals	lb/hr	2.68	2.12	1.68	2.51	2.54	2.01	1.60	2.30	2.38	1.87	1.48	2.68	1.48
	tpy	1.00	0.80	0.63	0.94	0.95	0.75	0.60	0.86	0.89	0.70	0.56	1.00	0.56

Note: PAH = polycyclic aromatic hydrocarbon.
Heat input rates includes a 10-percent margin for vendor data uncertainty.
HAP emissions factors (except formaldehyde) from AP-42, Tables 3.1-4 (organics) and 3.1-5 (metals), April 2000.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-16. Natural Gas CC Mode—Startup/Shutdown Emissions Rates (PER CTG)

Parameter	Unit	Type of Startup Event			Shutdown
		Cold*	Warm†	Hot‡	Event
Frequency	event/year	10	40	200	250
Fuel consumption	lb/event	123,588	62,312	20,369	5,710
Heat input	MMBtu/event	2,836	1,430	467	131
Emission Rates					
NO_x	lb/event	720.5	371.5	121.5	34.9
	tpy	3.6	7.4	12.2	4.4
CO	lb/event	2,156.8	982.3	456.8	122.5
	tpy	10.8	19.6	45.7	15.3
VOC	lb/event	163.8	95.5	24.5	3.9
	tpy	0.82	1.91	2.45	0.49
SO_2	lb/event	16.5	8.3	2.8	3.9
	tpy	0.083	0.165	0.275	0.491
$PM_{10}/PM_{2.5}$ (total)	lb/event	40.0	20.8	6.5	1.6
	tpy	0.20	0.42	0.65	0.20
PM (filterable)	lb/event	19.0	10.0	3.0	0.8
	tpy	0.10	0.20	0.30	0.09
GHG					
CO_2	lb/event	331,522	167,150	54,639	15,318
	tpy	1,658	3,343	5,464	1,915
Methane	lb/event	6.25	3.15	1.03	0.29
	tpy	0.031	0.063	0.103	0.036
Nitrous oxide	lb/event	0.63	0.32	0.10	0.03
	tpy	0.0031	0.0063	0.0103	0.0036
CO_2e	lb/event	331,847	167,314	54,692	15,333
	tpy	1,659	3,346	5,469	1,917

*Greater than 48 hours from a shutdown event; equipment at ambient temperature.
†Less than 48 and greater than 8 hours from a shutdown event.
‡8 hours or less from a shutdown event.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-17. ULSD Fuel Oil CC Mode—Startup/Shutdown Emissions Rates (PER CTG)

Parameter	Unit	Type of Startup Event Cold*	Type of Startup Event Warm†	Type of Startup Event Hot‡	Shutdown Event
Frequency	event/year	2	8	40	50
Fuel consumption	lb/event	137,542	69,347	22,669	5,710
Heat input	MMBtu/event	2,700	1,361	445	112
Emission Rates					
NO_x	lb/event	1,705.3	826.8	312.3	97.1
	tpy	1.7	3.3	6.2	2.4
CO	lb/event	569.5	426.5	233.0	50.1
	tpy	0.6	1.7	4.7	1.3
VOC	lb/event	23.8	12.5	7.0	1.6
	tpy	0.02	0.05	0.14	0.04
SO_2	lb/event	4.0	2.0	0.8	0.2
	tpy	0.004	0.008	0.015	0.005
$PM_{10}/PM_{2.5}$ (total)	lb/event	157.8	82.5	25.0	6.3
	tpy	0.16	0.33	0.50	0.16
PM (filterable)	lb/event	78.8	41.0	12.5	3.1
	tpy	0.08	0.16	0.25	0.08
GHG					
CO_2	lb/event	440,192	221,940	72,549	18,275
	tpy	440	888	1,451	457
Methane	lb/event	17.86	9.00	2.94	0.74
	tpy	0.018	0.036	0.059	0.019
Nitrous oxide	lb/event	3.57	1.80	0.59	0.15
	tpy	0.0036	0.0072	0.0118	0.0037
CO_2e	lb/event	441,674	222,687	72,793	18,337
	tpy	442	891	1,456	458

*Greater than 48 hours from a shutdown event; equipment at ambient temperature.
†Less than 48 and greater than 8 hours from a shutdown event.
‡8 hours or less from a shutdown event.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-18. Emergency Generator Diesel Engine Criteria Pollutant Emissions Estimates

A. Emissions Estimate Methodology

References - Cummins Data (NO_x, CO, VOC, and PM), and Mass Balance (SO_2).

E_1 = EF x P
E_2 = EF x P x OP x (1 ton / 2,000 lb)
EFSO2 = FOFLOW x FODENSITY x (FOSULFUR / 100) x (1 / P) x (2 lb SO_2 / lb S) x (453.59 g / lb)

where:
E_1 = hourly emissions rate; pound per hour (lb/hr)
E_2 = annual emissions rate; ton per year (tpy)
EF = emission sfactor; gram per brake horsepower-hour (g/bhp-hr)
P = engine output; brake horsepower-hour (bhp-hr)
OP = annual operating hours; hour per year (hr/yr)
EFSO2 = SO_2 emission factor; gram per brake horsepower hour (g/bhp-hr)
FOFLOW = ULSD fuel oil flow rate; gallon per hour (gal/hr)
FODENSITY = ULSD fuel oil density; pound per gallon (lb/gal)
FOSULFUR = ULSD fuel oil sulfur content; weight percent (weight %)

B. Input Data

Diesel Engine Data	Unit	Emergency Generator Diesel Engine
Engine manufacturer*	Not applicable	Caterpillar
Engine model number*	Not applicable	CAT C15 ATAAC
Applicable EPA nonroad tier	—	2
Engine output	bhp	762
	kW	568
Engine ULSD fuel oil flow rate	gal/hr	36.6
Engine operating hours	hr/yr	500
ULSD fuel oil sulfur content	weight %	0.0015
ULSD fuel oil density	lb/gal	7.08
ULSD fuel oil heat content	Btu/gal, HHV	139,000
Heat Input	MMBtu/hr, HHV	5.1
	MMBtu/yr, HHV	2,544

*Or equivalent engine.
†Based on use of ULSD fuel oil.

Sources: Caterpillar, 2011.
Black & Veatch, 2012.
ECT, 2012.

C. Calculations

Criteria Pollutants and CO_2	Emergency Generator Diesel Engine
NO_x	
g/bhp-hr	3.4
lb/hr	5.6
tpy	1.4
CO	
g/bhp-hr	2.6
lb/hr	4.4
tpy	1.1
VOC (NMHC)	
g/bhp-hr	1.4
lb/hr	2.4
tpy	0.60
$PM/PM_{10}/PM_{2.5}$	
g/bhp-hr	0.15
lb/hr	0.25
tpy	0.063
SO_2	
g/bhp-hr†	0.0046
lb/hr	0.0078
tpy	0.0019
CO_2	
lb/MMBtu	163.1
lb/hr	830
tpy	207.4

Table B-19. Emergency Generator Diesel Engine—HAP Emissions Estimates

A. Emission Estimate Methodology

References - AP-42 Table 3.3-2. and engine vendor data..

E_1 = EF x HI
E_2 = EF x HI x OP x (1 ton / 2,000 lb)

where: E_1 = hourly emission rate; pound per hour (lb/hr)
E_2 = annual emission rate; ton per year (tpy)
EF = emission factor; pound per million British thermal units (lb/MMBtu)
HI = engine heat input; million British thermal units per hour (MMBtu/hr)
OP = annual operating hours; hour per year (hr/yr)

B. Input Data

Diesel Engine Data	Units	Emergency Generator Diesel
Engine manufacturer*	N/A	Caterpillar
Engine model number*	N/A	CAT C15 ATAAC
Engine output	bhp	762
Engine ULSD fuel oil flow rate	gal/hr	36.6
ULSD fuel oil heat content, HHV	MMBtu/gal	139,000
Engine heat input, HHV	MMBtu/hr	5.1
Engine operating hours	hr/yr	500

*Or equivalent engine.

Sources: Caterpillar, 2011.
Black & Veatch, 2012.
ECT, 2012.

C. Calculations

HAP	Emergency Generator Diesel	HAP	Emergency Generator Diesel
1,3-Butadiene		Naphthalene	
lb/MMBtu	3.91E-05	lb/MMBtu	8.48E-05
lb/hr	1.99E-04	lb/hr	4.31E-04
tpy	4.97E-05	tpy	1.08E-04
Acrolein		PAH	
lb/MMBtu	9.25E-05	lb/MMBtu	1.68E-04
lb/hr	4.71E-04	lb/hr	8.55E-04
tpy	1.18E-04	tpy	2.14E-04
Acetaldehyde		Toluene	
lb/MMBtu	7.76E-04	lb/MMBtu	4.09E-04
lb/hr	3.95E-03	lb/hr	2.08E-03
tpy	9.87E-04	tpy	5.20E-04
Benzene		Xylenes	
lb/MMBtu	9.33E-04	lb/MMBtu	2.85E-04
lb/hr	4.75E-03	lb/hr	1.45E-03
tpy	1.19E-03	tpy	3.62E-04
Formaldehyde			
lb/MMBtu	1.18E-03		
lb/hr	6.00E-03		
tpy	1.50E-03		

POTENTIAL EMISSIONS INVENTORY WORKSHEET

Polk 2-5 Conversion Project - Cooling Tower

Table B-20
Cooling Tower

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Mechanical Draft Cooling Tower
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	

EMISSION ESTIMATION EQUATIONS

PM Emission Rate (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) / 10^6) x 60 min/hr

PM Emission Rate (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM_{10} Emission Rate (lb/hr) = PM Emissions (lb/hr) x PM_{10}/PM Fraction

PM_{10} Emission Rate (ton/yr) = PM_{10} Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

$PM_{2.5}$ Emission Rate (lb/hr) = PM Emissions (lb/hr) x $PM_{2.5}$/PM Fraction

$PM_{2.5}$ Emission Rate (ton/yr) = $PM_{2.5}$ Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Sources: ECT, 2012.

Reisman and Frisbie, AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data

Operating Hours:	8,760	hrs/yr
Number of Cells:	6	
Recirculating Water Flow Rate:	62,450	gal/min
Drift Loss Rate:	0.0005	%
Total Dissolved Solids (TDS):	514	ppmw
PM_{10}/PM Fraction:	0.89	
$PM_{2.5}$/PM Fraction:	0.0059	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.013	0.06	0.080	0.35
PM_{10}	0.012	0.05	0.072	0.31
$PM_{2.5}$	0.00008	0.00035	0.00047	0.0021

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	TEC, 2012.
Recirculating Water Flow Rate (gpm)	B & V, 2012.
Drift Loss Rate (%)	B & V, 2012.
Total Dissolved Solids (ppmw)	B & V, 2012.
$PM/PM_{10}/PM_{2.5}$ Fraction:	ECT, 2012.

Table B-21. Cooling Tower PM/PM_{10} Fractions

Procedure Citation:

Reisman and Frisbie, AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM $_{10}$ Emissions from Cooling Towers.

Cooling Tower Design Data:

Cooling tower recirculating water total dissolved solids:	514	ppmw
Cooling tower PM_{10} density (assumed NaCl):	2.2	g/cm^3

Droplet Diameter (μm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (μm)	Mass Fraction (%)
Particle Size Distribution						
10	5.24E-16	5.24E-10	2.69E-13	1.22E-19	0.616	0.000
20	4.19E-15	4.19E-09	2.15E-12	9.79E-19	1.232	0.196
30	1.41E-14	1.41E-08	7.27E-12	3.30E-18	1.848	0.226
40	3.35E-14	3.35E-08	1.72E-11	7.83E-18	2.464	0.514
50	6.54E-14	6.54E-08	3.36E-11	1.53E-17	3.080	1.816
60	1.13E-13	1.13E-07	5.81E-11	2.64E-17	3.695	5.702
70	1.80E-13	1.80E-07	9.23E-11	4.20E-17	4.311	21.348
90	3.82E-13	3.82E-07	1.96E-10	8.92E-17	5.543	49.812
110	6.97E-13	6.97E-07	3.58E-10	1.63E-16	6.775	70.509
130	1.15E-12	1.15E-06	5.91E-10	2.69E-16	8.007	82.023
150	1.77E-12	1.77E-06	9.08E-10	4.13E-16	9.239	88.012
180	3.05E-12	3.05E-06	1.57E-09	7.13E-16	11.086	91.032
210	4.85E-12	4.85E-06	2.49E-09	1.13E-15	12.934	92.468
240	7.24E-12	7.24E-06	3.72E-09	1.69E-15	14.782	94.091
270	1.03E-11	1.03E-05	5.30E-09	2.41E-15	16.629	94.689
300	1.41E-11	1.41E-05	7.27E-09	3.30E-15	18.477	96.288
350	2.24E-11	2.24E-05	1.15E-08	5.24E-15	21.557	97.011
400	3.35E-11	3.35E-05	1.72E-08	7.83E-15	24.636	98.340
450	4.77E-11	4.77E-05	2.45E-08	1.11E-14	27.716	99.071
500	6.54E-11	6.54E-05	3.36E-08	1.53E-14	30.795	99.071
600	1.13E-10	1.13E-04	5.81E-08	2.64E-14	36.954	100.000
Linear Interpolation						
150	1.77E-12	1.77E-06	9.08E-10	4.13E-16	9.239	88.012
180	3.05E-12	3.05E-06	1.57E-09	7.13E-16	11.086	91.032
					10.000	89.257

Note: Mass fraction of cooling tower PM $\leq PM_{10}$: 0.893.

Sources: Black & Veatch, 2012.
ECT, 2012.

Table B-22. Cooling Tower PM/$PM_{2.5}$ Fractions

Procedure Citation:

Reisman and Frisbie, AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM_{10} Emissions from Cooling Towers.

Cooling Tower Design Data:

Cooling tower recirculating water total dissolved solids:	514	ppmw
Cooling tower PM_{10} density (assumed NaCl):	2.2	g/cm^3

Droplet Diameter (μm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (μm)	Mass Fraction (%)
Particle Size Distribution						
10	5.24E-16	5.24E-10	2.69E-13	1.22E-19	0.616	0.000
20	4.19E-15	4.19E-09	2.15E-12	9.79E-19	1.232	0.196
30	1.41E-14	1.41E-08	7.27E-12	3.30E-18	1.848	0.226
40	3.35E-14	3.35E-08	1.72E-11	7.83E-18	2.464	0.514
50	6.54E-14	6.54E-08	3.36E-11	1.53E-17	3.080	1.816
60	1.13E-13	1.13E-07	5.81E-11	2.64E-17	3.695	5.702
70	1.80E-13	1.80E-07	9.23E-11	4.20E-17	4.311	21.348
90	3.82E-13	3.82E-07	1.96E-10	8.92E-17	5.543	49.812
110	6.97E-13	6.97E-07	3.58E-10	1.63E-16	6.775	70.509
130	1.15E-12	1.15E-06	5.91E-10	2.69E-16	8.007	82.023
150	1.77E-12	1.77E-06	9.08E-10	4.13E-16	9.239	88.012
180	3.05E-12	3.05E-06	1.57E-09	7.13E-16	11.086	91.032
210	4.85E-12	4.85E-06	2.49E-09	1.13E-15	12.934	92.468
240	7.24E-12	7.24E-06	3.72E-09	1.69E-15	14.782	94.091
270	1.03E-11	1.03E-05	5.30E-09	2.41E-15	16.629	94.689
300	1.41E-11	1.41E-05	7.27E-09	3.30E-15	18.477	96.288
350	2.24E-11	2.24E-05	1.15E-08	5.24E-15	21.557	97.011
400	3.35E-11	3.35E-05	1.72E-08	7.83E-15	24.636	98.340
450	4.77E-11	4.77E-05	2.45E-08	1.11E-14	27.716	99.071
500	6.54E-11	6.54E-05	3.36E-08	1.53E-14	30.795	99.071
600	1.13E-10	1.13E-04	5.81E-08	2.64E-14	36.954	100.000
Linear Interpolation						
40	3.35E-14	3.35E-08	1.72E-11	7.83E-18	2.464	0.514
50	6.54E-14	6.54E-08	3.36E-11	1.53E-17	3.080	1.816
					2.500	0.591

Note: Mass fraction of cooling tower PM ≤ PM_{10}: 0.0059.

Sources: Black & Veatch, 2012.
ECT, 2012.

Table B-23. Natural Gas CC Modes—Fuel Flow Rates (Per CTG/HRSG Unit)

Natural gas heat content	22,949	Btu/lb
Natural gas density	0.04528	lb/ft^3

Parameter	Unit	Operating Case															Maximum	Minimum
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9	CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18		
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG / HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,077.6	2,077.6	1,656.5	2,077.6	1,314.3	1,951.0	1,967.1	1,967.1	1,566.7	1,790.8	1,852.1	1,852.1	1,454.3	1,852.1	1,152.9	2,077.6	1,152.9
HRSG duct burner	MMBtu/hr, HHV	0.0	263.9	0.0	263.9	0.0	0.0	0.0	263.9	0.0	0.0	0.0	263.9	0.0	263.9	0.0	263.9	0.0
CTG/HRSG heat input	MMBtu/hr, HHV	2,077.6	2,341.5	1,656.5	2,341.5	1,314.3	1,951.0	1,967.1	2,231.0	1,566.7	1,790.8	1,852.1	2,116.0	1,454.3	2,116.0	1,152.9	2,341.5	1,152.9
Flow rates: natural gas																		
CTG	lb/hr	90,530	90,530	72,181	90,530	57,270	85,013	85,717	85,717	68,270	78,034	80,704	80,704	63,371	80,704	50,238	90,529.9	50,237.9
	lb/sec	1,509	1,509	1,203	1,509	954	1,417	1,429	1,429	1,138	1,301	1,345	1,345	1,056	1,345	837	1,508.8	837.3
	MMft^3/hr	2.00	2.00	1.59	2.00	1.26	1.88	1.89	1.89	1.51	1.72	1.78	1.78	1.40	1.78	1.11	2.00	1.11
Duct burner	lb/hr	0	11,499	0	11,499	0	0	0	11,499	0	0	0	11,499	0	11,499	0	11,499.0	0.0
	lb/sec	0	192	0	192	0	0	0	192	0	0	0	192	0	192	0	191.6	0.0
	MMft^3/hr	0.00	0.25	0.00	0.25	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.25	0.00	0.25	0.00	0.25	0.00
CTG + duct burner	lb/hr	90,530	102,029	72,181	102,029	57,270	85,013	85,717	97,216	68,270	78,034	80,704	92,203	63,371	92,203	50,238	102,028.8	50,237.9
	lb/sec	1,509	1,700	1,203	1,700	954	1,417	1,429	1,620	1,138	1,301	1,345	1,537	1,056	1,537	837	1,700.5	837.3
	MMft^3/hr	2.00	2.25	1.59	2.25	1.26	1.88	1.89	2.15	1.51	1.72	1.78	2.04	1.40	2.04	1.11	2.25	1.11

Note: Heat input includes a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-24. ULSD Fuel Oil CC Modes—Fuel Flow Rates (Per CTG/HRSG Unit)

ULSD fuel oil	19,628	Btu / lb
USLD fuel oil density	7.1	lb / gal

Parameter	Unit	Operating Case													
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26	CC-28	CC-29	CC-30	CC-32	CC-33	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	100.0	50.0	100.0	100.0	75.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG / HRSG × STG	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	Yes	No	No	Yes	No	Yes	No		
CTG heat input	MMBtu/hr, HHV	2,238.7	1,770.7	2,238.7	1,388.8	2,109.7	2,122.0	1,671.3	1,948.4	2,002.8	1,560.5	2,002.8	1,225.6	2,238.7	1,225.6
ULSD fuel oil flow rates	lb/hr	114,057	90,211	114,057	70,754	107,484	108,111	85,151	99,268	102,036	79,502	102,036	62,442	114,057.5	62,442.4
	lb/sec	1,901	1,504	1,901	1,179	1,791	1,802	1,419	1,654	1,701	1,325	1,701	1,041	1,901.0	1,040.7
	10^3 gal/hr	16.06	12.71	16.06	9.97	15.14	15.23	11.99	13.98	14.37	11.20	14.37	8.79	16.06	8.79

Note: Heat input include a 10% margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-25. Natural Gas Simple Cycle Modes—Fuel Flow Rates (Per CTG/HRSG Unit)

Natural gas heat content	22,949	Btu/lb
Natural gas density	0.04528	lb/ft^3

Parameter	Unit	Operating Case											Maximum	Minimum
		SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11		
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of Base Load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,078.1	1,648.5	1,306.9	1,950.9	1,968.6	1,560.9	1,239.4	1,787.9	1,849.4	1,449.5	1,150.8	2,078.1	1,150.8
CTG natural gas flow rates	lb/hr	90,554	71,831	56,948	85,008	85,780	68,016	54,005	77,909	80,589	63,160	50,147	90,553.8	50,146.8
	lb/sec	1,509	1,197	949	1,417	1,430	1,134	900	1,298	1,343	1,053	836	1,509.2	835.8
	10^6 ft^3/hr	2.00	1.59	1.26	1.88	1.89	1.50	1.19	1.72	1.78	1.39	1.11	2.00	1.11

Note: Heat input includes a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-26. ULSD Fuel Oil Simple Cycle Modes—Fuel Flow Rates (Per CTG/HRSG Unit)

ULSD fuel oil	19,628	Btu / lb
USLD fuel oil density	7.1	lb / gal

Parameter	Units	Operating Case												
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of Base Load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
CTG heat input	MMBtu/hr, HHV	2,235.5	1,755.3	1,374.9	2,110.8	2,123.7	1,666.0	1,311.5	1,943.6	1,998.8	1,550.7	1,219.4	2,235.5	1,219.4
ULSD fuel oil flow rates	lb/hr	113,895	89,427	70,047	107,540	108,195	84,876	66,819	99,021	101,835	79,003	62,123	113,894.9	62,123.0
	lb/sec	1,898	1,490	1,167	1,792	1,803	1,415	1,114	1,650	1,697	1,317	1,035	1,898.2	1,035.4
	10^3 gal/hr	16.04	12.60	9.87	15.15	15.24	11.95	9.41	13.95	14.34	11.13	8.75	16.04	8.75

Note: Heat input include a 10-percent margin for vendor data uncertainty.

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-27. Natural Gas CC Modes—Exhaust Flow Rates (Per CTG/HRSG Unit)

Parameter	Units	Operating Case																
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9	CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	Yes	No	Yes	No		
Exhaust Gas Composition (wet)																		
Argon	Volume %	0.94	0.94	0.94	0.94	0.94	0.93	0.93	0.93	0.93	0.92	0.92	0.91	0.92	0.91	0.92	0.94	0.91
CO_2	Volume %	3.72	4.17	3.81	4.17	3.68	3.74	3.74	4.22	3.74	3.70	3.73	4.24	3.61	4.24	3.46	4.24	3.46
Water	Volume %	7.43	8.31	7.60	8.31	7.35	8.50	8.50	9.43	8.50	9.83	9.88	10.86	9.66	10.86	9.38	10.86	7.35
Nitrogen	Volume %	75.03	74.69	74.97	74.69	75.06	74.21	74.21	73.85	74.21	73.14	73.12	72.74	73.21	72.74	73.32	75.06	72.74
Oxygen	Volume %	12.88	11.89	12.68	11.89	12.96	12.61	12.61	11.57	12.61	12.41	12.35	11.25	12.60	11.25	12.92	12.96	11.25
Total	Volume %	100.00	100.00	100.00	100.00	99.99	99.99	99.99	100.00	99.99	100.00	100.00	100.00	100.00	100.00	100.00	100.00	99.99
Exhaust Gas Flow Rates																		
Stack temperature	°F	211.40	196.20	193.20	166.00	156.80	207.60	208.40	194.40	192.90	209.90	212.20	198.00	198.90	169.30	164.70	212.20	156.80
Mass flow rate	lb/hr	3,845,521	3,855,976	2,993,198	3,855,976	2,458,930	3,575,118	3,603,347	3,613,801	2,870,561	3,303,306	3,389,940	3,400,395	2,749,222	3,400,395	2,273,191	3,855,976	2,273,191
Actual flow rate, wet	ft^3/min	1,107,512	1,087,387	838,595	1,037,259	650,388	1,027,848	1,037,165	1,020,298	807,107	957,960	986,474	970,814	783,988	928,309	614,141	1,107,512	614,141
Standard flow rate (dry, 68°F)	ft^3/min	806,145	802,141	626,268	802,096	515,785	743,722	749,565	745,503	597,156	680,732	698,207	694,325	567,479	694,221	470,341	806,145	470,341
Oxygen	Volume %, dry	13.91	12.97	13.72	12.97	13.99	13.78	13.78	12.77	13.78	13.76	13.70	12.62	13.95	12.62	14.26	14.26	12.62
Standard flow rate (dry, 68°F, 15% oxygen)	ft^3/min	954,559	1,078,457	761,823	1,078,396	604,244	897,330	904,379	1,026,691	720,491	823,467	851,581	974,339	668,730	974,192	529,545	1,078,457	529,545

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-28. ULSD Fuel Oil CC Modes—Exhaust Flow Rates (Per CTG/URSG Unit)

Parameter	Units	Operating Case													
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26	CC-28	CC-29	CC-30	CC-32	CC-33	Maximum	Minimum
Ambient temperature	°F	20.0	20.0	20.0	20.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	100.0	50.0	100.0	100.0	75.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative cooling	Yes/No	No	No	No	No	No	Yes	No	No	Yes	No	Yes	No		
Exhaust Gas Composition (wet)															
Argon	Volume %	0.90	0.90	0.90	0.91	0.89	0.89	0.89	0.88	0.88	0.89	0.88	0.89		0.88
CO_2	Volume %	5.18	5.41	5.18	5.18	5.23	5.22	5.32	5.22	5.24	5.09	5.24	4.85		4.85
Water	Volume %	11.10	11.14	11.10	10.24	12.08	12.00	11.72	13.07	12.97	12.19	12.97	11.32		10.24
Nitrogen	Volume %	71.46	71.52	71.46	72.14	70.72	70.78	71.04	69.95	70.03	70.58	70.03	71.16		69.95
Oxygen	Volume %	11.36	11.03	11.36	11.53	11.08	11.11	11.03	10.88	10.88	11.26	10.88	11.78		10.88
Total	Volume %	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.01	100.00	100.00	100.01	100.00
Exhaust Gas Flow Rates															
Stack temperature	°F	217.10	194.80	186.70	157.50	212.60	213.50	194.40	213.70	215.80	201.10	186.40	165.80	217.10	157.50
Mass flow rate	lb/hr	4,010,372	3,039,835	4,010,372	2,493,363	3,727,512	3,755,285	2,909,897	3,432,755	3,520,367	2,831,471	3,520,367	2,338,574	4,010,372	2,338,574
Actual flow rate, wet	ft^3/min	1,173,034	859,260	1,120,231	662,819	1,086,570	1,095,918	823,986	1,006,370	1,034,988	812,161	989,810	633,364	1,173,034	633,364
Standard flow rate (dry, 68°F)	ft^3/min	813,081	615,607	813,000	508,669	749,832	755,959	586,841	685,545	703,656	569,506	703,564	473,844	813,081	473,844
Oxygen	Volume %, dry	12.78	12.41	12.78	12.85	12.60	12.63	12.49	12.52	12.50	12.82	12.50	13.28	13.28	12.41
Standard flow rate (dry, 68°F, 15% oxygen)	ft^3/min	1,119,240	885,558	1,119,129	694,431	1,054,548	1,060,265	836,066	974,192	1,001,645	779,630	1,001,513	611,682	1,119,240	611,682

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-29. Natural Gas Simple Cycle Modes—Exhaust Flow Rates (Per CTG/HRSG Unit)

Parameter	Units	Operating Case											Maximum	Minimum
		SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11		
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
Exhaust Gas Composition (wet)														
Argon	Volume %	0.94	0.94	0.94	0.93	0.93	0.93	0.93	0.92	0.92	0.92	0.92	0.94	0.92
CO_2	Volume %	3.72	3.79	3.64	3.74	3.75	3.72	3.54	3.69	3.72	3.58	3.43	3.79	3.43
Water	Volume %	7.43	7.56	7.26	8.50	8.51	8.46	8.12	9.82	9.87	9.61	9.31	9.87	7.26
Nitrogen	Volume %	75.03	74.98	75.10	74.21	74.21	74.23	74.36	73.15	73.13	73.23	73.34	75.10	73.13
Oxygen	Volume %	12.88	12.73	13.06	12.61	12.61	12.66	13.04	12.43	12.36	12.66	12.99	13.06	12.36
Total	Volume %	100.00	100.00	100.00	99.99	100.01	100.00	99.99	100.01	100.00	100.00	99.99	100.01	99.99
Exhaust Gas Flow Rates														
Stack temperature	°F	1,061	1,116	1,163	1,106	1,102	1,143	1,178	1,134	1,125	1,151	1,185	1,185.00	1,061.00
Mass flow rate	lb/hr	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549	3,845,549
Actual flow rate, wet	ft^3/min	2,471,406	2,007,695	1,711,584	2,379,240	2,390,863	1,967,744	1,680,729	2,253,362	2,297,774	1,909,070	1,620,838	2,471,406	1,620,838
Standard flow rate (dry, 68°F)	ft^3/min	793,856	621,520	516,176	733,705	739,097	593,059	497,571	672,830	689,605	565,325	471,610	793,856	471,610
Oxygen	Volume %, dry	13.91	13.77	14.08	13.78	13.78	13.83	14.19	13.78	13.71	14.01	14.32	14.32	13.71
Standard flow rate (dry, 68°F, 15% oxygen)	ft^3/min	940,007	750,975	596,456	885,244	891,561	710,663	565,677	811,553	839,971	660,570	525,683	940,007	525,683

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-30. ULSD Fuel Oil Simple Cycle Modes—Exhaust Flow Rates (Per CTG/HRSG Unit)

Parameter	Units	Operating Case											Maximum	Minimum
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22		
Ambient Temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative Cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
Exhaust Gas Composition (wet)														
Argon	Volume %	0.90	0.90	0.91	0.89	0.89	0.89	0.90	0.88	0.88	0.89	0.89		0.88
CO_2	Volume %	5.17	5.36	5.11	5.23	5.23	5.28	4.97	5.21	5.23	5.05	4.78		4.78
Water	Volume %	11.10	10.98	10.04	12.08	12.01	11.58	10.54	13.02	12.94	12.08	11.16		10.04
Nitrogen	Volume %	71.46	71.63	72.27	70.72	70.77	71.13	71.82	69.98	70.05	70.65	71.26		69.98
Oxygen	Volume %	11.37	11.12	11.68	11.08	11.10	11.11	11.77	10.91	10.90	11.33	11.90		10.90
Total	Volume %	100.00	99.99	100.01	100.00	100.00	99.99	100.00	100.00	100.00	100.00	99.99	100.01	99.99
Exhaust Gas Flow Rates														
Stack temperature	°F	1,038	1,116	1,163	1,083	1,079	1,141	1,175	1,122	1,113	1,147	1,181	1,181.00	1,038.00
Mass flow rate	lb/hr	4,010,213	3,038,880	2,504,270	3,727,679	3,755,469	2,920,423	2,450,004	3,432,236	3,519,952	2,835,283	2,360,611	4,010,213	2,360,611
Actual flow rate, wet	ft^3/min	2,555,843	2,048,205	1,737,546	2,460,889	2,471,098	2,004,870	1,717,861	2,336,209	2,380,074	1,960,126	1,666,985	2,555,843	1,666,985
Standard flow rate (dry, 68°F)	ft^3/min	800,538	610,602	508,297	740,064	745,659	584,383	496,077	677,919	695,239	565,988	476,301	800,538	476,301
Oxygen	Volume %, dry	12.79	12.49	12.98	12.60	12.62	12.57	13.16	12.54	12.52	12.89	13.39	13.39	12.49
Standard flow rate (dry, 68°F, 15% oxygen)	ft^3/min	1,100,448	870,203	682,019	1,040,810	1,047,073	825,561	651,062	960,219	987,463	768,716	605,882	1,100,448	605,882

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-31. Construction Grading and Earth Moving Operations PM_{10} / $PM_{2.5}$ Emissions Rates

AP-42, Section 11.9 Western Surface Coal Mining, Table 11.9-1, Grading

$PM_{10} = 0.60 \times .051 \times (S)^{2.0}$	0.122	lb/VMT
$PM_{2.5} = 0.031 \times .051 \times (S)^{2.0}$	0.0063	lb/VMT
Vehicle speed (S)	2.00	mph
	2,600	hr/yr
	5	number of grading and earth moving equipment
Vehicle miles traveled (VMT)	26,000	VMT/yr
PM_{10}	3,182	lb/yr
PM_{10}	1.6	tpy
$PM_{2.5}$	164	lb/yr
$PM_{2.5}$	0.082	tpy

Source: ECT, 2012.

Table B-32. Construction Unpaved Roads $PM_{10}/PM_{2.5}$ Emissions Rates

AP-42, Section 13.2.2 Unpaved Roads, Equation (1a).

E= particulate emission factor (having units matching the units of k)
k = particle size multiplier for particle size range and units of interest
s = road surface silt loading
W = average weight (tons) of the vehicles traveling the road
Control Efficency - watering, as needed
Annual VMT = round trip distance * number of trucks/yr

hr/yr	2,600	Assume 10 hr/dy, 5 days/week, 52 weeks/year
k (PM-10)	1.5	Table 13.2.2-2
k (PM-2.5)	0.15	Table 13.2.2-2
s	8.5	%, Table 13.2.2-1, mean for construction site)
W	30	Average vehicle weight (20 tons empty, 40 tons loaded)
a (PM-10)	0.9	Table 13.2.2-2
a (PM-2.5)	0.9	Table 13.2.2-2
b (PM-10)	0.45	Table 13.2.2-2
b (PM-2.5)	0.45	Table 13.2.2-2
EF (PM-10)	3.10	lb/VMT
EF (PM-2.5)	0.31	lb/VMT

	Material		Load (ton)	No. trips/yr	Trip Length (mi)	VMT/yr
Miscellaneous	25,000	tpy	20	1,250	0.50	625

Pollutant	Emission Factor (lb/VMT)	Uncontrolled Emissions Rates		Control Efficiency (%)	Controlled Emissions Rates	
		lb/hr	tpy		lb/hr	tpy
PM_{10}	3.10	0.75	0.97	50	0.37	0.48
$PM_{2.5}$	0.31	0.075	0.097	50	0.037	0.048

Source: ECT, 2012.

Table B-33. Construction Diesel Engine Emission Rates

Heavy equipment	15	total number
Operating hours	2,600	hr/yr (10 hr/dy, 5 dy/wk, 52 wk/yr)
Fuel use	5.0	gal/hr
Fuel use	195,000	gal/yr
Engine rating	500	hp
Diesel fuel	7.0	lb/gal
Fuel sulfur	0.0015	wt% S

Pollutant	Emissions Factor* (gm/hp-hr)	Emissions (tpy)
PM_{10}	0.15	3.2
$PM_{2.5}$	0.15	3.2
NO_x	2.1	45.1
SO_2	0.0010	0.020
CO	2.6	55.9
VOC	0.9	19.3

*EPA Nonroad Diesel Engine Tier 3.

Source: ECT, 2012.

Table B-34. Natural Gas CC Modes—CTG/HRSG Stack Parameters (Per CTG/HRSG Unit)

Parameter	Units	Value
Stack height	ft	130
	meters	39.6
Stack exit diameter	ft	19
	meters	5.8

Parameter	Units	Operating Case							
		CC-1	CC-2	CC-3	CC-5	CC-6	CC-7	CC-8	CC-9
Ambient temperature	°F	20.0	20.0	20.0	20.0	20.0	59.0	59.0	59.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	100.0	100.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1
Evaporative Cooling	Yes/No	No	No	No	No	No	No	Yes	Yes
HRSG duct burner firing	Yes/No	No	Yes	Yes	Yes	No	No	No	Yes
Stack exhaust flow rate	actual ft^3/min	1,107,512	1,087,387	838,595	1,037,259	650,388	1,027,848	1,037,165	1,020,298
	actual m^3/min	31,361	30,791	23,746	29,372	18,417	29,105	29,369	28,892
Exit temperature	°F	211.4	196.2	193.2	166.0	156.8	207.6	208.4	194.4
	K	372.8	364.4	362.7	347.6	342.5	370.7	371.2	363.4
Exit velocity	ft/sec	65	64	49	61	38	60	61	60
	m/s	19.8	19.5	14.9	18.6	11.6	18.3	18.6	18.3

Parameter	Units	Operating Case								
		CC-10	CC-12	CC-13	CC-14	CC-15	CC-17	CC-18	Maximums	Minimums
Ambient temperature	°F	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	75.0	100.0	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	4 on 1	1 on 1	4 on 1	1 on 1
Evaporative Cooling	Yes/No	No	No	Yes	Yes	No	Yes	No		
HRSG duct burner firing	Yes/No	No	No	No	Yes	No	Yes	No		
Stack exhaust flow rate	actual ft^3/min	807,107	957,960	986,474	970,814	783,988	928,309	614,141	1,107,512	614,141
	actual m^3/min	22,855	27,126	27,934	27,490	22,200	26,287	17,391	31,361	17,391
Exit temperature	°F	192.9	209.9	212.2	198.0	198.9	169.3	164.7	212.2	156.8
	K	362.5	372.0	373.3	365.4	365.9	349.4	346.9	373.3	342.5
Exit velocity	ft/sec	47	56	58	57	46	55	36	65	36
	m/s	14.3	17.1	17.7	17.4	14.0	16.8	11.0	19.8	11.0

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-35. ULSD Fuel Oil CC Modes—CTG/HRSG Stack Parameters (Per CTG/HRSG Unit)

Parameter	Units	Value
Stack height	ft	130
	meters	39.6
Stack exit diameter	ft	19
	meters	5.8

Parameter	Units	Operating Case						
		CC-19	CC-20	CC-22	CC-23	CC-24	CC-25	CC-26
Ambient temperature	°F	20.0	20.0	20.0	20.0	59.0	59.0	59.0
Load	% of base load	100.0	75.0	100.0	50.0	100.0	100.0	75.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	4 on 1	4 on 1
Evaporative Cooling	Yes/No	No	No	No	No	No	Yes	No
Stack exhaust flow rate	actual ft^3/min	1,173,034	859,260	1,120,231	662,819	1,086,570	1,095,918	823,986
	actual m^3/min	33,217	24,332	31,721	18,769	30,768	31,033	23,333
Exit temperature	°F	217.1	194.8	186.7	157.5	212.6	213.5	194.4
	K	376.0	363.6	359.1	342.9	373.5	374.0	363.4
Exit velocity	ft/sec	69	51	66	39	64	64	48
	m/s	21.0	15.5	20.1	11.9	19.5	19.5	14.6

Parameter	Units	Operating Case						
		CC-28	CC-29	CC-30	CC-32	CC-33	Maximum	Minimum
Ambient temperature	°F	90.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	100.0	75.0	100.0	50.0	100.0	50.0
Configuration	CTG/HRSG × STG	4 on 1	4 on 1	4 on 1	1 on 1	1 on 1	4 on 1	1 on 1
Evaporative Cooling	Yes/No	No	Yes	No	Yes	No		
Stack exhaust flow rate	actual ft^3/min	1,006,370	1,034,988	812,161	989,810	633,364	1,173,034	633,364
	actual m^3/min	28,497	29,308	22,998	28,028	17,935	33,217	17,935
Exit temperature	°F	213.7	215.8	201.1	186.4	165.8	217.1	157.5
	K	374.1	375.3	367.1	358.9	347.5	376.0	342.9
Exit velocity	ft/sec	59	61	48	58	37	69	37
	m/s	18.0	18.6	14.6	17.7	11.3	21.0	11.3

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-36. Natural Gas Simple Cycle Modes (Cases SC-1 through SC-11)—CTG/HRSG Stack Parameters (Per CTG/HRSG Unit)

Parameter	Units	Value
Stack height	ft	114
	meters	34.7
Stack exit diameter	ft	18
	meters	5.5

Parameter	Units	Operating Case											Maximums	Minimums
		SC-1	SC-2	SC-3	SC-4	SC-5	SC-6	SC-7	SC-8	SC-9	SC-10	SC-11		
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	No	No	No	No	Yes	No	No	No	Yes	No	No		
Stack exhaust flow rate	actual ft^3/min	2,509,861	2,027,173	1,723,140	2,412,012	2,423,894	1,984,996	1,691,126	2,279,788	2,326,023	1,925,178	1,630,002	2,509,861	1,630,002
	actual m^3/min	71,071	57,403	48,794	68,301	68,637	56,209	47,887	64,556	65,866	54,515	46,157	71,071	46,157
Exit temperature	°F	1,061.2	1,116.4	1,162.5	1,106.2	1,101.7	1,142.8	1,177.8	1,133.9	1,124.6	1,150.6	1,185.1	1,185.1	1,061.2
	K	844.9	875.6	901.2	869.9	867.4	890.3	909.7	885.3	880.2	894.6	913.8	913.8	844.9
Exit velocity	ft/sec	164	133	113	158	159	130	111	149	152	126	107	164	107
	m/s	50.0	40.5	34.4	48.2	48.5	39.6	33.8	45.4	46.3	38.4	32.6	49.99	48.46

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-37. ULSD Fuel Oil Simple Cycle Modes (Cases SC-12 through SC-22)—CTG/HRSG Stack Parameters (Per CTG/HRSG Unit)

Parameter	Units	Value
Stack height	ft	114
	m	34.7
Stack exit diameter	ft	18
	m	5.5

Parameter	Units	Operating Case											Maximums	Minimums
		SC-12	SC-13	SC-14	SC-15	SC-16	SC-17	SC-18	SC-19	SC-20	SC-21	SC-22		
Ambient temperature	°F	20.0	20.0	20.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	20.0
Load	% of base load	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	100.0	75.0	50.0	100.0	50.0
Evaporative cooling	Yes/No	N	N	N	N	Y	N	N	N	Y	N	N		
Stack exhaust flow rate	actual ft^3/min	2,594,608	2,067,451	1,748,815	2,494,439	2,504,898	2,022,880	1,728,478	2,363,667	2,409,407	1,976,192	1,676,821	2,594,608	1,676,821
	actual m^3/min	73,471	58,544	49,521	70,635	70,931	57,282	48,945	66,932	68,227	55,960	47,482	73,471	47,482
Exit temperature	°F	1,037.7	1,116.5	1,162.8	1,083.3	1,078.7	1,141.0	1,175.4	1,122.4	1,113.2	1,146.6	1,181.3	1,181.3	1,037.7
	K	831.9	875.7	901.4	857.2	854.7	889.3	908.4	878.9	873.8	892.4	911.7	911.7	831.9
Exit velocity	ft/sec	170	135	115	163	164	132	113	155	158	129	110	170	110
	m/s	51.8	41.1	35.1	49.7	50.0	40.2	34.4	47.2	48.2	39.3	33.5	51.82	49.99

Sources: Black & Veatch, 2012.
Tampa Electric, 2012.
ECT, 2012.

Table B-38. Emergency Diesel Engine and Cooling Tower Stack Parameters

Point Emissions Source	Emissions ID	Base Elevation ft-msl	Base Elevation m-msl	Orientation	Height ft	Height meters	Diameter ft	Diameter meters	Temperature °F	Temperature K
Cooling tower (six cells, per cell)	COOL1-COOL6	143.5	43.7	Vertical	51	15.5	31.6	9.6	98	309.8
Emergency generator diesel engine	EDG	143.5	43.7	Vertical	10	3.0	0.50	0.15	941	778.2

Point Emissions Source	Emissions ID	Area ft^2	Area m^2	Actual Flow Rate ft^3/min	Actual Flow Rate m^3/min	Standard Flow Rate* ft^3/min	Standard Flow Rate* m^3/min	Velocity ft/sec	Velocity m/s
Cooling tower (six cells, per cell)	COOL1-COOL6	785.51	72.98	1,186,000	33,584	1,122,313	31,780	25.2	7.7
Emergency generator diesel engine	EDG	0.20	0.02	3,846	108.9	1,451	41.1	326.4	99.5

*At 68°F.

Sources: Black & Veatch, 2012.
ECT, 2012.

APPENDIX C

DISPERSION MODELING FILES

Polk Power Station 2-5 Conversion Project
Class I Area Dispersion Modeling Files

Directory Name	Number of Files	File Name	File Description
CLASS I/PUFF-INP	3	POLK_YY.INP	CALPUFF input files
		YY = 01, 02, and 03	
CLASS I/PUFF-OUT	3	POLK_YY.CON	CALPUFF Output Concentration Files
	3	POLK_YY.DRY	CALPUFF Output Concentration Files, Dry Deposition Flux Files
	3	POLK_YY.WET	CALPUFF Output Concentration Files, Wet Deposition Flux Files
	3	POLK_YY.LST	CALPUFF Output Concentration List Files
	3	VISBYY.ZIP	CALPUFF Output Visibility Relative Humidity (RH) files
		YY = 01, 02, and 03	
Subtotal Files	15		
CLASS I/UTIL-INP	3	POLK_UTIL_NO3_YY.INP	POSTUTIL Input Files; NO_3/HNO_3 Repartition
	3	POLK_UTIL_VIS__YY.INP	POSTUTIL Input Files, Visibility Species Processing
	3	POLK_UTIL_DEP_YY.INP	POSTUTIL Input Files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	9		
CLASS I/UTIL-OUT	3	POLK_UTIL1_YY.CON	POSTUTIL Output Concentration Files, NO_3/HNO_3 Repartition
	3	POLK_UTIL1_YY.LST	POSTUTIL Output List Files, NO_3/HNO_3 Repartition
	3	POLK_UTIL2_YY.CON	POSTUTIL Output Concentration Files, Visibility Species Processing
	3	POLK_UTIL2_YY.LST	POSTUTIL Output List Files, Visibility Species Processing
	3	POLK_DEP_YY.FLX	POSTUTIL Output Flux Files, Nitrogen and Sulfur Deposition
	3	POLK_DEP_YY.LST	POSTUTIL Output List Files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	18		
CLASS I/POST-INP	3	POLK_NO2_CHAS_YY.INP	CALPOST Input NO_2 Files - Chassahowitzka NWA
	3	POLK_PM_CHAS_YY.INP	CALPOST Input $PM_{10}PM_{2.5}$ Files - - Chassahowitzka NWA
	3	POLK_SO2_CHAS_YY.INP	CALPOST Input SO_2 Files - - Chassahowitzka NWA
	3	POLK_ND_CHAS_YY.INP	CALPOST Input Nitrogen Deposition Files - Chassahowitzka NWA
	3	POLK_SD_CHAS_YY.INP	CALPOST Input Sulfur Deposition Files - Chassahowitzka NWA
	3	POLK_VIS_CHAS_YY.INP	CALPOST Input Visibility Files; - Chassahowitzka NWA
	3	POLK_NO2_ENP_YY.INP	CALPOST Input NO_2 Files - Everglades NP
	3	POLK_PM_ENP_YY.INP	CALPOST Input $PM_{10}PM_{2.5}$ Files - Everglades NP
	3	POLK_SO2_ENP_YY.INP	CALPOST Input SO_2 Files - Everglades NP
		YY = 01, 02, and 03	
Subtotal Files	27		
CLASS I/POST-OUT	3	POLK_NO2_CHAS_YY.LST	CALPOST Output NO_2 Files - Chassahowitzka NWA
	3	POLK_PM_CHAS_YY.LST	CALPOST Output $PM_{10}PM_{2.5}$ Files - Chassahowitzka NWA
	3	POLK_SO2_CHAS_YY.LST	CALPOST Output SO_2 Files - Chassahowitzka NWA
	3	POLK_NDEP_CHAS_YY.LST	CALPOST Output Nitrogen Deposition Files - Chassahowitzka NWA
	3	POLK_SDEP_CHAS_YY.LST	CALPOST Output Sulfur Deposition Files - Chassahowitzka NWA
	3	POLK_VIS_CHAS_YY.LST	CALPOST Output Visibility Files; Chassahowitzka NWA
	3	POLK_NO2_CHAS_YY.LST	CALPOST Output NO_2 Files - Everglades NP
	3	POLK_PM_CHAS_YY.LST	CALPOST Output $PM_{10}PM_{2.5}$ Files - Everglades NP
	3	POLK_SO2_CHAS_YY.LST	CALPOST Output SO_2 Files - Everglades NP
		YY = 01, 02, and 03	
Subtotal Files	27		
Total Files	99		

Source: ECT, 2012.

Polk Power Station 2-5 Conversion Project
Class II Area Dispersion Modeling Files

Directory Name	Number of Files	File Name	File Description
AERMOD MET DATA	5	MCO1MYYYY.SFC	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Surface Air Files
	5	MCO1MYYYY.PFL	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Upper Air Files
	1	MCO1M06_10.SFC	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Surface Air Files (2006-2010)
	1	MCO1M06_10.PFL	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Surface Air Files (2006-2010)
		YYYY = 2006 - 2010	
Subtotal Files	12		
GEP	1	POLK UNIT 2.BPI	Building Profile Input Program (BPIP) Input File
	1	POLK UNIT 2.PRO	Building Profile Input Program (BPIP) Output File - Summary
	1	POLK UNIT 2.SUP	Building Profile Input Program (BPIP) Output File - Detail
Subtotal Files	3		
RECEPTOR	1	POLK_UNIT 2.ROU	AERMOD Receptor File; Significant Impacts
	1	CC20_1HNO2_SIL.ROU	AERMOD Receptor File; 1-Hour NO_2 SIL Receptors, Case CC-20
	1	NGWS_1HNO2_SIL.ROU	AERMOD Receptor File; 1-Hour NO_2 SIL Receptors, Natural Gas Warm Start
	1	CC9_1HSO2_SIL.ROU	AERMOD Receptor File; 1-Hour SO_2 SIL Receptors, Case CC-9
	1	CC26_24HPM10_SIL.ROU	AERMOD Receptor File; 24-Hour PM_{10} SIL Receptors, Case CC-26
	1	CC26_24HPM25_SIL.ROU	AERMOD Receptor File; 24-Hour $PM_{2.5}$ SIL Receptors, Case CC-26
Subtotal files	6		
CC SIL			
NG	5	CC_NG_SIL.INP	AERMOD Input File; Combined Cycle SIL Analysis; Natural Gas
	5	CC_NG_SIL.OUT	AERMOD Output File; Combined Cycle SIL Analysis, Natural Gas
FO	5	CC_FO_SIL.INP	AERMOD Input File; Combined Cycle SIL Analysis; ULSD Fuel Oil
	5	CC_FO_SIL.OUT	AERMOD Output File; Combined Cycle SIL Analysis; ULSD Fuel Oil
Subtotal files	20		
1-HOUR CO WS SIL	1	CC_WS_1HCO_SIL.INP	AERMOD Input File; CO Warm Start SIL Analysis
	1	CC_WS_1HCO_SIL.OUT	AERMOD Output File; CO Warm Start SIL Analysis
	1	CC_WS_1HCO_SIL.MAX	AERMOD Output File; CO Warm Start SIL Analysis
Subtotal files	3		
1-HOUR NO2 SIL			
CASE CC-20	1	CC20_1HNO2_SIL.INP	AERMOD Input File; 1-Hour NO_2 SIL Analysis, Case CC-20
	1	CC20_1HNO2_SIL.OUT	AERMOD Output File; 1-Hour NO_2 SIL Analysis, Case CC-20
	1	CC20_1HNO2_SIL.MAX	AERMOD Output File; 1-Hour NO_2 SIL Analysis, Case CC-20
CASE CC-26	1	CC26_1HNO2_SIL.INP	AERMOD Input File; 1-Hour NO_2 SIL Analysis, Case CC-26
	1	CC26_1HNO2_SIL.OUT	AERMOD Output File; 1-Hour NO_2 SIL Analysis, Case CC-26
	1	CC26_1HNO2_SIL.MAX	AERMOD Output File; 1-Hour NO_2 SIL Analysis, Case CC-26
Subtotal files	6		
1-HOUR SO2 SIL	1	CC9_1HSO2_SIL.INP	AERMOD Input File; 1-Hour SO_2 SIL Analysis, Case CC-9
	1	CC9_1HSO2_SIL.OUT	AERMOD Output File; 1-Hour SO_2 SIL Analysis, Case CC-9
	1	CC9_1HSO2_SIL.MAX	AERMOD Output File; 1-Hour SO_2 SIL Analysis, Case CC-9
Subtotal files	3		
24-HOUR PM10 SIL	1	CC26_24HPM10_SIL.INP	AERMOD Input File; 24-Hour PM_{10} SIL Analysis, Case CC-26
	1	CC26_24HPM10_SIL.OUT	AERMOD Output File; 24-Hour PM_{10} SIL Analysis, Case CC-26
	1	CC26_24HPM10_SIL.MAX	AERMOD Output File; 24-Hour PM_{10} SIL Analysis, Case CC-26
Subtotal files	3		
24-HOUR PM25 SIL	1	CC26_24HPM25_SIL.INP	AERMOD Input File; 24-Hour $PM_{2.5}$ SIL Analysis, Case CC-26
	1	CC26_24HPM25_SIL.OUT	AERMOD Output File; 24-Hour $PM_{2.5}$ SIL Analysis, Case CC-26
	1	CC26_24HPM25_SIL.MAX	AERMOD Output File; 24-Hour $PM_{2.5}$ SIL Analysis, Case CC-26
Subtotal files	3		
1-HOUR NO2 CUMULATIVE			
CASE CC-20	1	CC20_1HNO2_CUM.INP	AERMOD Input File; 1-Hour NO_2 NAAQS, Case CC-20
	1	CC20_1HNO2_CUM.OUT	AERMOD Output File; 1-Hour NO_2 NAAQS, Case CC-20
	1	CC20_1HNO2_CUM.OUT	AERMOD Output File; 1-Hour NO_2 NAAQS, Case CC-20

Polk Power Station 2-5 Conversion Project
Class II Area Dispersion Modeling Files

Directory Name	Number of Files	File Name	File Description
WARM START	1	NGWS_1HNO2_CUM.INP	AERMOD Input File; 1-Hour NO_2 NAAQS, Natural Gas Warm Start
	1	NGWS_1HNO2_CUM.OUT	AERMOD Output File; 1-Hour NO_2 NAAQS, Natural Gas Warm Start
	1	NGWS_1HNO2_CUM.MAX	AERMOD Output File; 1-Hour NO_2 NAAQS, Natural Gas Warm Start
Subtotal files	6		
1-HOUR SO2 CUMULATIVE	1	CC9_1HSO2_CUM.INP	AERMOD Input File; 1-Hour SO_2 NAAQS, Case CC-9
	1	CC9_1HSO2_CUM.OUT	AERMOD Output File; 1-Hour SO_2 NAAQS, Case CC-9
	1	CC9_1HSO2_CUM.MAX	AERMOD Output File; 1-Hour SO_2 NAAQS, Case CC-9
Subtotal files	3		
24-HOUR PM10 PSD	5	CC26_24HPM10_PSD_YY.INP	AERMOD Input File; 24-Hour PM_{10} PSD Increment Analysis, Case CC-26
	5	CC26_24HPM10_PSD_YY.OUT	AERMOD Output File; 24-Hour PM_{10} PSD Increment Analysis, Case CC-26
	5	CC26_24HPM10_PSD_YY.MAX	AERMOD Output File; 24-Hour PM_{10} PSD Increment Analysis, Case CC-26
		YY = 06 - 10	
Subtotal files	15		
24-HOUR PM10 CUMULATIVE	1	CC26_24HPM10_CUM.INP	AERMOD Input File; 24-Hour PM_{10} NAAQS, Case CC-26
	1	CC26_24HPM10_CUM.OUT	AERMOD Output File; 24-Hour PM_{10} NAAQS, Case CC-26
Subtotal files	2		
24-HOUR PM25 CUMULATIVE	1	CC9_1HSO2_CUM.INP	AERMOD Input File; 1-Hour SO_2 NAAQS, Case CC-9
	1	CC9_1HSO2_CUM.OUT	AERMOD Output File; 1-Hour SO_2 NAAQS, Case CC-9
	1	CC9_1HSO2_CUM.MAX	AERMOD Output File; 1-Hour SO_2 NAAQS, Case CC-9
Subtotal files	3		
24-HOUR PM25 PSD	5	CC26_24HPM25_PSD_YY.INP	AERMOD Input File; 24-Hour $PM_{2.5}$ PSD Increment Analysis, Case CC-26
	5	CC26_24HPM25_PSD_YY.OUT	AERMOD Output File; 24-Hour $PM_{2.5}$ PSD Increment Analysis, Case CC-26
	5	CC26_24HPM25_PSD_YY.MAX	AERMOD Output File; 24-Hour $PM_{2.5}$ PSD Increment Analysis, Case CC-26
		YY = 06 - 10	
Subtotal files	15		
Total Files	103		

Source: ECT, 2012.

Polk 2-5 Combined Cycle Conversion Project

Polk Power Station Site Certification Application

Dispersion Modeling Files

October 2012

Prepared by:

ECT Environmental Consulting & Technology, Inc.

Gainesville, Florida

ECT No. 110888-0100

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APPENDIX D

RBLC INFORMATION TABLES

APPENDIX D
RBLC SUMMARY TABLES

Table D-1. RBLC NO_x Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENAR	1944 MMBTU	CEM SYSTEMS AND GOOD COMBUSTION PR.	2 PPMVD	BACT-PSD
AZ-0038	GILA BEND POWER GENERATING STATI	05/15/02	TURBINE, COMBINED CYCLE, DUC	170 MW	SCR AND LOW NOX COMBUSTORS	2 PPM @ 15% O2	BACT-PSD
AZ-0039	SALT RIVER PROJECT/SANTAN GEN. PL	03/07/03	TURBINE, COMBINED CYCLE, DUC	175 MW	SCR	2 PPM @ 15% O2	LAER
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A'	11/12/03	TURBINE, COMBINED CYCLE &	325 MW	SCR	2 PPM @ 15% O2	BACT-PSD
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A'	11/12/03	TURBINE, COMBINED CYCLE	325 MW	SCR	2 PPM @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STA	12/01/04	COMBUSTION TURBINE GENERAT	180 MW	LOW NOX BURNERS AND SELECTIVE CATAL	2 PPM @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STA	12/01/04	COMBUSTION TURBINE GENERAT	170 MW	LOW NOX BURNERS AND SELECTIVE CATAL	2 PPM AT 15% O2	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	SIEMENS WESTINGHOUSE COMBU	1080 MW	LOW NOX BURNERS AND SELECTIVE CATAL	2 PPMVD	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	GE COMBUSTION TURBINES AND I	1040 MW	LOW NOX BURNERS WITH SELECTIVE CATA	2 PPMVD	BACT-PSD
CA-0997	SACRAMENTO MUNICIPAL UTILITY DIS	09/01/03	GAS TURBINES, (2)	1611 MMBTU/H	SCR	2 PPM @ 15% O2	LAER
CA-1096	VERNON CITY LIGHT & POWER	05/27/03	GAS TURBINE: COMBINED CYCLE	43 MW GAS TU	SCR SYSTEM, AND OXIDATION CATALYST	2 PPMVD @ 15% O	BACT-PSD
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	05/27/03	GAS TURBINE: COMBINED CYCLE	181 NET MW (GA	SCR SYSTEM AND OXIDATION CATALYST	2 PPMVD @ 15% O	BACT-PSD
CA-1144	BLYTHE ENERGY PROJECT II	04/25/07	2 COMBUSTION TURBINES	170 MW	SELECTIVE CATALYTIC REDUCTION	2 PPMVD	BACT-PSD
CA-1177	OTAY MESA ENERGY CENTER LLC	07/22/09	Gas turbine combined cycle	171.7 MW	SCR	2 PPMVD@15% O	OTHER CAS
CA-1178	APPLIED ENERGY LLC	03/20/09	Gas turbine combined cycle	0	SCR	2 PPM	BACT-PSD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTIO	2.1 MMCF/H	LOW NOX BURNER AND SELECTIVE CATAL	2 PPM @ 15% O2	LAER
FL-0263	FPL TURKEY POINT POWER PLANT	02/08/05	170 MW COMBUSTION TURBINE, 4	170 MW	NOX EMISSIONS WILL BE REDUCED WITH DI	2 PPMVD@ 15 % O	BACT-PSD
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	COMBINED CYCLE COMBUSTION (	2333 MMBTU/H	WATER INJECTION	2 PPMVD @15%O2	BACT-PSD
FL-0303	FPL WEST COUNTY ENERGY CENTER UN	07/30/08	THREE NOMINAL 250 MW CTG (EA	2333 MMBTU/H	SELECTIVE CATALYST REDUCTION	2 PPMVD (GAS)	BACT-PSD
FL-0304	CANE ISLAND POWER PARK	09/08/08	300 MW COMBINED CYCLE COMBU	1860 MMBTU/H	SCR	2 PPMVD	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	COMBUSTION TURBINE, COMBINE	2375 MMBTU/H	(SCR),	2 PPMVD	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJE	08/16/05	TURBINE, COMBINED CYCLE COM	306 MW	SELECTIVE CATALYTIC REDUCTION WITH A	2 PPM @ 15% O2	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJE	08/16/05	TURBINE, COMBINED CYCLE COM	306 MW	SELECTIVE CATALYST REDUCTION W/ AMM	2 PPM @ 15% O2	BACT-PSD
NV-0037	COPPER MOUNTAIN POWER	05/14/04	LARGE COMBUSTION TURBINES, (	600 MW	DRY LOW-NOX COMBUSTOR, STEAM INJECT	2 PPMVD	BACT-PSD
NV-0038	IVANPAH ENERGY CENTER, L.P.	12/29/03	LARGE COMBUSTION TURBINES, (	500 MW	DRY LOW NOX COMBUSTION CONTROL IN C	2 PPMVD	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2221 MMBUT/H	SCR	2 PPMVD@15%02	BACT-PSD
NY-0098	ATHENS GENERATING PLANT	01/19/07	FUEL COMBUSTION (GAS)	3100 MMBTU/H	THE TURBINES EMPLOY DRY LOW NOX TEC	2 PPMVD @ 15% O	LAER
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (NATURAL GA	2099 MMBTU/H	DRY LOW NOX COMBUSTION TECHNOLOGY	2 PPMVD AT 15% (	LAER
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERATIO	1882 MMBTU/H	SCR AND DRY LOW-NOX	2 PPM	BACT-PSD
OR-0041	WANAPA ENERGY CENTER	08/08/05	COMBUSTION TURBINE & HEA	2384.1 MMBTU/H	DRY LOW-NOX BURNERS AND SCR.	2 PPMDV @ 15% O	BACT-PSD
OR-0048	CARTY PLANT	12/29/10	COMBINED CYCLE NATURAL GAS	2866 MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR)	2 PPM@15%O2	BACT-PSD
PA-0226	LIMERICK POWER STATION	04/09/02	TURBINE, COMBINED CYCLE	550 MW	LOW NOX BURNERS	2 PPM @15% O2	LAER
TX-0546	PATTILLO BRANCH POWER PLANT	06/17/09	ELECTRICITY GENERATION	350 MW	SELECTIVE CATALYTIC REDUCTION	2 PPMVD	BACT-PSD
TX-0547	Lamar Energy Center	06/22/09	ELECTRICITY GENERATION	250 MW	SELECTIVE CATALYTIC REDUCTION	2 PPMVD	BACT-PSD
TX-0548	MADISON BELL ENERGY CENTER	08/18/09	ELECTRICITY GENERATION	275 MW	SELECTIVE CATALYTIC REDUCTION	2 PPMVD	BACT-PSD
TX-0590	KING POWER STATION	08/05/10	Turbine	1350 MW	DLN burners and SCR	2 PPMVD AT 15% (	LAER
TX-0600	THOMAS C. FERGUSON POWER PLANT	09/01/11	Natural gas-fired turbines	390 MW	Dry low NOx burners and Selective Catalytic Reduc	2 PPMVD	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE (2)	1717 MMBTU/H	TWO STAGE LEAN PERMIX DRY LOW NOX C	2 PPM	Other Case-b
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENAR	1717 MMBTU/H	2 STAGE PREMIX NOX COMBUSTION AND SC	2 PPM	BACT-PSD
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION SECNARI(	2204 MMBTU/H	2 STAGE LEAN PREMIX AND GOOD COMBUS	2 PPMVD	BACT-PSD
WA-0315	SUMAS ENERGY 2 GENERATION FACILI	04/17/03	TURBINES, COMBINED CYCLE, (2)	660 MW	DRY LOW NOX BURNERS, SCR	2 PPMVD	BACT-PSD
UT-0066	CURRANT CREEK	05/17/04	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY		CONVENTIONAL SELECTIVE CATALYTIC RE	2.25 PPMVD	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), I	171 MW	W/AMMONIA	2.5 PPM @ 15% O2	BACT-PSD
VA-0262	MIRANT AIRSIDE INDUSTRIAL PARK	12/06/02	TURBINE, COMBINED CYCLE, (2)	170 MW	COMBUSTION	2.5 PPMVD @ 15% O	BACT-PSD
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COME	173 MW	DRY LOW NOX + SCR	2.5 PPM @ 15% O2	BACT-PSD
CA-1142	PASTORIA ENERGY FACILITY	12/23/04	3 COMBUSTION TURBINES	168 MW	XONON CATALYTIC COMBUSTORS OR DRY	2.5 PPMVD	BACT-PSD

Table D-1. RBLC NO_x Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
CA-1143	SUTTER POWER PLANT	08/16/04	2 COMBUSTION TURBINES	170 MW	DRY LOW NOX BURNERS & SCR	2.5 PPMVD	BACT-PSD
FL-0241	CPV CANA	01/17/02	TURBINE, COMBINED CYCLE, NAT	1680 MMBTU/H	DRY LOW NOX, SCR, WET INJECTION	2.5 PPMVD @ 15% O	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE WITH	170 MW	DRY LOW NOX COMBUSTORS AND SCR	2.5 PPM @ 15% O2	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYLE, NATU	170 MW	DRY LOW NOX COMBUSTORS AND SCR	2.5 PPMVD @ 15% O	BACT-PSD
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, COMBINED CYCLE, NAT	170 MW	DRY LOW NOX COMBUSTORS WITH SCR	2.5 PPMVD @ 15% O	BACT-PSD
FL-0256	HINES ENERGY COMPLEX, POWER BLOC	09/08/03	COMBUSTION TURBINES, COMBIN	1830 MMBTU/H	CATALYTIC	2.5 PPMVD @15% O:	BACT-PSD
FL-0265	HINES POWER BLOCK 4	06/08/05	COMBINED CYCLE TURBINE	530 MW	SCR	2.5 PPM	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, NAT	140 MW	DRY LOW NOX COMBUSTORS, SCR	2.5 PPM @ 15% O2	BACT-PSD
GA-0138	LIVE OAKS POWER PLANT	04/08/10	COMBINED CYCLE COMBUSTION T	600 MW	DRY LOW NOx BURNERS, SELECTIVE CATAL	2.5 PPM@15%02	BACT-PSD
MI-0366	BERRIEN ENERGY, LLC	04/13/05	3 COMBUSTION TURBINES AND DU	1584 MMBTU/H	DRY LOW NOX BURNERS AND SELECTIVE C.	2.5 PPMDV @ 15% O	BACT-PSD
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, NA	1715 MMBTU/H	DLN AND SCR	2.5 PPMVD	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE	175 MW	DRY LOW NOX AND SCR	2.5 PPMVD	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MH	175 MW	DRY-LOW NOX AND SCR	2.5 PPMVD	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MH	175 MW	DRY LOW NOX AND SCR	2.5 PPMVD	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE	175 MW	DRY LOW NOX AND SCR	2.5 PPMVD	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, NAT	1844 MMBTU/H	SELECTIVE CATALYTIC	2.5 PPM @ 15% O2	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH	3202 MMBTU/H	SCR	2.5 PPMVD @ 15% O	Other Case-b
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	SCR- AMMONIA FLOW RTE AT 11.46 GAL/H	2.5 PPMVD @ 15 % (	Other Case-b
OR-0035	PORT WESTWARD PLANT	01/16/02	(2) COMBUSTION TURBINES, WITH	325 MW, EACH	LOW NOX	2.5 PPM @ 15% O2	BACT-PSD
OR-0039	COB ENERGY FACILITY, LLC	12/30/03	TURBINE, COMBINED CYCLE, DUC	1150 MW	DLN COMBUSTORS, AND SCR	2.5 PPMVD @ 15% O	BACT-PSD
OR-0040	KLAMATH GENERATION, LLC	03/12/03	TURBINE, COMBINED CYCLE, DUC	480 MW	DRY LOW NOX COMBUSTION, SCR	2.5 PPMVD @ 15% O	BACT-PSD
PA-0188	FAIRLESS ENERGY LLC	03/28/02	TURBINE, COMBINED CYCLE	1190 MW	SCR, DRY LOW NOX COMBUSTION	2.5 PPMV @ 15% O2	LAER
PA-0189	CONECTIV BETHLEHEM, INC.	01/16/02	TURBINE, COMBINED CYCLE, (6)	122 MW	COMBUSTERS,	2.5 PPMVD @ 15% O	LAER
PA-0223	DUKE ENERGY FAYETTE, LLC	01/30/02	TURBINE, COMBINED CYCLE, (2)	280 MW	LO NOX BURNERS, SCR	2.5 PPMVD @ 15% O	LAER
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	COMBUSTION PRACTICE.	2.5 PPM @ 15% O2	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NAT	1973 MMBTU/H	AMMONIA INJECTION	2.5 PPM	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NAT	1973 MMBTU/H	AMMONIA INJECTION	2.5 PPM	BACT-PSD
VA-0289	DUKE ENERGY WYTHE, LLC	02/05/04	TURBINE, COMBINED CYCLE, NAT	170 MW	COMBUSTION	2.5 PPMVD	BACT-PSD
VA-0289	DUKE ENERGY WYTHE, LLC	02/05/04	TURBINE, COMBINED CYCLE, DUC	170 MW	SCR AND LOW NOX BURNERS; GOOD COMBI	2.5 PPMVD	BACT-PSD
WA-0291	WALLULA POWER PLANT	01/03/03	TURBINE, COMBINED CYCLE, NAT	1300 MW	SCR	2.5 PPMDV @15%02	Other Case-b
WA-0328	BP CHERRY POINT COGENERATION PRO	01/11/05	GE 7FA COMBUSTION TURBINE &a	174 MW	LEAN PRE-MIX DRY LOW-NOX BURNERS ON	2.5 PPMDV	BACT-PSD
WY-0061	BLACK HILLS CORP./NEIL SIMPSON TWO	04/04/03	TURBINE, COMBINED CYCLE, &am	40 MW	DRY LOW NOX BURNERS AND SCR	2.5 PPM @ 15% O2	Other Case-b
MI-0357	KALKASKA GENERATING, INC	02/04/03	TURBINE, COMBINED CYCLE, (2)	605 MW	SCR AND LOW-NOX BURNERS.	3 PPMVD @ 15% O	BACT-PSD
MI-0361	SOUTH SHORE POWER LLC	01/30/03	TURBINE, COMBINED CYCLE, (2)	172 MW	CATALYTIC	3 PPMVD @ 15% O	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, NAT	1876 MMBTU/H	SCR AND DLN.	3 PPMVD @ 15% O:	BACT-PSD
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE, (3),	61200 MMSCF/YR	CONTINUOUS	3 PPMVD	BACT-PSD
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LI	08/11/02	TWO (2) NATURAL GAS FIRED, COI	2311 MMBTU/H	(POLLUTION PREVENTION)	3 PPM @ 15% O2	BACT-PSD
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LI	05/02/06	NATURAL-GAS FIRED, COMBINED-	300 MW	LOW NOX BURNERS AND SCR	3 PPM @ 15% O2	BACT-PSD
GA-0101	MURRAY ENERGY FACILITY	10/23/02	TURBINE, COMBINED CYCLE, (4)	173 MW	CATALYTIC	3 PPM @ 15% O2	BACT-PSD
GA-0102	WANSLEY COMBINED CYCLE ENERGY F	01/15/02	TURBINE, COMBINED CYCLE, (2)	167 MW	CATALYTIC	3 PPM @ 15% O2	BACT-PSD
IA-0058	GREATER DES MOINES ENERGY CENTEI	04/10/02	COMBUSTION TURBINES - COMBII	350 MW	DRY LOW NOX	3 PPM @ 15% O2	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE, NAT	1491 MMBTU/H	NATURAL GAS IS ONLY	3 PPMVD @ 15% O	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE AND	1491 MMBTU/H	LOW NOX BURNERS, SCR, NATURAL GAS FU	3 PPMVD @ 15% O	BACT-PSD
LA-0192	CRESCENT CITY POWER	06/06/05	GAS TURBINES - 187 MW (2)	2006 MMBTU/H	LOW NOX BURNERS AND SELECTIVE CATLY	3 PPM	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE, 2	1916 MMBTU/H	LEAN PRE-MIX COMBUSTION & SCR	3 PPMVD 15% 02	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	COMBINED CYCLE COMBUSTION T	1758 MMBTU/H	DRY LOW NOX COMBUSTION FOR NG; WATI	3 PPMVD	BACT-PSD

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Table D-1. RBLC NO_x Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
MT-0019	CONTINENTAL ENERGY SERVICES, INC.,	06/07/02	TURBINE, COMBINED CYCLE 2	500 MW	SCR	3 PPM @ 15% O2	BACT-PSD
MT-0019	CONTINENTAL ENERGY SERVICES, INC.,	06/07/02	TURBINE, COMBINED CYCLE 1	500 MW	SCR	3 PPM @ 15% O2	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (NATURAL GA	646 MMBTU/H	DRY LOW NOX COMBUSTION TECHNOLOGY	3 PPMVD AT 15% (	LAER
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE,	180 MW	BURNERS (LNB)	3 PPM @ 15% O2	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE,	180 MW	BURNERS(LNB)&	3 PPM @ 15% O2	BACT-PSD
OH-0252	DUKE ENERGY HANGING ROCK ENERGY	12/28/04	TURBINES (4) (MODEL GE 7FA), DU	172 MW	SELECTIVE CATALYTIC	3 PPM @ 15% O2	BACT-PSD
OH-0252	DUKE ENERGY HANGING ROCK ENERGY	12/28/04	TURBINES (4) (MODEL GE 7FA), DU	172 MW	SELECTIVE CATALYTIC	3 PPM @ 15% O2	BACT-PSD
WA-0289	TRANSALTA CENTRALIA GENERATION I	02/22/02	(4) TURBINE/HRSG		CATALYTIC	3 PPM @ 15% O2	BACT-PSD
MI-0365	MIRANT WYANDOTTE LLC	01/28/03	TURBINE, COMBINED CYCLE, (2)	2200 MMBTU/H	CATALYTIC	3.5 PPM	BACT-PSD
TX-0374	CHOCOLATE BAYOU PLANT	03/24/03	(2) COGENERATION TRAINS 2 &am	70 MW, TOTAL	CATALYTIC	3.5 PPM @ 15% O2	Other Case-b
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE, NAT	1937 MMBTU/H		3.5 PPMVD @ 15% O	LAER
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, NATURAL GAS, NO DUC	1937 MMBTU/H	REDUCTION,	3.5 PPMVD @ 15% O	LAER
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	TURBINES, COMBINED CYCLE, NA	170 MW	AND DRY LOW-	3.5 PPM @ 15% 02	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (	170 MW	DRY LOW NOX COMBUSTOR/SCR	3.5 PPMVD @ 15% O	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (	170 MW	DRY LOW NOX COMBUSTOR/SCR	3.5 PPMVD @ 15% O	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (	170 MW	DRY LOW NOX COMBUSTOR/SCR	3.5 PPMVD @ 15% O	BACT-PSD
FL-0239	JEA/BRANDY BRANCH	03/27/02	TURBINES, COMBINED CYCLE, (2)	1911 MMBTU/H	GAS, SCR & WATER	3.5 PPMVD	BACT-PSD
MS-0055	EL PASO MERCHANT ENERGY CO.	06/24/02	TURBINE, COMBINED CYCLE, DUC	1737 MMBTU/H	CATALYTIC REDUCTION	3.5 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-001 W/DUCT BURNER	2168 MMBTU/H	CATALYTIC	3.5 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-002 W /DUCT BURNE	2168 MMBTU/H	CATALYTIC	3.5 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-003 /DUCT BURNER	2168 MMBTU/H	CATALYTIC	3.5 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-004 W/ DUCT BURNEI	2168 MMBTU/H	CATALYTIC	3.5 PPMV @ 15% O2	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-001 GEN. ELE	230 MW	SCR	3.5 PPMV @ 15% 02	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-002 GEN ELEC	230 MW	SCR	3.5 PPMV @ 15% 02	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-003 GEN. ELE	230 MW	SCR	3.5 PPMV @ 15 02	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, NAT	154 MW	DRY LOW NOX AND SCR	3.5 PPMVD @ 15% O	BACT-PSD
NE-0017	BEATRICE POWER STATION	05/29/03	TURBINE, COMBINED CYCLE, (2)	80 MW	CATALYTIC	3.5 PPM @ 15% O2	BACT-PSD
NM-0044	CLOVIS ENERGY FACILITY	06/27/02	TURBINES, COMBINED CYCLE, NA	1515 MMBTU/H	PIPELINE QUALITY	3.5 PPMV @ 15% O2	BACT-PSD
NV-0033	EL DORADO ENERGY, LLC	08/19/04	COMBUSTION TURBINE, COMBINI	475 MW	LOW NOX BURNER + SCR	3.5 PPM @ 15% O2	BACT-PSD
OH-0254	DUKE ENERGY WASHINGTON COUNTY I	08/14/03	TURBINES (2) (MODEL GE 7FA), DU	170 MW	BURNERS AND	3.5 PPM @ 15% O2	BACT-PSD
OH-0254	DUKE ENERGY WASHINGTON COUNTY I	08/14/03	TURBINES (2) (MODEL GE 7FA), DU	170 MW	BURNERS AND	3.5 PPM @ 15% O2	BACT-PSD
OH-0264	NORTON ENERGY STORAGE, LLC	05/23/02	COMBUSTION TURBINE (9), COMB	300 MW	AND DRY LOW	3.5 PPM @ 15% O2	BACT-PSD
OH-0264	NORTON ENERGY STORAGE, LLC	05/23/02	COMBUSTION TURBINES (9), COMI	300 MW	AND DRY LOW	3.5 PPM @ 15% O2	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	GE COMBUSTION TURBINE & I	1705 MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR) W	3.5 PPMVD @ 15% O	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	SW COMBUSTION TURBINE	1872 MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR) W	3.5 PPM @ 15% O2	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	MHI COMBUSTION TURBINE &amp	1767 MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR) W	3.5 PPM @ 15% O2	BACT-PSD
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHE	03/21/03	TURBINES, COMBINED CYCLE (2)	1701 MMBTU/H	SCR, DRY LOW NOX COMBUSTORS	3.5 PPM @ 15% O2	BACT-PSD
OK-0096	REDBUD POWER PLANT	06/03/03	COMBUSTION TURBINE AND DUC	1832 MMBTU/H	WITH DRY LOW	3.5 PPMVD @ 15% O	BACT-PSD
OK-0115	LAWTON ENERGY COGEN FACILITY	12/12/06	COMBUSTION TURBINE AND DUCT BURNER		SCR W/ DRY LOW NOX BURNERS AND DRY L	3.5 PPMVD	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/ D	1990 MMBTU/H	DRY LOW NOX BURNERS, SCR	3.5 PPM @ 15% O2	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/O	1990 MMBTU/H	DRY LOW NOX BURNERS, SCR	3.5 PPM @ 15% O2	BACT-PSD
TX-0352	BRAZOS VALLEY ELECTRIC GENERATIN	12/31/02	(2) HRSG/TURBINES, HRSG-003 &an	175 MW	SELECTIVE CATALYTIC REDUCTION	3.5 PPM @ 15% O2	BACT-PSD
TX-0352	BRAZOS VALLEY ELECTRIC GENERATIN	12/31/02	(2) HRSG/TURBINES, HRSG-001 &an	175 MW, EA	SELECTIVE CATALYTIC REDUCTION	3.5 PPM @ 15% O2	BACT-PSD
TX-0411	AMELIA ENERGY CENTER	03/26/02	TURBINE, COMBINED CYCLE, &am	180 MW	SELECTIVE CATALYTIC REDUCTION	3.5 PPM @ 15% O2	LAER
LA-0224	ARSENAL HILL POWER PLANT	03/20/08	TWO COMBINED CYCLE GAS TURI	2110 MMBTU/H	LOW NOX TURBINES, DUCT BURNERS COME	4 PPMVD@15% O2	BACT-PSD
TX-0391	OXY COGENERATION FACILITY	12/20/02	COMBINED-CYCLE GAS TURBINES	87 MW (EACH)	SCR AND NH3 INJECTION.	4 PPM @ 15% O2	BACT-PSD

Table D-1. RBLC NO_x Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
TX-0428	HOUSTON OPERATIONS -- BATTLEGROU	12/19/02	TURBINE, COMBINED CYCLE &	87 mw	SCR	4 PPMVD @ 15% O	BACT-PSD
MI-0363	BLUEWATER ENERGY CENTER LLC	01/07/03	TURBINE, COMBINED CYCLE, (3)	180 MW	CATALYTIC	4.5 PPMV	BACT-PSD
LA-0157	PERRYVILLE POWER STATION	03/08/02	TURBINES, COMBINED CYCLE, GA	170 MW	CATALYTIC	4.5 PPM @ 15% O2	BACT-PSD
LA-0164	ACADIA POWER STATION, ACADIA POW	01/31/02	GAS TURBINE UNITS 1, 2, 3, 4	183 MW EACH	SELECTIVE	4.5 PPM @ 15% O2	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 7	171 MW	SCR W/AMMONIA	5 PPM @ 15% O2	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLAN	12/20/10	GE LM6000PF-25 Turbines (4)	59900 hp ISO	Selective Catalytic Reduction and Dry Low NOx Cc	5 PPMDV	BACT-PSD
LA-0120	GEISMAR PLANT	02/26/02	(2) COGENERATION UNITS POINT #	40 MW EACH	CATALYTIC	5 PPM @ 15% O2	BACT-PSD
LA-0136	PLAQUEMINE COGENERATION FACILIT	07/23/08	(4) GAS TURBINES/DUCT BURNERS	2876 MMBTU/H	CATALYTIC	5 PPMVD @ 15% O	BACT-PSD
TX-0388	SAND HILL ENERGY CENTER	02/12/02	COMBINED CYCLE GAS TURBINE	164 MW		5 PPM @ 15% O2	BACT-PSD
TX-0407	STERNE ELECTRIC GENERATING FACILI	12/06/02	TURBINES, COMBINED CYCLE, AN	190 MW	DRY LOW NOX COMBUSTORS FOR THE TURI	5 PPMVD @ 15% O	BACT-PSD
TX-0437	HARTBURG POWER, LP	07/05/02	TURBINE, COMBINED CYCLE &	277 mw	SCR FOR BOTH TURBINE AND DUCT BURNEI	5 PPMVD @ 15% O	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE 2 I	1827 MMBTU/H	WATER INJECTION AND SCR	5.5 PPMVD @15% 02	BACT-PSD
OK-0117	PSO SOUTHWESTERN POWER PLT	02/09/07	GAS-FIRED TURBINES		DRY LOW NOX	9 PPM	BACT-PSD
TX-0350	ENNIS TRACTEBEL POWER	01/31/02	COMBUSTION TURBINE W/HEAT R	350 MW	NONE INDICATED	9 PPM @ 15% O2	Other Case-b
TX-0351	WEATHERFORD ELECTRIC GENERATION	03/11/02	(2) GE7121EA GAS TURBINES, S-3&	1079 MMBTU/H	NONE INDICATED	9 PPM @ 15% O2	N/A
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	TURBINES AND DUCT BURNERS	310 MW TOTAL	SCR	12.5 PPM @ 15% O2	BACT-PSD
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	COMBINED CYCLE COMBUSTION T	1972 MMBTU/H	WATER INJECTION	15 PPMVD UNCORF	BACT-PSD
TX-0234	EDINBURG ENERGY LIMITED PARTNERS	01/08/02	(4) COMBINED CYCLE GAS TURBIN	180 MW	PPMVD WHEN	15 PPM @ 15% O2	BACT-PSD
MI-0362	MIDLAND COGENERATION (MCV)	04/21/03	TURBINE, COMBINED CYCLE, (1)	984 MMBTU/H	RECONSTRUCTION	25 PPM @ 15% O2	BACT-PSD
OH-0268	LIMA ENERGY COMPANY	03/26/02	COMBUSTION TURBINE (2), COMBI	170 MW	AND DILUTION	25 PPM @ 15% O2	BACT-PSD
OK-0055	MUSTANG ENERGY PROJECT	02/12/02	COMBUSTION TURBINES W/DUCT	0	SCR	25 PPM @ 15% 02	BACT-PSD
TX-0365	TEXAS CITY OPERATIONS	01/23/03	(4) GAS TURBINES - ONLY - 501-2&	14.2 MW	LOW NOX COMBUSTORS	25 PPM @ 15% O2	Other Case-b
TX-0365	TEXAS CITY OPERATIONS	01/23/03	(2) GAS TURBINES & WHB - CC	14.2 MW	LOW NOX COMBUSTORS	25 PPM @ 15% O2	Other Case-b
TX-0365	TEXAS CITY OPERATIONS	01/23/03	(2) GAS TURBINES & WHB - CC	14.2 MW	LOW NOX COMBUSTORS	25 PPM @ 15% O2	Other Case-b
WA-0299	SUMAS ENERGY 2 GENERATION FACILI	09/06/02	TURBINES, COMBINED CYCLE, (2)	334.5 MW	SCR	27 PPM @ 15% O2	BACT-PSD
MI-0362	MIDLAND COGENERATION (MCV)	04/21/03	TURBINE, COMBINED CYCLE, (11)	984 MMBTU/H	AND	42 PPM @ 15% O2	BACT-PSD
LA-0194	SABINE PASS LNG TERMINAL	11/24/04	30 MW GAS TURBINE GNERATORS	30 mw each	DRY LOW NOX BURNER	50 PPMVD @ 15% O	BACT-PSD

Source: ECT, 2012.

Table D-2. RBLC SO_2 Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 2	1944 MMBTU	GOOD COMBUSTION PRACTICES.	0.0002 LB/MMBTU	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 1	1717 MMBTU/H	GOOD COMBUSTION PRACTICES	0.0003 LB/MMBTU	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION SECNARIO 3	2204 MMBTU/H	GOOD COMBUSTION PRACTICES.	0.0003 LB/MMBTU	N/A
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, NATURAL GA!	1844.3 MMBTU/H	⊐	0.0006 LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBINED	1844.3 MMBTU/H	LOW SULFUR FUEL (NATURAL GAS	0.0006 LB/MMBTU	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, NATURAL GA!	154 MW		0.0006 LB/MMBTU	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2221 MMBUT/H	LOW SULFUR FUEL	0.0011 LB/MMBTU	BACT-PSD
PA-0188	FAIRLESS ENERGY LLC	03/28/02	TURBINE, COMBINED CYCLE	1190 MW	LOW SULFUR FUEL	0.002 LB/MMBTU	Other Case-by
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	SIEMENS WESTINGHOUSE COMBUSTION TU	1080 MW		0.0021 LB/MMBTU	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	GE COMBUSTION TURBINES AND HEAT REC	1040 MW		0.0021 LB/MMBTU	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STATIOI	12/01/04	COMBUSTION TURBINE GENERATORS AND	180 MW		0.0023 LB/MMBTU	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STATIOI	12/01/04	COMBUSTION TURBINE GENERATORS AND	170 MW		0.0023 LB/MMBTU	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE, NATURAL GA!	1490.5 MMBTU/H	% S BY WT (2 GR/100 ⊐	0.0028 LB/MMBTU	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINES, SIMPLE CYCLE, NATURAL GAS, (·	1490.5 MMBTU/H	0.007 % S BY WT (2 ⊐	0.0028 LB/MMBTU	BACT-PSD
OK-0096	REDBUD POWER PLANT	06/03/03	COMBUSTION TURBINE AND DUCT BURNER	1832 MMBTU/H	VERY LOW SO2 EMISSION RATE-LO	0.003 LB/MMBTU	BACT-PSD
WA-0299	SUMAS ENERGY 2 GENERATION FACILITY	09/06/02	TURBINES, COMBINED CYCLE, (2)	334.5 MW	FUEL SULFUR CONTENT	0.0038 LB/MMBTU	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH DUCT BU	3202 MMBTU/H	NONE LISTED	0.004 LB/MMBTU	Other Case-by
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	ONLY USE NATURAL GAS WITH SU	0.004 LB/MMBTU	Other Case-by
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	TURBINES AND DUCT BURNERS	310 MW TOTAL	LOW SULFUR FUEL (NATURAL GAS	0.0056 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BUI	180 MW	BURNING NATURAL GAS	0.0057 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BUI	180 MW	BURNING NATURAL GAS	0.0057 LB/MMBTU	BACT-PSD
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS	03/21/03	TURBINES, COMBINED CYCLE (2)	1701 MMBTU/H	NATURAL GAS (VERY LOW ⊐	0.006 LB/MMBTU	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 100% LOAI	171 MW	LOW SULFUR FUELS AND GOOD CC	0.006 LB/MMBTU	BACT-PSD
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUSTION T	173 MW	NATURAL GAS ONLY	0.007 LB/MMBTU	BACT-PSD
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H		0.0119 LB/MMBTU	BACT-PSD
LA-0136	PLAQUEMINE COGENERATION FACILITY	07/23/08	(4) GAS TURBINES/DUCT BURNERS	2876 MMBTU/H	MAXIMUM SULFUR CONTENT OF	40.7 LB/H	BACT-PSD

Source: ECT, 2012.

Table D-3. RBLC H_2SO_4 Mist Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 1	1717 MMBTU/H	GOOD COMBUSTION PRACTICES	0.0001 MMBTU	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION SECNARIO 3	2204 MMBTU/H	GOOD COMBUSTION PRACTICES.	0.0001 LB/MMBTU	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 2	1944 MMBTU	GOOD COMBUSTION PRACTICES.	0.0002 LB/MMBTU	N/A
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2221 MMBUT/H	LOWSULFUR FUEL	0.0004 LB/MMBTU	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE (2)	1717 MMBTU/H	MAX. 0.002% BY WT MAX S CONT	0.0005 LB/MMBTU	Other Case-b
WA-0328	BP CHERRY POINT COGENERATION PROJI	01/11/05	GE 7FA COMBUSTION TURBINE & HEAT RECO	174 MW	LIMIT FUEL TYPE TO NATURAL G.	0.0008 LB/MMBTU	BACT-PSD
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUSTION TURBIN	173 MW	NATURAL GAS ONLY	0.0011 LB/MMBTU	BACT-PSD
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	GOOD COMBUSTION PRACTICES.	0.0012 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BURNERS	180 MW		0.0013 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BURNERS	180 MW		0.0013 LB/MMBTU	BACT-PSD

Source: ECT, 2012.

Table D-4. RBLC CO Summary for Large CTGs— Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTION TUI	2.1 MMCF/H	CO CATLYST	0.9 PPMVD @ 15 % O2	BACT-PSD
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 2	1944 MMBTU	CEM SYSTEM. GOOD COMBUSTION I	1.2 PPMVD	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE (2)	1717 MMBTU/H	OXIDATION CATALYST. GOOD COMI	1.3 PPMVD	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 1	1717 MMBTU/H	NG ONLY. GOOD COMBUSTION PRA(	1.3 PPMVD	BACT-PSD
GA-0127	PLANT MCDONOUGH COMBINED CYCLI	01/07/08	COMBINED CYCLE COMBUSTION TURE	254 MW	OXIDATION CATALYST	1.8 PPM @ 15% O2	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE AND DUC	1717 MMBTU/H	OXIDATION CATALYST, AND GOOD (	1.8 PPMVD	Other Case-b
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION SECNARIO 3	2204 MMBTU/H	CEM SYSTEM. GOOD COMBUSTION I	1.8 PPMVD	BACT-PSD
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A'	11/12/03	TURBINE, COMBINED CYCLE	325 MW	CATALYTIC OXIDIZER	2 PPM @ 15% O2	BACT-PSD
CA-1096	VERNON CITY LIGHT & POWER	05/27/03	GAS TURBINE: COMBINED CYCLE < 5	43 MW GAS TU	SCR SYSTEM, AND OXIDATION CATA	2 PPMVD @ 15% O2	BACT-PSD
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	05/27/03	GAS TURBINE: COMBINED CYCLE >=	181 NET MW (G/	SCR SYSTEM AND OXIDATION CATA	2 PPMVD @ 15% O2	BACT-PSD
GA-0102	WANSLEY COMBINED CYCLE ENERGY I	01/15/02	TURBINE, COMBINED CYCLE, (2)	167 MW	GOOD COMBUSTION PRACTICE	2 PPM @ 15% O2	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, NATURA	140 MW	CATALYTIC OXIDATION	2 PPM @ 15% O2	BACT-PSD
GA-0138	LIVE OAKS POWER PLANT	04/08/10	COMBINED CYCLE COMBUSTION TURE	600 MW	GOOD COMBUSTION PRACTICES ANI	2 PPM@15%02	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	COMBUSTION TURBINE, COMBINED CY	2375.28 MMBTU/H	DRY LOW NOX (DLN),□	2 PPMVD	BACT-PSD
MI-0366	BERRIEN ENERGY, LLC	04/13/05	3 COMBUSTION TURBINES AND DUCT I	1584 MMBTU/H	CATALYTIC OXIDATION.	2 PPMDV @ 15% O2	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH DUC	3202 MMBTU/H	CO CATALYST	2 PPMVD @ 15% O2	Other Case-b
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	CO CATALYST	2 PPMVD @ 15% O2	Other Case-b
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2221 MMBUT/H	OXIDATION CATALYST	2 PPMVD@15%02	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUC	180 MW	(GCP) AND OXIDATION □	2 PPM @ 15% O2	BACT-PSD
OR-0039	COB ENERGY FACILITY, LLC	12/30/03	TURBINE, COMBINED CYCLE, DUCT BU	1150 MW	CATALYTIC OXIDATION	2 PPMVD @ 15% O2	BACT-PSD
OR-0041	WANAPA ENERGY CENTER	08/08/05	COMBUSTION TURBINE & HEAT RI	2384.1 MMBTU/H	OXIDATION CATALYST.	2 PPMDV @ 15% O2	BACT-PSD
TX-0546	PATTILLO BRANCH POWER PLANT	06/17/09	ELECTRICITY GENERATION	350 MW	OXIDATION CATALYST	2 PPMVD	BACT-PSD
TX-0590	KING POWER STATION	08/05/10	Turbine	1350 MW	good combustion practices with an oxidati	2 PPMVD AT 15% O2	BACT-PSD
WA-0291	WALLULA POWER PLANT	01/03/03	TURBINE, COMBINED CYCLE, NATURA	1300 MW	OXIDATION CATALYST	2 PPMDV @ 15% 02	Other Case-b
WA-0299	SUMAS ENERGY 2 GENERATION FACILI	09/06/02	TURBINES, COMBINED CYCLE, (2)	334.5 MW	COMBUSTION CATALYSIS	2 PPM @ 15% O2	BACT-PSD
WA-0315	SUMAS ENERGY 2 GENERATION FACILI	04/17/03	TURBINES, COMBINED CYCLE, (2)	660 MW	OXIDATION CATALYST	2 PPMVD	BACT-PSD
WA-0328	BP CHERRY POINT COGENERATION PRO	01/11/05	GE 7FA COMBUSTION TURBINE & I	174 MW	LEAN PRE-MIX CT BURNER & OXIDA	2 PPMDV	BACT-PSD
AZ-0039	SALT RIVER PROJECT/SANTAN GEN. PL.	03/07/03	TURBINE, COMBINED CYCLE, DUCT BU	175 MW	CATALYTIC OXIDIZER	3 PPM @ 15% O2	LAER
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A'	11/12/03	TURBINE, COMBINED CYCLE & DU	325 MW	CATALYTIC OXIDIZER	3 PPM @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STA'	12/01/04	COMBUSTION TURBINE GENERATORS .	180 MW	OXIDATION CATALYST	3 PPM @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STA'	12/01/04	COMBUSTION TURBINE GENERATORS .	170 MW	OXIDATION CATALYST	3 PPM @ 15% O2	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	GE COMBUSTION TURBINES AND HEAT	1040 MW	OXIDATION CATALYST	3 PPMVD	BACT-PSD
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, L	05/02/06	NATURAL-GAS FIRED, COMBINED-CYC	300 MW	USE GOOD COMBUSTION CONTROL I	3 PPM @ 15% O2	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATIN	08/16/11	COMBINED CYCLE TURBINE GENERAT	7146 MMBTU/H	OXIDATION CATALYST AND GOOD C	3 PPMVD @ 15% O2	BACT-PSD
NV-0037	COPPER MOUNTAIN POWER	05/14/04	LARGE COMBUSTION TURBINES, COMI	600 MW	GOOD COMBUSTOR DESIGN AND AN	3 PPMVD	LAER
PA-0188	FAIRLESS ENERGY LLC	03/28/02	TURBINE, COMBINED CYCLE	1190 MW	OXIDATION CATALYST	3 PPMVD @ 15% O2	BACT-PSD
UT-0066	CURRANT CREEK	05/17/04	NATURAL GAS FIRED TURBINES AND H		OXIDATINO CATALYST FOR COMBIN	3 PPMVD	BACT-PSD
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	GOOD COMBUSTION PRACTICES.	3.1 PPM @ 15% O2	BACT-PSD
NV-0033	EL DORADO ENERGY, LLC	08/19/04	COMBUSTION TURBINE, COMBINED C'	475 MW	OXIDATION CATALYST	2.6 PPM @ 15% O2	LAER
NV-0035	TRACY SUBSTATION EXPANSION PROJE	08/16/05	TURBINE, COMBINED CYCLE COMBUST	306 MW	OXIDATION CATALYST SYSTEM	3.5 PPM @ 15% O2	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJE	08/16/05	TURBINE, COMBINED CYCLE COMBUST	306 MW	OXIDATION CATALYST	3.5 PPM @ 15% O2	BACT-PSD
MI-0365	MIRANT WYANDOTTE LLC	01/28/03	TURBINE, COMBINED CYCLE, (2)	2200 MMBTU/H	CATALYTIC OXIDATION SYSTEM.	3.8 PPM	BACT-PSD
AZ-0038	GILA BEND POWER GENERATING STATI	05/15/02	TURBINE, COMBINED CYCLE, DUCT BU	170 MW	OXIDATION CATALYST	4 PPM @ 15% O2	BACT-PSD
CA-0997	SACRAMENTO MUNICIPAL UTILITY DIS	09/01/03	GAS TURBINES, (2)	1611 MMBTU/H	GOOD COMBUSTION CONTROL	4 PPM @ 15% O2	LAER
CA-1143	SUTTER POWER PLANT	08/16/04	2 COMBUSTION TURBINES	170 MW	OXIDATION CATALYST SYSEM	4 PPMVD	BACT-PSD
CA-1144	BLYTHE ENERGY PROJECT II	04/25/07	2 COMBUSTION TURBINES	170 MW		4 PPMVD	BACT-PSD

Table D-4. RBLC CO Summary for Large CTGs— Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
LA-0192	CRESCENT CITY POWER	06/06/05	GAS TURBINES - 187 MW (2)	2006 MMBTU/H	CO OXIDATION CATALYST AND GOO	4 PPM @ 15%O2	BACT-PSD
MI-0361	SOUTH SHORE POWER LLC	01/30/03	TURBINE, COMBINED CYCLE, (2)	172 MW	OF GOOD COMBUSTION □	4 PPMVD @ 15% O2	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE, 2 EACI	1916 MMBTU/H	OXIDATION CATALYST AND GOOD C	4 PPMVD 15% 02	BACT-PSD
NV-0038	IVANPAH ENERGY CENTER, L.P.	12/29/03	LARGE COMBUSTION TURBINES, COMI	500 MW	GOOD COMBUSTION CONTROL AND	4 PPMVD	LAER
TX-0600	THOMAS C. FERGUSON POWER PLANT	09/01/11	Natural gas-fired turbines	390 MW	Good combustion practices and oxidation c	4 PPMVD	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE 2 EACH	1827 MMBTU/H	OXIDATION CATALYST AND GOOD C	4.8 PPMVD @15% 02	BACT-PSD
OR-0035	PORT WESTWARD PLANT	01/16/02	(2) COMBUSTION TURBINES, WITH DUC	325 MW, EACH	CO CATALYST AND GOOD COMBUST	4.9 PPM @ 15% O2	BACT-PSD
MI-0357	KALKASKA GENERATING, INC	02/04/03	TURBINE, COMBINED CYCLE, (2)	605 MW	OXIDATION CATALYST.	5 PPMVD @15% O2	BACT-PSD
OR-0040	KLAMATH GENERATION, LLC	03/12/03	TURBINE, COMBINED CYCLE, DUCT BU	480 MW	CATALYTIC OXIDATION	5 PPMVD @ 15% O2	BACT-PSD
PA-0223	DUKE ENERGY FAYETTE, LLC	01/30/02	TURBINE, COMBINED CYCLE, (2)	280 MW	OXIDATION CATALYST	5 PPMVD @ 15% O2	BACT-PSD
MT-0019	CONTINENTAL ENERGY SERVICES, INC.	06/07/02	TURBINE, COMBINED CYCLE 2	500 MW		5.27 PPM @ 15% O2	Other Case-b
MT-0019	CONTINENTAL ENERGY SERVICES, INC.	06/07/02	TURBINE, COMBINED CYCLE 1	500 MW		5.27 PPM @ 15% O2	Other Case-b
IA-0058	GREATER DES MOINES ENERGY CENTE	04/10/02	COMBUSTION TURBINES - COMBINED (	350 MW	CATALYTIC OXIDATION	5.4 PPM @ 15% O2	Other Case-b
CA-1142	PASTORIA ENERGY FACILITY	12/23/04	3 COMBUSTION TURBINES	168 MW	XONON CATALYTIC COMBUSTORS O	6 PPMVD	BACT-PSD
FL-0303	FPL WEST COUNTY ENERGY CENTER UI	07/30/08	THREE NOMINAL 250 MW CTG (EACH) \	2333 MMBTU/H	GOOD COMBUSTION	6 PPMVD (GAS)	BACT-PSD
FL-0304	CANE ISLAND POWER PARK	09/08/08	300 MW COMBINED CYCLE COMBUSTI(	1860 MMBTU/H	GOOD COMBUSTION PRACTICES	6 PPMVD	BACT-PSD
OH-0252	DUKE ENERGY HANGING ROCK ENERG'	12/28/04	TURBINES (4) (MODEL GE 7FA), DUCT B	172 MW		6 PPM @ 15% O2	BACT-PSD
PA-0189	CONECTIV BETHLEHEM, INC.	01/16/02	TURBINE, COMBINED CYCLE, (6)	122 MW	BACT FOR CO IS GOOD COMBUSTION	6 PPM @ 15% O2	BACT-PSD
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, COMBINED CYCLE, NATURA	170 MW	GOOD COMBUSTION DESIGN AND PR	10 PPMVD @ 15% O2	BACT-PSD
FL-0263	FPL TURKEY POINT POWER PLANT	02/08/05	170 MW COMBUSTION TURBINE, 4 UNI	170 MW	CO WILL BE MINIMIZED BY THE EFFI	8 PPMVD @ 15 % O2	BACT-PSD
FL-0247	TECO BAYSIDE POWER STATION	01/08/02	TURBINE, COMBINED CYCLE, (11)	170 MW	GOOD COMBUSTION DESIGN AND OI	7.8 PPMVD AT 15%O2	BACT-PSD
FL-0241	CPV CANA	01/17/02	TURBINE, COMBINED CYCLE, NATURA	1680 MMBTU/H	COMBUSTION CONTROLS	8 PPMVD @ 15% O2	BACT-PSD
FL-0265	HINES POWER BLOCK 4	06/08/05	COMBINED CYCLE TURBINE	530 MW	GOOD COMBUSTION	8 PPM	BACT-PSD
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	COMBINED CYCLE COMBUSTION TURE	1972 MMBTU/H	GOOD COMBUSTION	8 PPMVD	BACT-PSD
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	COMBINED CYCLE COMBUSTION GAS	2333 MMBTU/H		8 PPMVD @15%O2	BACT-PSD
MI-0363	BLUEWATER ENERGY CENTER LLC	01/07/03	TURBINE, COMBINED CYCLE, (3)	180 MW	CATALYTIC AFTERBURNER	8 PPM @ 15% O2	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERATION &	1882 MMBTU/H	GOOD COMBUSTION	8 PPMV	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 70% L	171 MW	GOOD COMBUSTION AND DESIGN. C	8 PPM @ 15% O2	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 100%	171 MW	CLEAN FUEL. GOOD COMBUSTION A	8 PPM @ 15% O2	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (GE)	170 MW	GOOD COMBUSTION PRACTICE	8.2 PPMVD @ 15% O2	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	GE COMBUSTION TURBINE & DUC	1705 MMBTU/H	COMBUSTION CONTROL	8.2 PPM @ 15% O2	BACT-PSD
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, L	08/11/02	TWO (2) NATURAL GAS FIRED, COMBIN	2311 MMBTU/H	PRACTICES (PREVENTION) □	9 PPMVD	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE, NATURA	1490.5 MMBTU/H	GOOD COMBUSTION PRACTICES, NA	9 PPMVD @ 15% O2	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, NATURA	154 MW	COMBUSTION CONTROL	9 PPMVD	BACT-PSD
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, NATUR	1715 MMBTU/H	GOOD COMBUSTION PRACTICES ANI	9 PPMVD	BACT-PSD
OH-0252	DUKE ENERGY HANGING ROCK ENERG'	12/28/04	TURBINES (4) (MODEL GE 7FA), DUCT B	172 MW		9 PPM @ 15% O2	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, NATURAL GAS, NO DUCT BU	1937 MMBTU/H		9 PPM @ 15% O2	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURA	1973 MMBTU/H	GOOD COMBUSTION PRACTICES	9 PPM	BACT-PSD
VA-0289	DUKE ENERGY WYTHE, LLC	02/05/04	TURBINE, COMBINED CYCLE, NATURA	170 MW	GOOD COMBUSTION PRACTICES.	9 PPMVD	BACT-PSD
AR-0052	THOMAS B. FITZHUGH GENERATING ST.	02/15/02	TURBINE, COMBINED CYCLE, NATURA	170.6 MW	GOOD COMBUSTION PRACTICES. DR	10 PPM @ 15% O2	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYLE, NATURAL	170 MW	GOOD COMBUSTION DESIGN AND PR	10 PPMVD @ 15% O2	BACT-PSD
FL-0256	HINES ENERGY COMPLEX, POWER BLO(	09/08/03	COMBUSTION TURBINES, COMBINED C	1830 MMBTU/H	COMBUSTION DESIGN, GOOD COMBI	10 PPMVD @15% O2	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/08	TWO COMBINED CYCLE GAS TURBINE!	2110 MMBTU/H	PROPER OPERATING PRACTICES	10 PPMVD@15%O2	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, NATURA	1876 MMBTU/H	GOOD COMBUSTION PRACTICES.	10 PPMVD @ 15% O2	BACT-PSD
MN-0066	NORTHERN STATES POWER CO. DBA X(	05/16/06	TURBINE, COMBINED CYCLE (2)	1885 mmbtu/h	GOOD COMBUSTION PRACTICES	10 PPMVD @ 15% O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	GOOD COMBUSTION PRACTICES	10 PPMVD	BACT-PSD

Table D-4. RBLC CO Summary for Large CTGs— Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
NM-0044	CLOVIS ENERGY FACILITY	06/27/02	TURBINES, COMBINED CYCLE, NATUR/	1515 MMBTU/H	FACILITY WILL ONLY □	10 PPM @ 15% O2	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUC'	180 MW	(GCP) AND OXIDATION □	10 PPM @ 15% O2	BACT-PSD
OH-0254	DUKE ENERGY WASHINGTON COUNTY	08/14/03	TURBINES (2) (MODEL GE 7FA), DUCT B	170 MW		10 PPM @ 15% O2	BACT-PSD
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHE	03/21/03	TURBINES, COMBINED CYCLE (2)	1701 MMBTU/H	COMBUSTION CONTROL	10 PPM @ 15% O2	BACT-PSD
PA-0226	LIMERICK POWER STATION	04/09/02	TURBINE, COMBINED CYCLE	550 MW		10 PPM @ 15% O2	BACT-PSD
TX-0234	EDINBURG ENERGY LIMITED PARTNER:	01/08/02	(4) COMBINED CYCLE GAS TURBINE, A]	180 MW	10 PPMVD WHEN □	10 PPM @15%O2	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (MHI)	170 MW	GOOD COMBUSTION PRACTICE/CO O	10.2 PPMVD @ 15% O2	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	MHI COMBUSTION TURBINE & DU(	1767 MMBTU/H	CATALYTIC OXIDATION	10.2 PPM @ 15% O2	BACT-PSD
VA-0262	MIRANT AIRSIDE INDUSTRIAL PARK	12/06/02	TURBINE, COMBINED CYCLE, (2)	170 MW	GOOD COMBUSTION PRACTICES.	10.3 PPMVD @ 15% O2	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	COMBINED CYCLE COMBUSTION TURE	1758 MMBTU/H	GOOD COMBUSTION	9 PPMVD	BACT-PSD
OH-0264	NORTON ENERGY STORAGE, LLC	05/23/02	COMBUSTION TURBINE (9), COMB CYC	300 MW	CONSIDERED COST □	11 PPM @ 15% O2	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, NATURA	1844.3 MMBTU/H	AND □	11.6 PPM @ 15% O2	BACT-PSD
GA-0101	MURRAY ENERGY FACILITY	10/23/02	TURBINE, COMBINED CYCLE, (4)	173 MW	GOOD COMBUSTION PRACTICE	12 PPM @ 15% O2	BACT-PSD
MI-0362	MIDLAND COGENERATION (MCV)	04/21/03	TURBINE, COMBINED CYCLE, (11)	984 MMBTU/H	RETROFIT COSTS TO ADD □	12 PPM @ 15% O2	BACT-PSD
MI-0362	MIDLAND COGENERATION (MCV)	04/21/03	TURBINE, COMBINED CYCLE, (1)	984 MMBTU/H	ADDITIONAL ADD ON □	12 PPM @ 15% O2	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURA	1973 MMBTU/H	GOOD COMBUSTION PRACTICES	12 PPM	BACT-PSD
FL-0239	JEA/BRANDY BRANCH	03/27/02	TURBINES, COMBINED CYCLE, (2)	1911 MMBTU/H	GOOD COMBUSTION	12.21 PPMVD	BACT-PSD
MS-0055	EL PASO MERCHANT ENERGY CO.	06/24/02	TURBINE, COMBINED CYCLE, DUCT BU	1737 MMBTU/H	GOOD COMBUSTION PRACTICE	13.8 PPMV @ 15% O2	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE AND DUC	1490.5 MMBTU/H	GOOD COMBUSTION PRACTICE, NAT	14 PPMVD @ 15% O2	BACT-PSD
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, DUCT B	1715 MMBTU/H	GOOD COMBUSTION PRACTICE AND	14 PPMVD	BACT-PSD
OH-0254	DUKE ENERGY WASHINGTON COUNTY	08/14/03	TURBINES (2) (MODEL GE 7FA), DUCT B	170 MW		14 PPM @ 15% O2	BACT-PSD
VA-0289	DUKE ENERGY WYTHE, LLC	02/05/04	TURBINE, COMBINED CYCLE, DUCT BU	170 MW	GOOD COMBUSTION PRACTICES	14.6 PPMVD	BACT-PSD
TX-0437	HARTBURG POWER, LP	07/05/02	TURBINE, COMBINED CYCLE & DU	277 mw	GOOD COMBUSTION PRACTICES, DE!	15 PPM	BACT-PSD
TX-0547	NATURAL GAS-FIRED POWER GENERAT	06/22/09	ELECTRICITY GENERATION	250 MW	GOOD COMBUSTION PRATICES	15 PPMVD	BACT-PSD
OK-0115	LAWTON ENERGY COGEN FACILITY	12/12/06	COMBUSTION TURBINE AND DUCT BURNER		GOOD COMBUSTION PRACTICES	16.38 PPMVD	BACT-PSD
OH-0264	NORTON ENERGY STORAGE, LLC	05/23/02	COMBUSTION TURBINES (9), COMB CY(	300 MW	CONSIDERED COST □	17 PPM @ 15% O2	BACT-PSD
TX-0352	BRAZOS VALLEY ELECTRIC GENERATII	12/31/02	(2) HRSG/TURBINES, HRSG-003 & -0(	175 MW	GOOD COMBUSTION CONTROLS	17 PPM @ 15% O2	BACT-PSD
TX-0352	BRAZOS VALLEY ELECTRIC GENERATII	12/31/02	(2) HRSG/TURBINES, HRSG-001 & -0(	175 MW, EA	GOOD COMBUSTION CONTROLS	17 PPM @ 15% O2	BACT-PSD
OK-0096	REDBUD POWER PLANT	06/03/03	COMBUSTION TURBINE AND DUCT BUI	1832 MMBTU/H	GOOD COMBUSTION PRACTICES/DES	17.2 PPMVD	BACT-PSD
TX-0388	SAND HILL ENERGY CENTER	02/12/02	COMBINED CYCLE GAS TURBINE	164 MW		17.5 PPM @ 15% O2	Other Case-b
TX-0548	MADISON BELL ENERGY CENTER	08/18/09	ELECTRICITY GENERATION	275 MW	GOOD COMBUSTION PRACTICES	17.5 PPMVD	BACT-PSD
MN-0060	HIGH BRIDGE GENERATING PLANT	08/12/05	2 COMBINED-CYCLE COMBUSTION TUI	330 MEGAWATT	GOOD COMBUSTION PRACTICES	10 PPM @ 15% O2	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY,	11/23/04	EMISSION POINT AA-001 GEN. ELEC. CC	230 MW	SCR	18.36 PPMV @ 1'5% 02	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY,	11/23/04	EMISSION POINT AA-002 GEN ELEC. CO	230 MW		18.36 PPMV @ 15% 02	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY,	11/23/04	EMISSION POINT AA-003 GEN. ELEC CO	230 MW	SCR	18.36 PPMV @ 15 02	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE, NATURA	1937 MMBTU/H		19.3 PPM @ 15% O2	BACT-PSD
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUSTI	173 MW	GOOD COMBUSTION PRACTICES	20 PPM @ 15% O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE, DUC	175 MW	GOOD COMBUSTION PRACTICES	20 PPMVD	BACT-PSD
TX-0350	ENNIS TRACTEBEL POWER	01/31/02	COMBUSTION TURBINE W/HEAT RECO'	350 MW	NONE INDICATED	20 PPM @ 15% O2	Other Case-b
TX-0407	STERNE ELECTRIC GENERATING FACILI	12/06/02	TURBINES, COMBINED CYCLE, AND DU	190 MW	GOOD COMBUSTION PRACTICES.	20.2 PPMVD @ 15% O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	GOOD COMBUSTION PRACTICES	20.6 PPMVD	BACT-PSD
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE, (3), NAT	61200 MMSCF/YR	BEST COMBUSTION CONTROL PRAC	21 PPMVD	BACT-PSD
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	TURBINES, COMBINED CYCLE, NATUR/	170 MW	GOOD OPERATING PRACTICE	23.6 PPM @ 15% O2	BACT-PSD
TX-0374	CHOCOLATE BAYOU PLANT	03/24/03	(2) COGENERATION TRAINS 2 & 3, (	70 MW, TOTAL	GOOD COMBUSTION PRACTICES	24.4 PPM @ 15% O2S	BACT-PSD
LA-0120	GEISMAR PLANT	02/26/02	(2) COGENERATION UNITS POINT # 720-	40 MW EACH	WITH NATURAL GAS AS □	24.8 PPM @ 15% O2	BACT-PSD
LA-0136	PLAQUEMINE COGENERATION FACILIT'	07/23/08	(4) GAS TURBINES/DUCT BURNERS	2876 MMBTU/H	GOOD COMBUSTION PRACTICES	25 PPMVD @ 15% O2	BACT-PSD

Table D-4. RBLC CO Summary for Large CTGs— Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
LA-0157	PERRYVILLE POWER STATION	03/08/02	TURBINES, COMBINED CYCLE, GAS, (2)	170 MW	OF CLEAN BURNING □	25 PPM @ 15 % O2	BACT-PSD
LA-0164	ACADIA POWER STATION, ACADIA POW	01/31/02	GAS TURBINE UNITS 1, 2, 3, 4	183 MW EACH	AND MAINTENANCE □	25 PPM @ 15% O2	BACT-PSD
OH-0268	LIMA ENERGY COMPANY	03/26/02	COMBUSTION TURBINE (2), COMBINED	170 MW	CATALYTIC OXIDATION PROVED NO	25 PPM @ 15% O2	BACT-PSD
OK-0117	PSO SOUTHWESTERN POWER PLT	02/09/07	GAS-FIRED TURBINES		COMBUSTION CONTROL	25 PPMVD	BACT-PSD
TX-0351	WEATHERFORD ELECTRIC GENERATIOI	03/11/02	(2) GE7121EA GAS TURBINES, S-3&4	1079 MMBTU/H	NONE INDICATED	25 PPM @ 15% O2	Other Case-b
TX-0391	OXY COGENERATION FACILITY	12/20/02	COMBINED-CYCLE GAS TURBINES (2)	87 MW (EACH)	GOOD COMBUSTION PRACTICES	25 PPM @ 15% O2	BACT-PSD
TX-0391	OXY COGENERATION FACILITY	12/20/02	HRSG UNITS 1 & 2 (2)	255 MMBTU/H	GOOD COMBUSTION PRACTICES.	25 PPM @ 15% O2	BACT-PSD
TX-0411	AMELIA ENERGY CENTER	03/26/02	TURBINE, COMBINED CYCLE, & DU	180 MW	GOOD COMBUSTION PRACTICE	25 PPM @ 15% O2	BACT-PSD
TX-0428	HOUSTON OPERATIONS -- BATTLEGROU	12/19/02	TURBINE, COMBINED CYCLE & DU	87 mw	GOOD COMBUSTION PRACTICES	25 PPMVD @ 15% O2	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBI	1844.3 MMBTU/H	AND EFFICIENT PROCESS □	25.9 PPM @ 15% O2	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/ DUCT	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	28.3 PPM @ 15% O2	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/O DUC	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	28.3 PPM @ 15% O2	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (SWH	170 MW	GOOD COMBUSTION PRACTICE	30 PPMVD @ 15% O2	BACT-PSD
WY-0061	BLACK HILLS CORP./NEIL SIMPSON TWC	04/04/03	TURBINE, COMBINED CYCLE, & DU	40 MW	GOOD COMBUSTION PRACTICE	37.2 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-001 W/DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	40 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-002 W /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	40 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-003 /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	40 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-004 W/ DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	40 PPMV @ 15% O2	BACT-PSD
OK-0055	MUSTANG ENERGY PROJECT	02/12/02	COMBUSTION TURBINES W/DUCT BURI	0	COMBUSTION CONTROLS	40 PPM @ 15% 02	BACT-PSD
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	TURBINES AND DUCT BURNERS	310 MW TOTAL	GOOD COMBUSTION CONTROL	40 PPM @ 15% 02	BACT-PSD
LA-0194	SABINE PASS LNG TERMINAL	11/24/04	30 MW GAS TURBINE GNERATORS (4) L	30 mw each	GOOD COMBUSTION PRACTICES	80 PPMVD @ 15% O2	BACT-PSD

Source: ECT, 2012.

Table D-5. RBLC CO Summary for Large CTGs—Natural Gas-Fired Without Oxidatation Catalyst

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
GA-0102	WANSLEY COMBINED CYCLE ENERGY FAC	01/15/02	TURBINE, COMBINED CYCLE, (:	167 MW	GOOD COMBUSTION PRACTICE	BACT-PSD	2 PPM @ 15% O2
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (:	2132 MMBTU/H	GOOD COMBUSTION PRACTICES.	BACT-PSD	3.1 PPM @ 15% O2
CA-0997	SACRAMENTO MUNICIPAL UTILITY DISTRI(	09/01/03	GAS TURBINES, (2)	1611 MMBTU/H	GOOD COMBUSTION CONTROL	LAER	4 PPM @ 15% O2
CA-1144	BLYTHE ENERGY PROJECT II	04/25/07	2 COMBUSTION TURBINES	170 MW		BACT-PSD	4 PPMVD
MT-0019	CONTINENTAL ENERGY SERVICES, INC., SII	06/07/02	TURBINE, COMBINED CYCLE 1	500 MW		Other Case-	5.27 PPM @ 15% O2
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT	07/30/08	THREE NOMINAL 250 MW CTG (	2333 MMBTU/H	GOOD COMBUSTION	BACT-PSD	6 PPMVD (GAS)
FL-0304	CANE ISLAND POWER PARK	09/08/08	300 MW COMBINED CYCLE COI	1860 MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	6 PPMVD
OH-0252	DUKE ENERGY HANGING ROCK ENERGY F/	12/28/04	TURBINES (4) (MODEL GE 7FA),	172 MW		BACT-PSD	6 PPM @ 15% O2
PA-0189	CONECTIV BETHLEHEM, INC.	01/16/02	TURBINE, COMBINED CYCLE, ((	122 MW	BACT FOR CO IS GOOD COMBUSTION PRACT	BACT-PSD	6 PPM @ 15% O2
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, COMBINED CYCLE, N	170 MW	GOOD COMBUSTION DESIGN AND PRACTICI	BACT-PSD	7.4 PPM @ 15% O2
FL-0263	FPL TURKEY POINT POWER PLANT	02/08/05	170 MW COMBUSTION TURBINI	170 MW	CO WILL BE MINIMIZED BY THE EFFICIENT (	BACT-PSD	7.6 PPM @ 15 % O2
FL-0247	TECO BAYSIDE POWER STATION	01/08/02	TURBINE, COMBINED CYCLE, (	170 MW	GOOD COMBUSTION DESIGN AND OPERATII	BACT-PSD	7.8 PPM @ 15% O2
FL-0241	CPV CANA	01/17/02	TURBINE, COMBINED CYCLE, N	1680 MMBTU/H	COMBUSTION CONTROLS	BACT-PSD	8 PPM @ 15% O2
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, SIMPLE CYCLE, NATI	170 MW	GOOD COMBUSTION DESIGN AND PRACTICI	BACT-PSD	8 PPM @ 15% O2
FL-0265	HINES POWER BLOCK 4	06/08/05	COMBINED CYCLE TURBINE	530 MW	GOOD COMBUSTION	BACT-PSD	8 PPM @ 15% O2
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	COMBINED CYCLE COMBUSTIC	1972 MMBTU/H	GOOD COMBUSTION	BACT-PSD	8 PPMVD
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	COMBINED CYCLE COMBUSTIC	2333 MMBTU/H		BACT-PSD	8 PPMVD @15%O2
MI-0363	BLUEWATER ENERGY CENTER LLC	01/07/03	TURBINE, COMBINED CYCLE, (:	180 MW	CATALYTIC AFTERBURNER	BACT-PSD	8 PPM @ 15% O2
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERA'	1882 MMBTU/H	GOOD COMBUSTION	BACT-PSD	8 PPMV
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, ((	171 MW	GOOD COMBUSTION AND DESIGN. CLEAN F	BACT-PSD	8 PPM @ 15% O2

Source: ECT, 2012.

Table D-6. RBLC VOC Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control Method Description	Emissions Limit	Basis
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERATION >2:	1882 MMBTU/H	GOOD COMBUSTION	0.3 PPM	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE (2)	1717 MMBTU/H	OXIDATION CATALYST AND GOOD C(	0.7 PPMVD	Other Case-'
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 1	1717 MMBTU/H	GOOD COMBUSTION PRACTICES AND	0.7 PPMVD	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 2	1944 MMBTU	GOOD COMBUSTION PRACTICES AND	0.7 PPMVD	N/A
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION SECNARIO 3	2204 MMBTU/H	GOOD COMBUSTION PRACTICES AND	0.7 PPMVD	N/A
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AV	11/12/03	TURBINE, COMBINED CYCLE	325 MW		1 PPM	BACT-PSD
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	01/07/08	COMBINED CYCLE COMBUSTION TURBINI	254 MW	OXIDATION CATALYST	1 PPM @ 15% O2	LAER
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, NATURAL G.	1876 MMBTU/H	GOOD COMBUSTION PRACTICES.	1 PPMVD @ 15% O2	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE 2 EACH	1827 MMBTU/H	OXIDATION CATALYST AND GOOD C(	1 PPMVD @ 15% O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	GOOD COMBUSTION PRACTICES	1 PPMVD	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	CO CATALYST	1 PPMVD @ 15% O2	Other Case-'
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (NATURAL GAS)	2099 MMBTU/H	OXIDATION CATALYST	1 PPMVD AT 15% O2	LAER
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE AND DUCT B	1717 MMBTU/H	OXIDATION CATALYST AND GOOD C(	1 PPMVD	Other Case-'
LA-0192	CRESCENT CITY POWER	06/06/05	GAS TURBINES - 187 MW (2)	2006 MMBTU/H	CO OXIDATION CATALYST AND GOOI	1.1 PPM @ 15% O2	BACT-PSD
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	COMBINED CYCLE COMBUSTION TURBINI	1972 MMBTU/H	GOOD COMBUSTION	1.2 PPMVD	BACT-PSD
FL-0303	FPL WEST COUNTY ENERGY CENTER UN	07/30/08	THREE NOMINAL 250 MW CTG (EACH) WIT	2333 MMBTU/H		1.2 PPMVD	BACT-PSD
PA-0189	CONECTIV BETHLEHEM, INC.	01/16/02	TURBINE, COMBINED CYCLE, (6)	122 MW		1.2 PPMVD@15% O2	Other Case-'
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, NATURAL GAS, NO DUCT BURNI	1937 MMBTU/H	PRACTICES FOR □	1.2 PPMVD @ 15% O2	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYLE, NATURAL GA	170 MW	GOOD COMBUSTION PRACTICES	1.3 PPMVD 15% O2	BACT-PSD
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, COMBINED CYCLE, NATURAL G.	170 MW	GOOD COMBUSTION PRACTICE	1.3 PPMVD @ 15% O2	Other Case-'
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, SIMPLE CYCLE, NATURAL GAS, (	170 MW	GOOD COMBUSTION	1.3 PPMVD @ 15% O2	BACT-PSD
FL-0263	FPL TURKEY POINT POWER PLANT	02/08/05	170 MW COMBUSTION TURBINE, 4 UNITS	170 MW	VOC EMISSIONS WILL BE MINIMIZED	1.3 PPMVD @ 15 % O2	
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE	175 MW	GOOD COMBUSTION PRACTICES	1.3 PPM @ 15% O2	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (GE)	170 MW	GOOD COMBUSTION PRACTICE	1.4 PPMVD @ 15% O2	BACT-PSD
AZ-0038	GILA BEND POWER GENERATING STATI(	05/15/02	TURBINE, COMBINED CYCLE, DUCT BURN	170 MW	OXIDATION CATALYST AND GOOD C(	1.4 PPM @ 15% O2	BACT-PSD
CA-0997	SACRAMENTO MUNICIPAL UTILITY DIST	09/01/03	GAS TURBINES, (2)	1611 MMBTU/H		1.4 PPM @ 15% O2	LAER
LA-0157	PERRYVILLE POWER STATION	03/08/02	TURBINES, COMBINED CYCLE, GAS, (2) EP:	170 MW	AND USE OF NATURAL GAS □	1.4 PPMV @ 15% O2	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATIN(	08/16/11	COMBINED CYCLE TURBINE GENERATOR:	7146 MMBTU/H	GOOD COMBUSTION PRACTICES	1.4 PPMVD @ 15% O2	BACT-PSD
NM-0044	CLOVIS ENERGY FACILITY	06/27/02	TURBINES, COMBINED CYCLE, NATURAL (	1515 MMBTU/H	PIPELINE QUALITY □	1.4 PPMV WET	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	GE COMBUSTION TURBINE & DUCT BI	1705 MMBTU/H	GOOD COMBUSTION PRACTICES AND	1.4 PPM @ 15% O2	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURAL G.	1973 MMBTU/H	GOOD COMBUSTION/DESIGN AND CLI	1.4 PPM	BACT-PSD
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	COMBINED CYCLE COMBUSTION GAS TUF	2333 MMBTU/H		1.5 PPMVD @ 15 % O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-001 W/DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	1.5 PPMVD	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH DUCT E	3202 MMBTU/H	CO CATALYST	1.7 PPMVD @ 15% O2	Other Case-'
TX-0590	KING POWER STATION	08/05/10	Turbine	1350 MW	DLN burners in combination with an oxidat	1.8 PPMVD AT 15% O2	LAER
CA-1096	VERNON CITY LIGHT & POWER	05/27/03	GAS TURBINE: COMBINED CYCLE < 50 M	43 MW GAS TI	SCR SYSTEM, AND OXIDATION CATAI	2 PPMVD @ 15% O2	BACT-PSD
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	05/27/03	GAS TURBINE: COMBINED CYCLE >= 50	181 NET MW (G	SCR SYSTEM AND OXIDATION CATAL	2 PPMVD @ 15% O2	BACT-PSD
CA-1177	OTAY MESA ENERGY CENTER LLC	07/22/09	Gas turbine combined cycle	171.7 MW		2 PPMVD@15% OXY(	OTHER CA
CA-1178	APPLIED ENERGY LLC	03/20/09	Gas turbine combined cycle	0	Oxidation catalyst	2 PPM	BACT-PSD
FL-0256	HINES ENERGY COMPLEX, POWER BLOC	09/08/03	COMBUSTION TURBINES, COMBINED CYC	1830 MMBTU/H	COMBUSTION DESIGN, GOOD COMBU	2 PPMVD % 15 O2	BACT-PSD
GA-0102	WANSLEY COMBINED CYCLE ENERGY F.	01/15/02	TURBINE, COMBINED CYCLE, (2)	167 MW	GOOD COMBUSTION PRACTICE	2 PPM @ 15% O2	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, NATURAL G.	140 MW	CATALYTIC OXIDATION	2 PPM @ 15% O2	BACT-PSD
GA-0138	LIVE OAKS POWER PLANT	04/08/10	COMBINED CYCLE COMBUSTION TURBINI	600 MW	GOOD COMBUSTION PRACTICES, CAT	2 PPM@15%02	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	COMBUSTION TURBINE, COMBINED CYCL	2375.28 MMBTU/H	DRY LOW NOX (DLN),□	2 PPMVD	BACT-PSD
MN-0066	NORTHERN STATES POWER CO. DBA XC:	05/16/06	TURBINE, COMBINED CYCLE (2)	1885 mmbtu/h	GOOD COMBUSTION PRACTICES	2 PPM @ 15% O2	BACT-PSD
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, NATURAL (	1715 MMBTU/H	GOOD COMBUSTION PRACTICES AND	2 PPMVW	BACT-PSD

Table D-6. RBLC VOC Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control Method Description	Emissions Limit	Basis
TX-0546	PATTILLO BRANCH POWER PLANT	06/17/09	ELECTRICITY GENERATION	350 MW	OXIDATION CATALYST	2 PPMVD	BACT-PSD
TX-0600	THOMAS C. FERGUSON POWER PLANT	09/01/11	Natural gas-fired turbines	390 MW	Natural gas, good combustion practices and	2 PPMVD	BACT-PSD
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	GOOD COMBUSTION PRACTICES.	2 PPMVD @ 15% O2	BACT-PSD
NV-0038	IVANPAH ENERGY CENTER, L.P.	12/29/03	LARGE COMBUSTION TURBINES, COMBINI	500 MW	GOOD COMBUSTION CONTROL AND (	2.3 PPMVD	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE, NATURAL G.	1937 MMBTU/H	PRACTICES FOR □	2.3 PPMVD @ 15% O2	BACT-PSD
PA-0226	LIMERICK POWER STATION	04/09/02	TURBINE, COMBINED CYCLE	550 MW		2.4 PPM @ 15% O2	LAER
TX-0548	MADISON BELL ENERGY CENTER	08/18/09	ELECTRICITY GENERATION	275 MW	GOOD COMBUSTION PRACTICES	2.5 PPMVD	BACT-PSD
VA-0262	MIRANT AIRSIDE INDUSTRIAL PARK	12/06/02	TURBINE, COMBINED CYCLE, (2)	170 MW	GOOD COMBUSTION PRACTICES.	2.7 PPMVD @ 15% O2	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (SWH)	170 MW	GOOD COMBUSTION PRACTICE	3 PPMVD @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STAT	12/01/04	COMBUSTION TURBINE GENERATORS ANI	180 MW	OXIDATION CATALYST	3 PPM @ 15% O2	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STAT	12/01/04	COMBUSTION TURBINE GENERATORS ANI	170 MW	OXIDATION CATALYST	3 PPM @ 15% O2	BACT-PSD
MI-0357	KALKASKA GENERATING, INC	02/04/03	TURBINE, COMBINED CYCLE, (2)	605 MW	CONTROL VOC, MOST OF □	3.5 PPM	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/ DUCT FIR	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	3.5 PPM @ 15% O2	BACT-PSD
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/O DUCT F	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	3.5 PPM @ 15% O2	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-001 GEN. ELEC. COME	230 MW	SCR	3.64 PPMV @ 15% 02	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-002 GEN ELEC. COMB	230 MW	SCR	3.64 PPMV @ 15% 02	BACT-PSD
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-003 GEN. ELEC COMB	230 MW	SCR	3.64 PPMV @ 15% 02	BACT-PSD
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, DUCT BURI	1715 MMBTU/H	GOOD COMBUSTION PRACTICES AND	3.7 PPMVW	BACT-PSD
AZ-0039	SALT RIVER PROJECT/SANTAN GEN. PLA	03/07/03	TURBINE, COMBINED CYCLE, DUCT BURN	175 MW	CATALYTIC OXIDIZER	4 PPM @ 15% O2	LAER
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AV	11/12/03	TURBINE, COMBINED CYCLE & DUCT	325 MW		4 PPM	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE WITH DUCT I	170 MW	GOOD COMBUSTION PRACTICES	4 PPMVD @ 15% O2	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJE(	08/16/05	TURBINE, COMBINED CYCLE COMBUSTIO]	306 MW	OXIDATION CATALYST FOR CO ALSO	4 PPM @ 15% O2	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJE(	08/16/05	TURBINE, COMBINED CYCLE COMBUSTIO]	306 MW	OXIDATION CATALYST FOR CO ALSO	4 PPM @ 15% O2	BACT-PSD
NV-0037	COPPER MOUNTAIN POWER	05/14/04	LARGE COMBUSTION TURBINES, COMBINI	600 MW	GOOD COMBUSTION CONTROL AND (	4 PPMVD	LAER
NY-0098	ATHENS GENERATING PLANT	01/19/07	FUEL COMBUSTION (GAS)	3100 MMBTU/H	GOOD COMBUSTION CONTROL	4 PPMVD @ 15% O2	LAER
TX-0428	HOUSTON OPERATIONS -- BATTLEGROU]	12/19/02	TURBINE, COMBINED CYCLE & DUCT	87 mw	GOOD COMBUSTION DESIGN AND OPI	4 PPMVD @ 15% O2	BACT-PSD
TX-0437	HARTBURG POWER, LP	07/05/02	TURBINE, COMBINED CYCLE & DUCT	277 mw	GOOD COMBUSTION DESIGN, PROPEF	4 PPM	BACT-PSD
TX-0547	NATURAL GAS-FIRED POWER GENERATI	06/22/09	ELECTRICITY GENERATION	250 MW	GOOD COMBUSTION PRACTICES	4 PPMVD	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURAL G.	1973 MMBTU/H	GOOD COMBUSTION/DESIGN AND CLI	4 PPM	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	GE COMBUSTION TURBINES AND HEAT RE	1040 MW	OXIDATION CATALYST	4.5 PPMVD	BACT-PSD
GA-0101	MURRAY ENERGY FACILITY	10/23/02	TURBINE, COMBINED CYCLE, (4)	173 MW	GOOD COMBUSTION PRACTICE	4.5 PPM @ 15% O2	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	COMBINED CYCLE COMBUSTION TURBINI	1758 MMBTU/H		4.6 PPMVD 15% O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW, DI	175 MW	GOOD COMBUSTION PRACTICES	4.6 PPMVD	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/08	TWO COMBINED CYCLE GAS TURBINES	2110 MMBTU/H	PROPER OPERATING PRACTICES	4.9 PPMVD@15%O2	BACT-PSD
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE, DUCT E	175 MW	GOOD COMBUSTION PRACTICES	4.9 PPMVD	BACT-PSD
OR-0035	PORT WESTWARD PLANT	01/16/02	(2) COMBUSTION TURBINES, WITH DUCT E	325 MW, EACH	CO CATALYST, GOOD COMBUSTION	4.9 PPM @ 15% O2	BACT-PSD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTION TURBI	2.1 MMCF/H	SOME REDUCTIONS OF VOC ARE GAII	5 PPMVD @ 15% O2	BACT-PSD
WA-0291	WALLULA POWER PLANT	01/03/03	TURBINE, COMBINED CYCLE, NATURAL G.	1300 MW	GOOD COMBUSTION PRACTICES	5 PPMDV @ 15% O2	Other Case-'
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUSTION	173 MW	GOOD COMBUSTION PRACTICES	5.3 PPM	BACT-PSD
PA-0223	DUKE ENERGY FAYETTE, LLC	01/30/02	TURBINE, COMBINED CYCLE, (2)	280 MW	OXIDATION CATALYST	5.3 PPMVD @ 15% O2	LAER
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBINE	1844.3 MMBTU/H	AND EFFICIENT PROCESS □	5.7 PPM @ 15% O2	BACT-PSD
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	TURBINES AND DUCT BURNERS	310 MW TOTAL	CATALYTIC OXIDATION	6 PPM	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, NATURAL G	154 MW	COMBUSTION CONTROL	7 PPMVW	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (NATURAL GAS) DUCT	646 MMBTU/H	OXIDATION CATALYST	7 PPMDV AT 15 % O2	LAER
TX-0411	AMELIA ENERGY CENTER	03/26/02	TURBINE, COMBINED CYCLE, & DUCT	180 MW	GOOD COMBUSTION DESIGN AND OPI	7 PPM @ 15% O2	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE, 2 EACH	1916 MMBTU/H	OXIDATION CATALYST AND GOOD C(	7.1 PPMVD @15% 02	BACT-PSD

Table D-6. RBLC VOC Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control Method Description	Emissions Limit	Basis
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	TURBINES, COMBINED CYCLE, NATURAL (	170 MW	GOOD COMBUSTION CONTROL	8.4 PPMVD	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (MHI)	170 MW	GOOD COMBUSTION PRACTICE/CO O:	8.4 PPMVD @ 15% O2	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	MHI COMBUSTION TURBINE & DUCT I	1767 MMBTU/H	CATALYTIC OXIDATION	8.4 PPM @ 15%O2	BACT-PSD
TX-0234	EDINBURG ENERGY LIMITED PARTNERS	01/08/02	(4) COMBINED CYCLE GAS TURBINE, ABB	180 MW	9.0 PPMVD WHEN ▢	9 PPMVD@15%O2	BACT-PSD
MI-0365	MIRANT WYANDOTTE LLC	01/28/03	TURBINE, COMBINED CYCLE, (2)	2200 MMBTU/H	SOME CONTROL FOR VOC ▢	10 PPM	Other Case-
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE, (3), NATUR	61200 MMSCF/YR	BEST COMBUSTION CONTROL PRACT	15.5 PPMVD	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-002 W /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	22.8 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-003 /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	22.8 PPMV @ 15% O2	BACT-PSD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-004 W/ DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	22.8 PPMV @ 15% O2	BACT-PSD
MN-0060	HIGH BRIDGE GENERATING PLANT	08/12/05	2 COMBINED-CYCLE COMBUSTION TURBII	330 MEGAWAT	GOOD COMBUSTION PRACTICES.	34 PPMVD @15% 02	BACT-PSD

Source: ECT, 2012.

Table D-7. RBLC VOC Summary for Large CTGs—Natural Gas-Fired Without Oxidation Catalyst

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERATION &	1882 MMBTU/H	GOOD COMBUSTION	BACT-PSD	0.3 PPM
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A\	11/12/03	TURBINE, COMBINED CYCLE	325 MW		BACT-PSD	1 PPM
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, NATURA	1876 MMBTU/H	GOOD COMBUSTION PRACTICES.	BACT-PSD	1 PPMVD @ 15% (
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	1 PPMVD
FL-0285	PROGRESS BARTOW POWER PLANT	01/26/07	COMBINED CYCLE COMBUSTION TURI	1972 MMBTU/H	GOOD COMBUSTION	BACT-PSD	1.2 PPMVD
FL-0303	FPL WEST COUNTY ENERGY CENTER UN	07/30/08	THREE NOMINAL 250 MW CTG (EACH) '	2333 MMBTU/H		BACT-PSD	1.2 PPMVD
PA-0189	CONECTIV BETHLEHEM, INC.	01/16/02	TURBINE, COMBINED CYCLE, (6)	122 MW		Other Case-by	1.2 PPMVD@15% O2
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, NATURAL GAS, NO DUCT BU	1937 MMBTU/H	PRACTICES FOR □	BACT-PSD	1.2 PPMVD @ 15% O2
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYLE, NATURAL	170 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	1.3 PPMVD 15% O2
FL-0245	FPL MANATEE PLANT - UNIT 3	04/15/03	TURBINE, COMBINED CYCLE, NATURA	170 MW	GOOD COMBUSTION PRACTICE	Other Case-by	1.3 PPMVD @ 15% O2
FL-0263	FPL TURKEY POINT POWER PLANT	02/08/05	170 MW COMBUSTION TURBINE, 4 UNI'	170 MW	VOC EMISSIONS WILL BE MINIMIZED BY		1.3 PPMVD @ 15 % O2
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE	175 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	1.3 PPM @ 15% O2
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (GE)	170 MW	GOOD COMBUSTION PRACTICE	BACT-PSD	1.4 PPMVD @ 15% O2
CA-0997	SACRAMENTO MUNICIPAL UTILITY DIS1	09/01/03	GAS TURBINES, (2)	1611 MMBTU/H		LAER	1.4 PPM @ 15% O2
LA-0157	PERRYVILLE POWER STATION	03/08/02	TURBINES, COMBINED CYCLE, GAS, (2)	170 MW	AND USE OF NATURAL GAS □	BACT-PSD	1.4 PPMV @ 15% O2
LA-0254	NINEMILE POINT ELECTRIC GENERATIN	08/16/11	COMBINED CYCLE TURBINE GENERAT	7146 MMBTU/H	GOOD COMBUSTION PRACTICES	BACT-PSD	1.4 PPMVD @ 15% O2
NM-0044	CLOVIS ENERGY FACILITY	06/27/02	TURBINES, COMBINED CYCLE, NATUR.	1515 MMBTU/H	PIPELINE QUALITY □	BACT-PSD	1.4 PPMV WET
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	GE COMBUSTION TURBINE & DUC	1705 MMBTU/H	GOOD COMBUSTION PRACTICES AND DF	BACT-PSD	1.4 PPM @ 15% O2
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURA	1973 MMBTU/H	GOOD COMBUSTION/DESIGN AND CLEAI	BACT-PSD	1.4 PPM
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/07	COMBINED CYCLE COMBUSTION GAS '	2333 MMBTU/H		BACT-PSD	1.5 PPMVD @ 15 % O2
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-001 W/DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	BACT-PSD	1.5 PPMVD
CA-1177	OTAY MESA ENERGY CENTER LLC	07/22/09	Gas turbine combined cycle	171.7 MW		OTHER CASI	2 PPMVD@15% O
FL-0256	HINES ENERGY COMPLEX, POWER BLOC	09/08/03	COMBUSTION TURBINES, COMBINED C	1830 MMBTU/H	COMBUSTION DESIGN, GOOD COMBUSTI	BACT-PSD	2 PPMVD % 15 O2
GA-0102	WANSLEY COMBINED CYCLE ENERGY F	01/15/02	TURBINE, COMBINED CYCLE, (2)	167 MW	GOOD COMBUSTION PRACTICE	BACT-PSD	2 PPM @ 15% O2
MN-0066	NORTHERN STATES POWER CO. DBA XC	05/16/06	TURBINE, COMBINED CYCLE (2)	1885 mmbtu/h	GOOD COMBUSTION PRACTICES	BACT-PSD	2 PPM @ 15% O2
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, NATUR.	1715 MMBTU/H	GOOD COMBUSTION PRACTICES AND DE	BACT-PSD	2 PPMVW
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H	GOOD COMBUSTION PRACTICES.	BACT-PSD	2 PPMVD @ 15% (
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE, NATURA	1937 MMBTU/H	PRACTICES FOR □	BACT-PSD	2.3 PPMVD @ 15% (
PA-0226	LIMERICK POWER STATION	04/09/02	TURBINE, COMBINED CYCLE	550 MW		LAER	2.4 PPM @ 15% O2
TX-0548	MADISON BELL ENERGY CENTER	08/18/09	ELECTRICITY GENERATION	275 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	2.5 PPMVD
VA-0262	MIRANT AIRSIDE INDUSTRIAL PARK	12/06/02	TURBINE, COMBINED CYCLE, (2)	170 MW	GOOD COMBUSTION PRACTICES.	BACT-PSD	2.7 PPMVD @ 15% (
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	TURBINE, COMBINED CYCLE, (2), (SWH	170 MW	GOOD COMBUSTION PRACTICE	BACT-PSD	3 PPMVD @ 15% (
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/ DUCT	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	3.5 PPM @ 15% O2
TN-0144	HAYWOOD ENERGY CENTER, LLC	02/01/02	TURBINE, COMBINED CYCLE, W/O DUC	1990 MMBTU/H	GOOD COMBUSTION PRACTICE	BACT-PSD	3.5 PPM @ 15% O2
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-001 GEN. ELEC. CC	230 MW	SCR	BACT-PSD	3.64 PPMV @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-002 GEN ELEC. CO	230 MW	SCR	BACT-PSD	3.64 PPMV @ 15% 02
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, I	11/23/04	EMISSION POINT AA-003 GEN. ELEC CO	230 MW	SCR	BACT-PSD	3.64 PPMV @ 15% 02
NC-0094	GENPOWER EARLEYS, LLC	01/09/02	TURBINES, COMBINED CYCLE, DUCT B	1715 MMBTU/H	GOOD COMBUSTION PRACTICES AND DE	BACT-PSD	3.7 PPMVW
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (A\	11/12/03	TURBINE, COMBINED CYCLE & DU	325 MW		BACT-PSD	4 PPM
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE WITH DU	170 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	4 PPMVD @ 15% (
NY-0098	ATHENS GENERATING PLANT	01/19/07	FUEL COMBUSTION (GAS)	3100 MMBTU/H	GOOD COMBUSTION CONTROL	LAER	4 PPMVD @ 15% (
TX-0428	HOUSTON OPERATIONS -- BATTLEGROU	12/19/02	TURBINE, COMBINED CYCLE & DU	87 mw	GOOD COMBUSTION DESIGN AND OPER/	BACT-PSD	4 PPMVD @ 15% (
TX-0437	HARTBURG POWER, LP	07/05/02	TURBINE, COMBINED CYCLE & DU	277 mw	GOOD COMBUSTION DESIGN, PROPER DI	BACT-PSD	4 PPM
TX-0547	NATURAL GAS-FIRED POWER GENERAT	06/22/09	ELECTRICITY GENERATION	250 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	4 PPMVD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, NATURA	1973 MMBTU/H	GOOD COMBUSTION/DESIGN AND CLEAI	BACT-PSD	4 PPM
GA-0101	MURRAY ENERGY FACILITY	10/23/02	TURBINE, COMBINED CYCLE, (4)	173 MW	GOOD COMBUSTION PRACTICE	BACT-PSD	4.5 PPM @ 15% O2

Table D-7. RBLC VOC Summary for Large CTGs—Natural Gas-Fired Without Oxidation Catalyst

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	COMBINED CYCLE COMBUSTION TURI	1758 MMBTU/H		BACT-PSD	4.6 PPMVD 15% O2
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, MHI/SW	175 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	4.6 PPMVD
LA-0224	ARSENAL HILL POWER PLANT	03/20/08	TWO COMBINED CYCLE GAS TURBINE:	2110 MMBTU/H	PROPER OPERATING PRACTICES	BACT-PSD	4.9 PPMVD@15%O2
NC-0095	MIRANT GASTONIA POWER FACILITY	05/28/02	TURBINES, COMBINED CYCLE, GE, DU(	175 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	4.9 PPMVD
WA-0291	WALLULA POWER PLANT	01/03/03	TURBINE, COMBINED CYCLE, NATURA	1300 MW	GOOD COMBUSTION PRACTICES	Other Case-by	5 PPMDV @ 15% (
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUST	173 MW	GOOD COMBUSTION PRACTICES	BACT-PSD	5.3 PPM
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMB:	1844.3 MMBTU/H	EFFICIENT PROCESS □	BACT-PSD	5.7 PPM @ 15% O2
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, NATURA	154 MW	COMBUSTION CONTROL	BACT-PSD	7 PPMVW
TX-0411	AMELIA ENERGY CENTER	03/26/02	TURBINE, COMBINED CYCLE, & DI	180 MW	GOOD COMBUSTION DESIGN AND OPER/	BACT-PSD	7 PPM @ 15% O2
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	TURBINES, COMBINED CYCLE, NATUR.	170 MW	GOOD COMBUSTION CONTROL	BACT-PSD	8.4 PPMVD
TX-0234	EDINBURG ENERGY LIMITED PARTNERS	01/08/02	(4) COMBINED CYCLE GAS TURBINE, A	180 MW	9.0 PPMVD WHEN □	BACT-PSD	9 PPMVD@15%O2
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE, (3), NAT	61200 MMSCF/YR	BEST COMBUSTION CONTROL PRACTICE	BACT-PSD	15.5 PPMVD
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-002 W /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	BACT-PSD	22.8 PPMV @ 15% O2
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE, AA-003 /DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	BACT-PSD	22.8 PPMV @ 15% O2
MS-0059	PIKE GENERATION FACILITY	09/24/02	TURBINE AA-004 W/ DUCT BURNER	2168 MMBTU/H	EFFICIENT COMBUSTION PRACTICES	BACT-PSD	22.8 PPMV @ 15% O2
MN-0060	HIGH BRIDGE GENERATING PLANT	08/12/05	2 COMBINED-CYCLE COMBUSTION TUI	330 MEGAWATT	GOOD COMBUSTION PRACTICES.	BACT-PSD	34 PPMVD @15% 02

Source: ECT, 2012.

Table D-8. RBLC $PM/PM_{10}/PM_{2.5}$ Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	NONE LISTED	0.003 LB/MMBTU	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	01/23/09	COMBINED CYCLE COGENERATION >25M	1882 MMBTU/H	NATURAL GAS FUEL	0.0035 LB/MMBTU	N/A
WA-0299	SUMAS ENERGY 2 GENERATION FACILIT	09/06/02	TURBINES, COMBINED CYCLE, (2)	334.5 MW	CLEAN FUEL -- NATURAL GAS ONLY	0.0039 LB/MMBTU	BACT-PSD
OR-0040	KLAMATH GENERATION, LLC	03/12/03	TURBINE, COMBINED CYCLE, DUCT BURNEI	480 MW	NATURAL GAS < 1 GR S/100 SCF OF GAS	0.0042 LB/MMBTU	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH DUCT BU	3202 MMBTU/H	NONE LISTED	0.005 LB/MMBTU	Other Case-
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2221 MMBUT/H	LOW SULFUR FUEL	0.0055 LB/MMBTU	BACT-PSD
AL-0185	BARTON SHOALS ENERGY	07/12/02	FOUR (4) COMBINED CYCLE COMBUSTION T	173 MW	GOOD COMBUSTION PRACTICES	0.006 LB/MMBTU	BACT-PSD
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LL	08/11/02	TWO (2) NATURAL GAS FIRED, COMBINED-C	2311 MMBTU/H	AND □	0.0065 LB/MMBTU	BACT-PSD
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LL	08/11/02	TWO (2) NATURAL GAS FIRED, COMBINED-C	2311 MMBTU/H	AND □	0.0065 LB/MMBTU	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/10	GE LM6000PF-25 Turbines (4)	59900 hp ISO	Good Combustion Practices	0.0066 LB/MMBTU	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/10	GE LM6000PF-25 Turbines (4)	59900 hp ISO	Good Combustion Practices	0.0066 LB/MMBTU	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/10	GE LM6000PF-25 Turbines (4)	59900 hp ISO	Good Combustion Practices	0.0066 LB/MMBTU	BACT-PSD
OK-0115	LAWTON ENERGY COGEN FACILITY	12/12/06	COMBUSTION TURBINE AND DUCT BURNER		GOOD COMBUSTION PRACTICES	0.0067 LB/MMBTU	BACT-PSD
OK-0055	MUSTANG ENERGY PROJECT	02/12/02	COMBUSTION TURBINES W/DUCT BURNERS	0	USE OF NO-ASH FUEL AND EFFICIENT COM	0.007 LB/MMBTU	BACT-PSD
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LL	05/02/06	NATURAL-GAS FIRED, COMBINED-CYCLE TU	300 MW	NATURAL GAS QUALITY FUEL ONLY AND	0.0074 LB/MMBTU	BACT-PSD
LA-0191	MICHOUD ELECTRIC GENERATING PLAN	10/12/04	HEAT RECOVERY STEAM GENERATORS 4 &a	200 MM BTU/H	USE OF CLEAN BURNING FUELS (NATURAL	0.008 LB/MMBTU	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, NATURAL GAS	140 MW	CLEAN FUEL, GOOD COMBUSTION PRACTI	0.009 LB/MMBTU	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE, 2 EACH	1916 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION PF	0.009 LB/MMBTU	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE, 2 EACH	1916 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION PF	0.009 LB/MMBTU	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	SW COMBUSTION TURBINE	1872 MMBTU/H	LOW ASH FUEL AND EFFICIENT COMBUSTI	0.0092 LB/MMBTU	BACT-PSD
OK-0117	PSO SOUTHWESTERN POWER PLT	02/09/07	GAS-FIRED TURBINES		USE OF LOW ASH FUEL (NATURAL GAS) AN	0.0093 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BUF	180 MW	BURNING NATURAL GAS	0.0096 LB/MMBTU	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, NATURAL GAS	1876 MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION PR.	0.01 LB/MMBTU	BACT-PSD
AZ-0039	SALT RIVER PROJECT/SANTAN GEN. PLA	03/07/03	TURBINE, COMBINED CYCLE, DUCT BURNEI	175 MW		0.01 LB/MMBTU	LAER
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	MHI COMBUSTION TURBINE & DUCT BU	1767 MMBTU/H	LOW ASH FUEL AND EFFICIENT COMBUSTI	0.01 LB/MMBTU	BACT-PSD
OH-0248	LAWRENCE ENERGY	09/24/02	TURBINES (3), COMBINED CYCLE, DUCT BUF	180 MW	BURNING NATURAL GAS	0.0101 LB/MMBTU	BACT-PSD
IA-0058	GREATER DES MOINES ENERGY CENTER	04/10/02	COMBUSTION TURBINES - COMBINED CYCL	350 MW		0.0108 LB/MMBTU	BACT-PSD
GA-0102	WANSLEY COMBINED CYCLE ENERGY FA	01/15/02	TURBINE, COMBINED CYCLE, (2)	167 MW	GOOD COMBUSTION PRACTICE, LOW SULF	0.011 LB/MMBTU	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJEC	08/16/05	TURBINE, COMBINED CYCLE COMBUSTION	306 MW	BEST COMBUSTION PRACTICES.	0.011 LB/MMBTU	BACT-PSD
NV-0035	TRACY SUBSTATION EXPANSION PROJEC	08/16/05	TURBINE, COMBINED CYCLE COMBUSTION	306 MW	BEST COMBUSTION PRACTICES.	0.011 LB/MMBTU	BACT-PSD
WA-0299	SUMAS ENERGY 2 GENERATION FACILIT	09/06/02	TURBINES, COMBINED CYCLE, (2)	334.5 MW	CLEAN FUEL -- NATURAL GAS ONLY	0.0115 LB/MMBTU	BACT-PSD
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	TURBINES AND DUCT BURNERS	310 MW TOTAL	LOW ASH FUEL (NATURAL GAS)	0.0117 LB/MMBTU	BACT-PSD
VA-0261	CPV CUNNINGHAM CREEK	09/06/02	TURBINE, COMBINED CYCLE, (2)	2132 MMBTU/H		0.0119 LB/MMBTU	BACT-PSD
OK-0096	REDBUD POWER PLANT	06/03/03	COMBUSTION TURBINE AND DUCT BURNER	1832 MMBTU/H	USE OF LOW ASH FUEL AND EFFICIENT CO	0.012 LB/MMBTU	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINE, COMBINED CYCLE, NATURAL GAS	1490.5 MMBTU/H		0.012 LB/MMBTU	BACT-PSD
IN-0114	MIRANT SUGAR CREEK LLC	07/24/02	TURBINES, SIMPLE CYCLE, NATURAL GAS, (	1490.5 MMBTU/H		0.012 LB/MMBTU	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 100% LOAI	171 MW	GOOD COMBUSTION DESIGN AND CLEAN I	0.013 LB/MMBTU	BACT-PSD
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 100% LOAI	171 MW	GOOD COMBUSTION DESIGN AND CLEAN I	0.013 LB/MMBTU	BACT-PSD
VA-0291	CPV WARREN LLC	07/30/04	TURBINE, COMBINED CYCLE (2)	1717 MMBTU/H	CLEAN BURNING FUEL NATURAL GAS ONL	0.013 LB/MMBTU	Other Case-
VA-0308	WARREN COUNTY FACILITY	01/14/08	ELECTRIC GENERATION - SCENARIO 1	1717 MMBTU/H	GOOD COMBUSTION PRACTICES	0.013 LB/MMBTU	N/A
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 70% LOAD	171 MW	GOOD COMBUSTION AND DESIGN. CLEAN	0.014 LB/MMBTU	BACT-PSD
AZ-0038	GILA BEND POWER GENERATING STATIO	05/15/02	TURBINE, COMBINED CYCLE, DUCT BURNEI	170 MW		0.014 LB/MMBTU	BACT-PSD
PA-0188	FAIRLESS ENERGY LLC	03/28/02	TURBINE, COMBINED CYCLE	1190 MW		0.014 LB/MMBTU	BACT-PSD
PA-0226	LIMERICK POWER STATION	04/09/02	TURBINE, COMBINED CYCLE	550 MW		0.014 LB/MMBTU	Other Case-
VA-0260	HENRY COUNTY POWER	11/21/02	TURBINE, COMBINED CYCLE, (4), 70% LOAD	171 MW	CLEAN FUEL. GOOD COMBUSTION AND DI	0.014 LB/MMBTU	BACT-PSD

Table D-8. RBLC PM/PM_{10}/$PM_{2.5}$ Summary for Large CTGs—Natural Gas-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	SIEMENS WESTINGHOUSE COMBUSTION TU	1080 MW		0.0148 LB/MMBTU	BACT-PSD
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE (3)	2964 MMBTU/H	NONE LISTED	0.015 LB/MMBTU	BACT-PSD
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHEN	03/21/03	TURBINES, COMBINED CYCLE (2)	1701 MMBTU/H	CLEAN FUEL AND EFFICIENT COMBUSTIO	0.015 LB/MMBTU	Other Case
NJ-0043	LIBERTY GENERATING STATION	03/28/02	COMBINED CYCLE TURBINE WITH DUCT BU	3202 MMBTU/H	NONE LISTED	0.017 LB/MMBTU	Other Case
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	GE COMBUSTION TURBINES AND HEAT REC	1040 MW		0.0188 LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, NATURAL GAS	1844.3 MMBTU/H	SULFUR □	0.019 LB/MMBTU	BACT-PSD
OK-0070	GENOVA OK I POWER PROJECT	06/13/02	GE COMBUSTION TURBINE & DUCT BUR	1705 MMBTU/H	LOW SULFUR FUEL AND EFFICIENT COMBU	0.019 LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBINED	1844.3 MMBTU/H	AND GOOD □	0.021 LB/MMBTU	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	COMBINED CYCLE COMBUSTION TURBINE \	1758 MMBTU/H		0.03 LB/MMBTU	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE 2 EACH	1827 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	0.057 LB/MMBTU	BACT-PSD
MN-0054	MANKATO ENERGY CENTER	12/04/03	COMBUSTION TURBINE, LARGE 2 EACH	1827 MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	0.057 LB/MMBTU	BACT-PSD
UT-0066	CURRANT CREEK	05/17/04	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS			0.066 LB/MMBTU	BACT-PSD
OR-0035	PORT WESTWARD PLANT	01/16/02	(2) COMBUSTION TURBINES, WITH DUCT BU	325 MW, EACH	USE OF PIPELINE QUALITY NATURAL GAS	0.14 LB/MMBTU	Other Case

Source: ECT, 2012.

Table D-9. RBLC NO_x Summary for Large CTGs—Fuel Oil-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
TX-0295	SAM RAYBURN GENERATION STATION	01/17/02	(3) COMBUSTION TURBINES 7,8,9, FUEL OI	45 MW, EA	SELECTIVE CATALYTIC REDUCTION /	5 PPM @ 15% O2	BACT-PSD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTION TURB	15119 GAL/H	WATER INJECTION AND SELECTIVE C	5.9 PPMVD @ 15% O2	LAER
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, FUEL OIL	2167 MMBTU/H	AMMONIA INJECTION □	6 PPM @ 15 % O2	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, DISTILLATE	1801 MMBTU/H	SCR AND WATER INJECTION.	6 PPMVD @ 15% 02	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, FUEL OIL, (4	140 MW	SCR	6 PPM @ 15% O2	BACT-PSD
AR-0105	AECI - DELL	03/31/10	COMBUSTION TURBINE #1 (SN-01) NO. 2 F	2112 MMBTU/H	SELECTIVE CATALYTIC REDUCTION	6 PPMVD	BACT-PSD
AR-0105	AECI - DELL	03/31/10	COMBUSTION TURBINE #2 (SN-02) NO. 2 F	2112 MMBTU/H	SELECTIVE CATALYTIC REDUCTION	6 PPMVD@1502	BACT-PSD
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE , (3), DISTIL	32 MMGAL/YR	AND CONTINUOUS □	6 PPMVD @ 15% O2	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2125 MMBTU/H	SCR	6.8 PPMVD@15%02	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (DISTILLATE OIL)	2099 MMBTU/H	WATER INJECTION WITH SELECTIVE (	9 PPMVD AT 15% O2	LAER
NY-0098	ATHENS GENERATING PLANT	01/19/07	FUEL COMBUSTION (OIL)	2940 MMBTU/H	THE TURBINE EMPLOYS DRY LOW NC	9 PPMVD @ 15% O2	LAER
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, FUEL OIL, (3	2003.2 MMBTU/H	USE OF WATER □	10 PPM @ 15% O2	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (DISTILLATE OIL) DU(	646 MMBTU/H	WATER INJECTION WITH SCR	10 PPMVD AT 15% O2	LAER
FL-0256	HINES ENERGY COMPLEX, POWER BLOCI	09/08/03	COMBUSTION TURBINES, COMBINED CY(	1830 MMBTU/H	WATER INJECTION AND SCR	10 PPM @ 15% O2	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE, FUEL OIL, (4	170 MW	WATER INJECTION WITH SCR	10 PPM @ 15 % O2	BACT-PSD
FL-0241	CPV CANA	01/17/02	TURBINE, COMBINED CYCLE, FUEL OIL	1898 MMBTU/H	SCR, DRY LOW NOX, WET INJECTION	10 PPM @ 15% O2	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, FUEL OIL, (2	1940 MMBTU/H	WATER INJECTION AND SCR	18 PPM @ 15% O2	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE , FUEL OIL	2080 MMBTU/H	CATALYTIC □	22 PPM @ 15% O2	LAER
PR-0008	PREPA	04/01/04	TURBINE, COMBINED CYCLE (2)	238 MW	STEAM INJECTION	34.2 PPM @ 15% O2	BACT-PSD
FL-0081	TECO-POLK POWER STATION/MULBERRY	12/23/02	TURBINE, COMBINED CYCLE, FUEL OIL	1765 MMBTU/H	WET INJECTION	42 PPM @ 15% O2	BACT-PSD

Source: ECT, 2012.

Table D-10. RBLC SO_2 Summary for Large CTGs— Fuel Oil-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COME	2003.2 MMBTU/H	S) □	0.0154 LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, FUEL OI	2003.2 MMBTU/H	FUEL OIL (0.015% SULFUR) LIMITED TO 1,200	0.0162 LB/MMBTU	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2125 MMBTU/H	LOW SULFUR FUEL	0.036 LB/MMBTU	BACT-PSD
FL-0081	TECO-POLK POWER STATION/MULBERR	12/23/02	TURBINE, COMBINED CYCLE, FUEL OI	1765 MMBTU/H	FUEL SPEC: LOW SULFUR FUEL OIL	0.048 LB/MMBTU	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, DISTILL	1801 MMBTU/H	LOW SULFUR FUEL.	0.051 LB/MMBTU	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, FUEL OI	1940 MMBTU/H	LOW SULFUR FUEL: 0.05% S FUEL OIL	0.052 LB/MMBTU	BACT-PSD

Source: ECT, 2012.

Table D-11. RBLC CO Summary for Large CTGs—Fuel Oil-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTION TURBI	15119 GAL/H	CO CATALYST	1.8 PPMVD @ 15% O2	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, FUEL OIL, (4	140 MW	CATALYTIC OXIDATION	2 PPM @ 15% O2	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/06	COMBUSTION TURBINE	2125 MMBTU/H	OXIDATION CATALYST	2 PPMVD@15%02	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, FUEL OIL	2167 MMBTU/H	GOOD COMBUSTION PRACTICE!	6 PPM @ 15% O2	BACT-PSD
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	01/07/08	COMBINED CYCLE COMBUSTION TURBINI	254 MW	OXIDATION CATALYST	9 PPM@15% O2	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, DISTILLATE	1801 MMBTU/H	GOOD COMBUSTION PRACTICE!	10 PPMVD @ 15% O2	BACT-PSD
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE, FUEL OIL, (4	170 MW	GOOD COMBUSTION DESIGN AN	15 PPM @ 15% O2	BACT-PSD
TX-0295	SAM RAYBURN GENERATION STATION	01/17/02	(3) COMBUSTION TURBINES 7,8,9, FUEL OII	45 MW, EA	OXIDATION CATALYST	15 PPM @ 15% O2	BACT-PSD
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE , (3), DISTILI	32 MMGAL/YR		15.6 PPMVD @ 15% O2	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, FUEL OIL, (3	2003.2 MMBTU/H	PROCESS □	15.7 PPM @ 15% O2	BACT-PSD
FL-0241	CPV CANA	01/17/02	TURBINE, COMBINED CYCLE, FUEL OIL	1898 MMBTU/H	COMBUSTION CONTROLS	17 PPM @ 15% O2	BACT-PSD
FL-0256	HINES ENERGY COMPLEX, POWER BLOCI	09/08/03	COMBUSTION TURBINES, COMBINED CYC	1830 MMBTU/H	COMBUSTION DESIGN, GOOD C(	20 PPM @ 15% O2	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, FUEL OIL, (2	1940 MMBTU/H	COMBUSTION CONTROL	20 PPM @ 15% O2	BACT-PSD
PR-0008	PREPA	04/01/04	TURBINE, COMBINED CYCLE (2)	238 MW		25 PPM @ 15% O2	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBINEI	2003.2 MMBTU/H	EFFICIENT COMBUSTION PROCI	25.1 PPM @ 15% O2	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE , FUEL OIL	2080 MMBTU/H		38 PPM @ 15% O2	BACT-PSD
FL-0081	TECO-POLK POWER STATION/MULBERRY	12/23/02	TURBINE, COMBINED CYCLE, FUEL OIL	1765 MMBTU/H	GOOD COMBUSTION	40 PPM @ 15% O2	BACT-PSD
AR-0052	THOMAS B. FITZHUGH GENERATING STA	02/15/02	TURBINE, COMBINED CYCLE, FUEL OIL	170.6 MW	GOOD COMBUSTION PRACTICE.	90 PPM @ 15% O2	BACT-PSD

Source: ECT, 2012.

Table D-12. RBLC VOC Summary for Large CTGs—Fuel Oil-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/03	TURBINE, COMBINED CYCLE, FUEL OIL, (	140 MW	CATALYTIC OXIDATION	2 PPM @ 15	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (DISTILLATE OIL)	2099 MMBTU/H	OXIDATION CATALYST	2 PPMVD A	LAER
FL-0244	FPL MARTIN PLANT	04/16/03	TURBINE, COMBINED CYCLE, FUEL OIL, (	170 MW	GOOD COMBUSTION PRACTICES	2.5 PPMVD @	BACT-PSD
VA-0255	VA POWER - POSSUM POINT	11/18/02	TURBINE, COMBINED CYCLE , FUEL OIL	2080 MMBTU/H	FOR □	2.6 PPMVD	BACT-PSD
VA-0256	TENASKA FLUVANNA	01/11/02	TURBINES, COMBINED CYCLE , (3), DISTI	32 MMGAL/YR		2.9 PPMVD	BACT-PSD
VA-0287	JAMES CITY ENERGY PARK	12/01/03	TURBINE, COMBINED CYCLE, FUEL OIL	2167 MMBTU/H	GOOD COMBUSTION/DESIGN AND CLEAN FUI	3.5 PPM	BACT-PSD
CT-0151	KLEEN ENERGY SYSTEMS, LLC	02/25/08	SIEMENS SGT6-5000F COMBUSTION TURE	15119 GAL/H	SOME VOC REDUCTIONS ARE ACHIEVED THR	3.6 PPMVD @	BACT-PSD
GA-0127	PLANT MCDONOUGH COMBINED CYCLE	01/07/08	COMBINED CYCLE COMBUSTION TURBIN	254 MW	OXIDATION CATALYST	4 PPM@15%	LAER
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, DISTILLAT	1801 MMBTU/H	GOOD COMBUSTION PRACTICES.	5 PPMVD @	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBIN	2003.2 MMBTU/H	EFFICIENT COMBUSTION DESIGN	6 PPM @ 15	BACT-PSD
NC-0086	FAYETTEVILLE GENERATION, LLC	01/10/02	TURBINE, COMBINED CYCLE, FUEL OIL, (	1940 MMBTU/H	COMBUSTION CONTROL	7 PPMVD	BACT-PSD
FL-0256	HINES ENERGY COMPLEX, POWER BLOCK 3	09/08/03	COMBUSTION TURBINES, COMBINED CY	1830 MMBTU/H	COMBUSTION DESIGN, GOOD COMBUSTION F	10 PPMVD @	BACT-PSD
NY-0100	EMPIRE POWER PLANT	06/23/05	FUEL COMBUSTION (DISTILLATE OIL) DU	646 MMBTU/H	OXYIDATION CATALYST	12 PPMVD A	LAER
NY-0098	ATHENS GENERATING PLANT	01/19/07	FUEL COMBUSTION (OIL)	2940 MMBTU/H	GOOD COMBUSTION CONTROL	13 PPMDV @	LAER

Source: ECT, 2012.

Table D-13. RBLC PM/PM_{10}/$PM_{2.5}$ Summary for Large CTGs—Fuel Oil-Fired

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput Rate	Control System Description	Emissions Limit	Basis
FL-0081	TECO-POLK POWER STATION/MULBER	12/23/02	TURBINE, COMBINED CYCLE, FUEL OIL	1765 MMBTU/H	GOOD COMBUSTION	0.009 LB/MMBTU	BACT-PSD
AR-0105	AECI - DELL	03/31/10	COMBUSTION TURBINE #1 (SN-01) NO. 2 F	2112 MMBTU/H	GOOD COMBUSTION	0.009 LB/MMBTU	BACT-PSD
AR-0105	AECI - DELL	03/31/10	COMBUSTION TURBINE #2 (SN-02) NO. 2 F	2112 MMBTU/H	GOOD COMBUSTION PRACTICES .	0.009 LB/MMBTU	BACT-PSD
GA-0105	MCINTOSH COMBINED CYCLE FACILIT	04/17/03	TURBINE, COMBINED CYCLE, FUEL OIL, (	140 MW	LOW SULFUR FUEL, GOOD COMBU	0.016 LB/MMBTU	Other Case-by-Case
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE & DUCT BURNER, COMBINI	2003.2 MMBTU/H	FUELS (< 0.015% S), □	0.0248 LB/MMBTU	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, SIMPLE CYCLE, DISTILLATE OI	1576 MMBTU/H	CLEAN FUEL AND GOOD COMBUS	0.03 LB/MMBTU	BACT-PSD
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	TURBINE, COMBINED CYCLE, DISTILLATI	1801 MMBTU/H	CLEAN FUEL AND GOOD COMBUS	0.03 LB/MMBTU	Other Case-by-Case
NC-0101	FORSYTH ENERGY PLANT	09/29/05	TURBINE, COMBINED CYCLE, FUEL OIL, (	2003.2 MMBTU/H	LOW-□	0.0358 LB/MMBTU	BACT-PSD
NY-0095	CAITHNES BELLPORT ENERGY CENTE	05/10/06	COMBUSTION TURBINE	2125 MMBTU/H	LOW SULFUR FUEL (0.04%).	0.041 LB/MMBTU	BACT-PSD

Source: ECT, 2012.

Table D-14. RBLC NO_x Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Update	Process Description	Throughput	Control System Description	Basis	Emissions Limit
LA-0194	SABINE PASS LNG TERMINAL	09/03/09	FIREWATER PUMP DIESEL ENGINES 1-3	660 HP EACH	GOOD ENGINE DESIGN AND PROPER (	BACT-PSD	0.02 G/B-HP-H
MD-0037	MEDIMMUNE FREDERICK CAMPUS	12/27/10	TWO (2) DIESEL (NO. 2 FUEL OIL) FIRED, NON-I	2500 KW	SELECTIVE CATALYTIC REDUCTION (	LAER	0.6 G/HP-H
MS-0086	CHEVRON PRODUCTS COMPANY, PASCAGC	03/04/10	TEMPORARY, PORTABLE CRUDE I GENERATOR		SELECTIVE CATALYTIC REDUCTION (	BACT-PSD	0.7 G/B-HP-H
VA-0276	INGENCO - CHARLES CITY PLANT	02/20/04	IC ENGINES, (48)	550 HP	AIR TO FUEL RATIO CONTROL, TURBC	N/A	0.7 G/B-HP-H
AK-0064	DUTCH HARBOR POWER PLANT	12/27/10	I.C.	5000 KW	REDUCE NOX BY 90%	BACT-PSD	1.0 G/B-HP-H
AK-0059	USAF EARECKSON AIR STATION	05/22/09	IC ENGINE, DIESEL, (2)	3000 KW	SCR	BACT-PSD	1.1 G/B-HP-H
PA-0209	ORCHARD PARK GENERATING STATION	08/16/06	IC ENGINE, GENERATOR	8086 BHP	LEAN BURN, SCR, LOW EMISSION CO!	Other Case-by-	1.5 G/BHP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	10/09/07	FIRE PUMP	540 HP	NO SPECIFIC CONTROL TECHNOLOGY	BACT-PSD	2.8 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, II	01/30/09	FIRE PUMP ENGINE	575 HP		BACT-PSD	2.9 G/B-HP-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	08/25/06	FIRE WATER PUMPS NOS 1 AND 2	5.46 MMBTU/H		BACT-PSD	3.0 G/B-HP-H
*SC-0113	PYRAMAX CERAMICS, LLC	06/12/12	EMERGENCY GENERATORS 1 THRU 8	757 HP	ENGINES MUST BE CERTIFIED TO CO!	BACT-PSD	3.0 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	10/09/07	EMERGENCY GENERATOR	1500 KW	NO SPECIFIC CONTROL TECHNOLOGY	BACT-PSD	4.5 G/B-HP-H
NM-0049	PHELPS DODGE TYRONE, INC	03/10/05	IC ENGINES, NON-DUAL FUEL MODE, (15)	3090 HP/H	GOOD OPERATING PRACTICE	Other Case-by-	4.6 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, II	01/30/09	EMERGENCY GENERATOR	700 KW		BACT-PSD	4.6 G/B-HP-H
AK-0066	ENDICOTT PRODUCTION FACILITY, LIBERT	08/06/09	EU ID 58, CAMP ENGINE 3	1041 HP	GOOD COMBUSTION PRACTICES	BACT-PSD	4.7 G/B-HP-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	08/25/06	EMERGENCY GENERATOR	10.9 MMBTU/H		BACT-PSD	4.8 G/B-HP-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCE	07/06/11	Emergency Generators, Two 2682 HP EA	0		BACT-PSD	4.8 G/B-HP-H
ID-0018	LANGLEY GULCH POWER PLANT	10/05/10	EMERGENCY GENERATOR ENGINE	750 KW	TIER 2 ENGINE-BASED,GOOD COMBU	BACT-PSD	4.8 G/B-HP-H
LA-0251	FLOPAM INC. FACILITY	12/12/11	Large Generator Engines (17 units)	0		LAER	4.8 G/B-HP-H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	05/18/12	EMERGENCY GENERATOR	2922 HP	GOOD COMBUSTION PRACTICES, GO(	BACT-PSD	4.8 G/B-HP-H
WV-0023	MAIDSVILLE	02/03/09	EMERGENCY GENERATOR	1801 HP	GOOD COMBUSTION PRACTICES	BACT-PSD	5.3 G/B-HP-H
NC-0074	BRIDGESTONE/FIRESTONE NORTH AMERIC	03/12/04	IC ENGINES, AIR COMPRESSORS, DIESEL, (5)	4.46 MMBTU/H	IGNITION TIMING RETARD	BACT-PSD	5.7 G/B-HP-H
NV-0050	MGM MIRAGE	03/15/10	EMERGENCY GENERATORS - UNITS LX024 AN	2206 HP	TURBOCHARGING, AFTER-COOLING, .	Other Case-by-	5.9 G/B-HP-H
MD-0037	MEDIMMUNE FREDERICK CAMPUS	12/27/10	THREE (3) DIESEL (NO. 2 FUEL OIL) FIRED, EMI	2500 KW		LAER	6.1 G/HP-H
AK-0060	DUTCH HARBOR SEAFOOD PROCESSING FA	06/03/05	IC ENGINE, GENERATOR, FUEL OIL, (3)	2220 KW	WATER INJECTION, LOW NOX DESIGI	BACT-PSD	6.5 G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	08/05/10	MOBILE EMERGENCY GENERATOR			OTHER CASE	6.8 G/B-HP-H
FL-0310	SHADY HILLS GENERATING STATION	01/26/10	2.5 MW EMERGENCY GENERATOR	2.5 MW	PURCHASE MODEL IS AT LEAST AS S1	BACT-PSD	6.9 G/B-HP-H
CA-0988	PACIFIC BELL	09/04/03	IC ENGINES	2935 HP		LAER	6.9 G/B-HP-H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	07/05/05	EMERGENCY DIESEL-FIRED GENERATOR	600 KW	LOW SULFUR FUEL, COMBUSTION CO	BACT-PSD	7.0 G/B-HP-H
OH-0266	UNIVERSITY OF CINCINNATI	04/29/08	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17 MMBTU/H		BACT-PSD	7.1 G/B-HP-H
AK-0072	DUTCH HARBOR POWER PLANT	11/18/11	EU 15 Caterpillar C-280-16	4400 KW	Engine has turbo charger and after cooler in	BACT-PSD	7.3 G/B-HP-H
NV-0047	NELLIS AIR FORCE BASE	10/21/08	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)		TURBOCHARGER AND AFTERCOOLEF	BACT-PSD	7.6 G/B-HP-H
MN-0053	FAIRBAULT ENERGY PARK	09/21/04	IC ENGINE, LARGE, FUEL OIL (1)	670 HP	GOOD COMBUSTION.	BACT-PSD	7.9 G/B-HP-H
NC-0074	BRIDGESTONE/FIRESTONE NORTH AMERIC	03/12/04	IC ENGINE, DIESEL GENERATOR, (2)	15.7 MMBTU/H	IGNITION TIMING RETARD	BACT-PSD	8.6 G/B-HP-H
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS	10/10/03	IC ENGINE, BACKUP GENERATOR, DIESEL	749 BHP	ENGINE DESIGN AND LIMITED HOURS	BACT-PSD	8.8 G/B-HP-H
*FL-0327	ANADARKO - PHEONIX PROSPECT	02/03/12	Main Propulsion Engines	0	Use of good combustion and maintenance p	BACT-PSD	9.5 G/B-HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	04/05/12	Main Propulsion Engines	0	Use of good combustion practices based on	BACT-PSD	9.5 G/B-HP-H
AK-0064	DUTCH HARBOR POWER PLANT	12/27/10	I.C.	5211 KW	FUEL INJECTION TIMING RETARD AN	BACT-PSD	10.1 G/B-HP-H
MN-0071	FAIRBAULT ENERGY PARK	05/29/08	EMERGENCY GENERATOR	1750 KW		BACT-PSD	10.9 G/B-HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC.	12/01/09	LARGE INTERNAL COMBUSTION ENGINES (&g	1232 HP	THE UNIT IS EQUIPPED WITH A TURB	BACT-PSD	10.9 G/B-HP-H
OK-0072	REDBUD POWER PLT	07/07/03	DIESEL ENGINE, EMERGENCY GENERATOR	1818 HP		BACT-PSD	10.9 G/B-HP-H
IA-0058	GREATER DES MOINES ENERGY CENTER	06/21/04	EMERGENCY GENERATOR	700 KW	RETARDED INGITION TIMING (3-4 DE(	BACT-PSD	11.0 G/B-HP-H
NJ-0073	TRIGEN	08/12/08	DUAL FUEL ENGINES ON 100 % DISTILLATE FU	1 MMGAL/YR		RACT	12.0 G/B-HP-H
MN-0054	MANKATO ENERGY CENTER	08/24/06	INTERNAL COMBUSTION ENGINE, LARGE	1850 HP	GOOD COMBUSTION	BACT-PSD	12.7 G/B-HP-H
WI-0207	ACE ETHANOL - STANLEY	08/16/05	IC ENGINE, DIESEL GENERATOR SET, B70	1850 BHP	LIMIT ON HOURS OF OPERATION (16.7	BACT-PSD	13.0 G/B-HP-H
AR-0051	DUKE ENERGY-JACKSON FACILITY	05/06/04	GENERATOR, DIESEL-FIRED	671 HP	GOOD OPERATING PRACTICE	BACT-PSD	14.0 G/B-HP-H

Table D-14. RBLC NO_x Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Update	Process Description	Throughput	Control System Description	Basis	Emissions Limit
TX-0407	STERNE ELECTRIC GENERATING FACILITY	10/26/04	EMERGENCY GENERATOR	1350 HP		BACT-PSD	14.0 G/B-HP-H
PA-0244	FIRST QUALITY TISSUE, LLC	03/10/05	FIRE PUMP	575 hp		BACT-PSD	14.1 G/B-HP-H
LA-0211	GARYVILLE REFINERY	07/16/08	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 &		USE OF DIESEL WITH A SULFUR CONT	BACT-PSD	14.1 G/B-HP-H

Source: ECT, 2012.

Table D-15. RBLC SO_2 Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
NV-0047	NELLIS AIR FORCE BASE	02/26/08	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)		LIMITING SULFUR CONTENT IN THE DIESI	BACT-PSI	0.02 G/B-HP-H
NV-0050	MGM MIRAGE	11/30/09	EMERGENCY GENERATORS - UNITS LX024 AND LX0	2206 HP	LIMITING SULFUR CONTENT IN THE DIESI	BACT-PSI	0.09 G/HP-H
CA-0988	PACIFIC BELL	02/01/03	IC ENGINES	2935 HP		LAER	0.16 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	FIRE PUMP	540 HP	BURN LOW-SULFUR DIESEL FUEL. 0.05% I	BACT-PSI	0.17 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	EMERGENCY GENERATOR	1500 KW	BURN LOW-SULFUR DIESEL FUEL. 0.05% I	BACT-PSI	0.17 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS,	09/19/08	EMERGENCY GENERATOR	700 KW	FUEL SULFUR LIMIT	BACT-PSI	0.17 G/HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS,	09/19/08	FIRE PUMP ENGINE	575 HP	LIMIT ON SULFUR IN FUEL	BACT-PSI	0.17 G/HP-H
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	EMERGENCY GENERATOR	1750 KW		BACT-PSI	0.18 G/HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/09	LARGE INTERNAL COMBUSTION ENGINES (>600 I	1232 HP	THE UNIT SHALL COMBUST ONLY LOW-SI	BACT-PSI	0.18 G/HP-H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LI	08/14/03	EMERGENCY DIESEL-FIRED GENERATOR	600 KW	LOW SULFUR FUEL, COMBUSTION CONTR	BACT-PSI	0.23 G/B-HP-H
MN-0054	MANKATO ENERGY CENTER	12/04/03	INTERNAL COMBUSTION ENGINE, LARGE	1850 HP	LOW SULFUR FUEL	BACT-PSI	0.59 G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	02/23/07	MOBILE EMERGENCY GENERATOR			OTHER C,	0.90 GR/B-HP-H

Source: ECT, 2012.

Table D-16. RBLC CO Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
NV-0047	NELLIS AIR FORCE BASE	02/26/08	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)		TURBOCHARGER AND AFTERCOOLEI	Other Case-by-	0.22 G/B-HP-H
OH-0266	UNIVERSITY OF CINCINNATI	08/15/02	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	19.17 MMBTU/H		BACT-PSD	0.30 G/B-HP-H
AK-0059	USAF EARECKSON AIR STATION	09/29/03	IC ENGINE, DIESEL, (2)	3000 KW	SCR OXIDATION CATALYST	BACT-PSD	0.50 G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	02/23/07	MOBILE EMERGENCY GENERATOR			OTHER CASI	0.78 G/B-HP-H
SC-0064	SCE&G - JASPER COUNTY GENERATI	05/23/02	GENERATOR, EMERGENCY,DIESEL FUEL	2000 KW		BACT-PSD	0.78 G/B-HP-H
NV-0050	MGM MIRAGE	11/30/09	EMERGENCY GENERATORS - UNITS LX024 AND LX02	2206 HP	TURBOCHARGER AND GOOD COMBU	LAER	0.82 G/B-HP-H
MS-0086	CHEVRON PRODUCTS COMPANY, PA	05/08/07	TEMPORARY, PORTABLE CRUDE I GENERATOR			BACT-PSD	0.85 G/B-HP-H
MN-0054	MANKATO ENERGY CENTER	12/04/03	INTERNAL COMBUSTION ENGINE, LARGE	1850 HP	GOOD COMBUSTION	BACT-PSD	1.00 G/B-HP-H
WI-0207	ACE ETHANOL - STANLEY	01/21/04	IC ENGINE, DIESEL GENERATOR SET, B70	1850 BHP	LIMITED OPERATION, DESIGN	BACT-PSD	1.00 G/B-HP-H
IA-0058	GREATER DES MOINES ENERGY CEN	04/10/02	EMERGENCY GENERATOR	700 KW		BACT-PSD	1.38 G/B-HP-H
NM-0049	PHELPS DODGE TYRONE, INC	05/20/02	IC ENGINES, NON-DUAL FUEL MODE, (15)	3090 HP/H	GOOD OPERATING PRACTICES	Other Case-by-	1.38 G/B-HP-H
MN-0053	FAIRBAULT ENERGY PARK	07/15/04	IC ENGINE, LARGE, FUEL OIL (1)	670 HP	GOOD COMBUSTION.	BACT-PSD	1.83 G/B-HP-H
WV-0023	MAIDSVILLE	03/02/04	EMERGENCY GENERATOR	1801 HP	GOOD COMBUSTION PRACTICES	BACT-PSD	2.20 G/B-HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJEC	10/27/11	Main Propulsion Engines	0	Use of good combustion practices based on	BACT-PSD	2.46 G/B-HP-H
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	EMERGENCY GENERATOR	1750 KW		BACT-PSD	2.49 G/B-HP-H
NV-0049	HARRAH'S OPERATING COMPANY, IN	08/20/09	LARGE INTERNAL COMBUSTION ENGINES (>600 H	1232 HP	THE UNIT IS EQUIPPED WITH A TURB	Other Case-by-	2.49 G/B-HP-H
AK-0066	ENDICOTT PRODUCTION FACILITY, L	06/15/09	EU ID 58, CAMP ENGINE 3	1041 HP	GOOD COMBUSTION PRACTICES	BACT-PSD	2.60 G/HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RA	06/29/07	FIRE PUMP	540 HP	NO SPECIFIC CONTROL TECHNOLOG\	BACT-PSD	2.60 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RA	06/29/07	EMERGENCY GENERATOR	1500 KW	NO SPECIFIC CONTROL TECHNOLOG\	BACT-PSD	2.60 G/B-HP-H
LA-0254	NINEMILE POINT ELECTRIC GENERA	08/16/11	EMERGENCY DIESEL GENERATOR	1250 HP	ULTRA LOW SULFUR DIESEL AND GO	BACT-PSD	2.60 G/HP-H
MI-0389	KARN WEADOCK GENERATING COM	12/29/09	FIRE PUMP	525 HP	ENGINE DESIGN AND OPERATION. 15	BACT-PSD	2.60 G/HP-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/05	FIRE WATER PUMPS NOS 1 AND 2	5.46 MMBTU/H		BACT-PSD	2.61 G/B-HP-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/05	EMERGENCY GENERATOR	10.9 MMBTU/H		BACT-PSD	2.61 G/B-HP-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADV	12/23/10	Emergency Generators, Two 2682 HP EA	2682 HP		BACT-PSD	2.61 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERI	09/19/08	EMERGENCY GENERATOR	700 KW		BACT-PSD	2.61 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERI	09/19/08	FIRE PUMP ENGINE	575 HP		BACT-PSD	2.61 G/B-HP-H
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	EMERGENCY GENERATOR ENGINE	750 KW	TIER 2 ENGINE-BASED,GOOD COMBU	BACT-PSD	2.61 G/B-HP-H
MI-0389	KARN WEADOCK GENERATING COM	12/29/09	EMERGENCY GENERATOR	2000 KW	ENGINE DESIGN AND OPERATION. 15	BACT-PSD	2.61 G/B-HP-H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/08	EMERGENCY GENERATOR	2922 HP	GOOD COMBUSTION PRACTICES ANI	BACT-PSD	2.61 G/HP-H
*SC-0113	PYRAMAX CERAMICS, LLC	02/08/12	EMERGENCY GENERATORS 1 THRU 8	757 HP	ENGINES MUST BE CERTIFIED TO CO	BACT-PSD	2.61 G/B-HP-H
TX-0407	STERNE ELECTRIC GENERATING FAC	12/06/02	EMERGENCY GENERATOR	1350 HP		BACT-PSD	3.03 G/B-HP-H
LA-0211	GARYVILLE REFINERY	12/27/06	EMERGENCY GENERATORS (DOCK & TANK FAR		USE OF DIESEL WITH A SULFUR CON	BACT-PSD	3.04 G/B-HP-H
PA-0244	FIRST QUALITY TISSUE, LLC	10/20/04	FIRE PUMP	575 hp		BACT-PSD	3.04 G/B-HP-H
OK-0090	DUKE ENERGY STEPHENS, LLC STEP	03/21/03	IC ENGINE, BACKUP GENERATOR, DIESEL	749 BHP	ENGINE DESIGN AND GOOD COMBUS	BACT-PSD	8.48 G/B-HP-H
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	GENERATOR, DIESEL-FIRED	671 HP	GOOD OPERATING PRACTICE	BACT-PSD	8.50 G/B-HP-H
CA-0988	PACIFIC BELL	02/01/03	IC ENGINES	2935 HP		LAER	8.50 G/B-HP-H
FL-0310	SHADY HILLS GENERATING STATION	01/12/09	2.5 MW EMERGENCY GENERATOR	2.5 MW	PURCHASED MODEL IS AT LEAST AS	BACT-PSD	8.50 G/HP-H
OH-0254	DUKE ENERGY WASHINGTON COUN	08/14/03	EMERGENCY DIESEL-FIRED GENERATOR	600 KW	LOW SULFUR FUEL, COMBUSTION CO	BACT-PSD	8.60 G/B-HP-H
VA-0276	INGENCO - CHARLES CITY PLANT	06/20/03	IC ENGINES, (48)	550 HP	LIMITING THE TREATED LANDFILL G	Other Case-by-	10.00 G/B-HP-H
OK-0072	REDBUD POWER PLT	05/06/02	DIESEL ENGINE, EMERGENCY GENERATOR	1818 HP	ENGINE DESIGN	BACT-PSD	25.00 G/B-HP-H

Source: ECT, 2012.

Table D-17. RBLC VOC Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN	09/19/08	FIRE PUMP ENGINE	575 HP		BACT-PSI	0.07 G/B-HP-H
MN-0054	MANKATO ENERGY CENTER	12/04/03	INTERNAL COMBUSTION ENGINE, LARGI	1850 HP	GOOD COMBUSTION	BACT-PSI	0.12 G/B-HP-H
WI-0207	ACE ETHANOL - STANLEY	01/21/04	IC ENGINE, DIESEL GENERATOR SET, B70	1850 BHP	LIMITED OPERATION, DESIGN	BACT-PSI	0.12 G/HP-H
NV-0050	MGM MIRAGE	11/30/09	EMERGENCY GENERATORS - UNITS LX02	2206 HP	TURBOCHARGER AND GOOD COMBUSTI	Other Case	0.14 G/B-HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN	09/19/08	EMERGENCY GENERATOR	700 KW		BACT-PSI	0.15 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	FIRE PUMP	540 HP	NO SPECIFIC CONTROL TECHNOLOGY IS	BACT-PSI	0.20 G/B-HP-H
NV-0047	NELLIS AIR FORCE BASE	02/26/08	LARGE INTERNAL COMBUSTION ENGINE		TURBOCHARGER AND AFTERCOOLER	Other Case	0.20 G/B-HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	10/27/11	Main Propulsion Engines	0	Use of good combustion practices based on the	BACT-PSI	0.29 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	EMERGENCY GENERATOR	1500 KW	NO SPECIFIC CONTROL TECHNOLOGY IS	BACT-PSI	0.30 G/B-HP-H
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	EMERGENCY GENERATOR	1750 KW		BACT-PSI	0.32 G/B-HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/09	LARGE INTERNAL COMBUSTION ENGINE	1232 HP	THE UNIT IS EQUIPPED WITH A TURBOC	Other Case	0.32 G/B-HP-H
OK-0072	REDBUD POWER PLT	05/06/02	DIESEL ENGINE, EMERGENCY GENERAT(	1818 HP	ENGINE DESIGN	BACT-PSI	0.32 G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	02/23/07	MOBILE EMERGENCY GENERATOR			OTHER C.	0.32 G/B-HP-H
CA-0988	PACIFIC BELL	02/01/03	IC ENGINES	2935 HP		LAER	1.00 G/B-HP-H
LA-0254	NINEMILE POINT ELECTRIC GENERATING PI	08/16/11	EMERGENCY DIESEL GENERATOR	1250 HP	ULTRA LOW SULFUR DIESEL AND GOOD	BACT-PSI	1.00 G/HP-H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	08/14/03	EMERGENCY DIESEL-FIRED GENERATOR	600 KW	LOW SULFUR FUEL, COMBUSTION CONT	BACT-PSI	1.00 G/B-HP-H
AR-0051	DUKE ENERGY-JACKSON FACILITY	04/01/02	GENERATOR, DIESEL-FIRED	671 HP	GOOD OPERATING PRACTICE	BACT-PSI	1.10 G/B-HP-H
LA-0211	GARYVILLE REFINERY	12/27/06	EMERGENCY GENERATORS (DOCK &amp		USE OF DIESEL WITH A SULFUR CONTEN	BACT-PSI	1.13 G/B-HP-H
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	EMERGENCY GENERATOR ENGINE	750 KW	TIER 2 ENGINE-BASED,GOOD COMBUSTI	BACT-PSI	4.77 G/B-HP-H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/08	EMERGENCY GENERATOR	2922 HP	GOOD COMBUSTION PRACTICES AND G(	BACT-PSI	4.77 G/B-HP-H
*SC-0113	PYRAMAX CERAMICS, LLC	02/08/12	EMERGENCY GENERATORS 1 THRU 8	757 HP	PURCHASE ENGINES CERTIFIED TO COM	BACT-PSI	4.77 G/B-HP-H
LA-0194	SABINE PASS LNG TERMINAL	11/24/04	FIREWATER PUMP DIESEL ENGINES 1-3	660 HP EACI	GOOD COMBUSTION PRACTICES	BACT-PSI	31.75 G/B-HP-H

Source: ECT, 2012.

Table D-18. RBLC PM Summary for Internal Combustion Engines Greater Than 500 Horsepower

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Basis	Emissions Limit
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/05	EMERGENCY GENERATOR	10.9 MMBTU/H		BACT-PSD	0.01 G/HP-H
OH-0266	UNIVERSITY OF CINCINNATI	08/15/02	DIESEL FIRED ENGINES (2), 2 MW, 2922 BHP	2922 HP		BACT-PSD	0.04 G/B-HP-H
NV-0050	MGM MIRAGE	11/30/09	EMERGENCY GENERATORS - UNITS LX024	2206 HP	TURBOCHARGER AND GOOD COMI	Other Case-t	0.05 G/HP-H
MN-0054	MANKATO ENERGY CENTER	12/04/03	INTERNAL COMBUSTION ENGINE, LARGE	1850 HP	GOOD COMBUSTION	BACT-PSD	0.07 G/B-HP-H
WI-0207	ACE ETHANOL - STANLEY	01/21/04	IC ENGINE, DIESEL GENERATOR SET, B70	1850 BHP	USE OF VERY LOW SULFUR DIESEL	BACT-PSD	0.07 G/HP-H
MN-0054	MANKATO ENERGY CENTER	12/04/03	INTERNAL COMBUSTION ENGINE, LARGE	1850 HP	GOOD COMBUSTION	BACT-PSD	0.07 G/B-HP-H
NV-0047	NELLIS AIR FORCE BASE	02/26/08	LARGE INTERNAL COMBUSTION ENGINES (	>500 HP	TURBOCHARGER AND AFTERCOOL	OTHER CA:	0.08 G/B-HP-H
CA-0988	PACIFIC BELL	02/01/03	IC ENGINES	2935 HP		LAER	0.10 G/B-HP-H
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/05	FIRE WATER PUMPS NOS 1 AND 2	5.46 MMBTU/H		BACT-PSD	0.15 G/HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	EMERGENCY GENERATOR	700 KW		BACT-PSD	0.15 G/HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	FIRE PUMP ENGINE	575 HP		BACT-PSD	0.15 G/HP-H
ID-0018	LANGLEY GULCH POWER PLANT	06/25/10	EMERGENCY GENERATOR ENGINE	750 KW	TIER 2 ENGINE-BASED,GOOD COMI	BACT-PSD	0.15 G/HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	EMERGENCY GENERATOR	700 KW		BACT-PSD	0.15 G/HP-H
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	FIRE PUMP ENGINE	575 HP		BACT-PSD	0.15 G/HP-H
LA-0251	FLOPAM INC. FACILITY	04/26/11	Large Generator Engines (17 units)	591 & 1175 HP		BACT-PSD	0.15 G/HP-H
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/08	EMERGENCY GENERATOR	2922 HP	GOOD COMBUSTION PRACTICES AI	BACT-PSD	0.15 G/HP-H
OK-0129	CHOUTEAU POWER PLANT	01/23/09	EMERGENCY DIESEL GENERATOR (2200 HF	2200 HP		BACT-PSD	0.15 G/HP-H
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED	12/23/10	Emergency Generators, Two 2682 HP EA	2682 HP		BACT-PSD	0.15 G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/09	EMERGENCY GENERATOR	2000 KW	ENGINE DESIGN AND OPERATION.	BACT-PSD	0.15 G/HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	FIRE PUMP	540 HP	NO SPECIFIC CONTROL TECHNOLO	BACT-PSD	0.15 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	EMERGENCY GENERATOR	1500 KW	NO SPECIFIC CONTROL TECHNOLO	BACT-PSD	0.15 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	FIRE PUMP	540 HP	NO SPECIFIC CONTROL TECHNOLO	BACT-PSD	0.15 G/B-HP-H
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	EMERGENCY GENERATOR	1500 KW	NO SPECIFIC CONTROL TECHNOLO	BACT-PSD	0.15 G/B-HP-H
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	EMERGENCY DIESEL GENERATOR	1250 HP	ULTRA LOW SULFUR DIESEL AND C	BACT-PSD	0.15 G/HP-H
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	EMERGENCY DIESEL GENERATOR	1250 HP	ULTRA LOW SULFUR DIESEL AND C	BACT-PSD	0.15 G/HP-H
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/09	FIRE PUMP	525 HP	ENGINE DESIGN AND OPERATION.	BACT-PSD	0.15 G/HP-H
PA-0271	MERCK & CO. WESTPOINT	02/23/07	MOBILE EMERGENCY GENERATOR	2795 HP		OTHER CA:	0.16 G/B-HP-H
PA-0271	MERCK & CO. WESTPOINT	02/23/07	MOBILE EMERGENCY GENERATOR	2795 HP		OTHER CA:	0.16 G/B-HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	10/27/11	Main Propulsion Engines		Use of good combustion practices based (	BACT-PSD	0.18 G/HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	10/27/11	Main Propulsion Engines		Use of good combustion practices based (	BACT-PSD	0.18 G/HP-H
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	EMERGENCY GENERATOR	1750 KW		BACT-PSD	0.18 G/HP-H
MN-0071	FAIRBAULT ENERGY PARK	06/05/07	EMERGENCY GENERATOR	1750 KW		BACT-PSD	0.32 G/HP-H
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/09	LARGE INTERNAL COMBUSTION ENGINES (	1232 HP	THE UNIT IS EQUIPPED WITH A TUR	Other Case-t	0.32 G/HP-H
*FL-0328	ENI - HOLY CROSS DRILLING PROJECT	10/27/11	Main Propulsion Engines		Use of good combustion practices based (	BACT-PSD	0.32 G/HP-H
AK-0072	DUTCH HARBOR POWER PLANT	07/14/11	EU 15 Caterpillar C-280-16	4400 KW	Positive Crankcase Ventilation Installed :	BACT-PSD	0.37 G/HP-H
FL-0310	SHADY HILLS GENERATING STATION	01/12/09	2.5 MW EMERGENCY GENERATOR	2.5 MW	FIRING ULSO WITH A MAXIMUM SU	BACT-PSD	0.40 G/HP-H
FL-0310	SHADY HILLS GENERATING STATION	01/12/09	2.5 MW EMERGENCY GENERATOR	2.5 MW	FIRING ULSO WITH A MAXIMUM SU	BACT-PSD	0.40 G/HP-H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	08/14/03	EMERGENCY DIESEL-FIRED GENERATOR	600 KW	LOW SULFUR FUEL, COMBUSTION (	BACT-PSD	0.41 G/B-HP-H
LA-0194	SABINE PASS LNG TERMINAL	11/24/04	FIREWATER PUMP DIESEL ENGINES 1-3	660 HP EACH	GOOD COMBUSTION PRACTICES	BACT-PSD	0.86 G/HP-H
LA-0211	GARYVILLE REFINERY	12/27/06	EMERGENCY GENERATORS (DOCK & 1	671 & 1341 HP	USE OF DIESEL WITH A SULFUR CO	BACT-PSD	1.00 G/HP-H

Source: ECT, 2012.

Table D-19. RBLC PM Summary for Industrial Cooling Towers

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Emissions Limit	Basis
FL-0299	CRYSTAL RIVER POWER PLANT	10/12/07	COOLING TOWERS	342306 GAL/MIN		0.0005 PERCENT	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	INDUSTRIAL COOLING TOWER	150000 GAL/MIN	DRIFT ELIMINATORS	0.0005 %	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06	08/08/07	COOLING TOWER, F80 (07-A-97	50000 GAL/MIN	DRIFT ELIMINATOR / DEMISTER	0.0005 % DRIFT L	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	COOLING TOWER		DRIFT ELIMINATORS	0.0005 %	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENT.	02/10/09	COOLING TOWER, SRC22	121000 GAL/MIN	DRIFT/MIST ELIMINATORS	0.0005 % OF TOT.	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	MECHANICAL DRAFT COOLIN(	173870 GAL/MIN	DRIFT ELIMINATORS	0.0005 % BY VOL	BACT-PSD
AZ-0049	LA PAZ GENERATING FACILITY	09/04/03	MECHANICAL DRAFT COOLIN(	141400 GAL/MIN	DRIFT ELIMINATORS	0.0005 % BY VOL	BACT-PSD
FL-0317	FPL TURKEY POINT NUCLEAR PLANT	05/30/09	Industrial Cooling Towers	210367 GAL/MIN/TO	Cooling Tower design plus high efficiency drift eliminat(	0.0005 %	BACT-PSD
GA-0142	OSCEOLA STEEL CO.	12/29/10	Cooling Towers, CT1, CT21, CT22	0	Drift Eliminators	0.0005 % MASS F	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/07	INDUSTRIAL COOLING TOWER	150000 GAL/MIN	DRIFT ELIMINATORS	0.0005 % EFF. DR	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06	08/08/07	COOLING TOWER, F80 (07-A-97	50000 GAL/MIN	DRIFT ELIMINATOR / DEMISTER	0.0005 % DRIFT L	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, IN(	09/19/08	COOLING TOWER		DRIFT ELIMINATORS	0.0005 %	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENT.	02/10/09	COOLING TOWER, SRC22	121000 GAL/MIN	DRIFT/MIST ELIMINATORS	0.0005 % OF TOT.	BACT-PSD
MT-0030	BILLINGS REFINERY	11/19/08	COOLING WATER TOWER	10000 GAL/MIN	HIGH EFFICIENCY DRIFT ELIMINATOR	0.0005 %	BACT-PSD
NV-0036	TS POWER PLANT	05/05/05	COOLING TOWER		DRIFT ELIMINATORS	0.0005 PERCENT	BACT-PSD
NY-0093	TRIGEN-NASSAU ENERGY CORPORATION	03/31/05	COOLING TOWER			0.0005 % DRIFT	BACT-PSD
MT-0030	BILLINGS REFINERY	11/19/08	COOLING WATER TOWER	10000 GAL/MIN	HIGH EFFICIENCY DRIFT ELIMINATOR	0.0005 %	BACT-PSD
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILI	12/17/10	Cooling Tower	0	Drift Eliminators	0.0005 % EFFECT	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/07	COOLING TOWER	80000 GAL/MIN	DRIFT ELIMINATOR	0.0005 % COOLIN	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	UNIT 6 COOLING TOWER	115847 GALS/MIN	HIGH EFFICIENCY MIST ELIMINATOR	0.0005 PERCENT	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	UNIT 6 COOLING TOWER	115847 GALS/MIN	HIGH EFFICIENCY MIST ELIMINATOR	0.0005 PERCENT	BACT-PSD
FL-0316	LEVY NUCLEAR PLANT	02/20/09	Industrial Process Cooling Tower	600000 GAL/MIN	Drift eliminators	0.0005 % DRIFT F	BACT-PSD
FL-0317	FPL TURKEY POINT NUCLEAR PLANT	05/30/09	Industrial Cooling Towers	210367 GAL/MIN/TO	Cooling tower design plus high efficiency drift eliminato:	0.0005 %	BACT-PSD
TX-0551	PANDA SHERMAN POWER STATION	02/03/10	Cooling tower	0	Drift eliminators	0.0005 % DRIFT	BACT-PSD
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	03/03/10	Cooling tower	0	Drift eliminators	0.0005 % DRIFT	BACT-PSD
TX-0553	LINDALE RENEWABLE ENERGY	01/08/10	Cooling tower	0	Drift eliminators	0.0005 % DRIFT	BACT-PSD
LA-0239	NUCOR STEEL LOUISIANA	05/24/10	TWR-103 - Air Separation Plant Cc	0	BACT is selected to be a combination of less than 1,000 :	0.0005 %	BACT-PSD
LA-0239	NUCOR STEEL LOUISIANA	05/24/10	TWR-102 - Iron Solidification Cool	0	BACT is selected to be a combination of less than 1,000 :	0.0005 %	BACT-PSD
LA-0248	DIRECT REDUCTION IRON PLANT	01/27/11	DRI-114 - DRI Unit #1 Clean Wate	17611 gpm	BACT is a combination of less than or equal to 1,000 mil	0.0005 %	BACT-PSD
LA-0248	DIRECT REDUCTION IRON PLANT	01/27/11	DRI-214 - DRI Unit #1 Clean Wate	17611 gpm	BACT is a combination of less than or equal to 1,000 mil	0.0005 %	BACT-PSD
LA-0248	DIRECT REDUCTION IRON PLANT	01/27/11	DRI-113 - DRI Unit #1 Process Wa	26857 gpm	BACT is a combination of less than or equal to 1,000 mil	0.0005 %	BACT-PSD
LA-0248	DIRECT REDUCTION IRON PLANT	01/27/11	DRI-213 - DRI Unit #2 Process Wa	26857 gpm	BACT is a combination of less than or equal to 1,000 mil	0.0005 %	BACT-PSD
LA-0239	NUCOR STEEL LOUISIANA	05/24/10	TWR-101 - Blast Furnace Cooling '	0	BACT is selected to be a combination of less than 1,000 :	0.0005 %	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LI	04/26/06	COOLING TOWER	55000 GAL/MIN	DRIFT ELIMINATORS @ 0.0005% DRIFT RATE	0.0005 %	BACT-PSD
FL-0323	GAINESVILLE RENEWABLE ENERGY CENTER	12/28/10	Mechanical draft cooling tower	78000 Gal/Min	The tower will be equipped with drift eliminatores to me(	0.0005 %	BACT-PSD
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/04	MECHANICAL DRAFT COOLIN(	170000 Gal/Min	DRIFT ELIMINATORS (NOT TO EXCEED A TOTAL	0.0005 %	BACT-PSD
OR-0041	WANAPA ENERGY CENTER	08/08/05	COOLING TOWER	6.2 CF/SEC	INSTALLATION OF HIGH EFFICIENCY 0.0005% DR:	0.0005 %	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENT.	02/10/09	ZLDS COOLING TOWER, SRC30	985 GAL/MIN	DRIFT/MIST ELIMINATORS	0.001 % OF TOT.	BACT-PSD
MD-0032	DICKERSON	11/05/04	COOLING TOWER	10 CELLS	MIST ELIMINATORS	0.001 %	BACT-PSD
AR-0070	GENOVA ARKANSAS I, LLC	08/23/02	COOLING TOWER	11.4 MMGAL/H	DRIFT ELIMINATORS	0.001 % DRIFT L	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENT.	02/10/09	ZLDS COOLING TOWER, SRC30	985 GAL/MIN	DRIFT/MIST ELIMINATORS	0.001 % OF TOT.	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/05	COOLING TOWER			0.001 LB/H	BACT-PSD
OK-0056	HORSESHOE ENERGY PROJECT	02/12/02	COOLING TOWERS	111438 GPM TOTAL	DRIFT ELIMINATORS DESIGN	0.001 % DRIFT	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	CHILLER COOLING TOWER (CH	12000 GALS/MIN	HIGH EFFICIENCY MIST ELIMINATOR	0.001 PERCENT	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PL	08/16/11	CHILLER COOLING TOWER (CH	12000 GALS/MIN	HIGH EFFICIENCY MIST ELIMINATOR	0.001 PERCENT	BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/07	COOLING TOWER	5000 GAL/MIN	DRIFT ELIMINATOR WITH A 99.999% CONTROL EI	0.001 %	BACT-PSD

Table D-19. RBLC PM Summary for Industrial Cooling Towers

RBLC ID	Facility Name	Permit Issuance	Process Description	Throughput	Control Method Description	Emissions Limit	Basis
FL-0293	CRYSTAL RIVER POWER PLANT	04/04/06	PORTABLE COOLING TOWER	180000 GAL/MIN	DRIFT ELIMINATORS	0.0015 % DRIFT F	BACT-PSD
WI-0228	WPS - WESTON PLANT	10/19/04	UNIT 4 WATER COOLING TOWER (P26, S26)		HIGH EFFICIENCY DRIFT ELIMINATORS (0.002%)	0.002 %	BACT-PSD
LA-0206	BATON ROUGE REFINERY	02/18/04	COOLING TOWERS		DRIFT ELIMINATOR SYSTEM	0.003 % DRIFT	BACT-PSD
OK-0055	MUSTANG ENERGY PROJECT	02/12/02	COOLING TOWERS		DRIFT ELIMINATORS	0.004 % DRIFT	BACT-PSD
IN-0119	AUBURN NUGGET	05/31/05	COOLING TOWER	23450 GAL/MIN		0.005 % OF THR	BACT-PSD
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/07	COOLING TOWER		DESIGNED TO MINIMIZE DRIFT	0.005 % DRIFT F	BACT-PSD
LA-0136	PLAQUEMINE COGENERATION FACILITY	07/23/08	COOLING TOWER	0.01 % DRIFT RA	GOOD OPERATING PRACTICES	0.005 % DRIFT F	BACT-PSD
LA-0211	GARYVILLE REFINERY	12/27/06	COOLING TOWER NOS. 1 & 2 (24-08 & 32-08) &		HIGH EFFICIENCY DRIFT ELIMINATORS	0.005 PERCENT	BACT-PSD
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/07	COOLING TOWER		DESIGNED TO MINIMIZE DRIFT	0.005 % DRIFT F	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	02/26/08	COOLING TOWERS		LIMIT OF TOTAL DISSOLVED SOLIDS IN THE CIRC	0.005 %	Other Case-by-
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/09	COOLING TOWER - UNIT HA19	7200 GAL/MIN	A DRIFT ELIMINATOR CONTROLS DRIFT RATE TC	0.005 %	Other Case-by-
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/09	COOLING TOWER - UNIT FL17	6900 GAL/MIN	DRIFT ELIMINATOR TO REDUCE DRIFT RATE TO	0.005 %	Other Case-by-
WI-0204	UWGP - FUEL GRADE ETHANOL PLANT	08/14/03	COOLING TOWERS, P80	22000 GAL/MIN	MAX □	0.005 %	Other Case-by-
NC-0112	NUCOR STEEL	11/23/04	COOLING TOWERS		MIST ELIMINATORS WITH A 0.008 PERCENT DRIF	0.008 %	BACT-PSD

Source: ECT, 2012.

APPENDIX E

OFFSITE EMISSIONS INVENTORY

APPENDIX E
EMISSIONS INVENTORY OF OFF SITE SOURCES

This appendix contains the emissions inventory of the sources that were included in the Prevention of Significant Deterioration (PSD) cumulative modeling analyses. Tables E-1 through E-3 list the individual emissions units of nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate matter (PM). The model IDs are unique codes that designate the county, facility, and emissions unit. The first letter and following numbers designate the county and facility. This is followed by the emissions unit (EU) number, e.g. U005. The county codes are:

- F = Polk County.
- T = Hillsborough County.
- M = Manatee County.
- H = Hardee County.

For instance, the first source shown on Table E-1 is F055U001, which is the Mosaic Fertilizer - South Pierce plant, and emissions unit 001, which is an auxiliary boiler. In addition to the process type, each entry includes the coordinates, elevation, and modeling parameters, e.g., emissions rate and stack parameters. In some cases, the model ID is followed by the letter "c," indicating that the source was a combination of several emissions units, or by the letter "p," indicating that the source is a PSD increment-consuming source.

Following are some specific data substitutions that were made to individual emissions units:

- CPV Pierce Power Generating Facility (ID 1050349):
  - o EU 001—set missing temperature to be 190 degrees Fahrenheit (°F) and velocity to 60 feet per second (ft/s).
  - o EU 002—set missing temperature to 90°F and velocity to 30 ft/s.
- Mosaic Fertilizer, South Pierce Facility (ID 1050055):
  - o EU 053—set missing stack height to 25 feet (ft), stack diameter to 2 ft, and velocity to 50 ft/s.
  - o EUs 13-25, 31, 35, 40, and 42—set missing velocities to 1.0 ft/s.
  - o EU 026—set missing stack height to 30 ft.
- Florida Power Corp, Hines Facility (ID 1050234):
  - o EU 003—set missing temperature to 300°F and velocity to 50 ft/s.
- Agrifos Mining, Nichols Facility (ID 1050047):
  - o EUs 001 and 002—set missing stack height to 70 ft.

- Mosaic Fertilizer, Bartow Facility (ID 1050046):
    - All internal combustion engines were assumed to be used infrequently.
- Mosaic Fertilizer, New Wales Facility (ID 1050059):
    - EU 067—set missing stack height to 25 ft, diameter to 0.1 ft, and temperature to 90°F.
    - EU 067 to 069—set missing velocity to 0.1 ft/s.
    - EU 60 to 66—set missing velocity to 0.42 ft/s based on flow rate of 80 actual cubic feet per minute (acfm).
- IMC Phosphates, Nichols (ID 1050057):
    - EUs 21 and 22—set temperature to 90°F.
    - EUs 20 through 22—set velocity to 1 ft/s.
- Mosaic Fertilizer, Central Florida Operations (ID 1050034):
    - EU 007—set missing temperature to 77°F and velocity to 20 ft/s.
    - EU 028—set missing temperature to 77°F and velocity to 20 ft/s.
- U.S. Agri Chemicals, Fort Meade Facility (ID 1050051):
    - EU 038—set missing velocity to 34.41 ft/s based on flow rate of 73,000 dry standard cubic feet per minute (dscfm).
- Calpine, Osprey Energy Center (ID 1050334):
    - EU 005—set missing temperature to 90°F and velocity to 30 ft/s.
- Cutrale Citrus Juices (ID 1050023):
    - EU 010—set missing temperature to 90°F and velocity to 30 ft/s.
- Florida Juice Partners Limited (US Beverage Packing), Lakeland Plant (ID 1050015):
    - EU 005—set missing velocity to 25 ft/s.
- Lakeland Electric, Winston Peaking Facility (ID 1050352)
    - EU 001 to EU 020—the emissions of these 20 identical diesel engines were combined into a single model source.
- CF Industries (ID 1050052)—Since this facility dramatically reduced PM emissions and shutdown some sources, it is now a minor source and was not included in the modeling.

Table E-1. Modeling Inventory of NO_x Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U001	407900.0	3071900.0	40.2	1	Auxiliary Boiler	17.64	2.22	10.67	1.46	494	15.54
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U004	407240.0	3073280.0	40.2	4	Sulfuric Acid Plant No. 10	15.00	1.89	43.89	2.74	350	12.53
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U005	407250.0	3073280.0	40.2	5	Sulfuric Acid Plant No. 11	15.00	1.89	43.89	2.74	350	12.53
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U052	407240.0	3073310.0	40.2	52	Phosphate Rock Dryer (supplies rock to No. 2 Ball Mill	5.52	0.70	27.43	2.44	344	3.84
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U053	407240.0	3073310.0	40.2	53	Auxiliary Boiler	14.30	1.80	7.62	0.61	494	15.24
CENTRAL FLORIDA MINERAL OPERATIONS	F034U008	392960.0	3058550.0	39.6	8	BOILER @ FOUR CORNERS MINE	0.55	0.07	7.92	0.29	478	7.16
CENTRAL FLORIDA MINERAL OPERATIONS	F034U011	392960.0	3058550.0	39.6	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN M	46.69	5.88	23.16	1.98	394	17.31
CENTRAL FLORIDA MINERAL OPERATIONS	F034U012	392960.0	3058550.0	39.6	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORA	44.18	5.57	16.76	2.83	341	8.84
HINES ENERGY COMPLEX	F234U001	414170.0	3074100.0	49.7	1	POWER BLOCK 1, CT 1A	349.00	43.97	38.10	5.79	361	18.07
HINES ENERGY COMPLEX	F234U002	414340.0	3073900.0	49.7	2	POWER BLOCK 1, CT 1B	349.00	43.97	38.10	5.79	361	18.07
HINES ENERGY COMPLEX	F234U003	414170.0	3074100.0	49.7	3	Auxiliary Boiler firing natural gas and low sulfur fuel o	9.90	1.25	6.71	0.61	422	15.24
HINES ENERGY COMPLEX	F234U014	414400.0	3073900.0	49.7	14	POWER BLOCK 2, CT 2A	99.70	12.56	38.10	5.79	361	18.07
HINES ENERGY COMPLEX	F234U015	414400.0	3073900.0	49.7	15	POWER BLOCK 2, CT 2B	99.70	12.56	38.10	5.79	361	18.07
HINES ENERGY COMPLEX	F234U016	414400.0	3073900.0	49.7	16	POWER BLOCK 3, CT 3A	82.00	10.33	38.10	5.79	361	18.11
HINES ENERGY COMPLEX	F234U017	414400.0	3073900.0	49.7	17	POWER BLOCK 3, CT 3B	82.00	10.33	38.10	5.79	361	18.11
HINES ENERGY COMPLEX	F234U018	414170.0	3074100.0	49.7	18	Power Block 4, CT 4A	82.40	10.38	38.10	5.49	368	20.70
HINES ENERGY COMPLEX	F234U019	414170.0	3074100.0	49.7	19	Power Block 4, CT 4B	82.40	10.38	38.10	5.49	368	20.70
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U002	396670.0	3079300.0	47.9	2	Sulfuric Acid Plant No. 1	17.00	2.14	60.96	2.59	350	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U003	396670.0	3079300.0	47.9	3	Sulfuric Acid Plant No. 2	17.00	2.14	60.96	2.59	350	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U004	396670.0	3079300.0	47.9	4	Sulfuric Acid Plant No. 3	17.00	2.14	60.96	2.59	350	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U009	396670.0	3079300.0	47.9	9	DAP Plant No. 1	10.30	1.30	40.54	2.13	314	14.94
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U042	396670.0	3079300.0	47.9	42	Sulfuric Acid Plant No. 4	14.50	1.83	60.66	2.59	350	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U044	396670.0	3079300.0	47.9	44	Sulfuric Acid Plant No. 5	14.50	1.83	60.66	2.59	350	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U045	396670.0	3079300.0	47.9	45	DAP Plant No 2 - East Train	12.60	1.59	52.12	1.83	316	17.68
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U046	396450.0	3079290.0	47.9	46	DAP Plant No 2 - West Train	12.60	1.59	52.12	1.83	316	17.68
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U074	396670.0	3079300.0	47.9	74	Multifos C Kiln Scrubber	9.11	1.15	52.43	1.37	314	21.40
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U078	396670.0	3079300.0	47.9	78	Granular Monoammonium Phosphate (GMAP) PLANT	19.96	2.51	40.54	1.83	336	33.41
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U081	396670.0	3079300.0	47.9	81	89.5 MMBTU/hr. boiler (non-NSPS) - rental boiler	12.80	1.61	5.49	1.10	478	10.64
TIGER BAY COGENERATION FACILITY	F223U001	416250.0	3069370.0	48.2	1	Combustion Turbine and Heat Recovery System Gener	326.00	41.08	54.86	5.79	369	19.20
TIGER BAY COGENERATION FACILITY	F223U003	416200.0	3069220.0	48.2	3	100 MMBtu/hr Package Steam Boiler	10.00	1.26	12.19	1.22	433	11.80
MULBERRY COGEN FACILITY	F217U001	413600.0	3080600.0	44.8	1	Combustion Turbine with HRSG(Phase II, Acid Rain U	164.00	20.66	38.10	4.57	378	19.54
MULBERRY COGEN FACILITY	F217U002	413600.0	3080600.0	44.8	2	Secondary Boiler	23.40	2.95	38.10	0.91	378	20.27
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U007	409500.0	3080100.0	52.4	7	SOUTH AP FERTILIZER PLANT	8.57	1.08	39.01	2.29	322	12.65
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U029	409050.0	3079050.0	52.4	29	NORTH MAP/DAP FERTILIZER PLANT	7.14	0.90	39.32	2.29	315	13.11
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U038	409500.0	3080100.0	52.4	38	2750 TPD No. 6 Sulfuric Acid Plant	13.80	1.74	45.72	2.74	355	9.27
PEACE RIVER STATION, LLC	F336U001	419500.0	3069700.0	36.3	1	GT-1, 170 MW simple cycle gas turbine peaking unit	330.60	41.66	18.29	6.40	865	34.85
PEACE RIVER STATION, LLC	F336U002	419500.0	3069700.0	36.3	2	GT-2, 170 MW simple cycle gas turbine peaking unit	330.60	41.66	18.29	6.40	865	34.85
PEACE RIVER STATION, LLC	F336U003	419500.0	3069700.0	36.3	3	GT-3, 170 MW simple cycle gas turbine peaking unit	330.60	41.66	18.29	6.40	865	34.85
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U003	398400.0	3084200.0	36.6	3	DAP PLANT DRYER	2.29	0.29	24.38	1.07	328	23.77
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U005	398400.0	3084200.0	36.6	5	SULFURIC ACID PLANT NO. 1 DOUBLE ABSORP	12.50	1.58	45.72	2.29	350	10.06
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U012	398400.0	3084200.0	36.6	12	Phosphate Rock Dryer	22.00	2.77	24.69	2.29	328	3.66
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U015	398400.0	3084200.0	36.6	15	North Auxiliary Boiler	3.50	0.44	8.23	0.61	533	13.72
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U016	398040.0	3084020.0	36.6	16	South Auxiliary Boiler	7.00	0.88	11.89	0.98	533	8.84

Table E-1. Modeling Inventory of NO_x Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
U.S. AGRI-CHEMICALS - FT. MEADE	F051U006	416950.0	3069280.0	47.9	6	AUXILIARY BOILER	30.00	3.78	21.34	1.13	478	14.94
U.S. AGRI-CHEMICALS - FT. MEADE	F051U016	416950.0	3069280.0	47.9	16	SULFURIC ACID PLANT #1	17.35	2.19	53.34	2.59	355	9.75
U.S. AGRI-CHEMICALS - FT. MEADE	F051U017	416950.0	3069280.0	47.9	17	SULFURIC ACID PLANT #2	17.35	2.19	53.34	2.59	355	9.75
CPV PIERCE POWER GENERATING FACILITY	F349U001	406700.0	3079300.0	45.4	1	245 MW Combustion Turbine with HRSG	80.00	10.08	53.34	5.64	361	18.29
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U001	409770.0	3087260.0	64.0	1	No. 3 Fertilizer(DAP/MAP) Plant	14.67	1.85	30.18	2.29	330.4	16.15
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U012	409080.0	3087000.0	64.0	12	No. 4 Sulfuric Acid Plant	13.00	1.64	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U021	409770.0	3087260.0	64.0	21	No. 4 Fertilizer Plant	14.67	1.85	42.67	3.32	328.7	16.15
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U032	409080.0	3087000.0	64.0	32	No. 6 Sulfuric Acid Plant	13.00	1.64	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U033	409080.0	3087000.0	64.0	33	No. 5 Sulfuric Acid Plant	13.00	1.64	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U051	409800.0	3087000.0	64.0	51	Cleaver Brooks Package Watertube Boiler	23.47	2.96	9.45	1.07	483.2	6.10
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U055	409770.0	3087260.0	64.0	55	Auxiliary Process Steam Boiler	23.93	3.02	7.62	1.45	449.3	8.60
ORANGE COGENERATION FACILITY	F231U001	418700.0	3083000.0	38.7	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid R	37.00	4.66	30.48	3.35	383.2	15.97
ORANGE COGENERATION FACILITY	F231U002	418700.0	3083000.0	38.7	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid R	37.00	4.66	30.48	3.35	383.2	15.97
ORANGE COGENERATION FACILITY	F231U003	418700.0	3083000.0	38.7	3	Auxiliary Boiler	13.00	1.64	19.81	1.13	424.8	14.02
AGRIFOS MINING, L.L.C. - NICHOLS	F047U001	398300.0	3085250.0	35.4	1	PHOSPHATE ROCK DRYER NO. 1, DRY CYCLONI	35.82	4.51	21.34	2.29	344.3	12.50
AGRIFOS MINING, L.L.C. - NICHOLS	F047U002	398300.0	3085250.0	35.4	2	PHOSPHATE ROCK DRYER NO. 2, DRY CYCLONI	35.20	4.44	21.34	2.29	344.3	12.50
WINSTON PEAKING STATION	F352U001	400080.0	3100690.0	54.9	1	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U002	400080.0	3100690.0	54.9	2	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U003	400080.0	3100690.0	54.9	3	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U004	400080.0	3100690.0	54.9	4	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U005	400080.0	3100690.0	54.9	5	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U006	400080.0	3100690.0	54.9	6	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U007	400080.0	3100690.0	54.9	7	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U008	400080.0	3100690.0	54.9	8	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U009	400080.0	3100690.0	54.9	9	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U010	400080.0	3100690.0	54.9	10	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U011	400080.0	3100690.0	54.9	11	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U012	400080.0	3100690.0	54.9	12	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U013	400080.0	3100690.0	54.9	13	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U014	400080.0	3100690.0	54.9	14	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U015	400080.0	3100690.0	54.9	15	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U016	400080.0	3100690.0	54.9	16	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U017	400080.0	3100690.0	54.9	17	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U018	400080.0	3100690.0	54.9	18	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U019	400080.0	3100690.0	54.9	19	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
WINSTON PEAKING STATION	F352U020	400080.0	3100690.0	54.9	20	2.5 MW GM EMD 20/645/E4B diesel engine .	13.90	1.75	9.14	0.56	666.5	41.24
US BEVERAGE LAKELAND PLANT	F015U001	399070.0	3102070.0	38.1	1	CITRUS PEEL DRYER W/ 2 WASTE HEAT EVAPO	11.66	1.47	27.43	0.91	333.2	7.32
US BEVERAGE LAKELAND PLANT	F015U002	399070.0	3102070.0	38.1	2	ERIE CITY MODEL 14-200 PROCESS STEAM BOIL	23.32	2.94	10.06	0.61	447.0	5.18
US BEVERAGE LAKELAND PLANT	F015U003	399070.0	3102070.0	38.1	3	ERIE CITY SIZE 50 PROCESS STEAM BOILER NO	8.09	1.02	10.36	0.91	447.0	9.14

Source: ECT, 2012.

Table E-2. Modeling Inventory of SO_x Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (meters)	EU ID	EU Description	Emiss Rate (lb/hr)	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U001	407900.0	3071900.0	40.2	1	Auxiliary Boiler	8.95	1.13	10.67	1.46	494.3	15.54
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U004	407240.0	3073280.0	40.2	4	Sulfuric Acid Plant No. 10	500.00	63.00	43.89	2.74	349.8	12.53
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U005	407250.0	3073280.0	40.2	5	Sulfuric Acid Plant No. 11	500.00	63.00	43.89	2.74	349.8	12.53
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U030	407240.0	3073310.0	40.2	30	Molten Sulfur Storage and Handling	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U031	407240.0	3073310.0	40.2	31	Molten Sulfur Storage - (East) Tank 1 - Vent 2	0.13	0.02	7.32	0.37	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U032	407240.0	3073310.0	40.2	32	'Molten Sulfur Storage - (East) Tank 1 - Vent 3	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U033	407240.0	3073310.0	40.2	33	'Molten Sulfur Storage - (East) Tank 1 - Vent 4	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U034	407240.0	3073310.0	40.2	34	'Molten Sulfur Storage - (East) Tank 1 - Vent 5	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U035	407240.0	3073310.0	40.2	35	Molten Sulfur Storage - (West) Tank 2 - Vent 1	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U036	407240.0	3073310.0	40.2	36	Molten Sulfur Storage - (West) Tank 2 - Vent 2	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U037	407240.0	3073310.0	40.2	37	'Molten Sulfur Storage - (West) Tank 2 - Vent 3	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U038	407240.0	3073310.0	40.2	38	'Molten Sulfur Storage - (West) Tank 2 - Vent 4	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U039	407240.0	3073310.0	40.2	39	'Molten Sulfur Storage - (West) Tank 2 - Vent 5	0.13	0.02	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U040	407240.0	3073310.0	40.2	40	Molten Sulfur Truck Pit, East Vent, with fan	1.19	0.15	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U041	407270.0	3073300.0	40.2	41	'Molten Sulfur Truck Pit, East Vent, without fan	1.19	0.15	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U042	407240.0	3073310.0	40.2	42	'Molten Sulfur Truck Pit, West Vent, with fan	1.19	0.15	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U043	407220.0	3073300.0	40.2	43	'Molten Sulfur Truck Pit, West Vent, without fan	1.19	0.15	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U044	407240.0	3073310.0	40.2	44	Molten Sulfur Rail Pit, North Vent	0.28	0.04	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U045	407240.0	3073310.0	40.2	45	Molten Sulfur Rail Pit, South Vent	0.28	0.04	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U052	407240.0	3073310.0	40.2	52	Phosphate Rock Dryer (supplies rock to No. 2 Ball Mill)	0.02	0.00	27.43	2.44	344.3	3.84
MOSAIC FERTILIZER - SOUTH PIERCE FACILIT	F055U053	407240.0	3073310.0	40.2	53	Auxiliary Boiler	5.23	0.66	7.62	0.61	494.3	15.24
CENTRAL FLORIDA MINERAL OPERATIONS	F034U008	392960.0	3058550.0	39.6	8	BOILER @ FOUR CORNERS MINE	1.95	0.25	7.92	0.29	477.6	7.16
CENTRAL FLORIDA MINERAL OPERATIONS	F034U011	392960.0	3058550.0	39.6	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MINE	467.86	58.95	23.16	1.98	394.3	17.31
CENTRAL FLORIDA MINERAL OPERATIONS	F034U012	392960.0	3058550.0	39.6	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORALYN	442.74	55.79	16.76	2.83	341.5	8.84
HINES ENERGY COMPLEX	F234U001	414170.0	3074100.0	49.7	1	POWER BLOCK 1, CT 1A	94.00	11.84	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U002	414340.0	3073900.0	49.7	2	POWER BLOCK 1, CT 1B	94.00	11.84	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U003	414170.0	3074100.0	49.7	3	Auxiliary Boiler firing natural gas and low sulfur fuel oil	0.55	0.07	6.71	0.61	422.0	15.24
HINES ENERGY COMPLEX	F234U014	414400.0	3073900.0	49.7	14	POWER BLOCK 2, CT 2A	105.60	13.31	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U015	414400.0	3073900.0	49.7	15	POWER BLOCK 2, CT 2B	105.60	13.31	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U016	414400.0	3073900.0	49.7	16	POWER BLOCK 3, CT 3A	105.60	13.31	38.10	5.79	360.9	18.11
HINES ENERGY COMPLEX	F234U017	414400.0	3073900.0	49.7	17	POWER BLOCK 3, CT 3B	105.60	13.31	38.10	5.79	360.9	18.11
HINES ENERGY COMPLEX	F234U018	414170.0	3074100.0	49.7	18	Power Block 4, CT 4A	109.20	13.76	38.10	5.49	367.6	20.70
HINES ENERGY COMPLEX	F234U019	414170.0	3074100.0	49.7	19	Power Block 4, CT 4B	109.20	13.76	38.10	5.49	367.6	20.70
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U002	396670.0	3079300.0	47.9	2	Sulfuric Acid Plant No. 1	567.00	71.44	60.96	2.59	349.8	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U003	396670.0	3079300.0	47.9	3	Sulfuric Acid Plant No. 2	567.00	71.44	60.96	2.59	349.8	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U004	396670.0	3079300.0	47.9	4	Sulfuric Acid Plant No. 3	567.00	71.44	60.96	2.59	349.8	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U009	396670.0	3079300.0	47.9	9	DAP Plant No. 1	82.10	10.34	40.54	2.13	313.7	14.94
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U042	396670.0	3079300.0	47.9	42	Sulfuric Acid Plant No. 4	483.30	60.90	60.66	2.59	349.8	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U044	396670.0	3079300.0	47.9	44	Sulfuric Acid Plant No. 5	483.30	60.90	60.66	2.59	349.8	15.24
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U045	396670.0	3079300.0	47.9	45	DAP Plant No 2 - East Train	22.00	2.77	52.12	1.83	316.5	17.68
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U046	396450.0	3079290.0	47.9	46	DAP Plant No 2 - West Train	22.00	2.77	52.12	1.83	316.5	17.68
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U060	396670.0	3079300.0	47.9	60	7500 Ton Rail Storage Molten Sulfur Storage Tank	0.50	0.06	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U062	396670.0	3079300.0	47.9	62	15,000 Ton Molten Sulfur Storage Tank No.3	0.50	0.06	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U063	396670.0	3079300.0	47.9	63	1500 Ton Truck Unloading Sulfur Pit (North) No.1	0.30	0.04	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U064	396670.0	3079300.0	47.9	64	350 Ton Truck Unloading Sulfur Pit (South) No. 2	0.10	0.01	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U065	396670.0	3079300.0	47.9	65	800 Railcar Unloading Pit	0.30	0.04	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U066	396670.0	3079300.0	47.9	66	200 Ton Molten Sulfur Transfer Pit	0.10	0.01	12.19	0.61	388.7	0.12
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U067	396670.0	3079300.0	47.9	67	1500 Ton Truck Unloading Sulfur Pit, Front Vent	0.30	0.04	7.62	0.03	305.4	0.03
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U068	396670.0	3079300.0	47.9	68	1500 Ton Truck Unloading Sulfur Pit, Rear Vent	0.30	0.04	7.62	0.03	305.4	0.03
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U069	396670.0	3079300.0	47.9	69	350 Ton Truck Unloading Sulfur Pit Vent No. 2	0.10	0.01	7.62	0.03	305.4	0.03

Table E-2. Modeling Inventory of SO_x Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (meters)	EU ID	EU Description	Emiss Rate (lb/hr)	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U074	396670.0	3079300.0	47.9	74	Multifos C Kiln Scrubber	9.11	1.15	52.43	1.37	313.7	21.40
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U078	396670.0	3079300.0	47.9	78	Granular Monoammonium Phosphate (GMAP) PLANT	166.68	21.00	40.54	1.83	335.9	33.41
MOSAIC FERTILIZER - NEW WALES FACILITY	F059U081	396670.0	3079300.0	47.9	81	89.5 MMBTU/hr. boiler (non-NSPS) - rental boiler	4.30	0.54	5.49	1.10	477.6	10.64
TIGER BAY COGENERATION FACILITY	F223U001	416250.0	3069370.0	48.2	1	Combustion Turbine and Heat Recovery System Generator	99.70	12.56	54.86	5.79	369.3	19.20
TIGER BAY COGENERATION FACILITY	F223U003	416200.0	3069220.0	48.2	3	100 MMBtu/hr Package Steam Boiler	0.56	0.07	12.19	1.22	433.2	11.80
CF INDUSTRIES - BARTOW PHOSPHATE COMPLEX	F052U006	408300.0	3082500.0	54.9	6	SULFURIC ACID PLANT NO.6	400.00	50.40	62.79	2.13	333.2	6.40
CF INDUSTRIES - BARTOW PHOSPHATE COMPLEX	F052U021	408300.0	3082500.0	54.9	21	BOILER NO. 1	17.20	2.17	10.97	0.76	588.7	13.41
PEACE RIVER STATION, LLC	F336U001	419500.0	3069700.0	36.3	1	GT-1, 170 MW simple cycle gas turbine peaking unit	99.23	12.50	18.29	6.40	864.8	34.84
PEACE RIVER STATION, LLC	F336U002	419500.0	3069700.0	36.3	2	GT-2, 170 MW simple cycle gas turbine peaking unit	99.23	12.50	18.29	6.40	864.8	34.84
PEACE RIVER STATION, LLC	F336U003	419500.0	3069700.0	36.3	3	GT-3, 170 MW simple cycle gas turbine peaking unit	99.23	12.50	18.29	6.40	864.8	34.84
MULBERRY COGEN FACILITY	F217U001	413600.0	3080600.0	44.8	1	Combustion Turbine with HRSG(Phase II, Acid Rain Unit)	58.20	7.33	38.10	4.57	377.6	19.54
MULBERRY COGEN FACILITY	F217U002	413600.0	3080600.0	44.8	2	Secondary Boiler	0.55	0.07	38.10	0.91	377.6	20.27
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U003	398400.0	3084200.0	36.6	3	DAP PLANT DRYER	8.11	1.02	24.38	1.07	327.6	23.77
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U005	398400.0	3084200.0	36.6	5	SULFURIC ACID PLANT NO. 1 DOUBLE ABSORPTION	416.80	52.52	45.72	2.29	349.8	10.06
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U012	398400.0	3084200.0	36.6	12	Phosphate Rock Dryer	188.40	23.74	24.69	2.29	327.6	3.66
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U015	398400.0	3084200.0	36.6	15	North Auxiliary Boiler	13.74	1.73	8.23	0.61	533.2	13.72
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U016	398040.0	3084020.0	36.6	16	South Auxiliary Boiler	27.48	3.46	11.89	0.98	533.2	8.84
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U020	398040.0	3084020.0	36.6	20	Molten Sulfur Storage & Handling - North Storage Tank	0.20	0.03	7.62	0.06	305.4	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U021	398400.0	3084200.0	36.6	21	Molten Sulfur Storage & Handling - South Storage Tank	0.10	0.01	1.83	0.23	305.4	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U022	398400.0	3084200.0	36.6	22	Molten Sulfur Storage & Handling - Railcar Unloading Pit	0.20	0.03	1.83	0.23	305.4	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U023	398400.0	3084200.0	36.6	23	Molten Sulfur Storage & Handling - Truck Unloading Pit	0.50	0.06	1.83	0.23	305.4	0.30
U.S. AGRI-CHEMICALS - FT. MEADE	F051U006	416950.0	3069280.0	47.9	6	AUXILIARY BOILER	51.00	6.43	21.34	1.13	477.6	14.94
U.S. AGRI-CHEMICALS - FT. MEADE	F051U016	416950.0	3069280.0	47.9	16	SULFURIC ACID PLANT #1	500.00	63.00	53.34	2.59	355.4	9.75
U.S. AGRI-CHEMICALS - FT. MEADE	F051U017	416950.0	3069280.0	47.9	17	SULFURIC ACID PLANT #2	500.00	63.00	53.34	2.59	355.4	9.75
U.S. AGRI-CHEMICALS - FT. MEADE	F051U028	416000.0	3068080.0	47.9	28	MOLTEN SULFUR STORAGE - TANK (4,210 TON, 7 VE	0.49	0.06	1.83	0.09	405.4	104.85
U.S. AGRI-CHEMICALS - FT. MEADE	F051U029	416030.0	3068080.0	47.9	29	MOLTEN SULFUR STORAGE - PIT (5 VENTS) (229 TC	0.23	0.03	1.83	0.09	399.8	47.85
CPV PIERCE POWER GENERATING FACILITY	F349U001	406700.0	3079300.0	45.4	1	245 MW Combustion Turbine with HRSG	95.85	12.08	53.34	5.64	360.9	18.29
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U004	409500.0	3080100.0	52.4	4	SULFURIC ACID PLANT #4 DOUBLE CONTACT/ABSC	350.00	44.10	30.48	2.29	355.4	12.07
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U005	409500.0	3080100.0	52.4	5	SULFURIC ACID PLANT #5 - REPLACES TWO OLD PL	467.00	58.84	45.72	2.44	355.4	13.44
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U007	409500.0	3080100.0	52.4	7	SOUTH AP FERTILIZER PLANT	3.04	0.38	39.01	2.29	322.0	12.65
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U029	409050.0	3079050.0	52.4	29	NORTH MAP/DAP FERTILIZER PLANT	2.54	0.32	39.32	2.29	315.4	13.11
MOSAIC FERTILIZER - GREEN BAY FACILITY	F053U038	409500.0	3080100.0	52.4	38	2750 TPD No. 6 Sulfuric Acid Plant	401.00	50.53	45.72	2.74	355.4	9.27
PRAIRIE MINE	F056U004	402900.0	3087000.0	36.6	4	LIMEROCK DRYER WITH CYCLONE AND BAGHOUS	116.18	14.64	21.34	1.34	357.6	15.54
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U001	409770.0	3087260.0	64.0	1	No. 3 Fertilizer(DAP/MAP) Plant	76.90	9.69	30.18	2.29	330.4	16.15
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U012	409080.0	3087000.0	64.0	12	No. 4 Sulfuric Acid Plant	433.30	54.60	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U021	409770.0	3087260.0	64.0	21	No. 4 Fertilizer Plant	102.53	12.92	42.67	3.32	328.7	16.15
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U032	409080.0	3087000.0	64.0	32	No. 6 Sulfuric Acid Plant	433.30	54.60	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U033	409080.0	3087000.0	64.0	33	No. 5 Sulfuric Acid Plant	433.30	54.60	60.96	2.07	355.4	18.59
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U045	409770.0	3087260.0	64.0	45	Molten Sulfur System-STACK 45 (PIT A), 200 TON MOLT	2.54	0.32	12.19	0.30	366.5	17.37
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U051	409800.0	3087000.0	64.0	51	Cleaver Brooks Package Watertube Boiler	165.17	20.81	9.45	1.07	483.2	6.10
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U054	409770.0	3087260.0	64.0	54	No. 3 Sulfuric Acid Plant	283.30	35.70	60.96	2.13	340.4	10.24
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U055	409770.0	3087260.0	64.0	55	Auxiliary Process Steam Boiler	44.40	5.59	7.62	1.45	449.3	8.60
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U056	409770.0	3087260.0	64.0	56	Molten Sulfur Storage/Handling- Truck Delivery Pit	0.05	0.01	12.19	0.30	366.5	17.47

Table E-2. Modeling Inventory of SO_x Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (meters)	EU ID	EU Description	Emiss Rate (lb/hr)	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U057	409770.0	3087260.0	64.0	57	Molten Sulfur Storage/Handling- Storage Tank, North Vent	0.05	0.01	12.19	0.30	366.5	17.47
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U058	409770.0	3087260.0	64.0	58	Molten Sulfur Storage/Handling- Storage Tank, Southeast V	0.05	0.01	12.19	0.30	366.5	17.47
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U059	409770.0	3087260.0	64.0	59	Molten Sulfur Storage/Handling- Storage Tank, Southwest \	0.05	0.01	12.19	0.30	366.5	17.47
MOSAIC FERTILIZER, LLC - BARTOW FACILITY	F046U060	409770.0	3087260.0	64.0	60	Molten Sulfur Storage/Handling- Storage Tank, Middle Ven	0.05	0.01	12.19	0.30	366.5	17.47
AGRIFOS MINING, L.L.C. - NICHOLS	F047U001	398300.0	3085250.0	35.4	1	PHOSPHATE ROCK DRYER NO. 1, DRY CYCLONES, \	255.65	32.21	24.38	2.29	344.3	12.50
AGRIFOS MINING, L.L.C. - NICHOLS	F047U002	398300.0	3085250.0	35.4	2	PHOSPHATE ROCK DRYER NO. 2, DRY CYCLONES, \	251.20	31.65	24.38	2.29	344.3	12.50
MOSAIC FERTILIZER - MULBERRY FACILITY	F048U002	408020.0	3085010.0	53.3	2	DC/DA SULFURIC ACID PLANT - MONSANTO DESIGI	283.3	35.70	60.96	2.13	366.5	9.75
MOSAIC FERTILIZER - MULBERRY FACILITY	F048U005	408020.0	3085010.0	53.3	5	MAP/DAP PLANT SCRUBBER	71.51	9.01	31.09	2.68	316.5	7.92
MOSAIC FERTILIZER - MULBERRY FACILITY	F048U009	408020.0	3085010.0	53.3	9	NEBRASKA MODEL NS-E-65 STEAM BOILER	48.77	6.15	13.72	1.13	299.8	2.44
U S AGRI-CHEMICALS - BARTOW	F050U038	413200.0	3086300.0	45.1	38	150 TPH MAP/DAP PLANT(79 TPH P2O5 INPUT)	113.09	14.25	39.93	2.13	316.5	17.16

Source: ECT, 2012.

Table E-3. Modeling Inventory of PM Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (ft)	(meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U001	407900.0	3071900.0	132.0	40.2	1	Auxiliary Boiler	2.40	0.30	10.67	1.46	494.3	15.54
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U026	407500.0	3071500.0	132.0	40.2	26	Dry Phosphate Rock Handling Hopper Bins	22.50	2.84	9.14	0.30	305.4	15.24
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U031	407240.0	3073310.0	132.0	40.2	31	Molten Sulfur Storage - (East) Tank 1 - Vent 2	0.50	0.06	7.32	0.37	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U035	407240.0	3073310.0	132.0	40.2	35	Molten Sulfur Storage - (West) Tank 2 - Vent 1	0.50	0.06	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U040	407240.0	3073310.0	132.0	40.2	40	Molten Sulfur Truck Pit, East Vent, with fan	0.92	0.12	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U042	407240.0	3073310.0	132.0	40.2	42	'Molten Sulfur Truck Pit, West Vent, with fan	0.92	0.12	7.32	0.30	366.5	0.30
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U052	407240.0	3073310.0	132.0	40.2	52	Phosphate Rock Dryer (supplies rock to No. 2 Ball Mill)	4.08	0.51	27.43	2.44	344.3	3.84
MOSAIC FERTILIZER - SOUTH PIERCE FA	F055U053	407240.0	3073310.0	132.0	40.2	53	Auxiliary Boiler	1.40	0.18	7.62	0.61	494.3	15.24
CPV PIERCE POWER GENERATING FACIL	F349U001	406700.0	3079300.0	149.0	45.4	1	245 MW Combustion Turbine with HRSG	36.00	4.54	53.34	5.64	360.9	18.29
CPV PIERCE POWER GENERATING FACIL	F349U002	406600.0	3079100.0	149.0	45.4	2	One five-cell cooling tower & Zero Wastewater Discharge	0.79	0.10	13.72	10.00	305.37	9.14
CENTRAL FLORIDA MINERAL OPERATIO	F034U003	392960.0	3058550.0	130.0	39.6	3	RAYMOND MILL NO 3 GRINDER W/SCRUBBER @ I	30.00	3.78	17.68	0.58	310.9	14.94
CENTRAL FLORIDA MINERAL OPERATIO	F034U004	392960.0	3058550.0	130.0	39.6	4	PHOS RK DRYER W/SCRUBBER @ KINGSFORD MI	44.20	5.57	21.34	2.13	347.0	14.33
CENTRAL FLORIDA MINERAL OPERATIO	F034U005	392960.0	3058550.0	130.0	39.6	5	PHOS ROCK TRANSFER AND STORAGE SILOS W/S	20.00	2.52	32.31	0.76	308.2	20.42
CENTRAL FLORIDA MINERAL OPERATIO	F034U006	398020.0	3075070.0	130.0	39.6	6	UNGROUND PHOSPHATE ROCK RR CAR LOAD OU	20.00	2.52	10.67	0.76	297.0	10.06
CENTRAL FLORIDA MINERAL OPERATIO	F034U007	392960.0	3058550.0	130.0	39.6	7	SODA ASH STORAGE & HANDLING @ FORT GREE	19.20	2.42	9.14	0.61	298.15	6.10
CENTRAL FLORIDA MINERAL OPERATIO	F034U008	392960.0	3058550.0	130.0	39.6	8	BOILER @ FOUR CORNERS MINE	0.06	0.01	7.92	0.29	477.6	7.16
CENTRAL FLORIDA MINERAL OPERATIO	F034U009	392960.0	3058550.0	130.0	39.6	9	MAGNETITE STORAGE BIN @ FOUR CORNERS MI	0.13	0.02	37.19	0.18	298.2	8.99
CENTRAL FLORIDA MINERAL OPERATIO	F034U010	392960.0	3058550.0	130.0	39.6	10	FERROSILICON STORAGE BIN @ FOUR CORNERS I	0.13	0.02	37.19	0.18	298.2	6.83
CENTRAL FLORIDA MINERAL OPERATIO	F034U011	392960.0	3058550.0	130.0	39.6	11	PHOSPHATE ROCK DRYER NO. 1 @ NORALYN MIN	42.20	5.32	23.16	1.98	394.3	17.31
CENTRAL FLORIDA MINERAL OPERATIO	F034U012	392960.0	3058550.0	130.0	39.6	12	PHOSPHATE ROCK DRYER NO. 2 EAST @ NORALY	45.10	5.68	16.76	2.83	341.5	8.84
CENTRAL FLORIDA MINERAL OPERATIO	F034U013	392960.0	3058550.0	130.0	39.6	13	PHOSPHATE ROCK STORAGE SILOS 1, 2, 3, & 12 @	35.00	4.41	45.72	1.07	310.9	15.85
CENTRAL FLORIDA MINERAL OPERATIO	F034U014	392960.0	3058550.0	130.0	39.6	14	BALL MILL TRANSFERS (C108) @ NORALYN MINE	15.00	1.89	7.32	0.61	316.5	8.08
CENTRAL FLORIDA MINERAL OPERATIO	F034U015	392960.0	3058550.0	130.0	39.6	15	BALL MILL TRANSFERS (C109) @ NORALYN MINE	10.00	1.26	7.32	0.61	316.5	8.08
CENTRAL FLORIDA MINERAL OPERATIO	F034U016	392960.0	3058550.0	130.0	39.6	16	BALL MILL NO. 3 @ NORALYN MINE (016)	10.00	1.26	7.62	0.46	297.0	11.49
CENTRAL FLORIDA MINERAL OPERATIO	F034U017	392960.0	3058550.0	130.0	39.6	17	BALL MILL NO. 4 @ NORALYN MINE (017)	10.00	1.26	8.23	0.61	297.0	4.85
CENTRAL FLORIDA MINERAL OPERATIO	F034U018	392960.0	3058550.0	130.0	39.6	18	NO. 3 BALL MILL RAILCAR LOADOUTS @ NORAL'	10.00	1.26	7.62	0.46	298.2	11.49
CENTRAL FLORIDA MINERAL OPERATIO	F034U019	392960.0	3058550.0	130.0	39.6	19	NO. 4 BALL MILL RAILCAR LOADOUTS @ NORAL'	10.00	1.26	8.84	0.55	298.2	6.00
CENTRAL FLORIDA MINERAL OPERATIO	F034U020	392960.0	3058550.0	130.0	39.6	20	A TRACK RAILCAR PHOSPHATE ROCK LOADOUT	15.00	1.89	8.23	0.61	302.6	16.18
CENTRAL FLORIDA MINERAL OPERATIO	F034U021	414700.0	3080300.0	130.0	39.6	21	B TRACK RAILCAR PHOSPHATE ROCK LOADOUT	15.00	1.89	8.23	0.58	300.4	21.88
CENTRAL FLORIDA MINERAL OPERATIO	F034U022	392960.0	3058550.0	130.0	39.6	22	T7 & T8 (TRANSFER POINTS TO CONVEYORS C31 &	10.00	1.26	12.19	0.46	310.9	14.39
CENTRAL FLORIDA MINERAL OPERATIO	F034U023	392960.0	3058550.0	130.0	39.6	23	MATERIAL TRANSFER SOURCES (C20 PIT TRANSF	15.00	1.89	13.11	0.61	303.2	8.08
CENTRAL FLORIDA MINERAL OPERATIO	F034U024	392960.0	3058550.0	130.0	39.6	24	DRY PHOSPHATE ROCK TRANSFER SYSTEM @ NC	15.00	1.89	41.15	0.85	288.7	16.76
CENTRAL FLORIDA MINERAL OPERATIO	F034U025	389920.0	3067780.0	130.0	39.6	25	SODA ASH MIX TANK & TRANSFER SYSTEM @ LC	16.00	2.02	10.67	0.15	298.2	31.58
CENTRAL FLORIDA MINERAL OPERATIO	F034U028	392960.0	3058550.0	130.0	39.6	28	DRY UNGROUND ROCK TRUCK LOADOUT @ NOR	0.30	0.04	8.23	0.61	298.15	6.10
MOSAIC FERTILIZER - NEW WALES FACI	F059U009	396670.0	3079300.0	157.0	47.9	9	DAP Plant No. 1	15.00	1.89	40.54	2.13	313.7	14.94
MOSAIC FERTILIZER - NEW WALES FACI	F059U011	396670.0	3079300.0	157.0	47.9	11	MAP Prill Plant	7.50	0.95	36.58	1.22	341.5	17.37
MOSAIC FERTILIZER - NEW WALES FACI	F059U015	396670.0	3079300.0	157.0	47.9	15	Animal Feed Ingredients (AFI) Shipping/Truck Loadout	3.60	0.45	19.81	0.30	313.7	51.51
MOSAIC FERTILIZER - NEW WALES FACI	F059U023	396670.0	3079300.0	157.0	47.9	23	AFI Storage Silos (3) - North "A" Side	4.75	0.60	34.75	0.30	313.7	10.06
MOSAIC FERTILIZER - NEW WALES FACI	F059U024	396670.0	3079300.0	157.0	47.9	24	AFI Storage/Shipping/Rail Car Loadout	3.60	0.45	31.39	0.30	313.7	42.67
MOSAIC FERTILIZER - NEW WALES FACI	F059U025	396670.0	3079300.0	157.0	47.9	25	AFI (2) Limestone Storage Silos	3.60	0.45	36.27	0.30	313.7	38.71
MOSAIC FERTILIZER - NEW WALES FACI	F059U026	396670.0	3079300.0	157.0	47.9	26	AFI Silica Storage Bin	1.60	0.20	5.49	0.30	313.7	9.45
MOSAIC FERTILIZER - NEW WALES FACI	F059U027	396700.0	3079400.0	157.0	47.9	27	AFI Granulation Plant	36.80	4.64	52.43	2.44	327.6	20.21
MOSAIC FERTILIZER - NEW WALES FACI	F059U028	396670.0	3079300.0	157.0	47.9	28	AFI Storage Silos (3) - South "B" Side	4.75	0.60	34.75	0.30	313.7	10.06
MOSAIC FERTILIZER - NEW WALES FACI	F059U036	396670.0	3079300.0	157.0	47.9	36	Multifos A and B Kilns, Dryer and Blending Operation	29.83	3.76	52.43	1.37	313.7	15.85
MOSAIC FERTILIZER - NEW WALES FACI	F059U045p	396670.0	3079300.0	157.0	47.9	45	DAP Plant No 2 - East Train	6.40	0.81	52.12	1.83	316.5	17.68
MOSAIC FERTILIZER - NEW WALES FACI	F059U046p	396450.0	3079290.0	157.0	47.9	46	DAP Plant No 2 - West Train	6.40	0.81	52.12	1.83	316.5	17.68
MOSAIC FERTILIZER - NEW WALES FACI	F059U047	396670.0	3079300.0	157.0	47.9	47	DAP Plant No 2 West Product Cooler	4.22	0.53	44.81	1.31	352.6	21.00
MOSAIC FERTILIZER - NEW WALES FACI	F059U052	396670.0	3079300.0	157.0	47.9	52	AFI Limestone Feed Bin	3.60	0.45	34.75	0.30	313.7	10.06
MOSAIC FERTILIZER - NEW WALES FACI	F059U055	396670.0	3079300.0	157.0	47.9	55	MAP Plant Cooler	4.00	0.50	7.62	1.31	333.2	10.36
MOSAIC FERTILIZER - NEW WALES FACI	F059U056	396670.0	3079300.0	157.0	47.9	56	DAP Plant No 2 East Product Cooler	6.06	0.76	51.82	1.52	316.5	19.66

Table E-3. Modeling Inventory of PM Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (ft)	(meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MOSAIC FERTILIZER - NEW WALES FACII	F059U060	396670.0	3079300.0	157.0	47.9	60	7500 Ton Rail Storage Molten Sulfur Storage Tank	0.60	0.08	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U062	396670.0	3079300.0	157.0	47.9	62	15,000 Ton Molten Sulfur Storage Tank No.3	0.60	0.08	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U063	396670.0	3079300.0	157.0	47.9	63	1500 Ton Truck Unloading Sulfur Pit (North) No.1	0.20	0.03	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U064	396670.0	3079300.0	157.0	47.9	64	350 Ton Truck Unloading Sulfur Pit (South) No. 2	0.10	0.01	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U065	396670.0	3079300.0	157.0	47.9	65	800 Railcar Unloading Pit	0.20	0.03	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U066	396670.0	3079300.0	157.0	47.9	66	200 Ton Molten Sulfur Transfer Pit	0.10	0.01	12.19	0.61	388.7	0.13
MOSAIC FERTILIZER - NEW WALES FACII	F059U067	396670.0	3079300.0	157.0	47.9	67	1500 Ton Truck Unloading Sulfur Pit, Front Vent	0.20	0.03	7.62	0.03	305.37	0.03
MOSAIC FERTILIZER - NEW WALES FACII	F059U068	396670.0	3079300.0	157.0	47.9	68	1500 Ton Truck Unloading Sulfur Pit, Rear Vent	0.20	0.03	7.62	0.03	305.4	0.03
MOSAIC FERTILIZER - NEW WALES FACII	F059U069	396670.0	3079300.0	157.0	47.9	69	350 Ton Truck Unloading Sulfur Pit Vent No. 2	0.10	0.01	7.62	0.03	305.4	0.03
MOSAIC FERTILIZER - NEW WALES FACII	F059U070	396700.0	3078880.0	157.0	47.9	70	Limestone Storage Silo/Rock Grinding	0.70	0.09	33.53	0.23	316.5	34.50
MOSAIC FERTILIZER - NEW WALES FACII	F059U074p	396670.0	3079300.0	157.0	47.9	74	Multifos C Kiln Scrubber	3.40	0.43	52.43	1.37	313.7	21.40
MOSAIC FERTILIZER - NEW WALES FACII	F059U078	396670.0	3079300.0	157.0	47.9	78	Granular Monoammonium Phosphate (GMAP) PLANT	9.68	1.22	40.54	1.83	335.9	33.41
U.S. AGRI-CHEMICALS - FT. MEADE	F051U006p	416950.0	3069280.0	157.0	47.9	6	AUXILIARY BOILER	20.00	2.52	21.34	1.13	477.6	14.94
U.S. AGRI-CHEMICALS - FT. MEADE	F051U028p	416000.0	3068080.0	157.0	47.9	28	MOLTEN SULFUR STORAGE - TANK (4,210 TON, 7 '	3.34	0.42	1.83	0.09	405.4	104.85
U.S. AGRI-CHEMICALS - FT. MEADE	F051U029p	416030.0	3068080.0	157.0	47.9	29	MOLTEN SULFUR STORAGE - PIT (5 VENTS) (229 '	1.57	0.20	1.83	0.09	399.8	47.85
U.S. AGRI-CHEMICALS - FT. MEADE	F051U032	416950.0	3069280.0	157.0	47.9	32	Prilled MAP Plant	16.40	2.07	41.15	2.05	320.4	17.95
U.S. AGRI-CHEMICALS - FT. MEADE	F051U033p	416950.0	3069280.0	157.0	47.9	33	LIME STORAGE SILO	13.87	1.75	21.34	0.18	298.2	8.99
U.S. AGRI-CHEMICALS - FT. MEADE	F051U038	416950.0	3069280.0	157.0	47.9	38	Granular MAP/DAP Plant	8.38	1.06	41.45	2.05	334.3	10.49
HINES ENERGY COMPLEX	F234U001	414170.0	3074100.0	163.0	49.7	1	POWER BLOCK 1, CT 1A	44.80	5.64	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U002p	414340.0	3073900.0	163.0	49.7	2	POWER BLOCK 1, CT 1B	44.80	5.64	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U014p	414400.0	3073900.0	163.0	49.7	14	POWER BLOCK 2, CT 2A	64.80	8.16	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U015p	414400.0	3073900.0	163.0	49.7	15	POWER BLOCK 2, CT 2B	64.80	8.16	38.10	5.79	360.9	18.07
HINES ENERGY COMPLEX	F234U016p	414400.0	3073900.0	163.0	49.7	16	POWER BLOCK 3, CT 3A	64.80	8.16	38.10	5.79	360.9	18.11
HINES ENERGY COMPLEX	F234U017p	414400.0	3073900.0	163.0	49.7	17	POWER BLOCK 3, CT 3B	64.80	8.16	38.10	5.79	360.9	18.11
HINES ENERGY COMPLEX	F234U018	414170.0	3074100.0	163.0	49.7	18	Power Block 4, CT 4A	39.10	4.93	38.10	5.49	367.6	20.70
HINES ENERGY COMPLEX	F234U019	414170.0	3074100.0	163.0	49.7	19	Power Block 4, CT 4B	39.10	4.93	38.10	5.49	367.6	20.70
MOSAIC FERTILIZER - GREEN BAY FACIL	F053U007	409500.0	3080100.0	172.0	52.4	7	SOUTH AP FERTILIZER PLANT	11.80	1.49	39.01	2.29	322.0	12.65
MOSAIC FERTILIZER - GREEN BAY FACIL	F053U029	409050.0	3079050.0	172.0	52.4	29	NORTH MAP/DAP FERTILIZER PLANT	31.80	4.01	39.32	2.29	315.4	13.11
TIGER BAY COGENERATION FACILITY	F223U001	416250.0	3069370.0	158.0	48.2	1	Combustion Turbine and Heat Recovery System Generato	17.00	2.14	54.86	5.79	369.3	19.20
PEACE RIVER STATION, LLC	F336U001	419500.0	3069700.0	119.0	36.3	1	GT-1, 170 MW simple cycle gas turbine peaking unit	17.00	2.14	18.29	6.40	864.8	34.85
PEACE RIVER STATION, LLC	F336U002	419500.0	3069700.0	119.0	36.3	2	GT-2, 170 MW simple cycle gas turbine peaking unit	17.00	2.14	18.29	6.40	864.8	34.85
PEACE RIVER STATION, LLC	F336U003	419500.0	3069700.0	119.0	36.3	3	GT-3, 170 MW simple cycle gas turbine peaking unit	17.00	2.14	18.29	6.40	864.8	34.85
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U001	398400.0	3084200.0	120.0	36.6	1	Phosphoric Acid Plant	22.60	2.85	12.80	1.22	310.9	10.36
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U002	398400.0	3084200.0	120.0	36.6	2	DAP COOLER USING VENTURI SCRUBBER WITH C	2.40	0.30	15.85	0.76	322.0	20.12
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U003	398400.0	3084200.0	120.0	36.6	3	DAP PLANT DRYER	7.30	0.92	24.38	1.07	327.6	23.77
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U004	398400.0	3084200.0	120.0	36.6	4	DAP PLT SCRUBBER 4A SERVES REACTOR/GRANU	10.10	1.27	21.95	0.98	360.9	30.78
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U009	398400.0	3084200.0	120.0	36.6	9	North Ball Mill	5.00	0.63	63.09	0.43	330.4	21.03
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U010	398400.0	3084200.0	120.0	36.6	10	South Ball Mill	5.00	0.63	63.09	0.43	330.4	21.03
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U012	398400.0	3084200.0	120.0	36.6	12	Phosphate Rock Dryer	35.24	4.44	24.69	2.29	327.6	3.66
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U015	398400.0	3084200.0	120.0	36.6	15	North Auxiliary Boiler	0.36	0.05	8.23	0.61	533.2	13.72
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U016	398040.0	3084020.0	120.0	36.6	16	South Auxiliary Boiler	0.72	0.09	11.89	0.98	533.2	8.84
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U019	398400.0	3084200.0	120.0	36.6	19	Dry Phosphate Rock Storage Bin - North	22.00	2.77	63.09	0.27	333.2	51.21
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U020	398040.0	3084020.0	120.0	36.6	20	Molten Sulfur Storage & Handling - North Storage Tank	0.20	0.03	7.62	0.06	305.4	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U021	398400.0	3084200.0	120.0	36.6	21	Molten Sulfur Storage & Handling - South Storage Tank	0.20	0.03	1.83	0.23	305.37	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U022	398400.0	3084200.0	120.0	36.6	22	Molten Sulfur Storage & Handling - Railcar Unloading Pit	0.20	0.03	1.83	0.23	305.37	0.30
IMC PHOSPAHTES COMPANY (NICHOLS)	F057U023	398400.0	3084200.0	120.0	36.6	23	Molten Sulfur Storage & Handling - Truck Unloading Pit	0.30	0.04	1.83	0.23	305.37	0.30

Table E-3. Modeling Inventory of PM Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (ft)	(meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
AGRIFOS MINING, L.L.C. - NICHOLS	F047U001	398300.0	3085250.0	116.0	35.4	1	PHOSPHATE ROCK DRYER NO. 1, DRY CYCLONES	38.10	4.80	24.38	2.29	344.3	12.50
AGRIFOS MINING, L.L.C. - NICHOLS	F047U002	398300.0	3085250.0	116.0	35.4	2	PHOSPHATE ROCK DRYER NO. 2, DRY CYCLONES	38.10	4.80	24.38	2.29	344.3	12.50
AGRIFOS MINING, L.L.C. - NICHOLS	F047U010	398300.0	3085250.0	116.0	35.4	10	DRY PHOSPHATE ROCK STORAGE BUILDING	40.00	5.04	25.91	1.68	299.8	14.33
AGRIFOS MINING, L.L.C. - NICHOLS	F047U011	398300.0	3085250.0	116.0	35.4	11	1500 TPH DRY PHOS ROCK RAILCAR LOADOUT SY	33.00	4.16	25.91	1.52	297.0	19.20
PRAIRIE MINE	F056U001	402900.0	3087000.0	120.0	36.6	1	LIMESTONE BUCKET ELEVATOR, BAGHOUSE	32.37	4.08	27.43	0.30	310.9	12.80
PRAIRIE MINE	F056U002	402900.0	3087000.0	120.0	36.6	2	RAYMOND MILL #1, LIMEROCK GRINDING	15.00	1.89	22.86	0.34	327.6	24.08
PRAIRIE MINE	F056U003	402900.0	3087000.0	120.0	36.6	3	RAYMOND MILL NO. 3, LIMEROCK GRINDING	19.20	2.42	22.86	0.34	327.6	40.54
PRAIRIE MINE	F056U004	402900.0	3087000.0	120.0	36.6	4	LIMEROCK DRYER WITH CYCLONE AND BAGHOL	32.37	4.08	21.34	1.34	357.6	15.54
PRAIRIE MINE	F056U005	402900.0	3087000.0	120.0	36.6	5	#4 RAYMOND MILL AT PRAIRIE PLANT	19.20	2.42	19.81	0.61	333.2	10.06
PRAIRIE MINE	F056U006	402900.0	3087000.0	120.0	36.6	6	LIMESTONE BIN & TRUCK LOADOUT	20.00	2.52	15.24	0.15	298.7	23.16
PRAIRIE MINE	F056U007	402900.0	3087000.0	120.0	36.6	7	FEED BIN AREA & ASSOC. EQUIP.	2.40	0.30	22.86	0.34	327.6	53.34
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U001	409770.0	3087260.0	210.0	64.0	1	No. 3 Fertilizer(DAP/MAP) Plant	11.00	1.39	30.18	2.29	330.4	16.15
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U002	409770.0	3087260.0	210.0	64.0	2	No. 4 Fertilizer Shipping Plant	10.54	1.33	30.48	1.52	260.9	15.24
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U021	409770.0	3087260.0	210.0	64.0	21	No. 4 Fertilizer Plant	22.80	2.87	42.67	3.32	328.7	16.15
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U045	409770.0	3087260.0	210.0	64.0	45	Molten Sulfur System-STACK 45 (PIT A), 200 TON MO	0.99	0.12	12.19	0.30	366.5	17.37
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U046	409770.0	3087260.0	210.0	64.0	46	Molten Sulfur Storage -- Vent 44 from 6,000 ton tank	0.99	0.12	10.36	0.30	366.5	0.12
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U047	409770.0	3087260.0	210.0	64.0	47	MOLTEN SULFUR SYSTEM (vent from 3000 ton surge	0.99	0.12	9.45	0.61	366.5	0.03
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U050	409080.0	3087000.0	210.0	64.0	50	MOLTEN SULFUR SYSTEM-STACK 47 (PIT B), 300 T	0.99	0.12	12.19	0.30	366.5	17.37
MOSAIC FERTILIZER, LLC - BARTOW FAC	F046U051	409800.0	3087000.0	210.0	64.0	51	Cleaver Brooks Package Watertube Boiler	4.38	0.55	9.45	1.07	483.2	6.10
U S AGRI-CHEMICALS - BARTOW	F050U038p	413200.0	3086300.0	148.0	45.1	38	150 TPH MAP/DAP PLANT(79 TPH P2O5 INPUT)	38.59	4.86	39.93	2.13	316.5	17.16
U S AGRI-CHEMICALS - BARTOW	F050U039p	413200.0	3086300.0	148.0	45.1	39	DAP/MAP STORAGE AND LOADING	22.70	2.86	22.25	0.85	298.2	24.75
WINSTON PEAKING STATION	F352U020c	400080.0	3100690.0	140.0	42.7	20c	2.5 MW GM EMD 20/645/E4B diesel engine .	380.00	47.88	9.14	0.56	666.5	41.24
OWENS-BROCKWAY GLASS CONTAINER	F007U001	406000.0	3102030.0	210.0	64.0	1	GLASS FURNACE "A"	13.40	1.69	22.86	0.91	629.3	22.56
OWENS-BROCKWAY GLASS CONTAINER	F007U002	406000.0	3102030.0	210.0	64.0	2	GLASS MELTING FURNACE "B"	14.60	1.84	26.21	0.91	632.6	18.29
CHARLES LARSEN MEMORIAL POWER PI	F003U003	408900.0	3102900.0	134.0	40.8	3	Fossil Fuel Fired Steam Generator # 6	31.00	3.91	50.29	3.05	444.3	6.40
CHARLES LARSEN MEMORIAL POWER PI	F003U004	409000.0	3102800.0	134.0	40.8	4	Steam Generator # 7 (Phase II Acid Rain unit)	60.00	7.56	50.29	3.05	444.3	6.71
CHARLES LARSEN MEMORIAL POWER PI	F003U005	409100.0	3102800.0	134.0	40.8	5	Peaking Gas Turbine # 3	7.94	1.00	9.45	3.60	699.8	30.78
CHARLES LARSEN MEMORIAL POWER PI	F003U006	409100.0	3102800.0	134.0	40.8	6	Peaking Gas Turbine # 2	7.94	1.00	9.45	3.60	699.8	30.78
CHARLES LARSEN MEMORIAL POWER PI	F003U008p	409000.0	3102800.0	134.0	40.8	8	Simple and Combined Cycle CTs (Phase II Aeid Rain unit	26.00	3.28	47.24	4.88	522.6	26.12
C.D. MCINTOSH, JR. POWER PLANT	F004U001	409200.0	3106200.0	137.0	41.8	1	McIntosh Unit 1- FFFSG (Phase II Acid Rain Unit)	98.50	12.41	45.72	2.74	409.3	24.75
C.D. MCINTOSH, JR. POWER PLANT	F004U002	409100.0	3106300.0	137.0	41.8	2	Diesel Engine Peaking Unit 2	1.74	0.22	6.10	0.79	652.6	23.47
C.D. MCINTOSH, JR. POWER PLANT	F004U003	409020.0	3106020.0	137.0	41.8	3	Diesel Engine Peaking Unit 3	1.74	0.22	6.10	0.79	652.6	23.47
C.D. MCINTOSH, JR. POWER PLANT	F004U004	409200.0	3106400.0	137.0	41.8	4	Gas Turbine Peaking Unit 1	12.16	1.53	10.67	4.11	755.4	24.23
C.D. MCINTOSH, JR. POWER PLANT	F004U005	409200.0	3106200.0	137.0	41.8	5	McIntosh Unit 2 FFFSG (Phase II Acid Rain Unit)	118.00	14.87	47.85	3.20	409.3	22.31
C.D. MCINTOSH, JR. POWER PLANT	F004U006p	409300.0	3106300.0	137.0	41.8	6	McIntosh Unit 3 FFFSG (Phase II Acid Rain Unit)	273.00	34.40	76.20	5.49	348.2	25.18
C.D. MCINTOSH, JR. POWER PLANT	F004U028	409000.0	3106800.0	137.0	41.8	28	250 MW Combustion Turbine UNIT 5 (Phase II Acid Rai	139.60	17.59	25.91	8.53	863.7	25.21
OSPREY ENERGY CENTER	F334U001	421000.0	3103200.0	145.0	44.2	1	170MW Combustion Turbine Configured for Combined C	24.10	3.04	43.28	5.64	366.5	19.29
OSPREY ENERGY CENTER	F334U002	421000.0	3103200.0	145.0	44.2	2	170MW Combustion Turbine Configured for Combined C	24.10	3.04	43.28	5.64	366.5	19.29
OSPREY ENERGY CENTER	F334U005	421000.0	3103200.0	145.0	44.2	5	cooling tower	1.96	0.25	16.76	8.53	305.4	9.14
OSPREY ENERGY CENTER	F334U006	420800.0	3103200.0	145.0	44.2	6	Simple Cycle Peaking CT	58.50	7.37	15.24	6.71	807.6	25.21
AUBURNDALE POWER PARTNERS, LP	F221U001p	420800.0	3103300.0	145.0	44.2	1	Combined Combustion Turbine System(Phase II, Acid Ra	36.80	4.64	48.77	5.49	368.2	16.76
AUBURNDALE POWER PARTNERS, LP	F221U006	420800.0	3103200.0	145.0	44.2	6	Simple Cycle Peaking CT	58.50	7.37	15.24	6.71	807.6	25.21
AUBURNDALE POWER PARTNERS, LP	F221U007	421000.0	3103200.0	145.0	44.2	7	170MW Combustion Turbine Configured for Combined C	24.10	3.04	43.28	5.64	366.5	19.29
AUBURNDALE POWER PARTNERS, LP	F221U008	421000.0	3103200.0	145.0	44.2	8	170MW Combustion Turbine Configured for Combined C	24.10	3.04	43.28	5.64	366.5	19.29

Table E-3. Modeling Inventory of PM Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (ft)	(meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
AUBURNDALE POWER PARTNERS, LP	F221U011	421000.0	3103200.0	145.0	44.2	11	Cooling Tower	1.96	0.25	16.76	8.53	305.4	9.14
CUTRALE CITRUS JUICES USA,INC	F023U001	421410.0	3103670.0	135.0	41.1	1	No. 1 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	15.00	1.89	28.35	1.07	333.2	16.76
CUTRALE CITRUS JUICES USA,INC	F023U003	421410.0	3103670.0	135.0	41.1	3	No. 2 Citrus Peel Dryer w/ WHEs A, B, C, D, E and F	15.00	1.89	30.48	0.98	344.8	14.94
CUTRALE CITRUS JUICES USA,INC	F023U005	421410.0	3103670.0	135.0	41.1	5	Pelletizer w/ Horizontal Cooler No. 1N	5.00	0.63	10.06	0.76	310.9	17.37
CUTRALE CITRUS JUICES USA,INC	F023U006	421410.0	3103670.0	135.0	41.1	6	Pelletizer w/ Horizontal Cooler NO. 2C	5.00	0.63	10.06	0.76	310.9	17.37
CUTRALE CITRUS JUICES USA,INC	F023U007	421410.0	3103670.0	135.0	41.1	7	Peel Cooler NO. 3S	5.00	0.63	10.36	0.82	305.4	14.94
CUTRALE CITRUS JUICES USA,INC	F023U010	421410.0	3103670.0	135.0	41.1	10	Pelletizer w/ Vertical Cooler	5.00	0.63	8.84	0.76	305.4	9.14
CUTRALE CITRUS JUICES USA,INC	F023U018	421410.0	3103670.0	135.0	41.1	18	Boiler No. 1	4.93	0.62	12.19	0.91	422.0	16.09
CUTRALE CITRUS JUICES USA,INC	F023U021	421410.0	3103670.0	135.0	41.1	21	Backup Feed Cooler	5.00	0.63	18.29	1.07	310.9	8.02
CITRUS WORLD, INC.	F002U001	440900.0	3087530.0	130.0	39.6	1	CITRUS PEEL DRYER No. 2 WITH WASTE-HEAT EV	15.00	1.89	25.91	1.42	344.3	15.12
CITRUS WORLD, INC.	F002U007	440900.0	3087530.0	130.0	39.6	7	CITRUS PEEL DRYER No. 1 WITH WASTE-HEAT EV	15.00	1.89	22.86	0.97	344.3	15.15
CITRUS WORLD, INC.	F002U013	440900.0	3087530.0	130.0	39.6	13	CITRUS PEEL DRYER No. 3 WITH WASTE-HEAT EV	15.00	1.89	25.91	1.42	344.3	15.12
CITRUS WORLD, INC.	F002U022	441000.0	3087300.0	130.0	39.6	22	CITRUS PELLET COOLER CF1	5.00	0.63	11.28	0.76	349.8	24.84
CITRUS WORLD, INC.	F002U023	441000.0	3087300.0	130.0	39.6	23	CITRUS PELLET COOLER CF2	5.00	0.63	11.28	0.76	349.8	24.84
FROSTPROOF CITRUS PROCESSING FACII	F019U001	447890.0	3068470.0	100.0	30.5	1	CITRUS PEEL DRYER W/ WASTE HEAT EVAPORAT	15.00	1.89	23.16	1.74	340.4	9.45
FROSTPROOF CITRUS PROCESSING FACII	F019U005	448000.0	3068500.0	100.0	30.5	5	PROCESS STEAM BOILER #2	0.49	0.06	18.90	1.07	458.2	9.45
FROSTPROOF CITRUS PROCESSING FACII	F019U006	447890.0	3068470.0	100.0	30.5	6	SPROUT-BAUER MOD. DP-740-S HORIZONAL DOUI	5.00	0.63	12.80	1.22	344.3	20.42
HOLLY HILL FRUIT PRODUCTS	F061U004	441000.0	3115040.0	130.0	39.6	4	CITRUS PEEL DRYER WITH WASTE HEAT EVAPOR	28.60	3.60	17.98	0.85	344.3	18.90
HOLLY HILL FRUIT PRODUCTS	F061U017	441000.0	3115040.0	130.0	39.6	17	PELLET MILL COOLER WITH CYCLONE	13.60	1.71	1.83	0.21	298.2	131.98
US BEVERAGE LAKELAND PLANT	F015U001	399070.0	3102070.0	125	38.1	1	CITRUS PEEL DRYER W/ 2 WASTE HEAT EVAPORA	30.7	3.87	27.43	0.91	333.2	7.32
US BEVERAGE LAKELAND PLANT	F015U002	399070.0	3102070.0	125	38.1	2	ERIE CITY MODEL 14-200 PROCESS STEAM BOILEI	8.31	1.05	10.06	0.61	447.0	5.18
US BEVERAGE LAKELAND PLANT	F015U003	399070.0	3102070.0	125	38.1	3	ERIE CITY SIZE 50 PROCESS STEAM BOILER NO. 2	3.02	0.38	10.36	0.91	447.0	9.14
US BEVERAGE LAKELAND PLANT	F015U004	399070.0	3102070.0	125	38.1	4	PELLET MILL COOLER WITH A CYCLONE SEPARA	14.40	1.81	9.14	0.91	344.3	7.62
US BEVERAGE LAKELAND PLANT	F015U005	399000.0	3101800.0	125	38.1	5	PELLET MILL & COOLER W/ CYCLONE SEPARATO	19.48	2.45	14.33	1.29	316.5	7.62
MULBERRY COGEN FACILITY	F217U001p	413600.0	3080600.0	147.0	44.8	1	Combustion Turbine with HRSG(Phase II, Acid Rain Uni	11.64	1.47	38.10	4.57	377.6	19.54
MULBERRY COGEN FACILITY	F217U002p	413600.0	3080600.0	147.0	44.8	2	Secondary Boiler	0.74	0.09	38.10	0.91	377.6	20.27
MULBERRY COGEN FACILITY		413600.0	3080600.0	147.0	44.8	4	Unregulated general purpose engines						
ORANGE COGENERATION FACILITY	F231U001p	418700.0	3083000.0	127.0	38.7	1	Combustion Turbine w/ HRSG, Unit 1 (Phase II Acid Rai	5.00	0.63	30.48	3.35	383.2	15.97
ORANGE COGENERATION FACILITY	F231U002p	418700.0	3083000.0	127.0	38.7	2	Combustion Turbine w/ HRSG, Unit 2 (Phase II Acid Rai	5.00	0.63	30.48	3.35	383.2	15.97
ORANGE COGENERATION FACILITY	F231U003p	418700.0	3083000.0	127.0	38.7	3	Auxiliary Boiler	1.00	0.13	19.81	1.13	424.8	14.02
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U002	408300.0	3082500.0	120	36.6	2	NO. 1 MAP/DAP/GTSP SHIPPING UNIT	2.74	0.35				0.01
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U006p	408300.0	3082500.0	120	36.6	6	SULFURIC ACID PLANT NO.6						
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U021p	408300.0	3082500.0	120	36.6	21	BOILER NO. 1	0.5	0.06				0.01
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U025p	408300.0	3082500.0	120	36.6	25	NO. 2 MAP/DAP SHIPPING UNIT	2.74	0.35				0.00
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U031p	408300.0	3082050.0	120	36.6	31	DAP/MAP/GTSTP RAILCAR UNLOADING AND TRANSFER OPERATION						
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U032p	408300.0	3082500.0	120	36.6	32	Rail/Truck Unloading Pit -- Molten Sulfur System	2.74	0.35	0.03	0.15		
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U034p	408300.0	3082500.0	120	36.6	33	North Storage Tank -- Molten Sulfur System	2.74	0.35	0.03	0.15		
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U035p	408300.0	3082500.0	120	36.6	34	South Storage Tank -- Molten Sulfur System	3.29	0.41	0.04	0.18		
CF INDUSTRIES - BARTOW PHOSPHATE C	F052U036p	408300.0	3082500.0	120	36.6	36	Fugitive Emissions						
MANATEE POWER PLANT	M010U001	367150.0	3054230.0	52.0	15.8	1	Fossil Fuel Steam Generator, Unit 1-Phase II Acid Rain U	295.50	37.23	152.10	8.32	446.5	23.77
MANATEE POWER PLANT	M010U002	367150.0	3054230.0	52.0	15.8	2	Fossil Fuel Steam Generator, Unit 2-Phase II Acid Rain U	295.50	37.23	152.10	7.99	435.9	25.15
MANATEE POWER PLANT	M010U005	367250.0	3054150.0	52.0	15.8	5	Unit 3A Combustion Turbine (170 MW) with HRSG	17.2	2.17	36.58	6.71	875.4	31.94
MANATEE POWER PLANT	M010U006	367250.0	3054150.0	52.0	15.8	6	Unit 3B Combustion Turbine (170 MW) with HRSG	17.2	2.17	36.58	5.79	367.6	17.98
MANATEE POWER PLANT	M010U007	367250.0	3054150.0	52.0	15.8	7	Unit 3C Combustion Turbine (170 MW) with HRSG	17.2	2.17	36.58	5.79	367.6	17.98

Table E-3. Modeling Inventory of PM Sources

Site Name	Model ID	UTM E (meters)	UTM N (meters)	Elevation (ft)	(meters)	EU ID	EU Description	Emiss Rate (lb/hr	Emiss Rate (g/s)	Stack Height (meters)	Stack Diameter (meters)	Exit Temperature (K)	Velocity (m/s)
MANATEE POWER PLANT	M081U008	367250.0	3054150.0	52.0	15.8	8	Unit 3D Combustion Turbine (170 MW) with HRSG	17.2	2.17	36.58	5.79	367.6	17.98
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U007	364590.0	3082380.0	0.0	0.0	7	No. 6 AP Plant	12.88	1.62	38.40	2.44	328.7	11.28
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U043	364590.0	3082380.0	0.0	0.0	43	AUXILIARY STEAM GENERATOR	13.00	1.64	6.10	1.22	488.7	15.85
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U051	364590.0	3082380.0	0.0	0.0	51	Conveyor 9 transfer pts & Railcar Unloading	2.40	0.30	15.24	0.76	299.8	18.44
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U052	364590.0	3082380.0	0.0	0.0	52	Conveyor 9 to Shipping Belt Conveyor	0.66	0.08	15.24	0.40	299.8	18.78
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U053	363020.0	3082030.0	0.0	0.0	53	Vessel Loading Operation	0.84	0.11	19.51	0.46	299.8	17.95
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U055	362900.0	3082500.0	0.0	0.0	55	NO. 5 GRANULATION PLANT	12.80	1.61	40.54	2.13	315.4	15.24
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U058	363020.0	3082030.0	0.0	0.0	58	Conveyor No. 6 to Conveyor No. 7	0.60	0.08	12.50	0.30	299.8	28.83
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U059	363020.0	3082030.0	0.0	0.0	59	Conveyor 7 to Conveyor 8	0.60	0.08	8.53	0.30	298.7	28.83
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U060	363020.0	3082030.0	0.0	0.0	60	Screening Tower & Conveyor 8 to Conveyor 9	4.11	0.52	22.86	0.76	298.7	31.64
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U061	364590.0	3082380.0	0.0	0.0	61	SHIPHOLD/CHOKEFEED	0.10	0.01			298.7	0.00
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U078	364590.0	3082380.0	0.0	0.0	78	COMMON STACK, ANIMAL FEED PLANT No. 1	13.00	1.64	38.10	1.83	298.7	0.00
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U079	364590.0	3082380.0	0.0	0.0	79	DIATOMACEOUS EARTH SILO	0.05	0.01	9.14	0.46	298.7	0.00
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U080	364590.0	3082380.0	0.0	0.0	80	LIMESTONE SILOS 1 & 2	0.32	0.04	25.91	0.46	298.7	0.00
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U081	364590.0	3082380.0	0.0	0.0	81	ANIMAL FEED INGREDIENT (AFI) LOADOUT SYST	2.06	0.26	28.96	0.46	298.7	0.00
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U100	364590.0	3082380.0	0.0	0.0	100	Raymond Mill No. 5	2.59	0.33	21.34	0.76	349.8	19.66
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U101	364590.0	3082380.0	0.0	0.0	101	Raymond Mill No. 9	2.59	0.33	21.34	0.76	349.8	19.66
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U102	364590.0	3082380.0	0.0	0.0	102	Ground Rock Handling/Storage System	0.41	0.05	20.42	0.15	299.8	64.68
MOSAIC FERTILIZER-RIVERVIEW FACILI	T008U103	364590.0	3082380.0	0.0	0.0	103	Common stack animal feed plant #2	13.00	1.64	38.10	1.83	338.7	17.07
BIG BEND STATION	T039U001	361716.0	3075060.0	0.0	0.0	1	Fossil Fuel Fired Steam Generator Unit No. 1	121.10	15.26	149.35	7.32	418.7	35.33
BIG BEND STATION	T039U002	361720.0	3074980.0	0.0	0.0	2	Fossil Fuel Fired Steam Generator Unit No. 2	119.90	15.11	149.35	7.32	324.8	26.70
BIG BEND STATION	T039U003	361820.0	3075060.0	0.0	0.0	3	Fossil Fuel Fired Steam Generator Unit No. 3	123.50	15.56	149.35	7.32	426.5	15.61
BIG BEND STATION	T039U004	361820.0	3075040.0	0.0	0.0	4	Fossil Fuel Fired Steam Generator Unit No. 4	43.30	5.46	149.35	7.32	325.9	18.14
BIG BEND STATION	T039U008	363150.0	3074910.0	0.0	0.0	8	Fly Ash Silo No. 1 Baghouse	5.16	0.65	31.09	0.76	394.3	15.85
BIG BEND STATION	T039U009	363150.0	3074910.0	0.0	0.0	9	Fly Ash Silo No. 2 Baghouse	5.16	0.65	34.44	0.27	394.3	123.75
BIG BEND STATION	T039U012	363150.0	3074910.0	0.0	0.0	12	Limestone Silo A with 2 Baghouses	0.05	0.01	30.78	0.15	338.7	14.02
BIG BEND STATION	T039U013	363150.0	3074910.0	0.0	0.0	13	Limestone Silo B with 2 Baghouses	0.05	0.01	30.78	0.15	338.7	14.02
BIG BEND STATION	T039U014	363150.0	3074910.0	0.0	0.0	14	Fly Ash Silo No. 3 Baghouse	0.20	0.03	42.37	0.49	333.2	17.98
BIG BEND STATION	T039U015	361900.0	3075000.0	0.0	0.0	15	Unit No. 1 Coal Bunker with Roto-Clone	0.48	0.06	54.56	0.52	298.7	21.03
BIG BEND STATION	T039U016	361900.0	3075000.0	0.0	0.0	16	Unit No. 2 Coal Bunker with Roto-Clone	0.48	0.06	54.56	0.52	298.7	21.03
BIG BEND STATION	T039U017	361900.0	3075000.0	0.0	0.0	17	Unit No. 3 Coal Bunker with Roto-Clone	0.48	0.06	54.56	0.52	298.7	21.03
BIG BEND STATION	T039U018	363150.0	3074910.0	0.0	0.0	18	Fly Ash Silo No. 1 Truck Loadout	5.16	0.65	0.00	0.00	298.2	0.00
BIG BEND STATION	T039U019	363150.0	3074910.0	0.0	0.0	19	Fly Ash Silo No. 2 Truck Loadout	5.16	0.65	34.44	0.27	394.3	123.75
BIG BEND STATION	T039U023	363150.0	3074910.0	0.0	0.0	23	Limestone Handling Converyors LB, LC, LD, &LE; 2 Ba;	0.65	0.08			298.15	
BIG BEND STATION	T039U027	363150.0	3074910.0	0.0	0.0	27	Fly Ash Silo No. 3 Truck Loadout	0.20	0.03			298.15	
BIG BEND STATION	T039U028	363150.0	3074910.0	0.0	0.0	28	Fly Ash Handling System Fugitive Emissions	0.20	0.03			298.15	
BIG BEND STATION	T039U039	363150.0	3074910.0	0.0	0.0	39	Unit No. 4 Coal Bunker with Roto-Clone	0.48	0.06	9.14	0.52	298.15	
BIG BEND STATION	T039U041	361900.0	3075000.0	0.0	0.0	41	Unit 4: SCCT 4A: PWPS FT8-3 SwiftPac CT/Gen Peakin;	7.50	0.95	18.29	2.90	751.5	30.88
BIG BEND STATION	T039U042	361900.0	3075000.0	0.0	0.0	42	Unit 4: SCCT 4B: PWPS FT8-3 SwiftPac CT/Gen Peakin;	7.50	0.95	18.29	2.90	751.5	30.88
HILLSBOROUGH CTY. RESOURCE RECOV	T261U001	368200.0	3092700.0	36.0	11.0	1	Municipal Waste Combustor & Auxiliary burners-Unit #1	175.90	22.16	67.06	1.55	416.5	22.10
HILLSBOROUGH CTY. RESOURCE RECOV	T261U002	368200.0	3092700.0	36.0	11.0	2	Municipal Waste Combustor & Auxiliary burners-Unit #2	175.90	22.16	67.06	1.55	416.5	22.10
HILLSBOROUGH CTY. RESOURCE RECOV	T261U003	368200.0	3092700.0	36.0	11.0	3	Municipal Waste Combustor & Auxiliary burners-Unit #3	175.90	22.16	67.06	1.55	416.5	22.10
HILLSBOROUGH CTY. RESOURCE RECOV	T261U100	369380.0	3092690.0	36.0	11.0	100	Ash Handling Systems	1.63	0.21	1.52	0.61	298.2	19.42
HILLSBOROUGH CTY. RESOURCE RECOV	T261U107	368200.0	3092700.0	36.0	11.0	107	Municipal Waste Combustor & Auxiliary Burners - Unit #	3.30	0.42	67.06	1.55	405.4	31.09

Source: ECT, 2012.