

SHADY HILLS COMBINED CYCLE FACILITY



SITE CERTIFICATION APPLICATION

Volume II of II

February 2018

APPENDIX 10.1
COORDINATION

10.1 Coordination

Federal, State, regional, and local agencies were contacted by SHCCF representatives to inform the agencies about the proposed SHCCF Project and to solicit input regarding the Project. The individuals contacted are listed below.

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APPENDIX 10.2

FEDERAL PERMIT APPLICATIONS OR APPROVALS

APPENDIX 10.2.1

316 DEMONSTRATIONS

Note: The SHCCF will not have a surface water discharge and therefore a 316 Demonstration is not required.

APPENDIX 10.2.2

NPDES APPLICATIONS/PERMITS

Note: The SHCCF does not have a surface water discharge and therefore, an NPDES Permit Application is not required.

APPENDIX 10.2.3

HAZARDOUS WASTE DISPOSAL APPLICATION/PERMIT

NOTE: No federal or state application or permit for hazardous waste disposal is required for the Project.

APPENDIX 10.2.4

SECTION 10 OR 404 APPLICATIONS/PERMITS

Note: The SHCCF will not impact wetlands or waters of the state, therefore, Section 10 or 404 Applications/Permits are not required.

APPENDIX 10.2.5

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION



PSD REPORT

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) / AIR CONSTRUCTION PERMIT APPLICATION FOR THE SHADY HILLS COMBINED CYCLE FACILITY (SHCCF) PASCO COUNTY, FLORIDA

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February 2018

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List of Acronyms

°C	degrees Celsius
°F	degrees Fahrenheit
µg/m ³	micrograms per cubic meter
AAQS	Ambient Air Quality Standards
AERMOD	American Meteorological Society and U.S. Environmental Protection Agency Regulatory Model
AFUE	annualized fuel utilization efficiency
AOR	Annual Operating Report
AQRV	air quality related value
ASOS	automatic surface observing system
BACT	Best Available Control Technology
BHP	brake-horsepower
BSER	best system of emission reduction
BPIP	Building Profile Impact Program
Btu/lb	British thermal unit per pound
Btu/yr	British thermal unit per year
Btu/kWh	British thermal unit per kilowatt hour
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCC	Citrus Combined Cycle "Project"
CCS	carbon capture and storage
CEC	cation exchange capacity
CEM	continuous emissions monitoring
CFR	Code of Federal Regulations
CH ₄	methane
CNWS	Chassahowitzka National Wilderness Area
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalent
CSAPR	Cross-State Air Pollution Rule
CT or CTG	combustion turbine or combustion turbine generator
DATs	Deposition analysis threshold
DBEC	Dania Beach Energy Center
DLN	dry-low NO _x
EC	elemental carbon
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization



FGR	flue gas recirculation
FGT	Florida Gas Transmission
FLM	Federal Land Manager
ft	foot
ft ³ /yr	cubic feet per year
FR	Federal Register
GCP	good combustion practices
GE	General Electric
GECUSH	General Electric Capital US Holdings
GEP	Good Engineering Practice
gr/100 scf	grains per 100 standard cubic feet
GS	Geological Sequestration
GHG	greenhouse gas
H ₂ SO ₄	sulfuric acid mist
HAP	hazardous air pollutant
HFCs	hydrofluorocarbons
HHV	higher heating value
Ha	hectares
hp	horsepower
hr/yr	hours per year
HRSG	heat recovery steam generator
IEC	International Electrotechnical Commission
kg/ha/yr	kilogram per hectare per year
km	kilometer
kW	kilowatt
LAER	Lowest Achievable Emission Rate
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt-hour
LDAR	leak detection and repair
LHV	lower heating value
m	meter
MACT	Maximum Available Control Technology
MECL	Minimum Emission Compliance Load
MMBtu/hr	million British thermal units per hour
MMcf/hr	million cubic feet per hour
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
N ₂ O	nitrous oxide
N	nitrogen



NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NWA	National Wilderness Area
NWS	National Weather Service
O ₂	oxygen
O ₃	ozone
OCEC	Okeechobee Clean Energy Center
PEEC	Port Everglades Energy Center
PFCs	perfluorocarbons
PM	particulate matter
PM _{2.5}	particulate matter less than 2.5 microns
PM ₁₀	particulate matter less than 10 microns
ppb	parts per billion
ppbvd	parts per billion by volume dry
ppm	parts per million
ppmvd	parts per million by volume dry
PSD	Prevention of Significant Deterioration
psi	pound per square inch
psia	pound per square inch absolute
psig	pound per square inch gauge
QA/QC	quality assurance/quality control
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
RICE	reciprocating internal combustion engines
SAM	sulfuric acid mist
scf/yr	standard cubic foot per year
SCR	selective catalytic reduction
SDWA	Safe Drinking Water Act
SHCCF	Shady Hills Combined Cycle Facility
SHEC	Shady Hills Energy Center, LLC
SHGS	Shady Hills Generating Station
SHPC	Shady Hills Power Company, LLC
SCRAM	Support Center for Regulatory Air Models
SER	significant emissions rate
SIL	significant impact level
SIP	State Implementation Plan
Site	Certified Site
SF ₆	sulfur hexafluoride
SMC	significant monitoring concentrations



SO ₂	sulfur dioxide
SO ₄	sulfate
ST or STG	Steam Turbine or Steam Turbine Generator
TPY	tons per year
TSP	total suspended particulate
TTN	Technology Transfer Network
UIC	Underground Injection Control
ULSD	ultra low sulfur distillate
UTM	Universal Transverse Mercator
USDW	Underground Source of Drinking Water
VOC	volatile organic compound



1.0 INTRODUCTION

Shady Hills Energy Center, LLC (SHEC) is proposing to construct the Shady Hills Combined Cycle Facility (“SHCCF”, “SHCCF Project”, or “Project”), a new 573 megawatt (MW) (winter) 1-on-1 combined cycle electric power generating facility that will consist of one advanced-technology nominal 385 MW GE 7HA.02 combustion turbine generator (CTG), one heat recovery steam generator (HRSG) with duct firing [approximately 200 million British thermal units per hour (MMBtu/hr)], and one nominal 210 MW steam turbine generator (STG), along with on-site supporting facilities. Natural gas will be the only fuel for the 7HA.02 CT. Other sources of air emissions will include one 60 MMBtu/hr natural gas-fired auxiliary boiler, one diesel-fired 2,205 horsepower (hp) emergency generator, one diesel-fired 347 hp emergency fire pump engine, and one 6-cell mechanical draft cooling tower.

SHEC is a wholly-owned, indirect subsidiary of GE Capital US Holdings (GECUSH), which in turn is a wholly-owned, indirect subsidiary of the General Electric Company (GE). GECUSH also wholly-owns, indirectly, Shady Hills Power Company, L.L.C. (SHPC), which owns and operates the adjacent Shady Hills Generating Station (SHGS) located at 14240 Merchant Energy Way, Shady Hills, Pasco County, Florida (see Figure 1-1). SHGS consists of three, dual-fuel, nominal 170 megawatt (MW) General Electric model PG7241FA (GE 7FA) combustion turbine-electric generators operating in simple-cycle peaking and intermittent-duty mode, one 10 MMBtu/hr natural gas-fired process heater, one 1,341 horsepower (hp) diesel-fired emergency generator, one 222 hp diesel-fired fire pump engine, and one 2.8 million gallon fuel oil storage tank. SHGS is authorized to operate under Florida Department of Environmental Protection (FDEP) Title V Air Operating Permit No. 1010373-018-AV.

Using the required regulatory comparison there will be an increase in several PSD pollutants above the significant emissions rate (SERs) for the Project including GHGs. Therefore, pursuant to FDEP Rule 62-212.400, F.A.C., PSD review is applicable for the Project.

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

- Section 1.0 presents an introduction to the Project.
- Section 2.0 presents a description of the Project, including air emissions and emission point release parameters.
- Section 3.0 provides a review of the regulatory analysis conducted, including PSD and nonattainment requirements that are applicable to the Project.
- Section 4.0 includes the Best Available Control Technology (BACT) analysis including GHG BACT analysis.



- Section 5.0 discusses the ambient air monitoring analysis.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the Project with National Ambient Air Quality Standards (NAAQS) and allowable PSD Increments.
- Section 7.0 presents the additional impact analysis required for PSD review.
- Appendices which include emission calculations, summary of previous BACT determinations, and FDEP application forms (Form No. 62-210.900(1): Application for Air Permit – Long Form).



2.0 PROJECT DESCRIPTION

2.1 Existing Facility Description

The existing SHGS is located in Pasco County at 14240 Merchant Energy Way in Shady Hills, Florida. The plant elevation is approximately 50 feet above sea level. The terrain surrounding the plant is flat.

The FDEP Title V Air Operating Permit No. 1010373-018-AV authorizes the operation of the facility consisting of three nominal 170 MW simple cycle units (GE model 7241FA; Emission Units (EU-001), EU-002 and EU-003). The units operate in simple-cycle and intermittent duty modes and are authorized to fire natural gas and distillate oil. The initial startup date for EU-001 was 12/01/2001. The initial startup dates for EU-002 and EU-003 were 01/02/2002 and 02/05/2002, respectively. The facility also includes a 10 million Btu/hour (MMBtu/hr) natural gas heater (EU-010), one emergency diesel generator (EU-011), and one emergency diesel fire pump (EU-012). A natural gas Florida Gas Transmission (FGT) lateral provides natural gas to the existing electrical generating units that are connected to a 230 kV transmission facility.

2.2 The Project

The proposed Project will be a single shaft combined cycle unit where the combustion turbine-generator (CTG) and steam turbine-generator (STG) are connected on a single shaft. The CTG proposed for the Project is the latest model of GE's Frame 7H.02. The CTG and STG will have a gross capacity of approximately 573 MW (winter) at an ambient air temperature of 59°F and evaporative cooling.

The generating capacity of a combined cycle plant is affected by ambient temperature. Generally, greater overall fuel consumption will occur at lower ambient temperatures. The CTG will utilize inlet air cooling that will consist of evaporative cooling. Evaporative cooling systems achieve adiabatic cooling using water evaporated from a treated media. The evaporated water extracts the latent heat of vaporization from the inlet air stream when the water droplet is converted to water vapor. The result is a cooler, denser air stream. This allows additional power to be produced. Appendix A contains the heat input and fuel use over an ambient temperature range of 30 °F to 95 °F including representative operation with evaporative cooling.

The heat recovery steam generator (HRSG) will have duct firing with heat input of approximately 210 MMBTU/hr. SHEC is also proposing to install one 60 MMBtu/hr natural gas-fired auxiliary boiler, one diesel-fired 2,205 hp emergency generator, one diesel-fired 347 hp emergency fire pump engine, and one 6-cell mechanical draft cooling tower. The new CTG and associated equipment will be constructed on a 14-acre parcel east of the existing SHGS power island.

The CTG will use only natural gas as fuel. Natural gas will be transported to the Site by the existing pipeline connection to the FGT lateral. The Project will be connected to a new natural gas metering yard. The



proposed auxiliary boiler will be used during start up and shutdown when steam is not available from the HRSG. An electric natural gas heater will be used during operation to heat natural gas. Emissions of nitrogen oxides (NO_x) will be controlled using dry low NO_x (DLN) combustion technology and a selective catalytic reduction (SCR) system.

2.3 Source Emission Units and Stack Parameters

The Project's air emission units are:

- GE 7H.02 CT (including HRSG duct firing)
- Auxiliary boiler
- Emergency diesel generator
- Fire water pump diesel engine
- Mechanical draft cooling tower
- Fugitive GHG Emissions [Circuit breakers containing sulfur hexafluoride (SF₆) and Natural gas leakage]

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

2.3.1 GE 7H.02 CTG

Table 2-1 presents the CTG performance and regulated air pollutant emission rates for the proposed Project. This table also includes the performance and emissions during duct firing. The maximum estimated emission rates for the conditions stated when firing natural gas were determined using the manufacturer's information for the equipment proposed for the Project. The design parameters are provided for the range of operating loads and ambient temperatures. The lowest operating load where compliance with emission levels are achieved are shown in Table 2-1. This is referred to as minimum emission compliance load (MECL) which is approximately 30 percent for the GE 7H.02 CTG but varies with ambient temperature. Appendix A, Tables A-1 and A-2 contain the performance and emissions for three loads (100 percent with duct firing, 100 percent without duct firing and MECL) and three ambient temperatures (30 °F, 59 °F, and 95 °F) used for Table 2-1. Evaporative cooling is employed at 100 percent load and ambient temperatures of 59 °F and 95 °F.

Potential annual emissions for regulated air pollutants were estimated at an ambient temperature of 59°F with evaporative cooling and duct firing. An ambient temperature of 59°F is used to determine potential emissions in tons/year, since it provides a conservative estimate of emissions. To estimate the potential annual emissions, different operating scenarios were evaluated including up to 4,000 hr/yr with duct firing at baseload conditions. Table 2-2 presents a summary of potential annual emissions for various operating conditions (baseload with duct firing, baseload without duct firing, and MECL).



A process flow diagram of the new CTG/HRSG/STG configuration, operating at base load conditions with an ambient temperature of 59°F, is presented in Figure 2-2.

During combustion, two primary types of NO_x are formed: fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. NO_x formation can be limited by lowering combustion temperatures (through water or steam injection) and/or staging combustion (a reducing atmosphere followed by an oxidizing atmosphere, known as DLN control). The proposed NO_x stack emissions rates will be further controlled using SCR to reduce emissions of NO_x to 2 parts per million by volume dry (ppmvd), corrected to 15 percent oxygen (O₂) or less.

Carbon monoxide (CO) is formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO formation. CO formation is limited by ensuring complete efficient combustion of the fuel in the turbines. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low CO emissions.

Similarly, volatile organic compound (VOC) emissions are formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize VOC formation. VOC formation is limited by ensuring complete efficient combustion of the fuel in the CTs. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low VOC emissions.

PM, sulfur dioxide (SO₂), and sulfuric acid mist (H₂SO₄) emissions will be controlled and minimized by the use of clean fuels, which include natural gas with a sulfur content of no greater than 2 gr/100 scf of natural gas.

GHG emissions will be minimized through the use of highly efficient combined cycle technology and the use of natural gas, the lowest GHG emitting fossil fuel. Appendix A, Table A-7 presents the GHG emissions for the CTG.

2.3.2 Auxiliary Boiler

The auxiliary boiler will be used to provide steam and steam cleaning during construction and initial startup of the CTG/HRSG/STG combined cycle unit. The auxiliary boiler will also provide steam to the combined cycle unit during cold, warm and hot startups and when the combined cycle unit is being shut down. The limited use auxiliary boiler will have a maximum heat input of 60 Million British thermal units per hour (MMBtu/hr) higher heat value (HHV) firing natural gas. This boiler may also be used during construction to provide steam for steam blows. Table 2-3 contains performance and emissions information for the auxiliary boiler. Appendix A, Table 8 presents the GHG emissions for the auxiliary boiler.



2.3.3 Emergency Diesel Generator and Fire Water Pump Diesel Generator

The Project will be equipped with a diesel-fired 1,500 kW (kW-electric) emergency generator to support the plant. The emergency generator will be used to provide electrical power during an emergency situation when electric power from the grid is interrupted or to ensure the safe shutdown of CTG and for maintenance checks and readiness testing. A 347 brake-horsepower (BHP) diesel-fired fire pump engine will also be installed, which will be used to provide power to pump water for fire suppression or protection. The emergency generator and fire pump will use ultra-low sulfur diesel (ULSD) fuel with a sulfur content not to exceed 0.0015%. Tables 2-4 and 2-5 contain emissions and performance information for the emergency generator and fire pump engine, respectively. Normally, the emergency generator and fire pump engine would be operated only 1 to 2 hours per month for maintenance and reliability testing. Appendix A, Table 8 presents the GHG emissions for the emergency diesel generator and fire water pump diesel engine.

2.3.4 Mechanical Draft Cooling Tower

Steam turbine condenser cooling will be provided by a 6-cell mechanical draft cooling tower. Particulate Matter (PM) will be emitted in the form of drift and controlled through the use of high efficiency mist eliminators that will have a design drift rate of 0.001 percent of the circulating water rate. Table 2-6 presents information on the auxiliary cooling system and potential PM, including PM with an aerodynamic diameter of 10 micros or less (PM₁₀) and PM with an aerodynamic diameter of 2.5 micros or less (PM_{2.5}) from drift.

2.3.5 Fugitive GHG Emissions

2.3.5.1 Circuit Breakers

In addition to combustion sources, the Project will have circuit breakers in the power block containing sulfur hexafluoride (SF₆). SF₆ is an electrical insulator and interrupter in equipment that transmits and distributes electricity. SF₆ has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulating oils.

Circuit breakers are required for connection of the electric power generated to the transmission and distribution system through the facilities located on the site. The circuit breakers associated with the Project are estimated to contain approximately 100 lbs of SF₆ each. Based on a design leak rate of 0.5 percent per year, the estimated GHG emissions from the circuit breakers are as follows:

- $100 \text{ lb SF}_6 \times 0.005 \text{ leakage/year} = 0.5 \text{ lb SF}_6/\text{year}$
- $0.5 \text{ lb SF}_6/\text{year} \times 22,800 \text{ lb CO}_2\text{e/lb SF}_6 \text{ (Table A-1, 40 CFR Part 98)} \times \text{ton}/2,000 \text{ lb} = 5.7 \text{ tons CO}_2\text{e}$



2.3.5.2 Natural Gas Leakage

Natural gas leaks from the new on-site natural gas supply connections, venting during maintenance, and venting during startup and shutdown represent a potential source of fugitive GHG emissions in the form of methane contained in the natural gas. EPA has developed emission factors to report GHG emissions for major source categories of GHG emissions in 40 CFR Part 98. The emission factors also include natural gas leaks for source categories handling major volume of natural gas including natural gas processing, transmission, distribution, gathering and boosting and transmission pipelines in Subpart W. At this time these emission factors provide the most technically appropriate emission factors for natural gas connections for facilities using natural gas. For the Project, natural gas leaks and venting were determined using 40 CFR Part 98, Subpart W emission factors. Table A-9 provides detailed calculations and assumptions for this estimate.

2.3.6 Hazardous Air Pollutants (HAPs)

Maximum annual potential HAPs emissions from the Project are presented in Table 2-7. Additional detail on the HAP emission calculations is also presented in Appendix A, Tables A-3, A-4 and A-5. The major source thresholds for HAPs are 10 TPY of a single HAP, or 25 TPY for all HAPs located on a single facility location. The existing SHGS with the three simple cycle combustion turbines is not a major source of HAPs emissions. The combined potential HAPs emissions from the proposed SHCCF and SHGS will remain under the "major source" threshold of 10 TPY for a single HAP (i.e., formaldehyde) and 25 TPY for all HAPs.

2.4 PSD Applicability

2.4.1 Criteria Pollutants

Table 2-8 presents a summary of the potential emissions of all criteria pollutants for all proposed emission units.

The U.S. Environmental Protection Agency's (EPA's) Prevention of Significant Deterioration (PSD) regulations are promulgated under Title 40, Parts 51 and 52 of the Code of Federal Regulations (40 CFR 51.166 and 40 CFR 52.21). Florida adopted EPA's PSD regulations by reference in Rule 62-204.800(3), Florida Administrative Code (F.A.C.), and Florida's PSD rules are codified in Rule 62-212.400, F.A.C. Florida's PSD rules have been approved by EPA as part of Florida's State Implementation Plan (SIP). The procedures for determining applicability of the PSD permitting program to the Project are set forth in Rule 62-212.400(2), F.A.C.

PSD is applicable to new "major stationary sources" and certain "modifications" that occur at an "existing major stationary source." A major stationary source is defined as one falling within any 1 of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary source not falling within one of those categories that has the potential to emit 250 TPY or more, of any pollutant subject to



regulation under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant under its physical and operational design after the application of control equipment.

The existing SHGS is one of the 28 listed source categories and has potential emissions of a PSD pollutant that exceeds 100 tons per year (TPY) [Rule 62-210.200(172), F.A.C.], and it therefore an "existing major stationary source." A modification to an existing major stationary source that results in an increase and a net increase in emissions of a PSD pollutant equal to or exceeding the significant emissions rates (SERs) as defined in Rule 62-210.200(256), F.A.C., is classified as a "major modification" and will be subject to the PSD preconstruction permitting program for those pollutants that exceed the PSD SERs.

Because this Project involves the construction of new emission units, the Baseline Actual-to-Potential Applicability Test for Construction of New Units in Rule 62-212.400(2)(a)2., F.A.C., is used to determine if there is a significant emissions increase. The baseline actual emissions for the SHCCF are presumed to be zero. The potential emissions from the new units are presumed to be an increase above zero. If the potential emissions of a PSD pollutant are above the SER for a pollutant, the increase is significant. For any PSD pollutant above the SER, the next part of the analysis is whether there is a significant "net" increase in emissions. As defined in Rule 62.210.200(187), F.A.C., a significant *net* emissions increase is determined by accounting for all other increases and decreases in actual emissions that are both contemporaneous and creditable. Emission increases or decreases for a particular modification are contemporaneous if they occur between five years before the construction of that change and the date the increase from the change occurs. In the case of the Project, there are no contemporaneous and creditable emission decreases in actual emissions, and the only contemporaneous and creditable emission increases in actual emissions would occur from the Project itself. As a result, a significant net emission increase occurs if the Project's potential emissions exceed the PSD SERs. Using the required regulatory comparison and pursuant to FDEP Rule 62-212.400, F.A.C., the Project will trigger PSD review for SO₂, PM [(total suspended particulate (TSP)], PM₁₀, PM_{2.5}, CO, and sulfuric acid mist as shown in Table 2-8.

2.4.2 GHGs

On June 3, 2010, the EPA promulgated regulations related to PSD applicability for Greenhouse Gas (GHG) Tailoring Rule (75 Federal Register 31514-31608). In EPA's 40 CFR 52.21 definition of "subject to regulation, GHGs are defined to include an aggregate group of six classes of compounds that have been determined to have GHG properties: carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆). Each of these GHGs has a specific Global Warming Potential (GWP) established under 40 CFR 98, Subpart A, Table A-1, which is calculated as "CO₂ equivalent (CO₂e) emissions" or CO₂e that is equivalent to the GHG properties of one ton of CO₂. For the Project, the GHGs emitted are CO₂, CH₄, and N₂O, with one ton of CH₄ equivalent to 25 tons of CO₂e and one ton of N₂O equivalent to 298 tons of CO₂e.



In 2014 the Supreme Court issued a decision that indicated that GHG alone could not trigger PSD review. Rather, PSD review for GHGs could only be triggered if PSD were required for other air pollutants [*Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427(2014)]. The decision vacated certain provisions under the 2010 federal GHG Tailoring Rule. EPA subsequently amended its PSD rules on August 19, 2015, to remove portions of the rule that were vacated. 80 Fed. Reg. 50199. FDEP has incorporated by reference EPA's Tailoring Rule definition of "subject to regulation" in effect as of July 1, 2016, which makes the state's version consistent with the current federal version.

Since the potential emissions from the Project will trigger PSD review for one or more criteria pollutants [SO₂, PM [(total suspended particulate (TSP)], PM₁₀, PM_{2.5}, CO, and sulfuric acid mist as shown in Table 2-7, PSD review for GHG emissions is required if the increase and net increase in GHG emissions are greater than 75,000 TPY CO₂e. As shown in Table 2-7 the increase and net increase in emissions of CO₂e emissions for the CTG, other combustion sources (auxiliary boiler, fire pump diesel engine, and emergency generator), circuit breakers and natural gas piping/venting will exceed the PSD significant emission rate for GHGs.

2.5 Layout, Structures, and Stack Sampling Facilities

A conceptual site plan of the Project is presented in Figure 2-1. Typical dimensions of the structures associated with the SHCCF Project are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with FDEP Rule 62-297.310(7), F.A.C.



3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

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

3.1 National AAQS

The existing applicable national ambient air quality standards (NAAQS) are presented in Table 3-1. Primary NAAQS were promulgated to protect the public health with an adequate margin of safety and secondary NAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with NAAQS are designated as attainment areas. Areas of the country not in compliance with NAAQS are designated as nonattainment areas. New sources to be located or modified sources located in or near these areas may be subject to more stringent air permitting requirements. When insufficient data exists to determine whether the area is in attainment, the area is considered "unclassifiable."

3.2 PSD Requirements

3.2.1 General Requirements

Florida's PSD program under FDEP Rule 62-212.400, F.A.C., requires new "major stationary sources" and "major modifications" to existing major stationary sources to undergo the following analysis for each pollutant emitted in significant amounts:

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

In addition to these analyses, a new major facility or major modification made to an existing major facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations that must be considered in the source impact analysis. As stated above, the proposed SHCCF Project triggers PSD review. Each of these requirements for a new major facility or major modification are presented and discussed in the following subsections.

3.2.2 Control Technology Review

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



BACT is defined in FDEP Rule 62-210.200(32), F.A.C., as:

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

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

For GHG emissions, control technology review is conducted by FDEP pursuant to its regulations in Rule 62-212.400, F.A.C. EPA approved FDEP's PSD permitting program for GHGs on May 9, 2014. EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases*", March 2011). This EPA guidance supplements previous EPA guidance on the determination of BACT that is specific to BACT determinations for GHG emissions.



3.2.3 Source Impact Analysis

PSD review requires a source impact analysis must be performed for a new “major stationary source” or “major modification” for each pollutant, subject to PSD review, for which net emissions exceed the SER (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. Designated EPA models that are approved by FDEP normally must be used in performing the impact analysis. Specific applications for other than EPA approved models require EPA’s consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised)*.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO₂, PM₁₀, PM_{2.5} and NO₂ concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. Florida has adopted the EPA class designations and allowable PSD increments for SO₂, PM₁₀, PM_{2.5} and NO₂.

The source impact analysis for criteria pollutants to address compliance with NAAQS and PSD Class II increments may be limited to the new source if the impacts as a result of the new source are below significant impact levels, as presented in Table 3-1.

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

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

3.2.4 Air Quality Monitoring Requirements

PSD review for a new “major stationary source” or “major modification” must also consider an analysis of continuous ambient air quality data in the area affected by the proposed major PSD source or major modification (FDEP Rule 62-212.400(7), F.A.C.). For a new “major stationary source” or “major modification”, the affected pollutants are those that the facility potentially would emit above the SERs.

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data



may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987).

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

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

3.2.5 Source Information/GEP Stack Height

Source subject to PSD review must provide detailed source information to adequately describe the proposed project, including the dimensions of building and emission stacks.

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

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

$$H_g = H + 1.5 L$$

where:

H_g = GEP stack height,

H = Height of the structure or nearby structure, and

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

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

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in the modeling analysis to determine compliance with NAAQS and PSD increments be no greater than the GEP stack height, the actual stack height of a project can be constructed with a stack height exceeding GEP.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured



or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, Florida PSD regulations require analyses for applicable pollutants of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of a project triggering PSD review [FDEP Rule 62-212.400(8), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with a project also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

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

3.2.7 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis is required for projects for those pollutants undergoing PSD review to assess the potential impact on AQRVs in PSD Class I areas. The nearest Class I areas to the Project is the Chassahowitzka National Wilderness Area (NWA), located about 28 km (~17.5 miles) from the Project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

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

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

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

3.3 Nonattainment Rules

FDEP has nonattainment provisions (FDEP Rule 62-212.500, F.A.C.) that apply to all new “major sources” or modifications to existing major stationary sources located in a nonattainment area and above certain nonattainment thresholds. In addition, for these facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Project is located in Pasco County, which is classified as an attainment or unclassifiable area for all criteria pollutants. The Project is also not located within an area of



influence of a nonattainment area. Therefore, nonattainment New Source Review (NSR) requirements are not applicable.

3.4 Emission Standards

3.4.1 New Source Performance Standards

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

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

Combustion Turbine/Duct Burners

NO_x and SO₂ emissions from stationary CTGs with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value (LHV) of the fuel fired, are limited per 40 CFR 60 Subpart KKKK. This NSPS applies to CTGs that commenced construction, modification or reconstruction after February 18, 2005. NO_x emissions for new CTGs with heat input capacities greater than 850 MMBtu/hr) are limited by Subpart KKKK to 15-ppmvd corrected to 15-percent O₂ for natural gas firing. At less than 75 percent load, the emission limit for gas turbines greater than 30 MW at peak load is 96 ppmvd at 15% O₂. SO₂ emissions are limited to using a fuel with a sulfur content of no greater than 20 gr/100 scf of sulfur natural gas firing. The emission standards of this NSPS also apply to the duct burners [Section 60.4305(a)]. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK.

EPA established NSPS for GHG emissions from new, modified, and reconstructed electric utility generating units (40 CFR Part 60, Subpart TTTT; Signed 8/3/15). The NSPS applies to new stationary CTs that commence construction after January 8, 2014, have a heat input rating of over 250 MMBtu/hr, and serve a generator capable of selling more than 25 MW of electricity to a utility distribution system. New baseload CTs that combust more than 90 percent natural gas are required to meet a CO₂ emissions rate of 1,000 lb/MWh (gross) or 1,030 lb/MWh (net) on a 12-month rolling average basis. EPA determined that these emission limits represent the Best System of Emission Reduction (BSER) required under Section 111(b) of the Clean Air Act. The monitoring requirements for natural gas fired units are based on 40 CFR Part 75 requirements. EPA announced on April 4, 2017 that these NSPS are being reviewed and if appropriate, will initiate proceedings to suspend, revise or rescind these NSPS (82 Fed. Reg. 16330).



FDEP adopted these NSPS by reference in Rule 62-204.800(8)(b)8, F.A.C. The monitoring requirements for natural gas fired units are based on 40 CFR Part 75 requirements.

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

40 CFR 60.7 Notification and Record Keeping

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

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

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

60.8 Performance Tests

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

Other Emission Units

NSPS are also applicable to the auxiliary boiler, emergency diesel generator, and fire pump engine. The EPA NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to the auxiliary boiler. The diesel engines associated with the emergency diesel generator and fire pump engine both meet the definition of “emergency stationary internal combustion engine” in NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This NSPS is applicable to the two diesel engines associated with the Project. These engines must be operated according to 40 CFR 60.4211(f) and required to meet the emission standards for the size and date of manufacturer of the engine (based on purchasing a certified engine from the manufacturer).

3.4.2 National Emission Standards for Hazardous Air Pollutants

EPA has promulgated maximum achievable control technology (MACT) standards under the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) regulations.

The SHGS is currently not a major source of HAPs since the potential HAP emissions from all emission units are not greater than the major source HAP thresholds of 25 TPY for total HAPs and 10 TPY for any single HAP. The proposed Project does not have the potential to emit a single HAP greater than the major source threshold of 10 TPY or all HAPs combined of more than 25 TPY. The total emissions from the



SHGS and the proposed Project will not exceed the major source HAP thresholds (see Table 2-7). As a result, neither SHGS nor SHCCF will be classified as a major source of HAPs. 40 CFR Part 63, Subpart YYYYY, NESHAP for Stationary Combustion Turbines, will therefore not apply. Subpart JJJJJJ applies to industrial, commercial and institutional boilers located at areas (minor) sources of HAPs. However, this NESHAP does not apply to boilers that fire only natural gas. Therefore, this NESHAP does not apply to the Project's auxiliary boiler. Subpart ZZZZ applies to the reciprocating internal combustion engines (RICE) located at major and area (minor) sources of HAPs. Meeting the requirements of NSPS Subpart IIII meets the requirements of NESHAP Subpart ZZZZ.

3.4.3 Florida Rules

FDEP has adopted the EPA NSPS by reference in FDEP Rule 62-204.800(8): Subsection (b)83., F.A.C., for stationary gas turbines (Subpart KKKK); Subsection (b)88 for the GHG emissions from the combustion turbine; Subsection (b)4., F.A.C., for the auxiliary boiler (NSPS Subpart Dc), and Subsection (b)82 for the emergency diesel generator and fire pump engine (Subpart IIII). FDEP has adopted EPA NESHAP by reference in Rule 62-204.800(11), Subsection (b)81 for the combustion turbines (Subpart YYYYY) and Subsection (b)82., F.A.C., for the emergency diesel generators and fire pump engine (Subpart ZZZZ). Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

FDEP Rule 62-296.406 applies to new and existing fossil fuel steam generators with less than 250 MMBtu/hr heat input and contains a visible emissions standard that applies to the auxiliary boiler.

3.4.4 Florida Air Permitting Requirements

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

3.4.5 Local Air Regulations

There are no air pollution regulations in Pasco County that would regulate the emission units proposed by the Project.



3.5 Source Applicability

3.5.1 Area Classification

The Project Site is located in Pasco County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Pasco County and surrounding counties are designated as PSD Class II areas for SO₂, PM [total suspended particulate (TSP)], and NO₂. The Class I area nearest to the Project is the Chassahowitzka NWA, located approximately 28 km (~17.5 miles) from the Site.

3.5.2 PSD Review

Pollutant Applicability

The proposed Project is considered to be a major modification under FDEP PSD rules because the increase in emissions of several regulated pollutants will exceed the PSD SERs. As shown in Table 2-8 potential emissions from the proposed Project will trigger PSD review for NO_x, SO₂, PM (TSP), PM₁₀, PM_{2.5}, CO, sulfuric acid mist, and GHGs. (Note: EPA no longer requires PSD review for HAPs. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

Emission Standards

NO_x and SO₂ emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK adopted by reference by FDEP in Rule 62-204.800(8)(b)83., F.A.C. NO_x emissions for the CTG associated with the Project (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15-ppmvd corrected to 15-percent O₂. At less than 75 percent load, the emission limit is 96 ppmvd at 15% O₂ for gas turbines greater than 30 MW at peak load. These emission standards are based on 30-day rolling average and must be met at all times, including startup, shutdown, and malfunctions. Under Subpart KKKK, SO₂ emissions are limited to using a fuel with a sulfur content of no greater than 20 grains per 100 standard cubic feet (gr/100 scf) of sulfur for natural gas firing. These requirements are summarized in Section 4.2. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. The proposed emissions rates for the Project will be well below the Subpart KKKK emission limit (see Section 4.0).

If not revised or eliminated based on EPA's current review of NSPS Subpart TTTT, GHG emissions as CO₂ from the SHCCF Project will be limited to 1,000 lb/MWh (gross) or 1,030 lb/MWh (net) by 40 CFR Part 60, Subpart TTTT, incorporated by reference by FDEP in Rule 62-204.800, F.A.C. This emission limit is applicable to SHCCF since the amount of electric output over a 3-year rolling average will exceed the threshold for this standard (estimated to be a capacity factor of approximately 42 percent for the proposed



CTG). Although the limit is applicable to the CTG, the amount of generation produced by the steam electric turbine generator is used in calculating the lb/MWh for the CTG/HRSG train. The proposed emissions for the CTG for SHCCF will be well below the Subpart TTTT CO₂ limit (see Section 4.0).

EPA has promulgated MACT standards under the NESHAP regulations and applicability is based on whether a source is major or minor for HAPs. As described in Section 3.4.2, the SHGS will not be classified as a major source of HAPS as the SHGS including the proposed Project does not have the potential to emit one HAP greater than the major source threshold of 10 TPY or all HAPs greater than the major source threshold of 25 TPY.

The NESHAP Subpart YYYY will not apply to the proposed CTG because this NESHAP applies to only major sources of HAPs.

The NESHAP Subpart ZZZZ addressing RICE applies to both major and area sources of HAPs. FDEP adopted this EPA rule by reference in Rule 62-204.800(11)(b)81, F.A.C. The method of compliance under this rule is demonstrating compliance with 40 CFR 60, Subpart IIII, which was previously cited in this section. The emergency diesel generator and fire pump engine will meet the requirements of Subpart IIII.

FDEP Rule 62-296.406 applies to the auxiliary boiler and limits visible emissions to 20 percent opacity except for one six-minute period per one-hour period during which opacity is limited to 27 percent.

Ambient Monitoring

For the proposed Project, the maximum ambient air impacts will be more than the PSD *de minimis* monitoring concentrations for all criteria air pollutants subject to PSD review (see Section 5.0). As a result, an air quality monitoring impact analysis for these pollutants is not required by NSR under FDEP air regulations. Additional discussion is presented in Section 5.0 of this application.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters (213 ft) high. The CTG/HRSG stack for the proposed Project will be 149 ft. As discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than the GEP stack height, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CTG/HRSG stack emissions caused by nearby structures is included in the modeling analysis.

3.5.3 Other Clean Air Act Requirements

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was promulgated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR 72), an allowance tracking system (Part 73), continuous emission monitoring (CEM)



(Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78). FDEP adopted these rules by reference in Rule 62-204.800(16), F.A.C. (permit provisions), Rule 62-204.800(17), F.A.C. (allowance system), Rule 62-204.800(19), F.A.C. (CEM), Rule 62-204.800(21), F.A.C. (excess emission procedures), and Rule 62-204.800(22), F.A.C. (appeal procedures).

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

The permit would require the units to hold SO₂ emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT for new units. An allowance is a market based financial instrument that is equivalent to 1 ton of SO₂ emissions. Allowances can be sold, purchased, or traded nation-wide. The Acid Rain Permit Application is attached with the permit application forms in Appendix C.

NO_x monitoring is required for natural gas-fired affected units using CEM or alternate procedures. SO₂ monitoring is also required, although use of CEM is optional. When a SO₂ CEM system is selected to monitor SO₂ mass emissions, a flow monitor is also required. Alternately, SO₂ emissions may be determined using procedures established in Appendix D, 40 CFR 75. CO₂ emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified [Part 75, Appendices A through I; FDEP Rule 62-204.800(19)(b)1-9, F.A.C.]. The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart KKKK. New units are required to meet the requirements by not later than 90 days after the unit commences commercial operation. Appendix C contains the Acid Rain Part Application for SHCCF.

EPA in 2011 finalized the Cross-State Air Pollution Rule (CSAPR) that required 27 states in the eastern half of the U.S. to reduce annual emissions from electric utility units that cross state lines and contribute to ozone (NO_x emissions) and fine particle concentrations (SO₂ and NO_x). Florida was originally included as one of the 27 states for contributing to ozone. A number of court actions delayed the implementation of CSAPR, leaving the former Clean Air Interstate Rule (CAIR) in place. On April 29, 2014, the Supreme Court upheld CSAPR, remanded the rule to the D.C. Circuit, and it became effective in Florida on January 1, 2015. In EPA's September 7, 2016 update to the CSAPR rule the Agency concluded that Florida no longer significantly contributes to downwind nonattainment and removed Florida from compliance with the rule.



4.0 CONTROL TECHNOLOGY DESCRIPTION

4.1 Introduction

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Subsection 3.2.2, one of these requirements is that BACT be applied to all applicable pollutants. This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires a site-specific analysis of the technical, economic, environmental, and energy impacts of the proposed and alternative control technologies (see Rule 62-212.400, F.A.C.).

The "top-down" approach consists of the following five steps, as described in the New Source Review Workshop Manual-Draft (EPA, 1990):

1. Identification of all available control technologies
2. Elimination of technically infeasible control options
3. Ranking of the technically feasible control technologies based on their effectiveness
4. Evaluation of the economic, environmental, and energy impacts of the feasible control options
5. Selection of BACT based on consideration of the above factors

The PSD regulations require that new major stationary sources and major modifications to existing major stationary sources undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. In the case of the proposed Project, NO_x, PM (TSP)/PM₁₀/PM_{2.5}, CO, SO₂ (including sulfuric acid mist) and GHG emissions require a BACT analysis utilizing the top-down approach. In each case, BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account the proposed Project's specific economic, environmental, and energy impacts, as well as consideration of the application of the technologies proposed. If it is impractical to impose an emission limit, a work practice standard may be specified.

An overview of the BACT analysis is presented in Section 4.2, and the following sections provide the required BACT analysis.

4.2 Overview of Proposed BACT

FDEP has issued many PSD permits with BACT determinations for projects involving natural gas and/or fuel oil-fired combined cycle CTs. These decisions for CT/HRSGs have included the use of advanced DLN combustors and an SCR system for limiting emissions of NO_x, good combustion practices for minimizing CO and VOC emissions, and the use of clean fuels such as pipeline-quality natural gas or ULSD oil for



control of other emissions including PM₁₀, PM_{2.5}, and SO₂. For NO_x emissions, concentration levels have been limited to 2.0 ppmvd corrected to 15-percent O₂ in the most recent determinations.

The BACT limits proposed for the Project are consistent with the DEP-issued PSD Permits for other combined cycle projects and other emission units. The proposed BACT limits for this Project are presented in Table 4-1.

The proposed limits contained in Table 4-1 are for normal operation and exclude startup, shutdown, malfunctions, and DLN tuning. During startup and shutdown of the CTG and STG, conditions exist where the CTG is operating at low loads where the DLN systems are ineffective and the SCR cannot function. Non-steady state operation results in emissions higher than of those proposed as a BACT for normal operation. The durations of these non-steady state operation periods depend upon the specific startup, shutdown, malfunctions, and DLN tuning condition. Presented below are suggested permit conditions for these periods of non-steady state operations. For NO_x and GHG, there are NSPS that have to be met at all times and are proposed as secondary BACT. In addition, work practice standards are proposed as secondary BACT for all pollutants. The suggested permit language is similar to the conditions for combined cycle projects using GE 7H CTs contained in the PSD/Air Construction Permit for the FPL Okeechobee Clean Energy Center (OCEC) Permit No. 0930117-001-AC/PSD-FL-434 and Dania Beach Energy Center Permit No. 0110037-017-AC/PSD-FL-442.

22. Demonstration of Compliance with Primary NO_x and GHG BACT: The Primary NO_x and GHG BACT limits apply at all times, except during the following operating conditions:

a. *Cold Startup:* During a cold startup, the Primary NO_x and GHG BACT emission limits do not apply to any CTG/HRSG system, for no more than 4 hours during any 24-hour period. A cold startup of the steam turbine is defined as startup of the 1-on-1 combined cycle system following a shutdown of the steam turbine equal to or greater than 72 hours.

{Permitting note: During a cold startup of the steam turbine, the CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam turbine and prevent thermal metal fatigue or equipment materials differential expansion damage. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

b. *Warm Startup:* During a warm startup of a CTG/HRSG system, the Primary NO_x and GHG BACT emission limits do not apply, for no more than 3 hours during any 24-hour period. A warm startup of the CTG/HRSG system is defined as startup of the 1-on-1 combined cycle unit following shutdown for a period exceeding 8 hours but less than 72 hours.

c. *Hot Startup:* During a hot startup of a CTG/HRSG system, the Primary NO_x and GHG BACT emission limits do not apply, for no more than 2 hours during any 24-hour period. A hot startup of the CTG/HRSG system is defined as startup of the 1-on-1 combined cycle unit following shutdown for a period less than or equal to 8 hours.



d. *Shutdown of Combined-Cycle Operation:* During the shutdown of combined cycle operation, the Primary NO_x and GHG BACT emission limits do not apply to any CTG/HRSG system, for no more than 3 hours during any 24-hour period.

e. *DLN Tuning:* The Primary NO_x and GHG BACT emission limits do not apply during a DLN tuning session and manufacturer required Full-Speed No-Load Tests (FSNL) trip tests, provided the tuning session is performed in accordance with the manufacturer's specifications or determined best practices. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.

f. *Documented Malfunction:* The Primary NO_x and GHG BACT emission limits do not apply during a documented malfunction, for no more than 2 hours in any 24-hour period. To qualify as a "documented malfunction," the malfunction must be documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The permittee shall report to the Department the nature, extent, and duration of the malfunction, and the actions taken to correct the problem.

Emissions during the startup, shutdown, DLN tuning and documented malfunction events listed above are not subject to the Primary BACT standards for NO_x or GHGs. These are considered separate events, and each event may occur independently within any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight). Data from the NO_x and CO₂ CEMS (or fuel use monitor) collected during the events described above will not be used to demonstrate compliance with the Primary BACT emission limits for NO_x and GHGs.

Data from the NO_x and CO₂ CEMS (or fuel use monitor if a CO₂ CEMS is not used) collected during the operating conditions described above, during which the Primary NO_x and GHG BACT limits do not apply, will be used to demonstrate compliance with the Secondary NO_x and GHG BACT emission limits at all times. All valid emissions data (including data collected during startups, shutdowns, malfunction, DLN tuning, and fuel switching) shall be used to report emissions for the Annual Operating Report.

23. Secondary NO_x and GHG BACT Emission Limits: During the operating conditions listed in **Specific Condition 22**, the permittee shall comply with the Secondary NO_x and GHG BACT limits specified in **Specific Condition 11**. Demonstrating compliance with the NO_x limit in NSPS Subpart KKKK at all times shall be sufficient for demonstrating compliance with the Secondary NO_x BACT limit. Demonstrating compliance with the GHG limit in NSPS Subpart TTTT at all times shall be sufficient for demonstrating compliance with the Secondary GHG BACT limit. [Rule 62-210.200(BACT), F.A.C., and 40 CFR 60, Subparts KKKK and TTTT]

{Permitting Note: Compliance with the Secondary NO_x and GHG BACT Emission Limits is continuous compliance with an applicable SIP emission limit.}

4.3 Combined Cycle CTG/HRSG

This section contains the BACT analysis for the NO_x, CO, PM (TSP)/PM₁₀/PM_{2.5}, SO₂ (including sulfuric acid mist), and GHG emissions from the combined cycle CTG/HRSG.



4.3.1 Nitrogen Oxides

4.3.1.1 Previous BACT Determinations

As part of the BACT analysis, a review was performed of previous BACT determinations issued within the last 12 years (i.e., since 2003) for NO_x emissions from combined cycle CTGs listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's web page. A summary of the BACT determinations for natural gas-fired CTGs and CTGs with HRSG duct firing are presented in Appendix B, Table B-1. Only large CTs with more than 100 MW electricity output or more than 1,000 MMBtu/hr heat input were included in the tables. These tables also include determinations from major source permits available on the FDEP website and in other recent relevant BACT analysis reports.

As shown in Appendix B, Table B-1, it is evident that the overwhelming majority of BACT emissions limits over the last 10 years for natural gas firing combined cycle CT/HRSGs are typically 2 and 2.5 ppmvd corrected at 15-percent O₂.

FDEP has issued several permits for natural gas-fired combined cycle units and have established BACT for NO_x emissions from these CT/HRSGs as DLN and/or SCR with a stack NO_x concentration of 2.0 ppmvd or higher. The most recent gas-fired combined cycle units in Florida that met NO_x levels either determined to be BACT or as equivalent to BACT were the Okeechobee Clean Energy Center and Dania Beach Energy Center that utilized the GE 7H CTs. The emission limits established by FDEP were based on DLN when firing gas along with SCR to meet an emission limit of 2 ppmvd corrected to 15-percent O₂ for natural gas firing.

4.3.1.2 Identification of Potentially Applicable Control Technologies

A list of potential control technologies for controlling NO_x emissions from the CTG/HRSG are identified in the following subsections.

Water Injection

The injection of water or steam in the combustion zone of CTGs reduces the flame temperature with a corresponding decrease of NO_x emissions. However, with the advent of DLN or equivalent combustion technology when firing natural gas, water injection is used only when units fire fuel oil. The Project will not be firing fuel oil, and will only be firing natural gas.

DLN Combustors

DLN combustors or equivalent technology, which are offered for conventional CTGs manufactured by GE, Siemens, Mitsubishi Heavy Industries (MHI), and ABB, can achieve NO_x emissions concentrations as low as 9 ppmvd or less when firing natural gas. All these vendors have offered DLN combustors on advanced heavy-duty industrial units. Formation of thermal NO_x, which is a product of combustion, is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For



the GE 7HA.02 CTG/HRSG proposed for the Project, the standard combustion chamber design includes the use of the latest DLN combustor technology.

Selective Catalytic Reduction

SCR is a process for controlling emissions of NO_x from stationary sources. The basic principle of SCR is the reduction of NO_x to nitrogen (N_2) and water (H_2O) by the reaction of NO_x and ammonia (NH_3) within a catalyst bed. The primary reactions are temperature dependent typically occurring in the range of 600 and 750 °F, although reaction also can occur at lower and higher temperatures. The SCR reaction requires O_2 , and performs effectively at O_2 levels above 2 to 3 percent, levels that are easily achieved in the exhaust gas of a CTG.

Several different catalysts are available for use at different exhaust gas temperatures. The most common catalysts in use are base metal catalysts that typically contain titanium and vanadium oxides and which may also contain molybdenum, tungsten, and other elements. Base metal catalysts are useful at exhaust gas temperatures between 450 and 800°F. For high temperature operation (700 to over 1,100°F), zeolite catalysts may be used. In clean, low-temperature (350 to 550°F) applications, catalysts containing precious metals such as platinum and palladium can be used.

An SCR system consists of a reactor chamber with a catalyst bed, composed of catalyst modules and an NH_3 handling, storage, and injection system, with the NH_3 injected into the flue gas upstream of the catalyst. In a combined cycle unit, the SCR catalyst and ammonia injection grid are located in the HRSG. A typical combined cycle SCR design places the reactor chamber after the super heater within a cavity of the HRSG system. The flue gas temperature in this area is within the operating range for base metal-type catalysts. For combined cycle CTG/HRSGs, SCR is considered an available, demonstrated technology. Other than spent catalyst, the SCR process produces no waste products.

In principle, SCR can provide reductions in NO_x emissions approaching 100 percent. Simple thermodynamic calculations indicate that a reduction of well over 99 percent is possible at 650°F. However, in practice, commercial SCR systems have only been able to reliably meet control targets of up to 90 percent in many cases.

SCONox Process

Goal Line Environmental Technologies developed the SCONox, a multi-pollutant post-combustion technology, which utilizes a coated oxidation catalyst to oxidize and remove NO_x and CO without a reagent such as NH_3 . Now offered by EmeraChem (formerly Goal Line), the technology is marketed under the name EMx™.



The SCONOx system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize CO to CO_2 and NO to NO_x . CO_2 generated in the catalyst bed is exhausted to the atmosphere with the flue gas, while NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Periodically, dilute hydrogen gas is passed across the catalyst to regenerate the potassium carbonate coating. The regeneration step converts KNO_2 and KNO_3 into K_2CO_3 , water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of five-module catalyst sections. During operation, four of the five modules are online and treating flue gas, while one module is isolated from the flue gas for regeneration. NO_x reduction in the system occurs in an operating temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

A regeneration cycle is typically set to last for 3 to 5 minutes. Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONOx system uses a gas generator to produce hydrogen and CO_2 . For SCONOx systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the SCONOx catalyst that reforms the natural gas.

The SCONOx system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SCOSOx) to remove sulfur compounds is installed upstream of the SCONOx catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the SCOSOx catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SCOSOx catalyst is regenerated along with the SCONOx catalyst.

The SCONOx catalyst must be recoated, or “washed” every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SCOSOx catalyst. The “washing” consists of removing the catalyst modules from the unit and placing each module in a K_2CO_3 reagent tank, which is the active ingredient of the catalyst. The SCOSOx catalyst also requires washing.

EmeraChem states that their EMx™ technology (the second-generation of the SCONOx NO_x absorber technology) is capable of reducing gas-fired NO_x emissions to less than 1.0 ppm, emit undetectable levels of CO, reduce VOC emissions by >90-percent, reduce fine PM by 30 percent, and reduce sulfur emissions by 95 percent.

Commercial experience with the SCONOx control system is extremely limited. The NO_x reduction system was commercially demonstrated first at the 32-MW (GE LM2500 turbine) Sunlaw Federal Cogeneration Facility located in Vernon, California in 1998. NO_x emissions from the process were <2 parts per million (ppm) during 100-percent operation, and <1 ppm for 90-percent operation. Other installations of the technology include a 15-MW (Solar Titan 130 turbines) installation at the University of California, San Diego,



and a 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. A number of smaller installations are also operating: two 5-MW installations at the Wyeth BioPharma cogeneration facility in Andover, Massachusetts, and at the Montefiore Medical Center in New York, New York. Actual NO_x emissions from these smaller installations are typically below 1.5 ppm, with substantial periods below 1.0 ppm. Alstom Power, one of the EMx™ licensees, engineered and installed the technology on one of their GTX100 (43-MW class) gas turbines.

The application of this technology has not advanced in over a decade and this technology is not commercially available at the size of modern combined cycle units.

XONON™ Catalytic Combustor

The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Energy Systems, Inc., that is designed to avoid high temperatures created in conventional combustors. The XONON™ combustor utilizes a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NO_x is formed. It also lowers CO and VOC emissions.

The XONON™ technology is installed as an integral part of the combustor. Conventional combustion fuel and air are supplied to combustor; however, rather than combusting the fuel in a flame, the XONON™ system combusts the fuel using a catalyst at lower temperatures. Fuel and air are thoroughly mixed prior to entering a catalyst region that acts to combust the fuel, releasing its energy. The XONON™ catalyst module consists of a channel structure whereby the fuel-air mixture readily passes through the channels coated with the catalyst. As fuel and O₂ molecules contact the channel walls, the molecules and catalyst interact and are rearranged at temperatures well below those of flame combustion. Energy is extracted from the fuel in this manner, producing CO₂ and water byproducts. Nitrogen molecules are not involved in the XONON™ chemistry and pass through the channels unchanged, thereby preventing the formation of NO_x.

The XONON™ technology was first designed into the combustor of a 1.4-MW Kawasaki Model M1A-13A gas turbine at Silicon Valley Power in Santa Clara, California, in 1999. Since its installation, the turbine has operated as a demonstration of XONON™'s performance. The California EPA's Air Resources Board (CA EPA, 2004) evaluated NO_x and CO CEM system data and concluded that XONON™ achieved a NO_x level of 2.5 ppmvd at 15-percent O₂ and a CO level of 6.0 ppmvd at 15-percent O₂.

Other commercial installations of the XONON™ technology include a 1.5-MW Kawasaki M1A-13X installation at Sonoma Development Center in Eldridge, California, and a 1.4-MW Kawasaki GPB15X installation at Plains Exploration & Production Company in San Luis Obispo, California. The Eldridge installation's expected performance was 3 ppmvd NO_x and 10 ppmvd CO. According to the manufacturer, the unit has consistently achieved continuous NO_x emission levels below the emission target, and on the



average, NO_x emissions are under 2.0 ppmvd at 15-percent O₂. Based on the manufacturer's report, the unit at the Plains Exploration & Production Co. has achieved NO_x emissions around 0.8 ppmvd at 15-percent O₂ on the average.

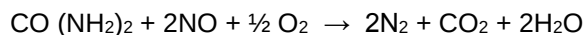
Kawasaki Gas Turbines-Americas started selling GPB 15X generators including a 1.4-MW M1A-13X gas turbine equipped with XONON™ in December 2000.

In September 2006, the XONON™ Combustion System (referred to as the XONON™ Cool Combustion® technology) was sold to Kawasaki Heavy Industries, Ltd. (KHI). Kawasaki is currently making the technology available to the gas turbine generators in the 1- to 1.4-MW range (KHI, 2008).

Similar to SCONOX, XONON™ technology has not advanced in a decade and is not commercially available for the size of modern combined cycle units. Moreover, advances in CTG combustion technology such as DLN or equivalent result very low NO_x, CO and VOC emissions that the manufacturers are willing to guarantee.

NOxOUT Process

The NOxOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NOxOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600 to 1,900°F. In the presence of O₂, the following reaction results:



The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600 and 1,950°F. Advantages of the system are as follows:

- Low capital and operating costs as a result of use of urea injection
- The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems

Disadvantages of the system are as follows:

- Formation of NH₃ from excess urea treatment rates and/or improper use of reagent catalysts
- Sulfur trioxide (SO₃), if present, will react with NH₃ created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream



Commercial application of the NO_xOUT system has been limited to oil- and coal-fired boilers and municipal solid waste combustors and has not been demonstrated on any combined cycle gas turbines.

Thermal DeNO_x

Thermal DeNO_x is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature selective noncatalytic reduction (SNCR) of NO_x using NH₃ as the reducing agent. Thermal DeNO_x requires the exhaust gas temperature to be above 1,800°F. However, use of NH₃ plus hydrogen from NH₃ decomposition lowers the temperature requirement to about 1,000°F. For some applications, the high temperature must be achieved by additional firing in the exhaust stream before NH₃ injection.

The only known commercial applications of Thermal DeNO_x are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with combined cycle units. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional natural gas-fired exhaust heater system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x emission control technology that reduces NO_x into nitrogen gas and water vapor by reacting the flue gas with a reagent. SNCR systems can either use NH₃ or urea as reagents. The chemical reaction for this technology is driven by high temperatures normally found in combustion sources, typically from 1,600 to 2,100°F. SNCR is "selective" in that the reagent reacts primarily with NO_x.

SNCR is a proven and reliable technology. SNCR was first applied commercially in 1974 and has been installed on approximately 400 applications worldwide. Applications include utility boilers and a broad range of industrial applications including wood-fired boilers, coal-fired boilers, co-generation boilers, pulp and paper boilers, steel industry furnaces, refinery process units, process heaters, cement kilns, municipal waste combustors, glass-melting furnaces, hazardous waste incinerators, and other combustion-type sources. Urea-based SNCR has been applied commercially to sources ranging in size from a 60-MMBtu/hr (gross heat input) paper mill sludge incinerator to a 640-MW pulverized coal-fueled, wall-fired electric utility boiler [Institute of Clean Air Companies (ICAC), 2006].

Non-Selective Catalytic Reduction

Stationary non-selective catalytic reduction (NSCR), as with the automobile sector, involves the use of a three-way catalyst technology to promote the reduction of NO_x to nitrogen and water and simultaneous oxidation of CO and hydrocarbons (HC) to CO₂ and water. NO_x is reduced by the CO and hydrogen (H₂)



over the catalyst under slightly rich or stoichiometric conditions to produce CO₂ and water with typical conversion efficiencies in the range 80- to 99-percent achievable together with corresponding decreases in HC and CO.

NSCR can be applied to various spark ignited internal combustion engines that are rich-burn, including natural gas-fueled engines. These types of engines are commonly found in the following applications: gas gathering and storage, gas transmission, power generation, combined heat and power, cogeneration/trigeneration, irrigation, inert gas production, and non-road mobile machinery. NSCR has been used routinely in the automotive industry to reduce vehicular carbon monoxide, hydrocarbons, and NO_x emissions with over a billion catalyst units equipped to automobiles since the mid-1970s. The application of NSCR to stationary gas engines for the control of NO_x and CO first became commercially available in North America in the late 1980s, and more than 5,000 stationary engine installations are in service today (ICAC, 2006).

4.3.1.3 Identification of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

Water Injection

Water injection is a demonstrated technology, but is only used when units fire oil. Since the proposed CTG for the Project will not fire oil, water injection is not considered technically feasible for the Project.

DLN Combustors

DLN combustors are available, demonstrated, and technically feasible for units in either simple cycle or combined cycle configurations. The DLN combustion technology alone can achieve NO_x emission rates as low as 9 ppm (corrected to 15-percent O₂ dry conditions) when firing natural gas in some CT models.

SCR

SCR has been demonstrated successfully in numerous applications and is considered technically feasible for the proposed CTG/HRSG associated with the Project.

SCONOX

The SCONOX control technology is not considered available (and therefore is considered technically infeasible) since it has not been commercially demonstrated on large combined cycle CTs. The proposed CT is the GE 7HA.02 turbine with a nominal generating capacity of 350 MW, approximately seven times larger than the 45-MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. Technical problems associated with scale-up of the SCONOX technology are unknown given the large differences in machine flow rates. Additional concerns with the SCONOX control technology include



process complexity (multiple catalytic oxidation / absorption / regeneration systems), brief operating history and no commercial availability.

XONON

While the XONON™ catalytic combustion system is applied directly to the CT, application on large CTs has not been demonstrated. The XONON™ technology is not considered available or technically feasible.

NOxOUT

As discussed previously, commercial application of the NOxOUT system is limited mainly to boilers. The ULTRA Systems by FuelTech, Inc. that is a version of the NOxOUT process injects urea and dilute ammonia through decomposition. This technology has not been commercially operated on any large combined cycle gas turbine unit; therefore, these technologies are not considered available or technically feasible for SHCCF. Even if the NOxOUT process were technically feasible for the proposed Project, the operating temperature range of the combined cycle exhaust is below the NOxOUT application temperature of 1,600 to 1,950°F. The maximum exhaust gas temperature of the CT associated with the Project (approximately 1,200 °F) is well below 1,600°F and not in the range of the NOxOUT process reaction. Raising the exhaust temperature to the required level would require installation of a natural gas fired heater. This would be economically prohibitive due to the amount of energy to increase exhaust temperature to the NOx OUT reaction range, resulting in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions including NO_x.

Thermal DeNO_x

As discussed previously, there are no known applications of the Thermal DeNO_x technology to combined cycle units. Since this technology has not been demonstrated for combined cycle units, it is not considered available or technically feasible. Additionally, even if this technology were technically feasible, the operating temperatures for the Thermal DeNO_x technology (approximately 1,800°F) would require higher temperature alloy materials constructed with very large piping and components since the exhaust gas volume would be increased significantly. As with the NOxOUT process, high capital, operating, and maintenance costs would be expected because of material requirements, a natural gas-fired exhaust heating system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

SNCR

Because the exhaust temperatures from the proposed CT will not approach the operating temperature window for SNCR, this technology is not technically feasible for this application. The CT exhaust temperature for SNCR is typically around 1,225°F; the temperature at the exhaust stack downstream of the HRSG is expected to range between approximately 160 and 220°F, which is far below the range of SNCR application. Further, a review of EPA's RBLC database and discussions with control technology vendors



do not indicate that SNCR systems have been successfully installed for combined cycle gas turbines. Based on the above limitations (i.e., operating temperature range and lack of actual application to combined cycle units), SNCR is considered technically infeasible for SHCCF.

NSCR

As discussed previously, the NSCR process requires low O₂ content in the exhaust gas stream to be effective. Combined cycle unit exhaust streams have high O₂ levels (greater than 12 percent); and therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for combined cycle units.

Summary

Based on the preceding discussion, the following technologies are considered to be technically feasible:

- DLN Combustors
- SCR

4.3.1.4 Ranking of Technically Feasible Control Alternatives

DLN combustors and SCR are compatible technologies and can be applied together. DLN combustors are pre-combustion technologies and SCR is a post-combustion technology. Considered together, this would be the best control strategy for the control of NO_x. Therefore, a ranking is not required to establish the top technology.

4.3.1.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Economic Impacts

DLN combustors are part of the standard design of modern CTs to substantially reduce NO_x emissions. The total capital cost of SCR is estimated to be about \$4.2 million. The total annualized cost of applying SCR is estimated to be approximately \$1.8 million. The incremental cost effectiveness of adding SCR to the DLN combustors is estimated to be \$1,321-per ton of NO_x removed, based on 8,760 hours of operation with 4,760 hours firing natural gas at baseload and 4,000 hours of duct firing. Detailed calculations are provided in Tables 4-2 and 4-3.

Environmental Impacts

Water injection or properly tuned DLN combustors do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. SCR requires storage and use of NH₃, which can cause environmental consequences if not handled and stored properly. NH₃ for the SCR can be either in anhydrous or aqueous liquid form. Storage of anhydrous and aqueous (20% or greater) will trigger requirements as specified by OSHA and the



Community Right-to-Know Act. SHEC intends to use aqueous ammonia in a 19% or lower solution. NH_3 slip (i.e., unreacted NH_3 emitted from the stack) is typically 9 ppm or less but has the potential to increase with increasing NH_3 feed rates. Additionally, during the life of the Project, the catalyst would require periodic regeneration or replacement. The used catalyst would be returned to the catalyst supplier for regeneration or would be disposed of in accordance with all applicable regulations.

The installation of SCR would reduce potential NO_x emissions by about 1,500 TPY while causing direct emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate (see Table 4-4). Ammonia emissions associated with SCR are 5 ppm corrected to 15 percent O_2 based on typical catalyst manufacturer guarantees; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 88 TPY at the end of the catalyst's life. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and $\text{PM}_{2.5}$; up to about 4 TPY.

Energy Impacts

Water injection and DLN combustors are inherent to the combustion process and do not create any energy impacts. With SCR, the output of the CT will be reduced by about 0.2 percent. This penalty in CT output would result in about 7,078 MWh per year in potential lost generation. The energy required by the SCR equipment would be about 2,891 MWh per year. Taken together, the total lost generation and energy requirements of SCR of 9,969 MWh per year that could supply the monthly electrical needs of about 831 residential customers assuming a monthly residential use of 1 MWh per month. To replace this lost energy, an additional 61,807 million British thermal units per year (Btu/yr) or about 62 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.6 Selection of BACT and Rationale

DLN combustors and SCR are proposed as the technologies to establish BACT emission limits for the combined cycle CTG/HRSG. These technologies are the only feasible control technologies and together, they represent the best and most cost effective NO_x control option. All NO_x BACT determinations for large natural gas-fired CT/HRSGs are based on these control technologies. The proposed BACT emissions limit is 2 ppmvd, corrected to 15-percent O_2 , based on a 24-hour block averaging period excluding startup and shutdown periods. The emission limits required by NSPS Subpart KKKK are required to be met at all times and are proposed as the secondary BACT limit for NO_x emissions.

The most recent NO_x emission limit determined to be BACT in Florida for a natural gas-fired combined cycle project using the GE 7H.02 CT is for the OCEC Project (Permit No. 0930117-001-AC, issued March 9, 2016) based on an emissions limit of 2 ppmvd at 15-percent O_2 . The NO_x emission limit established by FDEP for the DBEC (Permit No. 0110037-017-AC/PSD-FL-442), although not a BACT determination, was considered by FDEP to resemble BACT established for OCEC [Technical Evaluation and Preliminary Determination (TEPD) October 17, 2017].



The proposed Secondary BACT limits that will include emissions during periods of startup, shutdown and malfunctions are the NSPS limits of 15-ppmvd, corrected to 15-percent O₂ for natural gas firing based on 30-day rolling average pursuant to 40 CFR 60, Subpart KKKK.

4.3.2 Carbon Monoxide

4.3.2.1 Previous BACT Determinations

CO BACT determinations are presented together in this section since the same emission control technologies are used for both. As part of the BACT analysis, a review was performed of previous CO BACT determinations for large CTs similar in size to the proposed CTG in EPA's RBLC database. A summary of recent BACT determinations for CO are presented in Appendix B, Table B-2.

From the review of previous BACT determinations, it is evident that all CO BACT determinations for natural gas-fired CTs have been based on good combustion practices (GCP). Based on RBLC data for natural gas-fired GE 7H CTs, there have been two recent BACT determinations for CO in Florida (Okeechobee Clean Energy Center and Dania Beach Energy Center). These BACT determinations in Florida required emissions limits of 4.3 ppmvd at 15-percent O₂ for CO at baseload to 90 percent load and 7.1/7.2 ppmvd at 15-percent O₂ from MECL to less than 90 percent load.

The CO emission limits representative of large combined cycle CTG/HRSGs in Florida also include the FPL Port Everglades Energy Center (PEEC) Project with the permit issued in May 2012 and the Duke Energy Florida, Inc. Citrus Combined Cycle (CCC) Project with the permit issued in December 2014. The 250 MW CT/HRSGs for PEEC are natural gas fired with up to 3,000 aggregated hours per year of fuel oil firing for the three CT/HRSGs. The CO emissions limits for natural gas firing are 9.0 ppmvd at 15-percent O₂. The CCC Project consisted of two 2-on-1 combined cycle units using Mitsubishi Power Systems 501 GAC CTs with a nominal rating of 270 MWs each. Only natural gas is used as fuel for CCC Project. The emission rates for CCC Project at baseload conditions are 4.0 ppmvd at 15-percent O₂ for CO. Good combustion practice was used as a basis for the CO emission limits established for PEEC and CCC Projects.

4.3.2.2 Identification of Potentially Applicable Control Technologies

Combustion is a thermal oxidation process in which carbon and hydrogen contained in a fuel combine with oxygen in the combustion zone to form CO₂ and H₂O. Incomplete combustion occurs when there is not enough oxygen to allow the fuel to react completely to produce CO₂ and water. CO is a result of incomplete or partial combustion of fossil fuel primarily due to carbon in the fuel that does not experience the required temperature or residence time to be fully oxidized to CO₂. The important parameters in CO formation are combustion temperatures, fuel residence time, and local stoichiometric ratio of fuel and air (i.e., mixing of fuel and air). Properly designed and operated combustion units typically emit low levels of CO.



The following control options are evaluated in the BACT analysis. These control options were selected based on recent CO BACT analysis for large CTs and recent BACT determinations from the RBLC database.

Good Combustion Practices (GCP)

CO emissions are generated from the incomplete combustion of carbon in the fuel. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion is the primary mechanism available for lowering CO emissions. This process is often referred to as combustion controls. The combustion system design in modern CTGs provides all of the factors required to facilitate complete combustion, including continuous mixing of air and fuel in the proper proportions, extended residence time, and consistent temperatures in the combustion chamber. As a result, CO emissions from CTGs are inherently low.

GCP are typically employed to ensure that the CTGs are operated as designed.

Oxidation Catalyst

Catalytic oxidation technology is primarily designed to reduce CO emissions (VOC emissions are also reduced to a lesser extent). Oxidation catalysts operate at elevated temperatures. In the presence of an oxidation catalyst, excess O₂ in the exhaust reacts with CO to form CO₂. No chemical reagent is necessary. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components is considered toxic.

Oxidation catalysts are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning reduces catalyst activity and pollutant removal efficiencies. The most effective oxidation of CO emissions is achieved if the catalyst bed is located prior to the HRSG in the high-temperature region of the CTG exhaust.

SCONox Process

The SCONox system, an alternate technology for control of NO_x also controls CO and employs a single catalyst to simultaneously oxidize CO to CO₂ and NO to NO₂. The SCONox operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG.

4.3.2.3 Evaluation of Technically Feasible Control Alternatives

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.



Combustion Controls

Combustion controls have been applied successfully on combined cycle units similar to those proposed for the Project and are considered technically feasible.

Oxidation Catalyst

Oxidation catalyst technology has been applied successfully on combined cycle units in states other than Florida similar to those proposed for the Project and is considered technically feasible.

SCONOX

The application of the SCONOX system is limited to a few small turbines with no systems installed on large gas turbines similar to the ones proposed for the Project. Therefore, SCONOX is considered to not be technically feasible or commercially available for the Project.

4.3.2.4 Ranking of Technically Feasible Control Alternatives

Combustion controls and oxidation catalyst are compatible technologies and are considered together in combination as the top control option for CO; thus, a ranking is not required to establish the top technology.

4.3.2.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

Economic Impacts

DLN combustors and GCP are part of the standard design of modern CTGs that substantially reduce CO emissions. The total capital cost of an oxidation catalyst is estimated to be about \$881,000 per CTG/HRSG. The total annualized cost of applying an oxidation catalyst is estimated to be approximately \$717,000. The incremental cost effectiveness of adding an oxidation catalyst is estimated to be \$5,184 per ton of CO removed, based on 4,760 hours of operation at baseload and 4,000 hours at baseload with duct firing. Detailed calculations are provided in Tables 4-5 and 4-6.

Environmental Impacts

DLN combustors and GCP do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. The installation of an oxidation catalyst would theoretically reduce potential CO emissions by about 111 TPY per CT while causing increased oxidation of SO₂ to sulfuric acid mist with subsequent partial formation of ammonium sulfate as PM (see Table 4-7). Emissions of PM could increase by up to 7.7 TPY with a potential increase in sulfuric acid mist emissions of 11.5 TPY due to increased oxidation of SO₂ to sulfuric acid mist.

Energy Impacts

DLN combustors and GCP are inherent to the combustion process and do not create any energy impacts. With an oxidation catalyst, the output of the CTG would be reduced by the additional backpressure. This



penalty could amount to about 3,539 MWh per year in potential lost generation. This potential lost in generation could supply the monthly electrical needs of about 295 residential customers assuming a monthly residential use of 1 MWh per month. To replace this lost energy, an additional 21,942 British thermal units per year (Btu/yr) or about 22 million cubic feet per year (ft³/yr) of natural gas would be required for a generating unit similar to SHCCF to replace the lost generation.

4.3.2.6 Selection of BACT and Rationale

The evaluation of feasible technology demonstrate that emission limits using DLN technology are appropriate as BACT. The evaluation of the energy, environmental, and economic impacts of an oxidation catalyst system is cost effective for the proposed CTG. Therefore, GCP is proposed as the technology to meet BACT emission limits for CO. The proposed CO BACT emissions limits for natural gas are 4.3 ppmvd corrected to 15 percent O₂ from baseload to 90 percent load and 7.1 ppmvd corrected to 15 percent O₂ from MECL to less than 90 percent load. The CO emission limit proposed as BACT when duct firing is 6.5 ppmvd corrected to 15 percent O₂. As discussed previously, the proposed BACT emission limits for CO are the same as those established for DBEC using the GE 7HA CT.

Moreover, the air quality impacts at the proposed uncontrolled GCP CTG/HRSG emission rates are predicted to be much less than the PSD significant impact levels. The maximum predicted CO impacts are less than 5 percent of the applicable AAQS (see Section 6.0). Therefore, no measurable environmental benefit would be realized by the installation of a CO catalyst.

4.3.3 Particulate Matter (PM/PM₁₀/PM_{2.5})

4.3.3.1 Previous BACT Determinations

A small amount of PM/PM₁₀/PM_{2.5} emissions, collectively referred to as “PM” will result from the combustion of pipeline quality natural gas in the CTGs and HRSG duct burners, which are generally low emitters of PM. NSPS Subpart KKKK, which specifies performance standards for stationary CTGs, does not set any PM emissions limits for CTs. All PM₁₀ and PM_{2.5} emissions from CTG and HRSG duct burners are considered the same as PM emissions.

As part of the BACT analysis, a review was performed of previous BACT determinations within the last 10 years for PM emissions from natural gas-fired large combined cycle units in EPA's RBLC web page. A summary of these BACT determinations is presented in Appendix B, Table B-3 for natural gas-firing.

From the review of previous BACT determinations, it is evident that all PM BACT determinations are based on GCP and the use of natural gas or low-sulfur fuel. Add-on PM control technologies were not selected as BACT for any of the determinations. FDEP has issued several PM BACT determinations for natural gas-fired combined cycle units since 2003 and all determinations are based on GCP and the use of clean fuels.



4.3.3.2 Identification of Potentially Applicable Control Technologies

PM is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions can be classified as “filterable” or “condensable” PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM is composed of organic and inorganic compounds and is generally all considered to be less than 1.0 micron in aerodynamic diameter. EPA’s Compilation of Air Pollution Emission Factors (AP-42) states in Section 3.1 (Stationary Gas Turbines) – “PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content.”

The following control options are evaluated in the PM BACT analysis:

Good Combustion Practices (GCP)

PM emissions from natural gas combustion are inherently low, and combustion controls can further minimize the amount of PM emissions generated due to incomplete combustion in the CTG and duct burners. Optimization of the combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion are the primary mechanism available for lowering PM emissions. This process is often referred to as “good combustion practices.” Good combustion chamber design is inherent to modern CTGs and duct burners.

Clean Fuel

One mechanism for the formation of particulate matter is the oxidation of sulfur compounds, which can precipitate as PM in the exhaust stream. The proposed CTG will burn only pipeline-quality natural gas. Pipeline quality natural gas contains very low levels of impurities and sulfur; thus, emissions of PM and SO₂/SO₃ are minimized through the use of this clean-burning fuel.

Fabric Filter Baghouse

A fabric filter baghouse removes particles and condensed metals from a flue gas stream by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. A filter cake, composed of the removed particulate, builds up on the “dirty” side of the bag. Periodically, the cake is removed through physical mechanisms (i.e., blast of compressed air from the clean side of the bag, mechanical shaking of the bags, etc.), which causes the cake to fall. The dust is then collected in a hopper and removed.

Electrostatic Precipitator

An electrostatic precipitator (ESP) removes dust or other fine particles from a flue gas stream by charging the particles inductively with an electric field and then attracting the particles to highly charged collector



plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they collect in a layer. The plates are periodically cleaned by a rapping system to release the ash layer into ash hoppers as an agglomerated mass.

Wet Electrostatic Precipitator

A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike with a dry ESP, however, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid, rather than mechanically shaking the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes “sticky” particulate.

Wet Scrubber

Wet scrubbers trap suspended particles by direct contact with a spray of water or other liquid. In effect, a scrubber washes the particulates out of the dirty airstream as they collide with and are entrained by the tiny droplets in the spray. Several configurations of wet scrubbers are in use. In a spray-tower scrubber, an upward-flowing airstream is washed by water sprayed downward from a series of nozzles. The water is re-circulated after it is sufficiently cleaned to prevent clogging of the nozzles. In orifice scrubbers and wet-impingement scrubbers, the air and droplet mixture collides with a solid surface. Collision with a surface atomizes the droplets, reducing droplet size and thereby increasing total surface contact area. These devices have the advantage of lower water-recirculation rates.

Scrubber efficiency depends on the relative velocity between the droplets and the particulates. Venturi scrubbers achieve high relative velocities by injecting water into the throat of a venturi channel—a constriction in the flow path through which particulate-laden air is passing at high speed. As a result, Venturi scrubbers are the most efficient of the wet collectors.

4.3.3.3 Evaluation of Technically Feasible Control Alternatives

Technical feasibility of the potential control options is evaluated below. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.



Good Combustion Practices

Good combustion chamber design to minimize incomplete combustion is inherent to modern CTs. GCP is typically employed to operate the CTGs at optimum design conditions. GCP is considered technically feasible.

Clean Fuel

Pipeline quality natural gas is available and feasible for use in the Project.

Add-On Controls

Add-on control devices (including fabric filtration, ESP, WESP, and wet scrubbers) are not technically feasible for combined cycle CTGs because of high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates. EPA's RBLC database does not contain any natural gas-fired CTG/HRSGs with/HRSG duct burners that has been equipped with an add-on PM control device.

4.3.3.4 Ranking of Technically Feasible Control Alternatives

GCP and the use of clean fuels such as pipeline-quality natural gas are the only feasible PM control technologies for CTG/HRSGs with duct firing. These technologies are compatible control strategies and, considered together, they present the best control option for PM from CTG/HRSGs with duct firing. A ranking is therefore, not required to establish the top technology.

4.3.3.5 Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

The use of GCP and clean fuels are recognized to result in the lowest economic, environmental and energy impacts in reducing emissions of PM. Add-on controls are not technically feasible in reducing PM emissions due to the high exhaust flow and low PM loading. For the latter, the PM exhaust concentration of the CTGHRSG is about 0.002 grains/standard cubic feet (gr/scf) or less that is lower than the typical design outlet conditions for add-on controls used on fossil fuel steam generators that fire coal and oil.

4.3.3.6 Selection of BACT and Rationale

Based on the identification and technical evaluation of the available control technologies, the proposed BACT for PM emissions from the combined cycle CTG/HRSG with duct firing is the work practice standard of using GCP and clean fuel (natural gas). The proposed BACT emissions limits are consistent with most BACT emissions limits in Florida (see Appendix B, Table B-3).

4.3.4 Sulfur Oxides

4.3.4.1 Identification of SO₂ and SAM Control Technologies

SO₂ is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. While the SO₂ generally remains in a gaseous phase throughout the exhaust gas flow path, a



small portion of the SO_2 may be oxidized to SO_3 . Technologies employed to control SO_2 emissions from combustion sources consist of fuel treatment and post-combustion add-on controls that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the exhaust gas [also referred to as flue gas desulfurization (FGD) systems].

A summary of SO_2 BACT determinations from EPA's RBLC database for natural gas-fired combined-cycle units is presented in Appendix B, Table B-4.

Clean Fuels (Natural Gas and ULSD Oil)

Natural gas contains very low levels of sulfur; thus, emissions of sulfur compounds are minimized through the use of this clean-burning fuel.

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to the end user. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline.

Flue Gas Desulfurization

FGD systems are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts the SO_2 to sulfite or sulfate salts. FGD systems also removed a portion of the SO_3 emissions depending on the type of scrubber and reagent. The following are potential FGD systems.

Wet Scrubber

The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and the by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and/or calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.



Spray Dryer Absorber (Dry Scrubber)

The dry scrubber is a once-through dry technology. In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO₂ is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device, typically a baghouse.

4.3.4.2 Technical Feasibility Analysis

The only feasible technology for SO₂ emission from combined cycle unit is the use of pipeline quality natural gas. The SO₂ emission levels of this fuel is extremely low. Fuel treatment and FGD are not technically or economically feasible for combined cycle units.

4.3.4.3 Rank Control Technologies by Control Effectiveness

The third step in the BACT analysis is to evaluate the effectiveness of the remaining control technologies. Natural gas is the cleanest fossil fuel and does not require ranking.

4.3.4.4 Evaluate the Most Effective Controls

There are no potential energy, environmental, or economic impacts that would preclude the use of natural gas.

4.3.4.5 Select BACT

The use of pipeline quality natural gas is proposed as the BACT work practice standards for SO₂ and SAM for the CTG/HRSG with duct firing. A maximum sulfur content of 2 grains per 100 scf of gas is proposed as BACT and is the same as other recent FDEP BACT determinations for the OCEC and DBEC projects. A BACT work practice emission limit of 2 grains per 100 scf of gas for the CTG/HRSG with duct firing is a conservative basis even though this sulfur content is not guaranteed by Florida Gas Transmission Company, LLC (FGT). The sulfur content for pipeline natural gas is established by Federal Energy Regulatory Commission (FERC) through the approval of tariffs. The maximum sulfur content tariff for FGT is 10 grains sulfur per 100 scf (FGT FERC NGA Gas Tariff, Fifth Revised Volume No. 1, General Terms and Conditions Section 2 Quality, August 2015). However, the typical sulfur concentrations have consistently been reported by FGT and individual plant samples to be much less than 1 grain per 100 scf of gas.

4.4 Auxiliary Boiler

This section contains the BACT analysis for the proposed auxiliary boiler. The auxiliary boiler proposed for the Project has a maximum design heat input rating of 60 MMBtu/hr and will be exclusively fueled by pipeline quality natural gas. A boiler can be used during the startup and shutdown sequences of the CTG to provide steam to the steam cycle. A maximum limit on the hours of operation of the auxiliary boiler of



2,000 hr/yr is proposed. Based on emissions calculation presented in Table 2-3, the auxiliary boiler will potentially emit 0.34 TPY SO₂, 3.0 TPY of NO_x, 4.8 TPY CO, 0.3 TPY of VOC, and 0.42 TPY of PM emissions.

A search of EPA's RBLC database was conducted for previous BACT determinations for auxiliary boilers and a summary of the previous 5 years of determination is presented in Appendix B, Table B-5. It is evident that most of the BACT determinations are based on GCP and low-NO burners (LNBs). Flue gas recirculation (FGR) has been used as BACT in addition to LNB for NO_x control in some of the projects. LNBs are designed to limit NO_x formation by controlling the stoichiometric temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced O₂ in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperature. LNB systems are also designed to minimize CO and VOC emissions through staging the combustion process that balances the combustion temperatures to minimize NO_x formation at high combustion temperatures while maintaining adequate combustion temperatures to combust CO and VOCs. The proposed auxiliary boiler will be equipped with LNBs to minimize emissions of NO_x while maintaining low CO and VOC emissions through good combustion practices.

The use of LNBs with a NO_x emission limit of 0.05 lb/MMBtu is proposed as BACT. This is consistent with the BACT limits found in the EPA's RBLC database and meets the requirements of the NSPS for industrial-commercial-institutional steam generators as set forth in 40 CFR 60 Subpart Dc. The addition of SCR for further NO_x control would not be cost effective since the NO_x reduction would be limited (less than 3 TPY) resulting in SCR being cost prohibitive. In addition, operation of the auxiliary boiler would be limited to startup conditions of the CTG/HRSG limiting the amount of operation in greatly increasing the cost-effectiveness of SCR.

The auxiliary boiler will exclusively use natural gas that minimize emissions of PM/PM₁₀/PM_{2.5} and SO₂ along with GCP. The addition of add-on controls such as fabric filters for PM control and FGD for SO₂ removal would not result in meaningful emission reductions (less than 1 TPY combined). The additional cost would make the add-on control cost prohibitive.

4.5 Mechanical Draft Cooling Tower

This section contains the BACT analysis for the PM/PM₁₀/PM_{2.5} emissions, collectively referred as "PM" emissions from the mechanical draft cooling tower for the Project that is anticipated to be a 6-cell tower design. The cooling system uses a fan to move air through a re-circulated water system. This allows a considerable amount of water vapor and sometimes droplets to be introduced into the surroundings. The use of high-efficiency drift eliminating media to de-entrain droplets from the air flow exiting the cooling tower is a commercially proven technique to reduce PM emissions. The drift eliminators used in cooling towers



rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient.

Based on the review of EPA's RBLC database, which is presented in Appendix B, Table B-6, the most stringent BACT limit for a mechanical draft cooling tower is high efficiency drift eliminators with drift rate 0.0005 to 0.001 percent. There are no energy or environmental impacts associated with drift eliminators. Drift eliminators with a design drift rate of 0.001-percent or less is most common and demonstrated in practice.

The use high-efficiency drift eliminators with a design drift rate of 0.001 percent is proposed as the BACT work practice standard for PM emissions from the proposed cooling tower.

4.6 Emergency Diesel Generator and Fire Pump Engine

The emergency diesel generator and fire pump engine will normally be operated 1 to 2 hours per month for maintenance and testing. The amount of operation outside of an emergency condition will be 100 hr/yr or less for each engine. This low amount of operation coupled with good combustion practices and meeting the applicable requirements of EPA NSPS (Part 60, Subpart IIII) and NESHAP (Part 63, Subpart ZZZZ) is BACT for control of NO_x, CO, and PM emissions from each engine. The installation of controls would not be cost effective given the amount of operation. The emergency diesel generator and the fire pump engine will utilize ULSD oil. The use of ULSD oil and GCP will minimize the emissions of PM, PM₁₀, and PM_{2.5} and SO₂ and therefore, are proposed as BACT. The use of clean fuels and GCPs and use of clean fuels has consistently been determined as BACT for similar minor sources.

4.7 GHG (CO₂e) BACT Evaluation

EPA issued guidance on the determination of BACT for GHGs (*PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011). EPA believes, in BACT reviews of GHGs, the "top down" approach should be followed, and it is important to consider options that improve the overall energy efficiency of the source or modification through technologies, processes, and practices at the emitting unit. In general, a more energy-efficient technology burns less fuel than a less energy-efficient technology on a per-unit-of-output basis. Thus, considering the most energy-efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (e.g., NO_x, SO₂, PM/PM₁₀/PM_{2.5}, CO, etc.). Thus, EPA emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs). This is supported by EPA's NSPS for GHGs from new, modified, and reconstructed electric utility units. In this rule EPA determined that the BSER was 1,000 lb CO₂/MWh that is readily achievable in natural gas-fired combined cycle units. This CO₂ emission standard represents the BSER in establishing NSPS and is the highest emission limit that can be determined as BACT (i.e., BACT cannot be less stringent than this NSPS).



The following subsections provide the GHG BACT analysis for the Project.

4.7.1 Combustion Turbine/HRSG

The BACT analysis for the GHG emissions from the CTG/HRSG followed the EPA suggested five-step “top down” process as described in the following subsections.

4.7.1.1 Identification of Available Control Technologies

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

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

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

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

GHGs under EPA regulations are considered as a single air pollutant, which is the aggregate group of the six principal gases, CO₂, N₂O, CH₄, HFCs, PFCs, and SF₆. CO₂ emissions result from the oxidation of carbon in the fuel. CH₄ emissions result from incomplete combustion and N₂O emissions result primarily from the temperature of combustion. CO₂, N₂O, and CH₄ are the GHGs that will be emitted from the CT.

EPA recommends that permit applicants and permitting authorities should identify all “available” GHG control options that have the potential for practical application to the source under consideration. In its PSD and Title V Permitting Guidance for GHGs, EPA emphasizes two mitigation approaches for CO₂: 1) energy efficiency and 2) carbon capture and storage (CCS).

The GHG emissions from the Project will also include CH₄. However, emissions of CH₄ from CTGs are less than 0.04 percent of the total CO₂e GHG emissions. As a result, control options for CH₄ are not practicable although an oxidation catalyst system can potentially reduce CH₄ emissions.

EPA’s RBLC database of CO₂e BACT determinations for natural gas-fired combined-cycle units is presented in Appendix B, Table B-7. All the BACT determinations have been based on efficiency.



Clean Fuels

The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30 percent less CO₂ than oil, and about 45 percent less CO₂ than coal (source: www.naturalgas.org). The only fuel for the proposed CTG and duct burner will be natural gas. It is important to recognize that the definition of BACT in 40 CFR 52.21(b)(12) includes use of “clean fuels” as a pollution control technique. The EPA PSD and Title V Permitting Guidance for GHGs states that clean fuels which would reduce GHG emissions should be considered while recognizing at the same time that the BACT analysis does not need to include a clean fuel option that would fundamentally redefine the source. Therefore, the proposed CTG will be fired with “clean fuels” as included in the definition for BACT in the CAA Sec. 169(3), 42 U.S.C. §7479(3)(2013).

Energy Efficiency

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

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

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including CO₂). Several recent BACT determinations for GHG emissions concluded that high efficiency power generation technology is the only available and feasible control technology. Efficient combined cycle generation is technically feasible and is proposed for the CTG/HRSG.

Carbon Capture and Storage

CCS falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. EPA suggests that CCS is an add-on pollution control technology that is “available” for large CO₂ emitting facilities including fossil fuel-fired power plants and industrial facilities with high purity CO₂ streams. As a result, EPA suggests that CCS be considered in Step 1 of the BACT analysis.

CCS is composed of three main components: CO₂ capture and/or compression, transport, and storage.

Carbon Capture – Before CO₂ gas can be sequestered, it must be captured as a relatively pure gas, so that it can be feasibly stored. Most power plants and other large point sources use air-fired combustors, a



process that exhausts CO₂ diluted with nitrogen. Flue gas from natural gas combined cycle plants contains only about four percent CO₂ by volume. For effective carbon sequestration, the CO₂ in the exhaust gases must be separated and concentrated due to the low percent by volume.

The most likely options currently identifiable for CO₂ separation and capture include:

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

Carbon Transport – After the CO₂ is captured, it must be transported to a carbon sequestration site. Pipelines are the most common method for transporting large quantities of CO₂ over long distances. Shipping CO₂ via pipeline involves compressing gaseous CO₂ to a pressure above 1,160 pounds per square inch (psi), to increase CO₂ density and make it easier and less expensive to transport. A CO₂ pipeline would be similar to a high pressure natural gas pipeline and is technically possible. CO₂ also can be transported as a liquid in seagoing vessels or via tankers on roads or railways. In these instances, the CO₂ is held in insulated tanks at low temperatures and relatively low pressures.

Carbon Storage – In a CCS system, CO₂ is captured, it is transported, if necessary, and then stored. Geologic formations such as depleted oil and gas reservoirs, unmineable coal seams, and underground saline formations are potential options for long term storage. Pressurized CO₂ is injected into the deep geologic formations through drilled wells. Under high pressure, CO₂ turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO₂ tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO₂ and prevent further upward migration. When CO₂ is injected into a coal seam, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells. There are other mechanisms for CO₂ trapping as well: CO₂ molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of the porous rock.

Deep saline formations, which are layers of porous rock saturated with brine, present potential for geologic storage of CO₂. However, there is not much experience with saline formations such as that acquired through resource recovery from oil and gas reservoirs and coal seams. There is ongoing research focused on storage in organic rich shale, which is a thin horizontal layer of sedimentary rock with low vertical permeability and in basalt formations, which are geologic formations of solidified lava. Other possible options include liquid storage in deep ocean areas.

The paper “Realistic Costs of Carbon Capture” provides cost comparisons for electric generation using CCS (Harvard Kennedy School, July 2009). As provided in Annex C using data from National Energy



Technology Laboratory (NETL), Electric Power Research Institute (EPRI) and SFA, the range of avoided cost in dollars per metric ton of CO₂ separated is from \$63 to \$83 equivalent to \$70 to \$93 short tons of CO₂ separated, based on two advanced natural gas-fired F class turbines. Based on a cost of \$70 per short ton of CO₂, and an estimated annual CO₂ rate of 2 million short tons from the Project's CT, the annual cost for separation alone would be about \$140 million. This cost assumes that the separation equipment would be operating during the short operational periods required for the Project. Additionally per a footnote of Annex C of the Harvard study, this cost does not include expenses associated with transportation, injection and storage.

The maximum potential emissions of CO₂e for the CTG/HRSG and duct burner were estimated to about 2 million TPY (Table A-7). Assuming 90 percent CO₂ removal, the annualized cost for CO₂ would be calculated at \$70 per ton of CO₂ removed and sequestered. This cost represents full application of CCS. However, EPA found in its approval of the GHG NSPS for electric utility units (40 CFR Part 60 Subpart TTTT) that full application of CCS for controlling CO₂ emissions for higher GHG emitting coal-fired units was not cost-effective when compared to nuclear and other technologies. EPA concluded in its final rule that NSPS emission standards for partial CCS at approximately 16 to 32 percent GHG removal are reasonable. In contrast, EPA found the use of natural gas combined cycle units to be the most cost effective.

Oxidation Catalyst

Catalytic oxidation technology, which is primarily designed to reduce CO emissions, will also reduce CH₄ emissions but to a lesser extent. Oxidation catalysts operate at elevated temperatures where excess O₂ in the exhaust reacts with CH₄ to form CO₂. As a result, 28 lb of CO₂e are reduced to 2.75 lb of CO₂. At the very best only about 90 percent of the CO₂e from CH₄ could be reduced. Assuming a 90 percent removal of CH₄ the maximum control is only about 81 percent removal of CO₂e from CH₄. The total GHG emissions from the CTG/HRSG with duct firing would only be reduced by about 730 TPY assuming 90 percent removal or less than 0.04 percent of total GHG emissions from the Project.

4.7.1.2 Identification of Technically Feasible Control Alternatives

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

Energy Efficiency

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



Carbon Capture and Storage

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

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

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

In November 2010, EPA published the final rule for federal requirements of Underground Injection Control (UIC) for CO₂ Geologic Sequestration (GS) Wells, as authorized by the Safe Drinking Water Act (SDWA). The final rule establishes new federal requirements for the underground injection of CO₂ for the purpose of long-term underground storage, or GS, and a new well class – Class VI – to ensure the protection of underground sources of drinking water (USDWs) from injection-related activities. Therefore, authorization must be obtained from FDEP under this federally delegated program prior to GS. Permitting for a Class VI

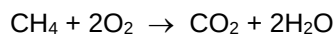


well takes many years as exploratory wells are likely required for CO₂ sequestration, including drilling deep holes, testing, etc., prior to approval of an injection well. Indeed, the exploratory well process to assess the formation can take over two years for drilling, testing, and approval of the start of an injection well process.

Based on these considerations and EPA determinations in the recent final NSPS for GHG emissions from electric utility units, it can be reasonably concluded that CCS is not applicable to the Project, and consequently not technically or economically feasible.

Oxidation Catalyst

Catalytic oxidation is an available control technology for CH₄, although no approval for its use for this purpose has occurred. The oxidation catalyst will reduce CH₄ with the following reaction:



While CH₄ emissions can be reduced using an oxidation catalyst, the amount of CO₂e reduced is less than 0.05 percent. Moreover, the amount of potential CO₂e that could be reduced from the combined cycle unit is 40 times lower than the EPA GHG thresholds.

In addition, the total amount of CO₂e resulting from CH₄ emissions is only 0.05 percent of total CO₂e emissions and is about 900 tons CO₂e. The secondary emission caused by the backpressure of an oxidation catalyst was estimated to be over 5,000 tons of CO₂. Therefore, the addition of an oxidation catalyst to the CTG/HRSG for GHG control is neither practicable nor feasible to reduce CH₄.

4.7.1.3 Ranking of Remaining Control Technologies

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

Based on the discussion in Steps 1 and 2, the only technically feasible control option for GHG emissions from the CTG/HRSG is energy efficiency.

4.7.1.4 Economic, Energy, and Environmental Impacts

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

The “top” control option, and in the case of GHG the “top” energy reduction technology, should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the



energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The “top” control option for the CTG/HRSG is energy efficiency. The CTG/HRSG will operate in the combined cycle mode and is among the largest and most efficient available. The CTG/HRSG and duct burner will only use natural gas as the fuel that has the lowest GHG emissions of any fossil fuel.

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

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

The proposed combined cycle units' net heat rate and energy efficiency were compared to data obtained from the U.S. Energy Information Administration (EIA). Based on data provided in the Electric Power Annual summary for 2016, the approximate heat rate for electricity for fossil fueled power plants in the U.S. in 2015 was 9,127 Btu/kWh net (HHV) (37.4 percent efficiency) (EIA, 2016 Tables 3.1a and Table 8.1).

Based on US EIA's 2016 annual review of the electrical power industry, the reported average net heat rate (HHV) for natural gas firing was 7,870 Btu/kWh net (HHV) (43.4 percent efficiency) including all types of generation (EIA 2017 Table 8.1). Of the generation types, the average tested heat rates when firing natural gas are (EIA 2017, Table 8.2):

- Steam turbine generator – 10,382 Btu/kWh net (HHV) (32.9 percent efficiency),
- Natural gas turbine – 11,214 Btu/kWh net (HHV) (30.4 percent efficiency),
- Internal combustion – 9,179 Btu/kWh net (HHV) (37.2 percent efficiency), and
- Combined cycle – 7,652 Btu/kWh net (HHV) (44.6 percent efficiency).

For comparison, the design (calculated) “new and clean” net heat rate of Project when firing natural gas is anticipated to be 6,200 Btu/kWh net (HHV) (55.0 percent efficiency) at baseload condition to 7,284 Btu/kWh (HHV) (47.0 percent efficiency) at MECL based on an ambient temperature of 77° F.



As part of EPA's clean energy initiatives, EPA developed the Emissions & Generation Resource Integrated Database (eGRID) as a resource tool in assessing GHG emissions. eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States with data available based on a variety of geographic regions and locations. Data is also available for units, plants, power control areas (system), states, National Electric Reliability Council (NERC) regions and subregions, and the U.S. Information is provided on several air pollutants as well as GHGs. Emissions are provided on a pound-per-megawatt-hour (lb/MWhr) basis. Based on the latest available eGRID data, the following are the emissions of CO₂ on a generation basis for generation facilities located in the same subregion as the project (2/27/17 data: <https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid>; gross heat rate as HHV):

- State of Florida – 1,099.4 lb CO₂/MWh gross (HHV) for all generation (including nuclear);
1,275.9 lb CO₂/MWh for total combustion generation.

4.7.1.5 Selection of BACT

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

BACT for GHG

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

The CCS option was eliminated in Step 2 as not technically feasible for the Project. Although EPA considers CCS as available, it is not commercially available. Indeed, EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO₂ capture and compression as supported by EPA's recent GHG NSPS for electric utility units. In the Guidance, EPA states that even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, CCS would be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO₂ near the power plant is feasible. In the case of the Project, CCS is not a technically or economically feasible control technology based on the current status of this technology.

The proposed GHG BACT limits for the Project were developed based on operating range of the CTG/HRSG including duct firing and contractual requirements. Table 4-8 presents the GHG emission rates for the operating range of the CTG/HRSG at an ambient temperature of 77 °F. This ambient temperature represents the average ambient temperature for operation. The table presents the various operating conditions (load, evaporative cooling operation and duct firing), design heat rate as calculated new and



clean, the EPC guaranteed heat rate limit, the “as built” GHG emission rates for each operating condition, degradation from new and clean and GHG emission rate. Based on standard Engineering and Procurement Contractor (EPC) contracts, the agreement will have a guaranteed heat limit that cannot be exceeded without significant penalties. The proposed GHG BACT was developed using the EPC contractual heat rate limit to develop the “new and clean” heat rate” and GHG emission rate. A 5 percent degradation was added to represent long-term operation (40 years) of the CTG/HRSG.

The GHG emission limit must consider the possible operation of the Project over its entire 40-year life. SHEC has a contract with Seminole Electric Cooperative (Seminole) with a term of 30-years from the anticipated commercial operation. Under the tolling agreement, Seminole will have the right to schedule the dispatch of the SHCCF, provide fuel for such scheduled operation, and receive the power produced. This contractually limits SHEC’s ability to control the resulting 12-month GHG emission rate through the operating range of the CTG/HRSG including duct firing. To account for an operating range that may occur under the tolling agreement, an operating schedule was developed based on possible operation under the contractual terms (i.e., as scheduled by Seminole). The 12-month operating schedule and resulting GHG emission rate is presented in Table 4-8 based on the potential operating range of the CTG/HRSG including duct firing. The operating range includes full load operation with and without duct firing and lower load operation. The capacity factor for the 12-month period as shown in the table is ranges from close to 100 percent to less than 50 percent, which is not unreasonable over the course of a 40-year life span. The resulting 12-month GHG emission rates for the potential operation scenarios is from about 800 to 900 lb CO₂e/MWh. Given the uncertainty over the potential operation over a 40-year life SHEC proposes a GHG BACT limit of 875 lb CO₂e/MWh that would envelope the possible operation of the SHCCF.

As shown in Appendix B Table B-7, the proposed Primary BACT GHG limit is similar to the BACT approved for other GE 7HA CTGs with duct firing. The Colorado Bend Energy Center is a 2-on-1 combined cycle unit with duct firing and has a GHG BACT limit that is equivalent to 880 lb CO₂e/MWh. The GHG limits established as BACT for the OCEC and DBEC projects using the GE 7H CTs did not include duct firing or the ability to operate the emission units within a utility system to assure compliance with the GHG emission limit. In addition, the proposed Primary BACT for the SHCCF CTG/HRSG is among the lowest GHG emission limits with GHG BACT limits as shown in the EPA BACT clearinghouse, summarized in Appendix B, Table B-7.

The output-based 12-month rolling average aggregate CO₂e emission limit on a gross generation basis is proposed as the Primary BACT standard that excludes startup, shutdown, DLN tuning and malfunctions. The aggregate CO₂e emissions is calculation in the following way:

$$\text{Aggregate GHG 12-month rolling emissions (lb CO}_2\text{e/MWhr)} = \frac{\text{Total 12-month rolling CO}_2\text{e (lb)}}{\text{Total 12-month rolling (MWh)}}$$



Since the NSPS for GHG are currently applicable pursuant to 40 CFR Part 60, Subpart TTTT, a Secondary BACT the NSPS emission limit of 1,000 lb CO₂e/MWh 12-month rolling average that would also include startup, shutdown, malfunctions, and DLN tuning (see Section 4.2) is proposed as secondary BACT. The proposed BACT emission limit of 875 lb CO₂e/MWh is 125 lb CO₂e/MWh lower than the recently promulgated Subpart TTTT NSPS limit of 1,000 lb CO₂e/MWh.

For the rolling proposed output based GHG limits, continuous monitoring based on 40 CFR Part 60 Subpart TTTT, Section 60.5535 is proposed.

4.7.2 Fugitive GHG Emissions (Circuit Breakers)

4.7.2.1 Circuit Breakers

SF₆ is an electrical insulator and interrupter in equipment that transmits and distributes electricity. SF₆ has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulating oils.

Circuit breakers associated with the Project are estimated to contain approximately 100 lbs of SF₆. Based on a leak rate of 0.5 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 100 lb SF₆ x 0.005 leakage/year = 0.5 lb SF₆/year
- 0.5 lb SF₆/year x 22,800 lb CO₂e/lb SF₆ (Table A-1, 40 CFR Part 98) x ton/2,000 lb = 5.7 tons CO₂e

4.7.2.1.1 Identification of Available Control Technologies

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

The available control options include alternative (non-SF₆) dielectric fluids and minimizing the fugitive emission of SF₆. Historically dielectric fluids such as dielectric oils have been used in high voltage applications. However, the use of these materials in circuit breakers has been predominately replaced with SF₆ that has excellent dielectric and arc-quenching properties and is not flammable.

Modern SF₆ circuit breakers are designed as totally enclosed-pressure systems with low potential SF₆ fugitive emissions. Average leak rate estimates range from an upper bound of 2.5 percent to a lower bound of 0.2 percent (Blackman, J, et. al., 2016). Over the life of a circuit breaker the National Electrical Manufacturers Association (NEMA) SF₆ management guidelines specify a total equipment leakage of 5 percent or 0.1 percent per year (NEMA, 1998). Circuit breakers have indicators that provide a warning if



a leak is occurring and corrective action is necessary. In addition, this equipment is routinely inspected to verify proper operation since this equipment is necessary for the safe operation of the CTs.

4.7.2.2 Identification of Technically Feasible Control Alternatives

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

Circuit breakers using SF₆ with alarms and periodic inspections are technically feasible for the Project. The use of alternative dielectric fluids is not practicable for high-voltage applications. Circuit breakers using SF₆ are presently superior in their performance to alternative systems such as dielectric oil, high pressure air blast or vacuum circuit breakers. Moreover, EPA's SF₆ Partnership has recognized that there is no clear alternative to using SF₆ and fugitive emissions are reduced by implementing detection, repair and replacement strategies [EPA, 2014; (SF₆ Emission Reduction Partnership for Electric Power Systems, 2013 Annual Report, April 2014)].

The International Electrotechnical Commission (IEC) has established a standard of 0.5 percent or 1 percent for leak rates (IEC Standard 62271-1, 2004). IEC also recognizes that implementing detection, repair, and replacement mechanisms of reducing emissions of SF₆. The IEC standards are recognized by the EPA's SF₆ Reduction Partnership as an effective criterion for minimizing fugitive SF₆ emissions.

4.7.2.3 Rank Remaining Control Technologies

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

The most effective control of fugitive SF₆ emissions is using a totally enclosed system equipped with leak detection, periodic inspection, and maintenance.

4.7.2.4 Economic, Energy, and Environmental Impacts

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

The "top" control option and in the case of GHG the "top" energy reduction technology should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not



“achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The “top” control option is the use of SF₆ circuit breakers that offer low economic, energy and environmental impacts. SF₆ is the preferred gas for electrical insulation, arc-quenching, and current insulation for high voltage equipment. It is chemically inert, non-toxic, non-flammable, non-explosive, and thermally stable. SF₆ exhibits properties that are beneficial from an economic, energy and environmental standpoint when used in totally enclosed systems.

4.7.2.5 Selection of BACT

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

Based on the top-down analysis, the only technically feasible controls technologies for the SF₆ circuit breakers associated with the Project are the use of modern totally enclosed circuit breakers with a design leakage rate of no more than 0.5 percent that are thoroughly tested, equipped with leak detection systems (density indication) and periodically inspected. Together these controls will minimize SF₆ fugitive emissions and potential CO₂e emissions by 99 percent.

SF₆ breakers will be monitored to confirm that SF₆ integrity is maintained. In the event of an indication of a potential leak, an inspection will be performed on the breaker. Preventative maintenance will be performed at intervals recommended by the manufacturer or at intervals standard in the electric power industry for the relevant type of breaker.

4.7.2.6 On-Site Natural Gas Supply

Natural gas leaks from the new on-site natural gas supply connections for the SHCCF, and venting during maintenance, startup and shutdown represent a potential source of fugitive GHG emissions in the form of methane contained in the natural gas. Based on the most technically accurate available emission factors from potential leaks of methane, approximately 57 TPY of CO₂e could be emitted from potential natural gas leaks. Of this total estimate, approximately 38 TPY of CO₂e could be emitted from potential leaks of the valves and connectors.

4.7.2.6.1 Identification of Available Control Technologies

There are no NSPS applicable to these types of emissions and these emissions are not required to be reported for power plants pursuant to EPA’s GHG Reporting Rule (40 CFR Part 98). There are no add-on control technologies for these types of fugitive sources. There are two potential best management practices for identification of leaks that include observations for odorants contained in the natural gas and a Leak Detection and Repair (LDAR) program.



Natural gas is required to have an odorant that can be detected so that at a concentration in ambient air of one-fifth of the lower explosive limit, the gas is *readily detectable* by a person with a *normal sense of smell* [49 CFR 192.625(a)]. The lower explosive limit for methane, the main constituent in natural gas, is 5 percent by volume. The concentration of natural gas in a leak that is required to be detectable by smell meeting the odorant requirement is 10,000 ppm.

LDAR is required for some NSPS (e.g., Subpart VV) and NESHAPS (e.g., Subpart H) that apply to major chemical facilities. A LDAR program used EPA Method 21 that involves taking measurements of the VOC concentration at connector or valves to determine if the “leak detection concentration” is exceeded and a repair warranted. LDAR for NSPS sources include have leak detection concentration of 10,000 ppm when measuring leaks. This is the same concentration that an odorant can be detected. The average number of valves and connectors in these type of facilities are well over 10,000. This is in contrast to an estimated 230 valves and connectors for the Project. EPA has indicated that quarterly monitoring program would result in 67 percent control effectiveness (EPA, Leak Detection and Repair, a Best Practices Guide). Assuming 67 percent control from quarterly monitoring, LDAR would only result in a decrease of about 16 TPY of CO₂e.

4.7.2.6.2 Identification of Technically Feasible Control technologies

Both the odorant detection and LDAR program are technically feasible control options.

4.7.2.6.3 Ranking of Feasible Control Technologies

A best management practices program involving either LDAR or an odorant detection procedure are feasible control technologies.

4.7.2.6.4 Economic, Energy and Environmental Impacts.

Since plant personnel routinely monitor plant operations through maintenance inspections the observation of natural gas odorants would not require any additional cost. While odorants are highly effective in the observation of leaks, it is unknown what the actual control effectiveness may be.

The implementation of a LDAR program would require either plant personnel or a contractor using calibrated instrumentation or a soap solution. LDAR is time consuming as the detection would occur at the connector/valve where a leak may occur and there are an estimated 230 valves and connectors for the Project. Considerable amount of documentation is also required. The cost for a quarterly LDAR program is estimated to exceed \$30,000 per year. The cost effectiveness for a quarterly LDAR program would be over \$1,000 per ton of CO₂e (as of February 15, 2018, the EU price for CO₂ allowance is \$14 per ton).



4.7.2.6.5 Selection of BACT

Given the minor amount of fugitive GHG emissions estimated from the Project and the relative high cost effectiveness of LDAR, the odorant detection method is proposed as BACT. An odorant detection program meeting the following permit condition is proposed:

Piping components used for the transmission of natural gas to the combustion turbine and duct burners of the HRSGs shall be inspected quarterly for potential leaks through odor detection and visible inspection. Any leaks identified by odor must be evaluated and repaired as soon as practical. Records of inspection, detected leaks, and repairs (including action taken and duration) shall be available upon request.

This condition is similar to other permit conditions establishing BACT for this type of GHG source.

4.7.3 BACT Analysis for Auxiliary Boiler, Emergency Diesel Generator, and Emergency Diesel Fire Pump Engine

The auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine are all necessary support facilities for the operation of the Project. GHG emissions potential for these sources is about 0.25 percent of the GHG emission levels for the combined cycle unit. The actual GHG emissions from these three minor sources are expected to be *de minimis* due to their function. The emergency diesel generator and emergency diesel fire pump will have non-emergency operational limits of no more than 100 hr/yr, but will normally only be operated a few hours per month for maintenance checks. The auxiliary boiler is used for startup and shutdowns up to a maximum of 2,000 hrs/yr, and these events are not expected to be at the maximum proposed annual operation over the 40-year life of the Project. Taken together, the actual GHG emissions of these sources are expected to be much less than 0.25 percent of the combined cycle unit's GHG emissions. Due to the negligible amount of GHG emissions from these sources compared to the emissions from the combined cycle system, even 100 percent control of GHG emissions from these units will be an insignificant reduction in total GHG emissions. As a result, any reduction of GHG emissions from these minor units will therefore be extremely minor given that GHG emissions from these units only support SHCCF. As demonstrated in Section 4.3.1, SHCCF will be among one of the most energy efficient combined cycle plants in the U.S.

GHGs are considered as a single air pollutant, which is the aggregate group of the six principal gases, CO₂, N₂O, CH₄, HFCs, PFCs, and SF₆. CO₂ emissions result from the oxidation of carbon in the fuel. CH₄ emissions result from incomplete combustion, and N₂O emissions result primarily from low temperature combustion. CO₂, N₂O, and CH₄ are the principal GHGs that will be emitted from the auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine. Emissions of CH₄ and N₂O are negligible compared to CO₂ and specific control options for these pollutants are not practicable.



A brief discussion of the BACT steps with respect to GHG emissions from the auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine is presented below.

4.7.3.1 Identification of Available Control Technologies

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

The definition of BACT in Title 40, Part 52.21(b)(12) of the Code of Federal Regulations [40 CFR 52.21(b)(12)] includes the use of clean fuels as a pollution control technique. The proposed auxiliary boiler will be fired with only natural gas, which is the cleanest GHG emitting fuel compared to other fossil fuels due to its low GHG emissions potential when combusted. The emergency diesel generator and emergency diesel fire pump require fuel to be located onsite in order to provide service during emergency situations. The emergency generator and fire pump engine will utilize ULSD fuel oil that is readily available and used extensively for emergency service. The use of ULSD fuel also allows on-site storage of fuel in sufficient quantities to provide service during emergencies. Natural gas cannot be stored on-site and may not be available during emergencies. The use of propane, while technically available for some engine sizes, requires larger quantities to be stored on-site since its density is about one-half that of ULSD fuel. In addition, the CO₂ emissions for propane are only 15 percent lower than that of ULSD fuel. Moreover, propane is also stored as a “liquid gas” making storage, handling and safety a greater consideration than ULSD fuel.

EPA recommends that permit applicants and permitting authorities should identify all “available” GHG control options that have the potential for practical application to the source under consideration. In its PSD and Title V Permitting Guidance for GHGs, EPA emphasizes two mitigation approaches for CO₂ – energy efficiency and CCS. CCS is not practical for CO₂ emissions from the auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine due to the small amount of CO₂ emissions potential from this equipment compared to the combined cycle system. Moreover, these units are not operated continuously or at their rated capacities making the addition of control equipment problematic and prohibitively expensive.

Energy Efficiency

In the GHG BACT guidance, EPA has stressed the importance of energy efficiency for combustion sources. The auxiliary boiler will be used to provide steam to the steam cycle during the startup sequences. A boiler's efficiency is measured by its annual fuel utilization efficiency (AFUE). AFUE is the ratio of heat output of the boiler compared to the total energy consumed by the boiler. An AFUE of 90 percent means that 90 percent of the energy in the fuel becomes heat and the other 10 percent is lost in the system. In



general, fossil fuel fired boilers have a high AFUE rating around 90 percent. For example, based on data from Cleaver Brooks fire tube boilers, the fuel to steam efficiencies for boilers are in the 90 percent range for natural gas.

The emergency diesel generator and emergency diesel fire pump are designed to meet the applicable NSPS and NESHAP for non-road engines. These units maximize efficiency while meeting the required emissions standards.

4.7.3.2 Identification of Technically Feasible Control Alternatives

Under the second step of the top down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available. The energy efficiency through the regulation of the amount of fuel used is considered to be the only technically feasible CO₂ control option for the auxiliary boiler, emergency diesel generators, and emergency diesel fire pump engine.

4.7.3.3 Ranking Remaining Control Technologies

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated PSD pollutant under review. Based on the discussion in Steps 1 and 2, the only technically feasible control option for CO₂ from the auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine is energy efficiency and limited operation of these emissions units to meet the SHCCF requirements.

4.7.3.4 Economic, Energy, and Environmental Impacts

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

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

The auxiliary boiler will only use natural gas. GHG emissions for natural gas firing is 116.9 lb CO₂e/MMBtu compared to 163.6 lb CO₂/MMBtu for distillate fuel oil firing based on Subpart C of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting. The emission factors include N₂O and CH₄ at the equivalent rates. Therefore, firing natural gas will generate less GHGs than firing ULSD oil.



The emergency generator and fire pump engine use efficient diesel technology with less than 150 tons CO₂e/year at 100 hours/year operation. These engines are normally operated for reliability testing and maintenance for 1 to 2 hours a month. The actual GHG emissions will typically be less than 35 TPY of CO₂e.

4.7.3.5 Selection of BACT

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

Energy efficiency through the regulation of fuel use to meet the function is the only remaining and feasible control technology and is selected as BACT for the GHG emissions from the auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine. Additionally, the use of natural gas in the auxiliary boiler results in the lowest GHG emission practicable.

As mentioned in Step 1, an important measure of the efficiency for a boiler is the unit's AFUE. Natural gas boilers have an AFUE rating around 90 percent in general, which is higher than other fossil fuel fired boilers. In addition, all units are operated only intermittently to meet the needs of the Project. Thus, fuel use is optimized, resulting in lower GHG emissions than if these units operated continuously.

The auxiliary boiler, emergency diesel generator, and emergency diesel fire pump engine together account for only about 0.25 percent of the total GHG emissions potential of the Project. Moreover, these minor GHG emission units support the overall Project. As discussed above, the Project will be among the most efficient combined cycle units in the U.S. and the GHG emissions on a lb/MW-hr basis from the Project will be among the lowest in the country. The operation of these minor units will be limited: the auxiliary boiler will be based on 2,000 hr/yr; emergency diesel generator and fire pump engine are limited to 100 hours or less during non-emergency situations (unlimited in true emergency events). Together, the negligible amount of GHG emissions potential, the limitation in operating hours, and the use of the natural gas and ULSD oil, represents the best available option in controlling GHG emissions from these emission units. This is consistent with the definition of BACT, which allows "a design, equipment, work practice, operational standard, or combination thereof to satisfy the requirement for the application of best available control technology." Due to the negligible amount of GHG emissions potential, and the limited operational use of the auxiliary boiler, emergency diesel generator, and fire pump engine, the combustion of natural gas and ULSD is proposed as a work practice BACT limit, rather than a numerical GHG emission limit. This is consistent with the FDEP BACT determinations of GHG emissions from these sources that have limited use restriction, use low-emitting GHG fuels, and function efficiently (FDEP Technical Evaluation and Preliminary Determinations for OCEC, Draft Permit No. PSD-FL-434, Project No. 0930117-001-AC and Dania Beach Energy Center, Permit No. 0110037-017-AC/PSD-FL-442).



5.0 AMBIENT MONITORING ANALYSIS

Pre-construction ambient monitoring analyses may be required for PM₁₀, PM_{2.5}, NO₂, SO₂, CO, and ozone (O₃) (based on NO_x and VOC emissions) because PSD review is applicable to these air pollutants. Ambient monitoring analyses are not required if it can be demonstrated that the Project's maximum air quality impacts will not exceed the PSD significant monitoring concentrations (SMC) and, for O₃, the Project's potential emissions will not exceed 100 TPY of NO_x or VOC emissions.

Maximum impacts due to the Project only are predicted to be below the SMC for PM₁₀, PM_{2.5}, NO₂, CO, and SO₂ (Table 5-1). As a result, a pre-construction ambient monitoring analysis is not required for these pollutants as part of the application pursuant to Rule 62-212.400(3)e, F.A.C., with the exception for PM_{2.5} due to a recent ruling by the US Court of Appeals (see the following paragraphs). It should be noted that EPA has not proposed SMC for the 1-hour average NO₂ concentration.

For O₃, the Project's VOC emissions are less than 100 TPY; however, NO_x emissions are more than 100 TPY or more, which requires that pre-construction ambient monitoring analysis for O₃ be submitted as part of the application.

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

Based on the impacts of PM₁₀, NO₂, SO₂, and CO being less than SMC, an exemption from the pre-construction monitoring requirement is applicable pursuant to Rule 62-212.400(3)(e), F.A.C. In addition, ambient O₃ and PM_{2.5} monitoring data collected by FDEP at monitoring stations near the Project are considered to be representative of air quality in the Project's vicinity. These data are being used to satisfy the pre-construction monitoring requirement for O₃ and PM_{2.5} that primarily form from atmospheric processes and are not directly emitted.

Air quality monitoring data collected in Pasco County from 2014 through 2016 for O₃ and PM_{2.5} are presented in Tables 5-2 and 5-3, respectively. These data indicate that the maximum air quality concentrations measured in the region are well below applicable standards.



6.0 AIR QUALITY IMPACT ANALYSIS

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

As described in Section 1.0, the proposed SHCCF Project involves the construction and operation of a 1-on-1 combined-cycle unit. SHCCF will utilize GE's latest offering of the 7HA CTG firing only natural gas. Other air emissions sources associated with the proposed SHCCF include an auxiliary boiler that will only be used during construction and for unit startup (cold, warm, and hot startups) and shut down, a diesel-fired emergency generator, a diesel-fired fire pump engine, and a 6-cell mechanical draft cooling tower. The emergency generator and the fire pump engine will only be used during emergencies and for 1 to 2 hours per month for readiness testing. Since the auxiliary boiler, emergency generator, and the fire pump engine are not part of normal operation, they were not included in the air quality impact analysis. Air emissions from the CTG and the 6-cell mechanical draft cooling tower were included in the air quality impact analysis.

The following sections present a summary of the air quality modeling methodology used and the results of the air quality impact analysis.

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

6.1.1 Model Selection

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

The latest version of AERMOD (Version 16216r) was used to predict the maximum pollutant concentrations due to the Project at nearby areas surrounding the facility.

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



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

The EPA regulatory default options were used to address maximum impacts.

6.1.2 Project Sources

Air quality analyses were performed to assess the maximum impacts of the proposed Project including the CTG and the 6-cell cooling tower. A summary of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTG used in the air modeling analysis is presented in Section 2. Initially, the CTG impacts were predicted for a range of possible operating conditions. The following 9 CTG/HRSG load and temperature scenarios were evaluated for natural gas firing:

- 100 percent load with duct burning and ambient temperatures of 30°F, 59°F, and 95°F
- 100 percent load and ambient temperature of 30°F, 59°F (including evaporative cooling), and 95°F (including evaporative cooling)
- MECL and ambient temperature of 30°F, 59°F, and 95°F

The new CTG/HRSG will have a stack height of 149 feet with an inner diameter of 25.6 ft.

6.1.3 Building Downwash Effects

The CTG stack is 149 ft above grade, which is below the Good Engineering Practice (GEP) stack height. Since the stack height is less than GEP, building downwash effects must be considered in the air modeling analysis. Major building structures such as the HRSG structure, air intake filter, and the cooling tower structure were included in the building downwash analysis. The direction-specific building information output by Building Profile Input Program (BPIP) were input to the air dispersion model for processing.

The dimensions of the building structures associated with the downwash analysis are provided in the table below.

Structure	Height (ft)	Width (ft)	Length (ft)
HRSG Structure	103	42	96.5
Cooling Tower	37.5	61	315.7
Air Intake Filter	55	25.1	60.2



6.1.4 Meteorological Data

Meteorological data used in the modeling analysis to estimate air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from Hernando County Airport (BKV) and twice-daily upper air sounding data collected from the National Weather Service (NWS) station located at Tampa International Airport (TPA). The 5-year period of the meteorological data was from 2012 through 2016 and was prepared by the Florida Department of Environmental Protection (FDEP) using the AERMET meteorological preprocessor Version 16216. AERMINUTE Version 11059 was used to process 1-minute wind data collected by the automatic surface observing system (ASOS) into hourly averages of wind direction and wind speed. A minimum wind speed threshold of 0.5 meters per second (m/s) was used. The ASOS at BKV is located approximately 15 km (9 miles) north-northeast of the SHGS. All areas between BKV and the SHGS site are flat to gently rolling with very similar land characteristics. As such, the meteorological parameters collected at BKV are considered to be representative of those that exist at or around SHGS.

6.1.5 Receptor Locations

For the air quality analysis, a Cartesian receptor grid was used to predict concentrations on and beyond the ambient air boundary out to approximately 10 km from the SHGS. Receptors were located at the following intervals and distances from the proposed Project:

- Along the ambient air boundary – 50 meters
- Beyond the fence line to 2 km – 100 meters, and
- From 2 km to 4 km – 250 meters

Note that the existing SHGS has wire fencing on all sides. The additional site for the SHCCF adjacent to the existing site will also be wire-fenced and as a result, the wire fencing around the entire 30-acre parcel was used as the ambient air boundary for the Project.

Overall, nearly 2,000 receptors were used to estimate the maximum concentrations predicted for the proposed Project impacts. Figures 6-1 and 6-2 show the near-field and far-field receptor locations, respectively.

6.1.6 CTG Load Analysis/Significant Impact Analysis

A CTG load analysis and a significant impact analysis were performed to determine the maximum air quality impact due to the proposed Project emissions. If the highest predicted impact for a particular pollutant and averaging time exceeds the respective PSD Class II significant impact level (SIL), more detailed modeling analyses are required for that pollutant and averaging time to address compliance with the National Ambient Air Quality Standards (NAAQS) and, if applicable, the allowable PSD increment.



The purpose of the load analysis was to determine the CTG operating case that generated the maximum ambient impact for each pollutant and averaging time combination. The following 9 CTG/HRSG load and temperature scenarios were evaluated:

- 100 percent load with duct burning and ambient temperatures of 30°F, 59°F, and 95°F
- 100 percent load and ambient temperature of 30°F, 59°F (including evaporative cooling), and 95°F (including evaporative cooling)
- MECL and ambient temperature of 30°F, 59°F, and 95°F

The significant impact analyses were performed for the following pollutants and averaging times:

- SO₂: 1-hour, 24-hour, 3-hour and annual averages
- PM₁₀: 24-hour and annual averages
- PM_{2.5}: 24-hour and annual averages
- NO₂: 1-hour and annual averages
- CO: 1-hour and 8-hour averages

The significant impact analyses for the 1-hour SO₂, 1-hour NO₂, and for the 24-hour and annual average PM_{2.5} concentrations are based on the maximum 5-year average concentrations predicted using 5 years of meteorological data. The significant impact analyses for the 24-hour and 3-hour SO₂, 24-hour PM₁₀, and 1-hour and 8-hour CO concentrations are based on the maximum predicted concentrations in any year over the 5-year period. The analyses for the annual average SO₂, NO₂, and PM₁₀ concentrations are based on maximum predicted concentrations for any year over the 5-year period.

Once the highest impacts were identified for the combination of ambient temperature and operating load condition (i.e., worst-case operating condition), all subsequent modeling analyses were performed using the pollutant-specific CTG/HRSG emission rates and exit gas operating data for the worse-case impacts identified for each pollutant. Only PM₁₀ and PM_{2.5} emissions from the cooling tower were modeled.

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



The results of the CTG load analysis are presented in Table 6-1. The results of the significant impact analyses are presented in Table 6-2, which shows maximum Project-only impacts due to the CTG/HRSG and the cooling tower (for PM₁₀ and PM_{2.5}) compared to the significant impact levels. Based on the results presented in Table 6-2, the proposed Project's maximum impacts are predicted to be less than the SIL for all evaluated pollutants and averaging times. As such, additional cumulative source modeling analyses are not required.

6.1.7 Secondary PM_{2.5} Formation

NO_x and SO₂ emissions are precursors to secondary PM_{2.5} formation in the atmosphere. EPA has developed a two-tiered demonstration approach for addressing single-source impacts on secondary PM_{2.5}. The Tier 1 demonstration involves use of technically credible relationships between emissions and ambient impacts based on existing modeling studies and the Tier 2 demonstration involves case-specific application of chemical transport modeling (e.g., with an Eulerian grid or Lagrangian model). As part of the latest air quality modeling guidelines (Appendix W, effective February 16, 2017) EPA has developed a Tier 1 demonstration tool for PM_{2.5} precursors called Modeled Emission Rates for Precursors (MERPs). A MERP represents a level of increased precursor emissions that is not expected to contribute to levels of ambient PM_{2.5} concentrations in order to determine causes or contributions to a violation of the NAAQS for PM_{2.5}. A finding that projected increases in the PM_{2.5} precursor emissions of NO_x and SO₂ from a proposed project are below the respective MERPs could be part of a sufficient demonstration that the construction will not cause or contribute to a violation of the appropriate NAAQS. Where project sources emit multiple precursors, the sum of precursor impacts would need to be considered for a sufficient demonstration of compliance. Also, if a project's sources emit both primary PM_{2.5} and precursors of secondary PM_{2.5}, EPA requires a combination of the primary and secondary impacts to determine total PM_{2.5} impacts as part of the PSD compliance demonstration.

On December 2, 2016, EPA published guidance on the use of MERPs. EPA has performed regional scale modeling and developed MERPs for eastern, central, and western regions of the US using the following equation:

$$\text{MERP (annual emission rate)} = \text{Critical Air Quality Threshold} * (\text{Modeled emission rate from hypothetical source} / \text{Modeled air quality impact from hypothetical source})$$

For the eastern US, the most conservative (lowest) SO₂ and NO_x MERP values for impacts on daily PM emissions are 675 tons/yr and 2,467 tons/yr, respectively. Similarly, the lowest SO₂ and NO_x MERP values for impacts on annual PM impacts are 4,013 tons/yr and 10,037 tons/yr, respectively.

According to EPA guidance, the maximum secondary PM_{2.5} impact from the NO_x and SO₂ emissions for the proposed Project can be estimated as follows:



- Maximum 24-hour average secondary PM_{2.5} impact in $\mu\text{g}/\text{m}^3$ = $[\text{NO}_x \text{ (TPY) from the Project}/\text{NO}_x \text{ daily PM}_{2.5} \text{ MERP (TPY)} + (\text{SO}_2 \text{ (TPY) from source}/\text{SO}_2 \text{ daily PM}_{2.5} \text{ MERP (TPY)})] \times \text{screening threshold concentration} = [126.2 \text{ TPY}/2467 \text{ TPY} + 90.9 \text{ TPY}/675 \text{ TPY}] \times 1.2 \mu\text{g}/\text{m}^3 = 0.223 \mu\text{g}/\text{m}^3$
- Maximum annual average secondary PM_{2.5} impact in $\mu\text{g}/\text{m}^3$ = $[\text{NO}_x \text{ (TPY) from the Project}/\text{NO}_x \text{ daily PM}_{2.5} \text{ MERP (TPY)} + (\text{SO}_2 \text{ (TPY) from source}/\text{SO}_2 \text{ daily PM}_{2.5} \text{ MERP (TPY)})] \times \text{screening threshold concentration} = [126.2 \text{ TPY}/10037 \text{ TPY} + 90.9 \text{ TPY}/4013 \text{ TPY}] \times 0.2 \mu\text{g}/\text{m}^3 = 0.007 \mu\text{g}/\text{m}^3$

The total PM_{2.5} impacts were determined after adding the primary PM_{2.5} impacts due to the primary PM_{2.5} emissions:

- Maximum 24-hour average total PM_{2.5} impact in $\mu\text{g}/\text{m}^3$ = Primary impact + Secondary impact = $0.90 \mu\text{g}/\text{m}^3 + 0.223 \mu\text{g}/\text{m}^3 = 1.13 \mu\text{g}/\text{m}^3$
- Maximum annual average total PM_{2.5} impact in $\mu\text{g}/\text{m}^3$ = Primary impact + Secondary impact = $0.08 \mu\text{g}/\text{m}^3 + 0.007 \mu\text{g}/\text{m}^3 = 0.088 \mu\text{g}/\text{m}^3$

Since the total 24-hour and annual average PM_{2.5} impacts are below the critical air quality thresholds of $1.2 \mu\text{g}/\text{m}^3$ and $0.2 \mu\text{g}/\text{m}^3$, respectively, the secondary formation of PM_{2.5} particles in the atmosphere due to the proposed Project are not expected to cause or contribute to violations of the PM_{2.5} NAAQS.

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

6.2.1 Model Selection and General Assumptions

For PSD Class I Areas, current EPA guidance indicates that the AERMOD model be used initially with a ring of 360 receptors spaced at 1-degree intervals to perform an initial assessment of impacts at a distance of 50 km from the project. The Chassahowitzka National Wilderness Area (CNWA) is located at a distance of 28.2 km from the proposed Project. Therefore, a receptor ring with a radius of 28.2 km was used to assess the maximum Project impacts at the CNWA. For this analysis, the elevations for all receptors were set to the highest receptor elevation in the CNWA (i.e., 3 m).

If the highest concentrations are predicted to be less than the significant impact levels, no additional modeling is required to address Class I pollutant impacts. If one or more maximum predicted concentrations from the AERMOD analyses are greater than the PSD Class I SILs, a cumulative source modeling analysis is required to demonstrate compliance with the allowable PSD Class I increments.

6.2.2 Project Sources

For the Class I analyses, the maximum impacts due to the proposed Project included only the CTG/HRSG. The cooling tower was not included in the analyses as the PM₁₀ and PM_{2.5} emissions from the tower are small compared to the emissions from the CTG and therefore, were assumed to cause an insignificant difference in maximum impacts at the Class I area 28.2 km away. A summary of the criteria pollutant



emission rates, and stack physical and operating parameters for the proposed CTG/HRSG used in the air modeling analysis are presented in Section 2. Initially, the CTG/HRSG impacts were predicted for a range of possible operating conditions. The following nine CTG/HRSG load and temperature scenarios were evaluated:

- 100 percent load with duct burning and ambient temperatures of 30°F, 59°F, and 95°F
- 100 percent load and ambient temperature of 30°F, 59°F (including evaporative cooling), and 95°F (including evaporative cooling)
- MECL and ambient temperature of 30°F, 59°F, and 95°F

6.2.3 Building Downwash Considerations

Building downwash was not included for the Class I analysis as the effect of building downwash was assumed to be insignificant or negligible at a distance of 28.2 km from the proposed Project.

6.2.4 Meteorological Data

The same 5-year meteorological data set used in the Class II analysis was also used in the AERMOD modeling for the Class I analysis.

6.2.5 Receptor Locations

A receptor ring with a radius of 28.2 km and with 360 receptors on the ring, spaced at 1-degree intervals was used in the AERMOD modeling for Class I analysis.

6.2.6 CTG Load Analysis and Significant Impact Analysis

A CTG load analysis was performed to determine the CTG operating case that has the potential to generate the maximum impact for each pollutant and averaging time combination. Using the worst-case operating case for the CTG from the load analysis, significant impact analyses were performed to assess the Project's impacts at the CNWA PSD Class I area. The maximum predicted SO₂, NO₂, PM₁₀, and PM_{2.5} concentrations due to the proposed Project were compared to EPA's proposed PSD Class I SILs. If the proposed Project's maximum predicted impacts exceed a proposed EPA PSD Class I SIL for any pollutant and averaging time then a more detailed PSD Class I increment analysis must be performed for that pollutant and averaging time.

The PSD Class I significant impact levels that are applicable to the proposed Project are:

- SO₂: 3-hour – 1.0 µg/m³, 24-hour – 0.2 µg/m³, and annual average – 0.1 µg/m³
- NO₂: annual average – 0.1 µg/m³
- PM₁₀: 24-hour – 0.3 µg/m³, and annual average – 0.2 µg/m³
- PM₁₀: 24-hour – 0.27 µg/m³, and annual average – 0.05 µg/m³



6.2.7 Model Results

The results of the CTG load analysis to determine the worst operating case from the 9 CTG/HRSG operating scenarios described in Section 6.2.2 are summarized in Table 6-3. The results of the analysis are compared to the Class I SILs in Table 6-4 and, as shown, the maximum impacts are below the Class I SILs. As such, additional modeling to determine compliance with the allowable PSD Class I increments is not required.



7.0 ADDITIONAL IMPACT ANALYSIS

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

(4) Source Information.

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

(8) Additional Impact Analyses.

(a) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.

(b) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

(9) Sources Impacting Federal Class I Areas. Sources impacting Federal Class I areas are subject to the additional requirements provided in 40 CFR 52.21(p), adopted by reference in Rule 62-204.800, F.A.C.

7.1 Potential Impacts Due to Associated Growth

7.1.1 Impacts of Associated Growth

Construction of the proposed Project will occur over approximately 18 to 24 months and will require an average of 230 workers during that time. It is anticipated that many of these construction personnel will commute to the site. Only approximately 11 to 15 permanent workers will be employed for the operation of the facility as a result of the Project. The workforce needed to construct and operate the Project represents a small fraction of the population already present in the region that includes Pasco and surrounding counties. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

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

As demonstrated in Section 6.0, the maximum air quality impacts resulting from the Project are predicted to be low and for some pollutants and averaging times, below the significant impact levels for the majority of air pollutant and averaging times. The predicted cumulative source 24-hour PM₁₀, 24-hour PM_{2.5}, and



1-hour average impacts demonstrate that the SHCCF and all nearby background source emissions will comply with the PSD increments and NAAQS.

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

7.2.1 Soils

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

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

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

7.2.2 Vegetation

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

In general, the effects of air pollutants on vegetation occur primarily from SO₂, NO₂, O₃, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term “injury,” as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below those that result in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with



some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

Sulfur Dioxide

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

SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercostal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury is usually evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis. Background levels of SO_2 range from 2.5 to 25 $\mu\text{g}/\text{m}^3$.

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

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu\text{g}/\text{m}^3$ SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu\text{g}/\text{m}^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu\text{g}/\text{m}^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48-percent reduction in photosynthesis (Carlson, 1979).

SO_2 is considered to be the primary factor causing the death of lichens in most urban and industrial areas. Sensitive species are damaged or killed by annual average levels of SO_2 ranging from 8 to 30 $\mu\text{g}/\text{m}^3$, and very few lichens can tolerate levels exceeding 125 $\mu\text{g}/\text{m}^3$ (Johnson, 1979; DeWit, 1976; Hawsworth and Rose, 1970; LeBlanc et al., 1972). In another study, two lichen species exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to 400 $\mu\text{g}/\text{m}^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).



Nitrogen Dioxide

Nitrogen dioxide (NO₂) can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO₂ can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru, et al., 1979).

For plants that have been determined to be more sensitive to NO₂ exposure than others, acute exposure (1, 4, and 8 hours) caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 µg/m³ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO₂ sensitive) to NO₂ concentrations of 2,000 to 4,000 µg/m³ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short-term exposure to NO_x at concentrations of 564 µg/m³ caused adverse effects in lichen species (Holopainen and Karenlampi, 1984).

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 µg/m³ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 µg/m³ did not appear to be injurious to the tested plants.

Carbon Monoxide

Information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome c oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome c oxidase depletes the supply of adenosine triphosphate (ATP), the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok, et al. (1989) reported that exposure to a CO:O₂ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10⁶ µg/m³) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik, et al. (1992) reported cytochrome c oxidase inhibition in corn, sorghum, millet, and Guinea grass at CO:O₂ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10⁵ µg/m³). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome c oxidase.

Ozone

O₃ can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis, and markings on the upper surface leaves known as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O₃ can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.



7.2.3 Wildlife

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

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). Although physiological and behavioral effects have been observed in experimental animals at or below secondary NAAQS, the most severe of these effects have been observed at concentrations above the secondary NAAQS.

7.2.4 Impact Analysis Methodology

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

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

7.3.1 Impacts on Vegetation and Soils

Vegetative communities in the vicinity of the Project include upland shrub and brushland, mixed wetland hardwood/exotic wetland hardwoods and mangrove swamp. Common vegetative species within the upland shrub and brushland include Brazilian pepper (*Schinus terebinthifolius*), Virginia creeper (*Parthenocissus quiquefolia*), camphorweed (*Heterotheca subaxillaris*), nettletree (*Trema micrantha*), castor bean (*Ricinus communis*), muscadine (*Vitis rotundifolia*), climbing hempvine (*Mikania scandens*), bermudagrass (*Cynodon dactylon*), and bushy broomsedge (*Andropogon glomeratus*).

The mixed wetland hardwoods/exotic wetland hardwoods is comprised of a mixture of exotic and native species, including the exotics Australian pine, Brazilian pepper, and melaleuca (*Melaleuca quinquenervia*), as well as native species pond apple, swamp bay (*Persea palustris*), red maple (*Acer rubrum*), myrsine,



and dahoon holly (*Ilex cassine*). A variety of understory species are present, including wild coffee tree (*Psychotria nervosa*), Carolina willow (*Salix caroliniana*), cocoplum, leather fern (*Acrostichum danaeifolium*), Peruvian primrosewillow (*Ludwigia peruviana*), royal palm (*Roystonea regia*), sawgrass (*Cladium jamaicense*), lance-leafed arrowhead (*Sagittaria lancifolia*), and pickerelweed (*Pontederia cordata*).

The mangrove swamp is dominated by native white mangrove and pond apple, with red mangrove (*Rhizophora mangle*) and black mangrove (*Avicennia germinans*) also present, as well as scattered Australian pine. The shrub and groundcover layer includes the exotic species Brazilian pepper, shoebutton ardisia (*Ardisia elliptica*), and napiergrass, as well as native species cocoplum (*Chrysobalanus icaco*), saltwater falsewillow (*Baccharis angustifolia*), salt grass (*Distichlis spicata*), and hurricane grass (*Fimbristylis spathacea*).

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

Since the project's impacts on the local air quality are predicted to be less than the NAAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible. With regard to O₃ concentrations, the Project's VOC and NO_x emissions (precursors to O₃ formation) represent an insignificant increase in VOC and decrease in NO_x emissions for Broward County.

7.3.2 Impacts on Wildlife

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

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from Unit 7 will cause adverse effects to wildlife due to the proposed Project's low impacts, which are predicted to be below the NAAQS based on worst-case operation.



7.4 Impacts to the PSD Class I Area

7.4.1 Identification of AQRVs and Methodology

An AQRV analysis was conducted to assess the potential risk to AQRVs at the CNWA due to the emissions from the proposed Project. The U.S. Department of the Interior in 1978 defined AQRVs to be:

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

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

7.4.2 Impacts to Soils

The soils of the CNWA are generally classified as entisols. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as CaCO_3).

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

7.4.3 Impacts to Vegetation

7.4.3.1 Sulfur Dioxide

The maximum 3-hour SO_2 concentration due to the Project is predicted to be $0.29 \mu\text{g}/\text{m}^3$ at the CNWA. This is several orders of magnitude lower than the reported injury level discussed in Section 7.2.2. As a result, no significant effects to vegetative AQRVs within the CNWA are expected as a result of the Project's SO_2 emissions.

7.4.3.2 Particulate Matter

The maximum 24-hour PM_{10} concentration due to the Project is predicted to be $0.06 \mu\text{g}/\text{m}^3$ at the CNWA. This impact is 0.03 percent of the values that affected plant foliage (i.e., $210 \mu\text{g}/\text{m}^3$, see previous



subsections). As a result, no significant effects to vegetative AQRVs within the CNWA are expected as a result of the Project's PM emissions.

7.4.3.3 Carbon Monoxide

The maximum 1-hour average concentration due to the Project at the CNWA was not determined. However, the maximum 1-hour average concentration in the near vicinity of the Project (in Class II areas) was determined to be $9.3 \mu\text{g}/\text{m}^3$ (see Table 6-2), which is approximately 0.00014 percent of the minimum value that caused inhibition in laboratory studies (i.e., $6.85 \times 10^6 \mu\text{g}/\text{m}^3$, see previous subsections). In addition, the maximum concentration at the CNWA is expected to be significantly lower than the maximum concentration in the near vicinity of the Project. Therefore, the amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season.

7.4.3.4 VOC and NO_x Emissions and Impacts to Ozone

VOC and NO_x emissions are precursors to O₃ formation. The NO_x emissions from the proposed CTG/HRSG are controlled by low-NO_x burners and an SCR system. The VOC emissions from the proposed project are small and did not trigger PSD review. Impacts to ground-level ozone formation are considered to be negligible.

7.4.3.5 Summary

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

7.4.4 Impacts to Wildlife

The maximum predicted impacts of the project in the Class I area are several orders of magnitude lower than values of potential impacts to wildlife (refer to Section 7.2.3). No effects on wildlife AQRVs from SO₂ and particulates are expected. The Project's contribution to cumulative impacts is negligible.

7.4.5 Impacts Upon Visibility

The Clean Air Act Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM₁₀ and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.



An analysis to determine the potential adverse plume visibility effects in the CNWA was conducted using the screening approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1992), which has been computerized by EPA in a program called the VISCREEN model. The VISCREEN model is currently recommended by FDEP and EPA to assess visual plume impacts in regulatory applications at Class I areas located within 50 km from a project site. The CNWA Class I area is located entirely between 28 and 46 km from the proposed project site. The VISCREEN model can be used to calculate potential plume impact of specific pollutant emissions for specific transport and meteorological dispersion conditions. The model can be applied in two successive levels of screening (i.e., referred to as Levels 1 and 2) without the need for extensive source, meteorological, or pollutant input. If the screening calculations demonstrate that, during worst-case meteorological conditions a plume is imperceptible or, if perceptible, is not likely to be considered objectionable ("adverse" or "significant" in the language of the EPA PSD and visibility regulations), further analysis of plume visual impact would not be required as part of the air quality review of the source. However, if the screening analyses demonstrate that the criteria are exceeded, plume visual impacts cannot be ruled out, and more detailed analyses to ascertain the magnitude, frequency, location, and timing of plume visual impacts would be required.

The Level 1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts that would be larger than those calculated with more realistic input and modeling assumptions). This analysis assumes worst-case meteorological conditions of stable stability (Pasquill-Gifford stability class F) and a 1 m/s wind speed persisting for 12 hours in one direction towards a PSD Class I area. The input required for the Level 1 analysis is limited to the following parameters:

- Emission rates of PM_{10} and NO_x ;
- Distance between the emission source and (a) the observer; (b) the closest Class I area boundary; and (c) the most distant Class I area boundary;
- Background visual range appropriate for the region in which the Class I area is located; and
- If available, emission rates of NO_2 , soot, and primary sulfate. For this analysis, the proposed project's H_2SO_4 emissions were included as primary sulfate.

Visibility impacts are then determined for two parameters:

- Contrast of a plume against a viewing background such as the sky or a terrain feature, and
- Perceptibility of a plume on the basis of the color difference between the plume and the viewing background (Delta E).

Results are provided by the model for several scenarios based on the background view, the viewing angle, visibility improvement due to plumes located both inside and outside the Class I area, and the sun angle. The critical values for contrast and Delta E are 0.05 and 2.00, respectively. If these levels are not exceeded



by the proposed source, the source is considered to pass the Level 1 visibility analysis, and the source will not have a significant impact on the Class I area.

The input parameters and results of the Level 1 analysis for the project are presented in Figure 7-1. As shown, the project will emit PM_{10} , NO_x , and primary SO_4 (as sulfuric acid mist). The maximum short-term average emission rates used in the analysis, which are presented in Section 2.0 and Appendix A, are based on the CT/HRSG operating at baseload conditions with an air inlet temperature of 30°F and includes duct burning. Primary NO_2 and soot are not emitted in significant quantities by natural gas- and oil-fired combustion sources; therefore, these emissions were set to zero.

The background visual range was assumed to be 178 km based on information provided by the Federal Land Manager's Air Quality Related Values Workgroup (FLAG), Phase I Report (December, 2010). The background visual range is equivalent to a reference level of 22.0 inverse Mega-meters (Mm^{-1}) presented in Table 2.B-1 of Appendix 2.B of the FLAG document. Other parameters input to the model were based upon default values given in the Workbook and incorporated into the computer model.

Per information provided by FDEP, VISCREEN results looking "outside" the Class I area pertain only to areas where an integral vista is being protected. As there are no integral vistas in Florida, the results looking outside the class I area are excluded from the analysis. Because the CNWA is a flat, wetland marsh area with no nearby elevated terrain, the viewing of distant terrain is not possible. As such, the visibility impacts for CNWA were based on the sky as the only viewing background.

As shown in Figure 7-1, the project's emissions are calculated to exceed the Level 1 visibility screening criteria at the Class I area. Because results from the Level 1 screening analysis exceed the visibility criteria, a Level 2 screening analysis was performed. One of the main differences in input between the Level 1 and Level 2 analyses is the meteorology and background visual range assumed for plume transport and dispersion patterns.

The Level 2 screening analysis is designed to account for more realistic occurrences of meteorological conditions that would transport the plumes of the proposed units towards the Class I area. In this analysis, an assessment of the frequency of the wind direction, wind speed, and atmospheric stability classes is made to determine the frequency of conditions that are most likely to cause a potentially adverse plume visual impact. If the Level 1 default parameters are selected for addressing visual plume impacts, the VISCREEN model assigns an appropriate estimate of particle size and density for the emitted and background atmosphere particulate and worst-case plume dispersion conditions. For this analysis, the particle size and density for the emission sources were not changed.

The first step in the analysis is to construct a table that shows worst case dispersion conditions ranked in order of decreasing severity and the frequency of occurrence of these conditions associated with the wind



direction that could transport emissions toward the Class I area. Dispersion conditions are ranked by evaluating the product of the horizontal dispersion parameter (called sigma y) times the vertical dispersion parameter (called sigma z) times the wind speed. Sigma y and sigma z account for the amount of plume spreading or dispersion that will occur as a plume travels away from a source for a given stability class. The dispersion conditions are then ranked in ascending order of the value of the dispersion product term (i.e., sigma y times sigma z times the wind speed).

For the Level 2 analysis, it is assumed that steady-state plume conditions are unlikely to persist for more than 12 hours. Thus, if a transit time of more than 12 hours is required to transport a plume parcel from the emission source to a Class I area for a given dispersion condition, it is assumed that the plume material is more dispersed than a standard Gaussian plume model would predict. This enhanced dilution would result from daytime convective mixing and wind direction and speed changes.

To obtain the worst-case meteorological conditions, it is necessary to determine the dispersion conditions (i.e., a given wind speed and stability class associated with the wind direction that would transport emissions toward the Class I area) that has a dispersion product term with a cumulative probability of 1 percent. Thus, the dispersion condition is selected to address potential plume visual impacts such that the sum of all frequencies of occurrence worse than this condition totals 1 percent (i.e., about 4 days per year). The 1 percentile meteorology is assumed to be worst-case plume visual impacts when the probability of worst-case meteorology conditions is coupled with the probability of other factors being ideal for maximizing plume visual impacts. Dispersion conditions associated with transport times of more than 12 hours are not considered in this cumulative frequency.

For this study, the FDEP provided surface meteorological data collected from the ASOS station at BKV for the years 2011 to 2015. These data were used to generate a frequency distribution of wind direction, wind speed, Pasquill-Turner stability class occurrences. Per the guidance document, the frequencies were calculated for the following four 6-hour periods of the day: 0001 to 0600, 0601 to 1200, 1201 to 1600, and 1601 to 2400 hours.

The PSD Class I area of the Chassahowitzka NWA is located mostly within a 22.5-degree wind direction sector that is located north-northwest of the project site at distances that vary from approximately 28 km to 46 km. A much smaller portion of the NWA (less than 5 percent) that is not located within this wind direction sector but is within an adjacent wind direction sector that extends due north of the site. The frequencies associated with these two wind direction sectors were included in the analysis (i.e., south and south-southeast winds) and evaluated individually to determine the worst-case meteorology.

This analysis is presented in Table 7-1, which shows the dispersion product term, transport time to the nearest part of the Class I area (i.e., distance of 28.2 km), and the frequency associated with each wind direction. As indicated in Table 7-1, the meteorological conditions considered in the analysis could be



transported to the Class I area in less than 12 hours. As a result, all of these conditions would be included in determining the worst-case meteorology using the cumulative probability of 1 percent.

As shown in Table 7-1 for SSE winds, the frequency of the worst-case weather condition (F stability, 1 m/s) exceeds 1 percent during the 6-hour period 0001 to 0600. As such, the worst-case weather condition that is assumed for a Level I analysis also had to be used for the Level II analysis.

In a Level I analysis, the background visual range (BVR) is based on data in the FLAG document. For a Level II analysis, the guidance suggests that the BVR can be based on a medium value determined from actual on-site measurements. IMPROVE data for CNWA was obtained from FDEP and indicated median BVRs for the following recent years: 2016 – 86.7 km; 2015 – 82.2 km; and 2014 – 79.0 km. Based on these data, a BVR of 86.7 km was used for the Level II visibility analysis.

The results of the Level II VISCREEN analysis are summarized in Figure 7-2. The result indicate that when a plume is viewed against a sky background the delta E for the project is estimated to be 1.4 compared to a criterion of 2.0 and the contrast is 0.021 compared to a criterion of 0.05.

Based on the analysis results, it is considered unlikely that the pollutant emissions from the project will cause adversely impact the visibility the CNWA.

7.4.6 Sulfur and Nitrogen Deposition at the CNWA

7.4.6.1 General Methods

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

For sulfur deposition, the species include:

- SO₂, wet and dry deposition; and
- SO₄, wet and dry deposition

The CALPUFF model produces results in units of micrograms per square meter per second (µg/m²/s), which are then converted to units of kg/ha/yr.

Deposition analysis threshold (DATs) for total nitrogen and sulfur deposition of 0.01 kg/ha/yr was provided by the FLM (January 2011). A DAT is the additional amount of nitrogen deposition within a Class I area below which estimated impacts from a new or modified source are considered insignificant. The maximum deposition predicted for the project is, therefore, compared to this DAT or significant impact levels.



7.4.6.2 Results

The maximum predicted total annual N and S depositions due to the proposed Project at the CNWA are summarized in Table 7-2. The maximum annual deposition rate predicted for the Project for either N or S is 0.0047 kg/ha/yr, which is well below the FLM's criteria of 0.01 kg/ha/yr.



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TABLES

Table 2-1: Stack, Operating, and Emission Data for CT/HRSG GE 7H.02, 1X1 Combined Cycle Combustion Turbine, HRST with Duct Burner, Natural Gas Firing, SCR

Parameter	Units	Operating and Emission Data ^a								
		Baseload and DB Firing			Baseload			MECL		
		Ambient Temperature			Ambient Temperature			Ambient Temperature		
		30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F
<u>CT/HRSG Stack Data</u>										
Height	ft	149	149	149	149	149	149	149	149	149
Diameter	ft	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6
Temperature	°F	159.7	161.1	167.3	165.7	166.1	175.0	151.3	151.9	161.6
Stack Exhaust Velocity	ft/sec	54.6	52.7	50.9	55.0	53.5	53.0	25.9	25.4	29.0
Maximum Hourly Emissions										
SO ₂	lb/hr	21.7	21.0	20.1	20.8	20.4	19.7	8.7	8.1	9.3
PM/PM ₁₀ /PM _{2.5}	lb/hr	14.6	14.4	14.8	12.9	12.8	12.7	10.6	10.4	10.7
NO _x	lb/hr	28.1	27.1	26.0	26.9	26.3	25.4	11.1	10.4	12.0
CO	lb/hr	49.8	48.3	51.9	35.2	34.7	33.1	24.2	22.4	25.9
VOC (as methane)	lb/hr	9.8	9.5	9.1	5.0	4.9	4.8	2.4	2.4	2.7
Sulfuric Acid Mist	lb/hr	4.0	3.9	3.7	3.2	3.1	3.0	1.3	1.2	1.4

^a Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Sources: GE, 2018; Golder, 2018.

Table 2-2: Summary of Maximum Potential Annual Emissions for the CT/HRSG^a
GE 7H.02, 1X1 Combined Cycle Combustion Turbine, HRSG with Duct Burner, Natural Gas Firing, SCR

CT/DB Operating Mode	Annual operating hours at each operating mode ^a						
	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	
Baseload	8,760	6,760	4,760	5,000	3,000	2,000	
Baseload with Duct Burner	0	2,000	4,000	3,000	4,000	4,000	
MECL	0	0	0	760	1,760	2,760	
	8,760	8,760	8,760	8,760	8,760	8,760	
Pollutant	Maximum Potential Annual Emissions (TPY)						Maximum Annual Emissions (TPY)
SO ₂	89.4	90.0	90.6	85.6	79.7	73.6	90.6
PM/PM ₁₀ /PM _{2.5}	56.1	57.7	59.3	57.6	57.2	56.0	59.3
NO _x	115.2	116.0	116.8	110.4	102.8	94.9	116.8
CO	151.8	165.4	179.1	167.6	168.3	162.1	179.1
VOC (as methane)	21.5	26.1	30.7	27.4	28.5	27.2	30.7
Sulfuric Acid Mist	13.7	14.4	15.2	14.1	13.5	12.6	15.2

^a Hourly emissions (lb/hr) based on 59 °F ambient air temperature.

Pollutant	Baseload	Baseload w DB	MECL
SO ₂	20.4	21.0	8.1
PM/PM ₁₀ /PM _{2.5}	12.8	14.4	10.4
NO _x	26.3	27.1	10.4
CO	34.7	48.3	22.4
VOC (as methane)	4.9	9.5	2.4
Sulfuric Acid Mist	3.1	3.9	1.2

Source: GE, 2018, Golder Associates, 2018.

**Table 2-3: Performance, Stack Parameters, and Emissions for the Auxiliary Boiler
Shady Hills Combined Cycle Facility**

Parameter	Units	Values
<u>Performance</u>		
Number of Units		1
Fuel		Natural gas
Heat Input (HHV) ^a	MMBtu/hr	60.0
Heat Content (HHV-Btu/scf)	Btu/scf	1,020
Fuel Usage	scf/hr	58,824
Rating ^a	lb steam/hr	85,000
Maximum operation/yr	hours	2,000
Maximum Fuel Usage	scf/yr	117,647,059
<u>Stack Parameters</u> ^a		
Diameter	ft	3.00
Height	ft	50
Temperature	°F	309
Velocity	ft/sec	60
Flow	acfm	25,447
<u>Emissions</u>		
SO ₂ -Basis ^b	grains S/100 scf	2
Emissions	lb/hr	0.34
	TPY	0.34
NO _x - Basis ^a	lb/MMBtu	0.050
Emissions	lb/hr	3.00
	TPY	3.00
CO - Basis ^a	lb/MMBtu	0.080
Emissions	lb/hr	4.80
	TPY	4.80
VOC - Basis ^a	lb/MMBtu	0.0050
Emissions	lb/hr	0.30
	TPY	0.30
PM/PM ₁₀ /PM _{2.5} - Basis ^{c,d}	lb/MMBtu	0.0070
Emissions	lb/hr	0.42
	TPY	0.42

Sources: POWER Engineers, Inc., 2018; Golder, 2018

^a Indeck Power Equipment Company.

^b Typical maximum sulfur content for natural gas

^c EPA, AP-42, Natural Gas Combustion (March 1998).

^d For PM, emissions include filterable and condensables.



**Table 2-4: Performance and Emission Data for the Emergency Generator
Shady Hills Combined Cycle Facility**

Parameter	Units	Values
<u>Performance</u>		
Number of Units		
Rating	BkW	1,645
Rating	Bhp	2,206
Fuel		Diesel
Fuel Heat content (HHV)	Btu/lb	19,170
Fuel density	lb/gal	7.39
Heat input (HHV)	MMBtu/hr	14.82
Fuel usage	gal/hr	104.6
Maximum operation/yr ^a	hours	500
Maximum fuel usage	gal/yr	52,300
<u>Stack Parameters</u>		
Diameter	ft	1.0
Height	ft	25
Temperature	°F	756.7
Flow	acfm	11,734
<u>Emissions</u>		
SO ₂ - Basis	%S	0.0015%
Conversion of S to SO ₂	%	100
Molecular weight SO ₂ / S (64/32)		2
Emission rate	lb/hr	0.023
	TPY	0.0058
NO _x - Basis ^b	g/kW-hr	6.4
Emission rate	lb/hr	23.2
	TPY	5.8
CO - Basis ^b	g/kW-hr	3.5
Emission rate	lb/hr	12.7
	TPY	3.2
VOC - Basis ^b (assumed portion of NO _x + NMHC)	g/kW-hr	1.0
Emission rate	lb/hr	3.6
	TPY	0.91
PM/PM ₁₀ /PM _{2.5} - Basis ^b	g/kW-hr	0.20
Emission rate	lb/hr	0.7
	TPY	0.18

Source: POWER Engineers, Inc., 2018; Golder, 2018.

^a Assumed actual annual operation, which includes 100 hrs/yr of operation for maintenance checks, readiness testing, and non-emergency operation.

^b Emissions based on Caterpillar 3512-C Emergency Diesel Generator meeting 40 CFR Part 60 Subpart IIII, Section 60.4202(a)(2); Table 1 in 40 CFR 89.112

**Table 2-5: Estimated Performance and Emission Data for Fire Pump Engine
Shady Hills Combined Cycle Facility**

Parameter	Units	Values
<u>Performance</u>		
Number		1
Rating	hp	347
Fuel		Diesel
Fuel Heat content (HHV)	MMBtu/hr	19,170
Fuel density	lb/gal	7.39
Heat input (HHV) ^a	MMBtu/hr	2.46
Fuel usage	gal/hr	17.4
Maximum operation/yr ^c	hours	500
Maximum fuel usage	gal/yr	8,700
<u>Stack Parameters</u>		
Exhaust Flow	acfm	2,036
Stack Velocity	ft/sec	173
Exhaust Temperature	°F	1,088
Stack Height	ft	15
Stack Diameter	ft	0.50
<u>Emissions</u>		
SO ₂ - Basis	%S	0.0015%
Conversion of S to SO ₂	%	100
Molecular weight SO ₂ /S (64/32)		2
Emission rate	lb/hr	0.0039
	TPY	0.00096
NO _x - Basis ^b	g/hp-hr	3.0
Emission rate	lb/hr	2.29
	TPY	0.574
CO - Basis ^b	g/hp-hr	2.60
Emission rate	lb/hr	1.99
	TPY	0.497
VOC - Basis ^b (assumed portion of NO _x + NMHC)	g/hp-hr	0.75
Emission rate	lb/hr	0.57
	TPY	0.143
PM/PM ₁₀ /PM _{2.5} - Basis ^b	g/hp-hr	0.15
Emission rate	lb/hr	0.11
	TPY	0.029

Source: POWER Engineers, Inc., 2018; Golder, 2018

^a Cummins CFP9E-F40.

^b Emissions based on 40 CFR Part 60 Subpart IIII, Table 4 of Subpart IIII.

^c Assumed actual annual operation, which includes 100 hrs/yr of operation for maintenance checks, readiness testing, and non-emergency operation.

**Table 2-6: Physical, Performance, and Emissions Data for the Mechanical Draft Cooling Tower
Shady Hills Combined Cycle Facility**

Parameter	
<u>Physical Data</u>	
Number of Cells	6
Deck Dimensions, ft	
Length	315.7
Width	61.0
Height	37.5
Stack Dimensions	
Height, ft above ground	51.2
Stack Top Effective Inner Diameter, per cell, ft	33
Effective Diameter, all cells, ft	80.8
<u>Performance Data</u>	
Discharge Velocity, ft/min	1,940
Circulating Water Flow Rate (CWFR), gal/min	94,258
Design hot water temperature, °F	115.0
Design cold water temperature, °F	83.5
Heat Rejected, million Btu/hr	1,714
Design Air Flow Rate per cell, acfm	1,659,000
Liquid/ Gas (Air Flow) (L/G) Ratio	1.32
Hours of operation	8,760
Temperature of Exit Air, °F	91.0
<u>Emission Data</u>	
Drift Rate ^a (DR), percent	0.0010
Total Dissolved Solids (TDS) Concentration ^b , maximum ppm	7,774
Solution Drift ^c (SD), lb/hr	471.7
PM Drift ^d , lb/hr	3.7
tons/year	16.1
PM ₁₀ Drift ^e	
PM ₁₀ Emissions, lb/hr	0.72
tons/year	3.17
PM _{2.5} Emissions, lb/hr	0.010
tons/year	0.044

^a Drift rate is the percent of circulating water.

^b A TDS of 7,774 results in maximum PM emissions.

^c Includes water and based on circulating water flow rate and drift rate
(CWFR x DR x 8.34 lb/gal x 60 min/hr).

^d PM calculated based on total dissolved solids and solution drift (TDS x SD).

^e PM₁₀ based on Calculating Realistic PM₁₀ Emissions from Cooling Towers, Joel Reisman and Gordon Frisbie.

Sources: POWER Engineers, Inc., 2018; Golder; 2018.

**Table 2-7: Summary of Maximum Potential Annual HAP Emissions for the Project
Shady Hills Combined Cycle Facility**

Pollutant	Proposed Project Maximum Potential Annual Emissions (TPY)					Existing SHGS HAP Emissions ^c	Total Facility HAP Emissions	HAP Major Source Threshold (TPY)
	CTs/HRSGs ^b	1 Auxiliary Boiler	1 Emergency Generator	1 Fire Pump Engine	TOTAL			
Total HAPs	7.0	5.29E-03	5.83E-03	0.0010	7.0	6.30	13.3	25
Single HAP ^a	3.5	4.41E-03	2.92E-04	4.86E-05	3.5	2.24	5.8	10

^a Based on formaldehyde emissions.

^b See Appendix A Tables A-3 and A-6-S for detailed HAP emissions calculation.

^c Response to request for additional information for the SHGS Title V renewal, Golder letter to FDEP dated 8/8/2017.

Note: NA= not applicable.

Source: Golder, 2018.

**Table 2-8: Summary of Maximum Potential Annual Emissions for Project
Shady Hills Combined Cycle Facility**

Pollutant	Maximum Potential Annual Emissions (TPY)						Fugitive Emissions SF ₆ NG Leaks	TOTAL	PSD Significant Emission Rate (TPY)
	1 CT/HRSG	1 Emergency Generator	1 Auxiliary Boiler	1 Fire Pump Engine	1 Cooling Tower				
SO ₂	90.6	0.00580	0.34	0.00096	--	--		90.9	40
PM	59.3	0.181	0.42	0.029	16.06	--		76.0	25
PM ₁₀	59.3	0.181	0.42	0.029	3.17	--		63.1	15
PM _{2.5}	59.3	0.181	0.42	0.029	0.010	--		59.9	10
NO _x	116.8	5.80	3.00	0.57	--	--		126.2	40
CO	179.1	3.17	4.80	0.497	--	--		187.5	100
VOC (as methane)	30.7	0.907	0.30	0.143	--	--		32.0	40
Sulfuric Acid Mist	15.2	Neg.	Neg.	Neg.	--	--		15.2	7
Greenhouse Gases (CO ₂ e)	1,877,683	606	7,019	100.8	--	62.4		1,885,409	75,000

Note: Neg.= negligible

Source: Golder, 2018.

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

Pollutant	Averaging Time	National and Florida AAQS ($\mu\text{g}/\text{m}^3$)		PSD Increments ($\mu\text{g}/\text{m}^3$)		Significant Impact Levels ($\mu\text{g}/\text{m}^3$)	
		Primary Standard	Secondary Standard	Class I	Class II	Class I	Class II
Particulate Matter (PM_{10}) ^a	Annual Arithmetic Mean	NA	NA	4	17	0.2	1
	24-Hour Maximum	150	150	8	30	0.3	5
Particulate Matter ($\text{PM}_{2.5}$) ^a	Annual Arithmetic Mean	12	15	1	4	0.05	0.3
	24-Hour Maximum	35	35	2	9	0.27	1.2
Sulfur Dioxide ^b	Annual Arithmetic Mean	80	NA	2	20	0.1	1
	24-Hour Maximum	365	NA	5	91	0.2	5
	3-Hour Maximum	NA	1,300	25	512	1	25
	1-Hour Maximum	197	NA	NA	NA	NA	7.9 ^e
Carbon Monoxide	8-Hour Maximum	10,000	10,000	NA	NA	NA	500
	1-Hour Maximum	40,000	40,000	NA	NA	NA	2,000
Nitrogen Dioxide ^c	Annual Arithmetic Mean	100	100	2.5	25	0.1	1
	1-Hour Maximum	188	NA	NA	NA	NA	7.6 ^e
Ozone ^d	1-Hour Maximum	NA	NA	NA	NA	NA	NA
	8-Hour Maximum	147	147	NA	NA	NA	NA
Lead	Rolling 3-Month Average	0.15	0.15	NA	NA	NA	NA

Note: NA = not applicable.

AAQS = ambient air quality standard.

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

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

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

^d On March 27, 2008, EPA promulgated revised AAQS for ozone. The O_3 standard was modified to be 0.075 ppm ($147 \mu\text{g}/\text{m}^3$) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less.

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

Sources: FR, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Florida Chapter 62.204, F.A.C. Golder, 2018.

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration ($\mu\text{g}/\text{m}^3$) ^a
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	NA
Particulate Matter (PM ₁₀)	NAAQS	15	10, 24-hour
Particulate Matter (PM _{2.5}) ^c	NAAQS	10, or	4, 24-Hour
	NAAQS	40 of SO ₂ , or	NA
	NAAQS	40 of NO _x	NA
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40 or NO _x	100 TPY ^b
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics (dioxin/furans)	NSPS	3.5x10 ⁻⁶	NM
MWC Metals (as PM)	NSPS	15	NM
MWC Acid Gases (SO ₂ + HCl)	NSPS	40	NM
MSW Landfill Gases (as NMOC)	NSPS	50	NM
Greenhouse Gases	--	75,000 (CO ₂ e basis)	NM

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

NA = not applicable

NM = no ambient measurement method established; therefore, no *de minimis* concentration has been established

mg/m³ = micrograms per cubic meter

MWC = municipal waste combustor

MSW = municipal solid waste

NMOC = non-methane organic compounds

^a Short-term concentration threshold for monitoring requirement applicability.

^b No *de minimis* concentration; an increase in VOC OR NO_x emissions of 100 TPY or more will require a monitoring analysis for ozone

^c Any emission rate of these pollutants.

Source: 40 CFR 52.21.

Rule 62-210.200 F.A.C. and Rule 62-212.400, F.A.C.

Table 4-1: Proposed BACT Emission Limits and Compliance Methods for CTG/HRSG including Duct Firing

Pollutant	Fuel	Operating Mode	Proposed BACT Emission Limits	Type of BACT Limit	Frequency and Compliance Methods
NO _x	Natural Gas	Normal and with Duct Firing ^a	2 ppmvd at 15% O ₂	Primary	CEMS RATA; CEMS 24-hour block average; excludes startup shutdown and malfunction
	Natural Gas	All	15 ppmvd at 15% O ₂	Secondary	40 CFR 60 Subpart KKKK; CEMS RATA, 30-day rolling, includes startup, shutdown and malfunctions
CO	Natural Gas	Baseload to 90% Load	4.3 ppmvd at 15% O ₂	Primary	Initial and Annual; EPA Method 10
		< 90% Load to MECL	7.1 ppmvd at 15% O ₂	Primary	Initial and Title V Renewal; EPA Method 10
	Natural Gas	Other ^b	Work Practice	Secondary	Recordkeeping of events.
PM/PM ₁₀	Natural Gas	Normal and with Duct Firing ^a	10% Opacity	Primary	Initial and Annual; EPA Method 9
	Natural Gas	Other ^b	20% Opacity	Secondary	Work Practice; EPA Method 9; 10-six minute periods per calendar day; 40 % maximum
SO ₂ and SAM	Natural Gas	All	2 grains S/100 scf	P & S ^c	Annual; Vendor Information
GHG	Natural Gas	Normal and with Duct Firing ^a	850 lb CO _{2e} /MW-hr	Primary	12-month rolling average; CO _{2e} per MWh based on total gross generation and total CO _{2e} ; CO _{2e} based on 40 CFR Parts 75 and 98; excludes startup and shutdown
	Natural Gas	All	1,000 lb CO _{2e} /MW-hr	Secondary	40 CFR 60 Subpart TTTT; 12-month rolling average, CO _{2e} per MWh based on gross generation and total CO _{2e} ; includes startup and shutdown

Note: CTG = combustion turbine generator; HRSG = heat recovery steam generator; CEMS = continuous monitoring system; RATA = relative accuracy test audit; S = sulfur; CO_{2e} = CO₂ equivalent; MW = megawatt.

^a Excluding periods of startup, shutdown, DLN tuning and malfunction.

^b Work practices include using best operational practices to minimize the amount and duration of emissions during specified events (startup, shut down and malfunction), following manufacturer-recommended procedures, and starting up on gas.

^c P = Primary; S = Secondary.

Table 4-2: Capital Cost for Selective Catalytic Reduction for General Electric 7HA.02 Combustion Turbine/HRSG with Duct Firing

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
SCR Associated Equipment	2,021,561	Golder 2017
Ammonia Storage Tank	included	
Flue Gas Ductwork	included	
Instrumentation and Auxiliary Systems	\$184,475	9% Golder, 2017
Emission Monitoring	\$101,078	5% of SCR Associated Equipment
Freight	\$101,078	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	2,408,192	
<u>Direct Installation Costs</u>		
Foundation and supports	\$192,655	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	\$337,147	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	\$96,328	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	\$48,164	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	\$24,082	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	\$24,082	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation (General Facilities)	\$120,410	5% of TDCC and RCC; OAQPS Cost Control Manual
Project Contingencies	\$240,819	10% of TDCC and RCC; OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	\$1,083,686	
Total Capital Costs (TCC)	\$3,491,878	Sum of TDCC and TDIC
<u>Indirect Costs</u>		
Engineering	included	
PSM/RMP Plan	\$50,000	Engineering Estimate
Construction and Field Expense	\$174,594	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$349,188	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$69,838	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$34,919	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	\$678,538	
Total Direct, Indirect and Capital Costs (TDICC)	\$4,170,417	Sum of TCC and TInCC

Table 4-3: Annualized Cost for Selective Catalytic Reduction for General Electric 7HA.02 Combustion Turbine/HRSG

Cost Component	Costs	Basis of Cost Component
<u>Direct Annual Costs</u>		
Operating Personnel	\$21,840	28 hours/week at \$15/hr
Supervision	\$3,276	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	\$309,784	\$556 per ton for anhydrous NH ₃ , 8,760 hr/year
PSM/RMP Update	\$25,000	Engineering Estimate
Inventory Cost	\$1,746	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Replacement	\$55,500	4 years catalyst life; CCEC costs
Contingency	\$12,514	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$429,661	
<u>Energy Costs</u>		
Electrical (SCR)	\$115,632	330kW/hr (SCR system) @ \$0.04/kWh,
MW Loss and Heat Rate Penalty	\$472,208	0.2% of MW output; and \$3/mmBtu fuel costs
Total Energy Costs (TEC)	\$587,840	
<u>Indirect Annual Costs</u>		
Overhead	\$200,940	60% of Operating/Supervision Labor and Ammonia
Property Taxes (exempt)	\$0	0% of Total Capital Costs
Insurance	\$41,704	1% of Total Capital Costs
Administration	\$83,408	2% of Total Capital Costs
Annualized Total Direct Capital	\$467,070	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDACC
Total Indirect Annual Costs (TIAC)	\$793,122	
Total Annualized Costs	\$1,810,623	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness (25 to 2 ppmvd)	\$1,321	NO _x Reduction Only
	\$1,417	Net Emission Reduction

Table 4-4. Potential Incremental Emission Changes (TPY) with Selective Catalytic Reduction

Pollutants	Incremental Emissions (tons/year) of SCR		Total
	Primary	Secondary	
Particulate (ammonium sulfate)	3.77	0.09	3.86
Sulfur Dioxide		0.18	0.18
Nitrogen Oxides	-1,370.57	0.23	-1,370.34
Carbon Monoxide		0.35	0.35
Volatile Organic Compounds		0.06	0.06
Ammonia (pmmvd at 15% O ₂)	87.95		87.95
Total:	-1,278.85	0.90	-1,277.95
Carbon Dioxide (additional from gas firing)		3,674.43	3,674.43

Table 4-5: Capital Costs for Oxidation Catalyst for General Electric 7H.02 Combustion Turbine/HRSG

Cost Component	Costs	Basis of Cost Component
<u>Direct Capital Costs</u>		
CO Associated Equipment	\$385,996	Esitimated based on actual catalyst costs.
Instrumentation and Auxiliary Systems	\$38,600	10% of Oxidation Catalyst Associated Equipment
Freight	\$19,300	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	\$443,895	
<u>Direct Installation Costs</u>		
Foundation and supports	\$35,512	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	\$62,145	14% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	\$4,439	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	\$4,439	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	\$22,195	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	\$128,730	
Total Capital Costs	\$572,625	Sum of TDCC, TDIC and RCC
<u>Indirect Costs</u>		
Engineering	\$57,262	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	\$28,631	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	\$57,262	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	\$11,452	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	\$5,726	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	\$160,335	
Contingencies	\$85,894	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	\$818,853	Sum of TCC and TInCC

Table 4-6: Annualized Cost for Oxidation Catalyst for General Electric 7H.02 Combustion Turbine/HRSG

Cost Component	Cost	Basis of Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	\$16,425	1/2 hr/shift, \$30/hr, 8760 yr
Supervision	\$2,464	15% of Operating Personnel; OAQPS Cost Control Manual
Maintenance (labor and materials)	\$12,283	1.5% of TDICC, OAQPS Section 4
Catalyst Replacement	\$46,371	7 year catalyst life, 50% catalyst replaced
Inventory Cost	\$28,597	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	\$5,307	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	\$111,447	
<u>Energy Costs</u>		
Heat Rate Penalty	\$330,646	0.1% of MW output reduction with additional backpressure and \$3/mmBtu addl fuel costs
Total Energy Costs (TEC)	\$330,646	
<u>Indirect Annual Costs</u>		
Overhead	\$18,703	60% of Operating/Supervision Labor
Property Taxes (exempt)	\$0	0% of Total Capital Costs
Insurance	\$8,189	1% of Total Capital Costs
Administration	\$16,377	2% of Total Capital Costs
Annualized Total Direct Capital	\$89,910	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	\$133,179	
Total Annualized Costs	\$575,272	Sum of TDAC, TEC and TIAC
Cost Effectiveness	110.96	Net CO Emission Reduction to meet previous BACT Limits with oxidation catalyst
	\$5,184	per ton of CO Removed
	\$6,289	Net Emission Reduction

Table 4-7: Potential Incremental Emission Changes (TPY) with Oxidation Catalyst

Pollutants	Incremental Emissions (TPY) of OC		Total
	Primary	Secondary ^a	
Particulate (ammonium sulfate)	7.67	0.03	7.70
Sulfur Dioxide		0.06	0.06
Nitrogen Oxides		0.08	0.08
Carbon Monoxide (reduced to 2 ppmvd @ 15% O ₂)	-110.96	0.12	-110.84
Volatile Organic Compounds		0.02	0.02
Sulfuric Acid Mist (additional over SCR)	11.50	Neg.	Neg.
Total:	-91.79	0.32	-91.47
Carbon Dioxide (additional from gas firing)		1,304.45	1,304.45

^a Basis of Secondary emissions:

Lost Energy (mmBtu/year)

21,942

Secondary Emissions (lb/mmBtu): Assumes same emission basis as the GE 7H.02 CTG.HRSG (including duct firing).

Particulate

0.0030 lb/MMBtu

Sulfur Dioxide

0.0057 lb/MMBtu

Nitrogen Oxides

0.0073 lb/MMBtu

Carbon Monoxide

0.0112 lb/MMBtu

Volatile Organic Compounds

0.0019 lb/MMBtu

Carbon Dioxide (equivalent)

118.9000 lb/MMBtu

Note: emissions in lb/MMBtu based on data in Tables A-1 and A-2.

Table 4-8: GHG Emission Rates for the Potential Operating Ranges of the SHCCF CTG/HRSG at 77 °F Ambient Temperature

Load	%	100%	100%	100%	80%	60%	MECL
Evap. Cooling		On	On	Off	Off	Off	Off
Duct Firing		On	Off	Off	Off	Off	Off
Design (Calculated) Heat Rate (Gross)	Btu/kWh (HHV)	6,115	6,062	6,053	6,144	6,343	7,074
EPC Contract Guarantee (Gross) ^b	Btu/kWh (HHV)	6,421	6,365	6,356	6,452	6,660	7,428
GHG Emission Rate (New and Clean)	lb CO ₂ e/MWh	764	757	756	768	792	884
Degradation from New and Clean ^c	%	5%	5%	5%	5%	5%	5%
GHG Emission Rate with Degradation	lb CO ₂ e/MWh	802	795	794	806	832	928
Generation	MW (Gross)	575	559	552	449	352	203

Basis of Proposed 12-month rolling GHG BACT Emission Limit

12-month Operation	%	20%	30%	40%	0%	5%	5%	100%
12-month GHG Emissions	Tons CO ₂ e	404,028	584,333	767,639	0	64,175	41,225	1,861,399
12-month Generation	MW/hr Gross	1,007,395	1,469,798	1,933,658	0	154,264	88,851	4,653,966

lb CO ₂ e/MWh	800
Capacity Factor ^d	96%

12-month Operation	%	46%	0%	0%	0%	0%	54%	100%
12-month GHG Emissions	Tons CO ₂ e	923,205	0	0	0	0	447,699	1,370,904
12-month Generation	MW/hr Gross	2,301,897	0	0	0	0	964,921	3,266,818

lb CO ₂ e/MWh	839
Capacity Factor ^d	68%

12-month Operation	%	0%	0%	0%	0%	20%	80%	100%
12-month GHG Emissions	Tons CO ₂ e	0	0	0	0	256,698	659,593	916,291
12-month Generation	MW/hr Gross	0	0	0	0	617,056	1,421,615	2,038,671

lb CO ₂ e/MWh	899
Capacity Factor ^d	42%

^a Based on 77 °F operation from calculated heat balances; actual range of operating temperatures is a 3% difference in heat rate.

^b Contract basis for EPC to deliver new and clean heat rate.

^c Contract degradation limit from new and clean.

^d Capacity factor based on no duct firing or evaporative cooling.

**Table 5-1: Maximum Impacts Analysis Compared to De Minimis Monitoring Concentration
SHCCF Project**

Pollutant	Averaging Time	Maximum Model-Predicted Concentrations ($\mu\text{g}/\text{m}^3$)	De Minimis Monitoring Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	24-Hour	1.03	13
PM ₁₀ (CTG/HRSG)	24-Hour	1.27	10
PM ₁₀ (CTG/HRSG with Coolong Tower)	24-Hour	1.47	10
PM _{2.5}	24-Hour	1.13	4.0
NO ₂	Annual	0.11	14
CO	8-Hour	5.5	575

Table 5-2: Summary of 8-Hour O₃ Measurements, 2013 to 2017

Site No.	Location	Distance from the SHCCF (km)	Measurement Period		Concentration (µg/m ³)		
					8-Hour ^a		
			Year	Months	Highest	4th Highest	3-year Average
Ozone NAAQS					NA	137	
12-101-0005	30908 Warder Road San Antonio, FL	25.36	2017	Jan-Aug	139.4	119.7	121.0
			2016	Jan-Dec	141.3	123.7	121.0
			2015	Jan-Dec	131.5	119.7	121.7
			2014	Jan-Dec	131.5	119.7	
			2013	Jan-Dec	133.5	125.6	
12-101-2001	3452 Darlington Rd., Holiday, FL	27.28	2017	Jan-Aug	145.3	117.8	119.8
			2016	Jan-Dec	137.4	123.7	122.4
			2015	Jan-Dec	125.6	117.8	125.6
			2014	Jan-Dec	143.3	125.6	
			2013	Jan-Dec	139.4	133.5	
12-103-5002	2200 East Lake Rd, Palm Harbor, FL 34865	34.1	2017	Jan-Sep	161.0	119.7	117.1
			2016	Jan-Dec	133.5	121.7	117.1
			2015	Jan-Dec	117.8	109.9	119.1
			2014	Jan-Dec	135.4	119.7	
			2013	Jan-Dec	133.5	127.6	

Note: NA = not applicable.

NAAQS = National Ambient Air Quality Standard.

^a The 8-hour O₃ standard is met when the 3-year average of the daily maximum 8-hour average concentration is less than 137 µg/m³.

Source: Monitor Values Report from EPA AirData website, 2013-2017.

Table 5-3: Summary of 24-Hour PM_{2.5} Measurements, 2013 to 2017

Site No.	Location	Distance from the SHCCF (km)	Measurement Period		Concentration (µg/m ³)				
					24-Hour ^a			Annual ^b	
			Year	Months	Highest	98th Percentile	3-Year Average	Mean	3-Year Average
PM _{2.5} NAAQS					NA	35		12	
12-057-0113	1497 N Munro Street Tampa, FL 33607	46.25	2017	January	33.7	22.5	19.8	10.0	9.3
			2016	Jan-Aug	24.5	17.0	17.0	8.6	8.6
			2015	Jan-Dec	No data	No data		No data	
			2014	Jan-Dec	No data	No data		No data	
			2013	Jan-Dec	No data	No data		No data	
12-057-3002	1167 N Dover Road, Valrico, FL 33527	55.58	2017	Jan-Aug	32.0	18.0	21.7	8.1	7.7
			2016	Jan-Nov	21.0	17.0	24.2	7.7	8.3
			2015	Jan-Nov	30.3	30.0	23.5	7.2	7.9
			2014	Jan-Oct	29.2	25.6		10.0	
			2013	Jan-Nov	26.9	15.0		6.5	
12-103-0018	7200-22 Avenue N., St. Petersburg, FL 33710	66.41	2017	Jan-Aug	22.9	23.0	20.0	8.3	7.2
			2016	Jan-Nov	12.9	13.0	17.3	6.6	6.6
			2015	Jan-Nov	23.7	24.0	18.3	6.8	6.5
			2014	Jan-Nov	22.7	15.0		6.4	
			2013	Jan-Oct	23.7	16.0		6.2	

Note: NA = not applicable.
NAAQS = National Ambient Air Quality Standard.

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

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

Source: Monitor Values Report from EPA AirData website, 2013-2017.

Table 6-1: CTG Load Analysis for Impacts at PSD Class II Areas, SHCCF Project

Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations (µg/m³) for CT by Operating Load and Air Temperature ^a										
Base Load w/ DB			Base Load w/o DB			MECL			Averaging Time	Base Load w/ DB			Base Load w/o DB			MECL				
30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F		30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F		
Generic ^b (1 g/s)	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	Annual	^c	0.03	0.03	0.03	0.03	0.03	0.03	0.07	0.07	0.06
										Annual	^d	0.03	0.03	0.03	0.03	0.03	0.02	0.06	0.06	0.05
										24-Hour	^c	0.26	0.27	0.28	0.25	0.26	0.25	0.94	0.97	0.73
										24-Hour	^d	0.22	0.23	0.23	0.21	0.22	0.21	0.67	0.69	0.54
										8-Hour	^c	0.67	0.70	0.71	0.65	0.67	0.65	1.79	1.81	1.58
										3-Hour	^c	0.99	1.04	1.04	0.96	0.99	0.96	2.33	2.37	1.93
										1-Hour	^c	1.33	1.38	1.42	1.30	1.34	1.32	3.01	3.05	2.61
										1-Hour	^e	0.97	1.01	1.03	0.92	0.97	0.94	2.32	2.38	1.96
<u>Emissions for 1 CC CT</u>																				
SO ₂	21.75	21.00	20.08	20.83	20.42	19.67	8.67	8.08	9.33	Annual	^c	0.09	0.09	0.08	0.08	0.08	0.07	0.08	0.08	0.07
										24-Hour	^c	0.72	0.71	0.71	0.67	0.67	0.62	1.03	0.98	0.86
										3-Hour	^c	2.72	2.74	2.64	2.51	2.55	2.38	2.54	2.42	2.27
										1-Hour	^e	2.64	2.66	2.61	2.40	2.50	2.32	2.54	2.43	2.31
PM ₁₀	14.60	14.40	14.80	12.90	12.80	12.70	10.60	10.40	10.70	Annual	^c	0.06	0.06	0.06	0.05	0.05	0.05	0.10	0.10	0.08
										24-Hour	^c	0.49	0.49	0.53	0.41	0.42	0.40	1.256	1.265	0.981
PM _{2.5}	14.60	14.40	14.80	12.90	12.80	12.70	10.60	10.40	10.70	Annual	^d	0.05	0.05	0.05	0.04	0.04	0.04	0.08	0.08	0.07
										24-Hour	^d	0.41	0.41	0.43	0.35	0.35	0.33	0.90	0.90	0.73
NO _x	28.10	27.10	26.00	26.90	26.30	25.40	11.10	10.40	12.00	Annual	^c	0.11	0.11	0.11	0.10	0.10	0.09	0.10	0.10	0.09
										1-Hour	^e	3.42	3.44	3.37	3.10	3.22	3.00	3.25	3.12	2.96
CO	49.77	48.28	51.89	35.16	34.66	33.13	24.24	22.38	25.89	8-Hour	^c	4.23	4.24	4.64	2.88	2.93	2.73	5.48	5.11	5.16
										1-Hour	^c	8.33	8.37	9.26	5.74	5.84	5.49	9.19	8.59	8.53

^a Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface data from the ASOS station at Hernando County AP and upper air data from Tampa International AP.

^b Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 7.937 lb/hr (1 g/s) for 1 CT/HRSG. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 1 g/s.

^c Based on the highest concentration of any year (2012-2016).

^d Based on highest 5-year average concentration (2012-2016).

^e Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).



Table 6-2: Significant Impact Analysis for PSD Class II Areas
SHCCF Project

Pollutant	Averaging Time	Maximum Model-Predicted Concentrations ($\mu\text{g}/\text{m}^3$)	EPA Class II Significant Impact Levels ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.09	1
	24-Hour	1.03	5
	3-Hour	2.74	25
	1-Hour	2.66	7.86
PM ₁₀	Annual	0.10	1
	24-Hour	1.27	5
PM _{2.5} - Primary	Annual	0.08	0.2
	24-Hour	0.90	1.2
PM _{2.5} - Secondary ^a	Annual	0.007	0.2
	24-Hour	0.223	1.2
PM _{2.5} - Total	Annual	0.09	0.2
	24-Hour	1.13	1.2
NO ₂	Annual	0.11	1
	1-Hour	3.44	7.52
CO	8-Hour	5.5	500
	1-Hour	9.3	2,000
<u>With Cooling Tower</u>			
PM ₁₀	Annual	0.12	1
	24-Hour	1.47	5

^a **Secondary PM_{2.5} Impacts:**

Project NO_x Emissions = 126.2 TPY

Project SO₂ Emissions = 90.9 TPY

	<u>24-Hour</u>	<u>Annual</u>
NO _x MERP (TPY) =	2467	10037
SO ₂ MERP (TPY) =	675	4013

Secondary Impact = (NO_x Emissions/NO_x MERP + SO₂ Emissions/SO₂ MERP) x Sig Impact Level

Table 6-3: CTG Load Analysis for Impacts at the Chassahowitzka National Wilderness Class I Area, SHCCF Project

Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature										Averaging Time	Maximum Predicted Concentrations (µg/m ³) for CT by Operating Load and Air Temperature ^a									
Base Load w/ DB			Base Load w/o DB			MECL			Base Load w/ DB			Base Load w/o DB			MECL					
30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F		59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F		
Generic ^b (1 g/s)	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	7.94	Annual	^c	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.004	0.003
										Annual	^d	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003
										24-Hour	^c	0.03	0.03	0.03	0.03	0.03	0.03	0.05	0.05	0.04
										24-Hour	^d	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.03
										3-Hour	^c	0.11	0.11	0.11	0.10	0.10	0.10	0.14	0.14	0.13
<u>Emissions for 1 CT</u>																				
SO ₂	21.70	21.00	20.10	20.80	20.40	19.70	8.70	8.10	9.30	Annual	^c	0.007	0.006	0.006	0.006	0.006	0.006	0.004	0.004	0.004
										24-Hour	^c	0.09	0.09	0.08	0.08	0.08	0.07	0.05	0.05	0.05
										3-Hour	^c	0.29	0.28	0.27	0.27	0.27	0.25	0.15	0.14	0.15
PM ₁₀	14.60	14.40	14.80	12.90	12.80	12.70	10.60	10.40	10.70	Annual	^c	0.004	0.004	0.005	0.004	0.004	0.004	0.005	0.005	0.004
										24-Hour	^c	0.058	0.058	0.059	0.050	0.050	0.048	0.062	0.061	0.058
PM _{2.5}	14.60	14.40	14.80	12.90	12.80	12.70	10.60	10.40	10.70	Annual	^d	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
										24-Hour	^d	0.044	0.044	0.045	0.038	0.038	0.037	0.047	0.046	0.043
NO ₂	28.10	27.10	26.00	26.90	26.30	25.40	11.10	10.40	12.00	Annual	^c	0.009	0.008	0.008	0.008	0.008	0.007	0.005	0.005	0.005

^a Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2012 to 2016 consisting of surface data from the ASOS station at Hernando County AP and upper air data from Tampa International AP. 360 receptors at distance of 28.2 km from the proposed Project and spaced at 1-degree intervals.

^b Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 7.937 lb/hr (1 g/s) for 1 CT/HRSG. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 1 g/s.

^c Based on the highest concentration of any year (2012-2016).

^d Based on highest 5-year average concentration (2012-2016).

^e Based on highest 5-year average daily maximum 1-hour concentration (2012-2016).



**Table 6-4: Significant Impact Analysis for PSD Class I Area
SHCCF Project**

Pollutant	Averaging Time	Maximum Model-Predicted Concentrations^a ($\mu\text{g}/\text{m}^3$)	EPA Class I Significant Impact Levels ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.01	0.1
	24-Hour	0.09	0.2
	3-Hour	0.29	1
PM ₁₀	Annual	0.005	0.2
	24-Hour	0.06	0.3
PM _{2.5}	Annual	0.004	0.05
	24-Hour	0.05	0.27
NO ₂	Annual	0.009	0.1

^a Maximum model-predicted concentrations on a receptor ring with a radius of 28.2 km.

Table 7-1: Worst-Case Meteorological Conditions for VISCREEN

Dispersion Conditions				Transport Time to Class I Area (hours) ^a	Frequency of Occurrence (percent) of Dispersion Conditions ^c - Daytime				Frequency of Occurrence (percent) of Dispersion Conditions ^c - Nighttime				
Stability		Wind Speed (m/s)	Sigma Y x Sigma Z x Wind Speed (m³/s)		7 a.m. to 12 a.m.		1 p.m. to 6 p.m.		1 a.m. to 6 a.m.		7 p.m. to 12 p.m.		
Category	Name				f ^b	cf ^b	f ^b	cf ^b	f ^b	cf ^b	f ^b	cf ^b	
South-southeast Wind Direction Sector													
F	Moderately Stable	1	45724	7.8	0.27	0.27	0.00	0.00	1.43	1.43	0.80	0.80	
F	Moderately Stable	2	91447	3.9	0.69	0.97	0.00	0.00	3.97	5.40	2.39	3.19	
E	Slightly Stable	1	126597	7.8	0.00	0.97	0.00	0.00	0.00	5.40	0.00	3.19	
F	Moderately Stable	3	137171	2.6	0.31	1.28	0.00	0.00	0.86	6.26	0.70	3.90	
E	Slightly Stable	2	253195	3.9	0.05	1.32	0.00	0.00	0.18	6.44	0.12	4.02	
D	Neutral	1	329620	7.8	0.08	1.05	0.00	0.00	0.19	6.64	0.09	4.11	
E	Slightly Stable	3	379792	2.6	0.05	1.10	0.00	0.00	0.30	6.94	0.27	4.38	
E	Slightly Stable	4	506389	2.0	0.03	1.13	0.00	0.00	0.26	7.20	0.22	4.60	
E	Slightly Stable	5	632987	1.6	0.04	1.17	0.00	0.00	0.07	7.68	0.04	4.82	
D	Neutral	2	659240	3.9	0.59	1.76	0.02	0.02	0.40	7.60	0.18	4.78	
D	Neutral	3	988861	2.6	0.92	2.68	0.16	0.18	0.21	7.89	0.16	4.98	
D	Neutral	4	1318481	2.0	0.49	3.18	0.19	0.37	0.37	8.25	0.18	5.17	
D	Neutral	5	1648101	1.6	0.55	3.72	0.21	0.58	0.37	8.62	0.18	5.35	
South Wind Direction Sector													
F	Moderately Stable	1	45724	7.8	0.09	0.09	0.00	0.00	0.61	0.61	0.64	0.64	
F	Moderately Stable	2	91447	3.9	0.16	0.25	0.00	0.00	1.02	1.63	1.62	2.26	
E	Slightly Stable	1	126597	7.8	0.00	0.25	0.00	0.00	0.00	1.63	0.00	2.26	
F	Moderately Stable	3	137171	2.6	0.05	0.29	0.00	0.00	0.50	2.14	0.80	3.07	
E	Slightly Stable	2	253195	3.9	0.02	0.31	0.00	0.00	0.06	2.20	0.16	3.22	
D	Neutral	1	329620	7.8	0.01	0.26	0.00	0.00	0.17	2.37	0.05	3.28	
E	Slightly Stable	3	379792	2.6	0.04	0.29	0.00	0.00	0.16	2.54	0.21	3.49	
E	Slightly Stable	4	506389	2.0	0.02	0.31	0.00	0.00	0.10	2.64	0.27	3.76	
E	Slightly Stable	5	632987	1.6	0.01	0.32	0.00	0.00	0.08	2.93	0.12	3.95	
D	Neutral	2	659240	3.9	0.28	0.60	0.05	0.05	0.21	2.85	0.07	3.83	
D	Neutral	3	988861	2.6	0.40	1.00	0.16	0.21	0.20	3.13	0.15	4.10	
D	Neutral	4	1318481	2.0	0.35	1.35	0.17	0.38	0.17	3.30	0.21	4.31	
D	Neutral	5	1648101	1.6	0.28	1.63	0.18	0.57	0.11	3.41	0.15	4.45	

^a Proposed project location is approximately^b f= frequency for given meteorological condition; cf= cumulative frequency up to and including condition.^c Based on surface meteorological data for 2011 to 2015 from the ASOS station at the Hernando County AP (BKV).^d Approximately 95 percent of the Chassahowitzka NWA is downwind of the proposed project with a south-southeast wind direction.

Table 7-2: Maximum Predicted Annual-Average Total Sulfur and Nitrogen Deposition [at the Chassahowitzka NWA Class I Area]

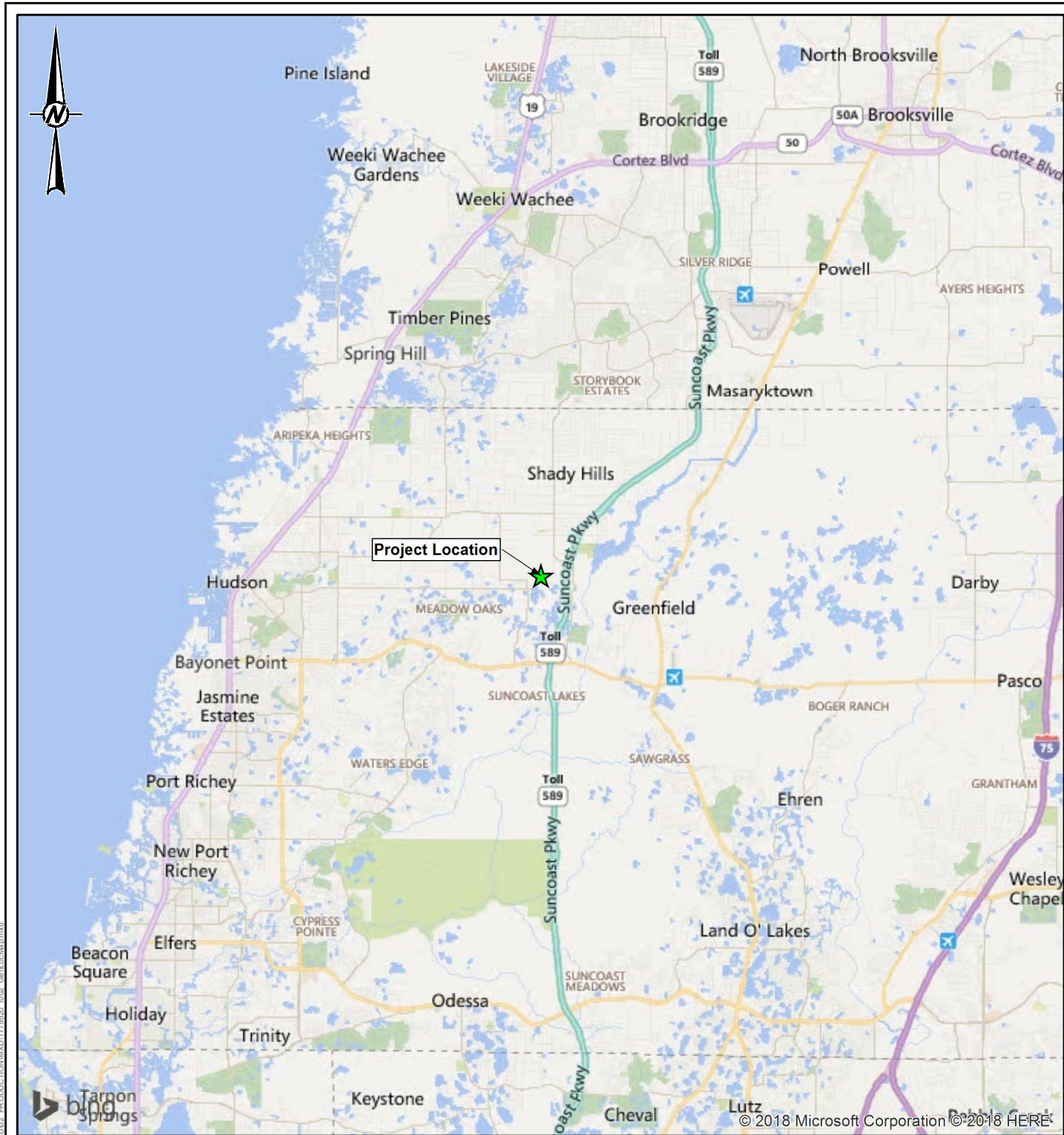
Total Deposition (Wet & Dry) (g/m²/s) (kg/ha/yr)^a			Year	Deposition Analysis Threshold ^b (kg/ha/yr)
<u>Sulfur</u>				
1.14E-11	0.0036	2001	0.01	
1.44E-11	0.0046	2002	0.01	
1.44E-11	0.0045	2003	0.01	
<u>Nitrogen</u>				
4.95E-12	0.0016	2001	0.01	
5.54E-12	0.0017	2002	0.01	
6.54E-12	0.0021	2003	0.01	

^a Conversion factor is used to convert g/m²/s to kg/hectare (ha)/yr with the following units:

$$\begin{aligned}
 &\text{g/m}^2/\text{s} \times 0.001 \text{ kg/g} \\
 &\quad \times 10,000 \text{ m}^2/\text{hectare} \\
 &\quad \times 3,600 \text{ sec/hr} \\
 &\quad \times 8,760 \text{ hr/yr} = \text{kg/ha/yr} \\
 &\text{or} \\
 &\text{g/m}^2/\text{s} \times 3.154\text{E}+08 = \text{kg/ha/yr}
 \end{aligned}$$

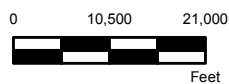
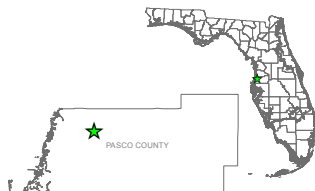
^b Deposition analysis thresholds (DAT) provided by the U.S. Fish and Wildlife Service, January 2002.

FIGURES



LEGEND

★ Project Location



REFERENCE(S)

PROJECT LOCATION, GOLDER ASSOCIATES INC., 2017

CLIENT

SHADY HILLS ENERGY CENTER, LLC

PROJECT

SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)
PSD / AIR CONSTRUCTION PERMIT APPLICATION

TITLE

GENERAL LOCATION MAP

CONSULTANT



YYYY-MM-DD 2018-01-18

DESIGNED NRL

PREPARED NRL

REVIEWED SM

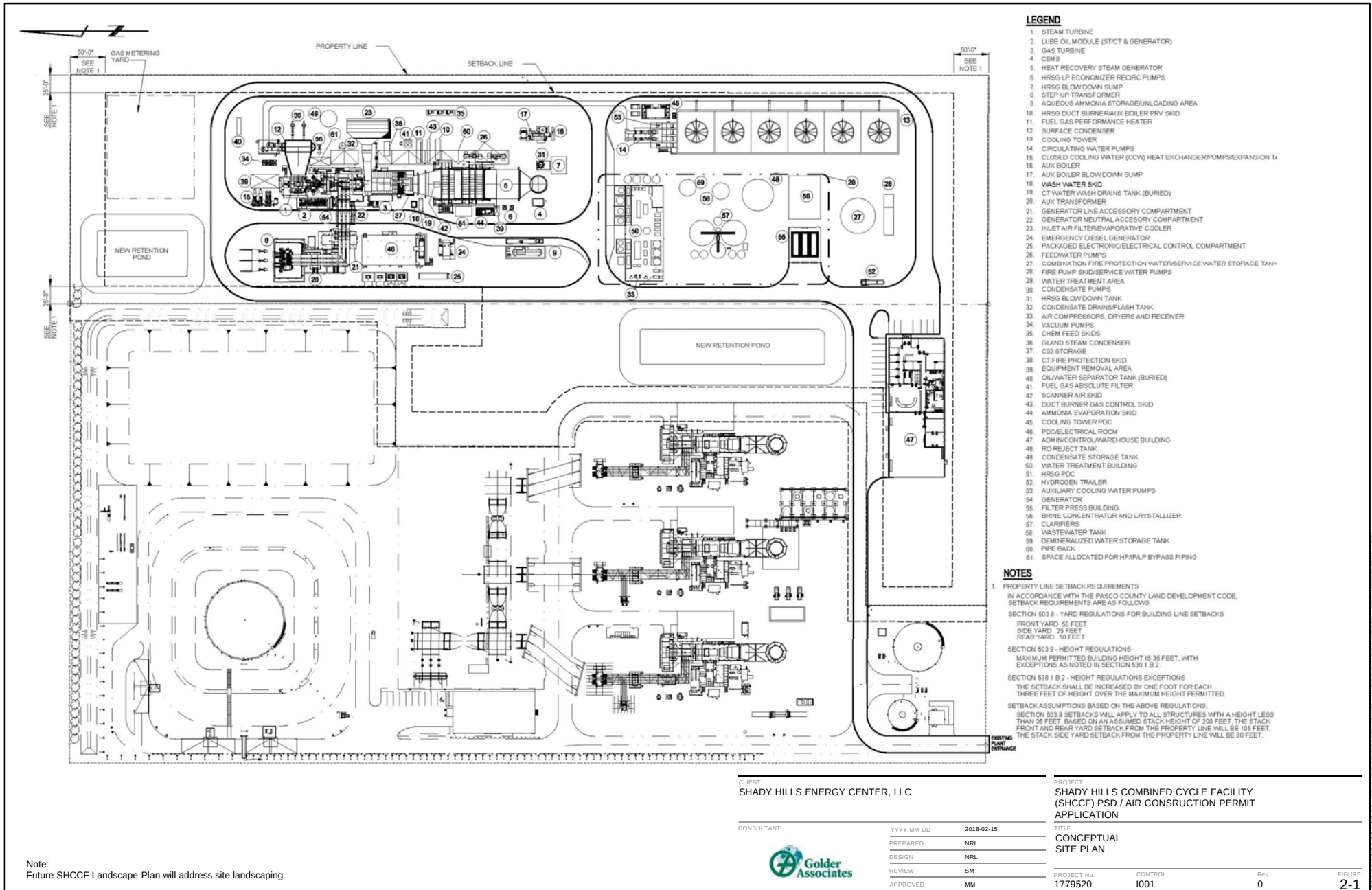
APPROVED MM

PROJECT NO.
1779520

CONTROL
I002

REV.
0

FIGURE
1-1



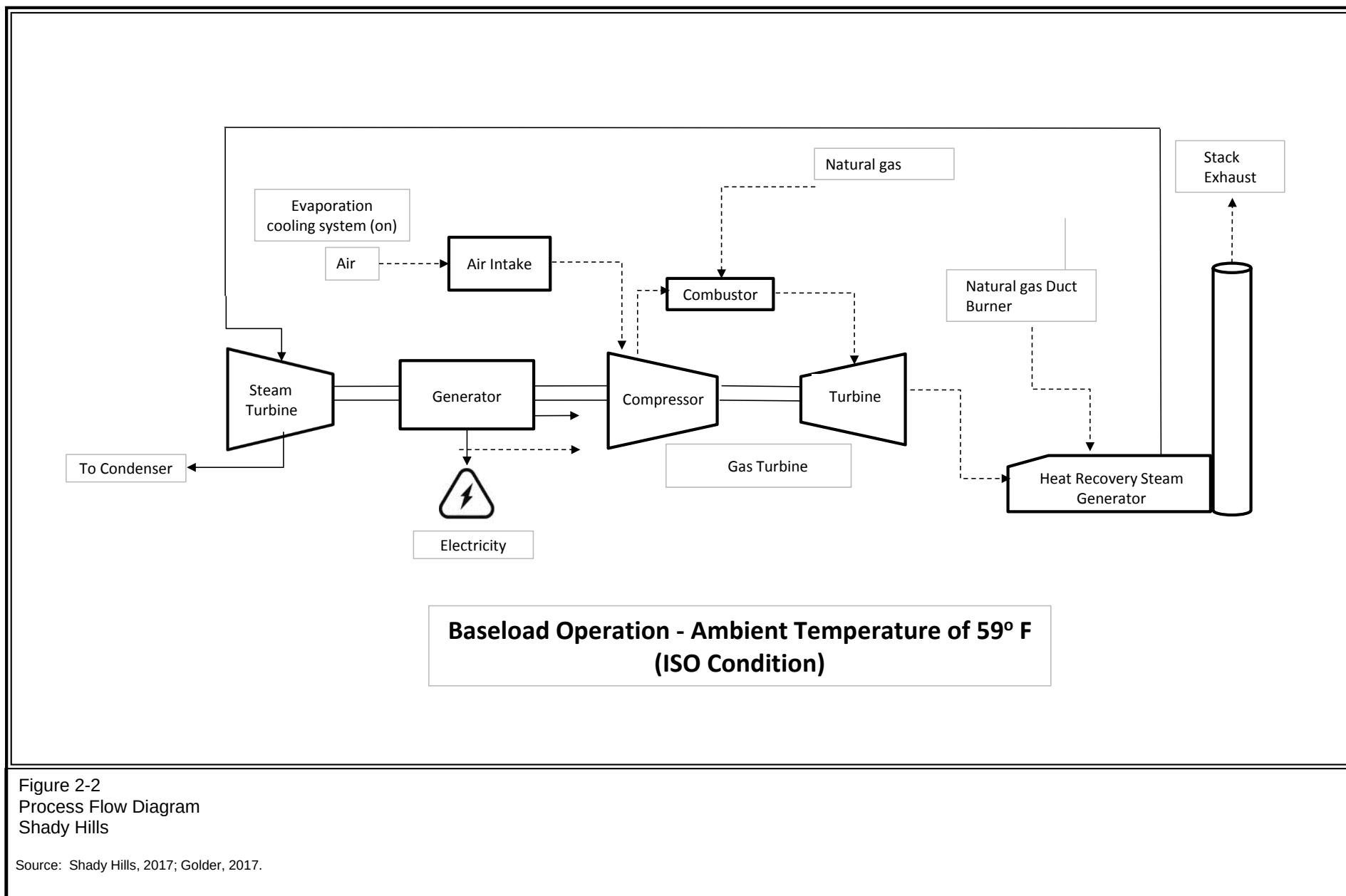
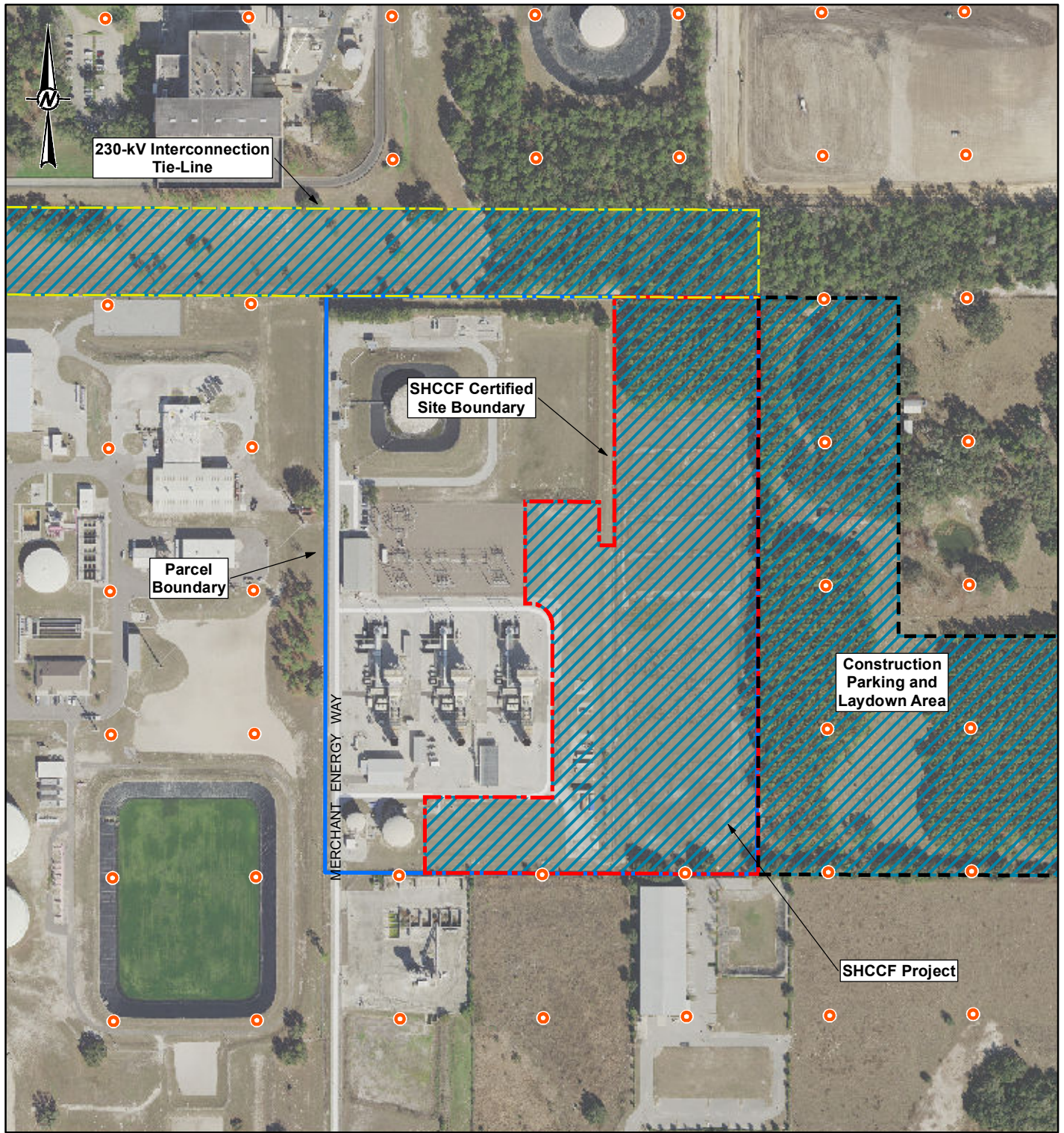


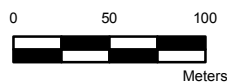
Figure 2-2
Process Flow Diagram
Shady Hills

Source: Shady Hills, 2017; Golder, 2017.



LEGEND

- Receptors
- ▨ SHCCF Project
- - - SHCCF Certified Site Boundary
- - - 230-kV Interconnection Tie-Line
- - - Construction Parking and Laydown Area
- Parcel Boundary



REFERENCE(S)

SHCCF PROJECT, CERTIFIED SITE BOUNDARY, TRANSMISSION LINE TIE-IN CORRIDOR, POWER ENGINEERS AND GOLDER ASSOCIATES INC., 2017-2018
RECEPTORS, GOLDER ASSOCIATES INC., 2018

CLIENT

SHADY HILLS ENERGY CENTER, LLC

PROJECT

SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)
PSD / AIR CONSTRUCTION PERMIT APPLICATION

TITLE

NEAR-FIELD RECEPTORS USED IN AIR QUALITY ANALYSIS

CONSULTANT



YYYY-MM-DD 2018-02-15

DESIGNED NRL

PREPARED NRL

REVIEWED SM

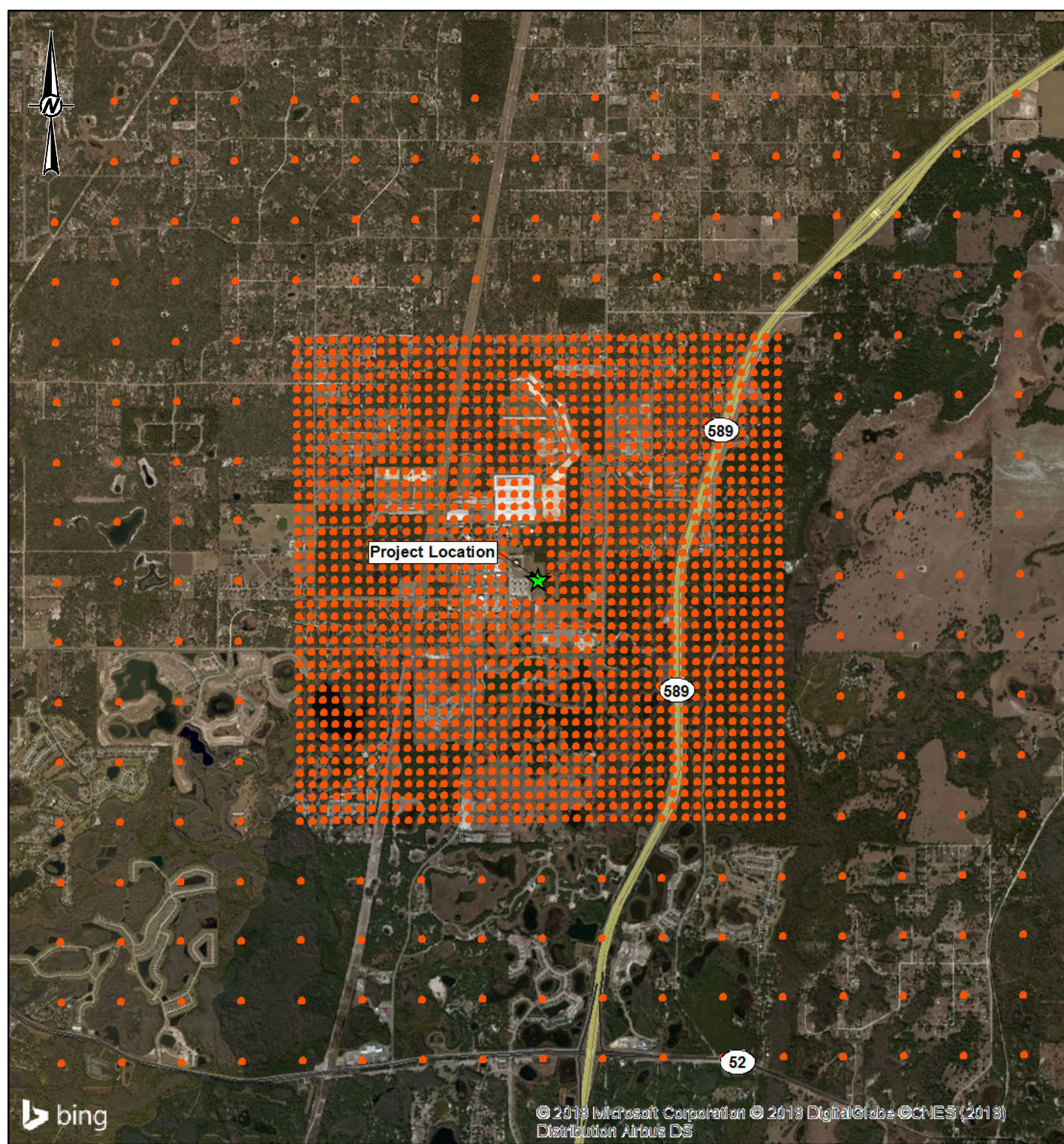
APPROVED KFK

PROJECT NO.
1779520

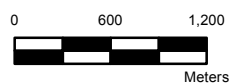
CONTROL
1003

REV.
0

FIGURE
6-1



LEGEND



REFERENCE(S)
RECEPTORS, GOLDBER ASSOCIATES INC., 2018

CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)
PSD / AIR CONSTRUCTION PERMIT APPLICATION

TITLE
**FULL RECEPTOR GRID
USED IN AIR QUALITY ANALYSIS**

CONSULTANT

YYYY-MM-DD 2018-01-18

DESIGNED NRL

PREPARED	NRL
----------	-----

REVIEWED SM

APPROVED KFK

PROJECT NO.
1779520

CONTROL
I004REV.
0FIGURE
6-2

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

Figure 7-1 020518.txt

Figure 7-1. VISCREEN Level I Modeling Results

Visual Effects Screening Analysis for
Source: SHADY HILLS CC CT
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***
Input Emissions for

Particulates	14.80	LB /HR
NOx (as NO2)	28.10	LB /HR
Primary NO2	0.00	LB /HR
Soot	0.00	LB /HR
Primary SO4	4.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	177.80 km
Source-Observer Distance:	28.20 km
Min. Source-Class I Distance:	28.20 km
Max. Source-Class I Distance:	46.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	152.	46.0	17.	2.00	3.172*	0.05	-0.062*
SKY	140.	152.	46.0	17.	2.00	1.193	0.05	-0.040
TERRAIN	10.	84.	28.2	84.	2.00	6.213*	0.05	0.044
TERRAIN	140.	84.	28.2	84.	2.00	0.478	0.05	0.006

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	17.121*	0.05	0.360*
SKY	140.	0.	1.0	168.	2.00	5.934*	0.05	-0.201*
TERRAIN	10.	0.	1.0	168.	2.00	30.053*	0.05	0.330*
TERRAIN	140.	0.	1.0	168.	2.00	7.714*	0.05	0.181*

Figure 7-1
VISCREEN Level I Modeling Results

Golder, 2018.



Figure 7-2 020518.txt

Figure 7-2. VISCREEN Level 2 Modeling Results

Visual Effects Screening Analysis for
 Source: SHADY HILLS CC CT
 Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***
 Input Emissions for

Particulates	14.80	LB /HR
NOx (as NO2)	28.10	LB /HR
Primary NO2	0.00	LB /HR
Soot	0.00	LB /HR
Primary SO4	4.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	86.70 km
Source-Observer Distance:	28.20 km
Min. Source-Class I Distance:	28.20 km
Max. Source-Class I Distance:	46.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
 Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	150.	43.9	19.	2.00	1.261	0.05	0.020
SKY	140.	150.	43.9	19.	2.00	0.589	0.05	-0.022
TERRAIN	10.	84.	28.2	84.	2.00	2.643*	0.05	0.024
TERRAIN	140.	84.	28.2	84.	2.00	0.343	0.05	0.008

Maximum Visual Impacts OUTSIDE Class I Area
 Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	6.019*	0.05	0.096*
SKY	140.	0.	1.0	168.	2.00	2.096*	0.05	-0.087*
TERRAIN	10.	0.	1.0	168.	2.00	12.851*	0.05	0.147*
TERRAIN	140.	0.	1.0	168.	2.00	3.596*	0.05	0.119*

Figure 7-2
 VISCREEN Level 2 Modeling Results

Golder, 2018.



APPENDIX A

EXPECTED PERFORMANCE, STACK AND EMISSION INFORMATION FOR GE 7HA COMBUSTION TURBINE/HRSG

Table A-1: Design Informtaion and Stack Parameters
GE7HA.02 SS, 1X1 Combnted Cycle Combustion Turbine, HRSG with Duct Burner, Natural Gas Firing, SCR

Parameter	Baseload and DB Firing Ambient Temperature			Baseload Ambient Temperature			MECL Load Ambient Temperature		
	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F
<u>Combustion Turbine Performance</u>									
CT Load	BASE	BASE	BASE	BASE	BASE	BASE	0.28	0.25	0.375
Net Power Output (MW)	--	--	--	--	--	--	--	--	--
Net Heat Rate (Btu/kWh, LHV)	--	--	--	--	--	--	--	--	--
Net Heat Rate (Btu/kWh, HHV)	--	--	--	--	--	--	--	--	--
Heat Input (MMBtu/hr, LHV)	3,338.0	3,229.5	3,024.0	3,338.0	3,266.9	3,151.0	1,383.0	1,292.4	1,495.4
(MMBtu/hr, HHV)	3,700.9	3,580.6	3,352.8	3,700.9	3,622.1	3,493.6	1,533.4	1,432.9	1,658.0
Evaporative Cooler Status	off	off	off	off	ON	ON	off	off	off
Relative Humidity (%)	60	60	60	60	60	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,612.0	20,612.0	20,612.0	20,612.0	20,612.0	20,612.0	20,612.0	20,612.0	20,612.0
(Btu/lb, HHV)	22,853.0	22,853.0	22,853.0	22,853.0	22,853.0	22,853.0	22,853.0	22,853.0	22,853.0
(HHV/LHV)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
<u>Duct Burner (DB)</u>									
Heat Input (MMBtu/hr, LHV)	137.7	131.0	188.3	0.0	0.0	0.0	0	0	0
(MMBtu/hr, HHV)	152.7	145.2	208.8	0.0	0.0	0.0	0.0	0.0	0.0
<u>Fuel Usage</u>									
Heat content (Btu/cf, LHV)	913	913	913	913	913	913	913	913	913
Fuel density (lb/ft ³)	0.0443	0.0443	0.0443	0.0443	0.0443	0.0443	0.0443	0.0443	0.0443
Fuel usage - CT (lb/hr)	161,944	156,680	146,712	161,944	158,496	152,873	67,098	62,701	72,551
Fuel usage - DB (lb/hr)	6.77	6.43	9.25	0	0	0	0	0	0
Fuel usage -CT (cf/hr)	3,654,240	3,535,457	3,310,529	3,654,240	3,576,434	3,449,554	1,514,067	1,414,835	1,637,097
Fuel usage -DB (cf/hr)	150,775	143,369	206,168	0	0	0	0	0	0
Total fuel usage -CT&DB (cf/hr)	3,805,015	3,678,827	3,516,697	3,654,240	3,576,434	3,449,554	1,514,067	1,414,835	1,637,097
<u>HRSG Stack</u>									
HRSG - Stack Height (feet)	149	149	149	149	149	149	149	149	149
Diameter (feet)	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6	25.6
<u>HRSG Stack Flow Conditions</u>									
Velocity (ft/sec) = Volume flow (acfm) / [((diameter) ² /4) x 3.14159] / 60 sec/min									
Mass flow (lb/hr)	6,332,600.0	6,082,600.0	5,762,400.0	6,325,600.0	6,129,100.0	5,934,200.0	3,060,800.0	2,986,400.0	3,325,300.0
HRSG Stack Temperature (°F)	159.7	161.1	167.3	165.7	166.1	175.0	151.3	151.9	161.6
Moisture (% Vol.)	9.3	10.0	12.2	8.9	9.9	12.1	7.7	8.0	10.5
Oxygen (% Vol.)	10.9	10.7	10.2	11.3	11.0	10.7	12.6	12.9	12.2
Molecular weight	28.4	28.3	28.1	28.4	28.3	28.0	28.5	28.4	28.2
Volume flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585	800,147	782,839	893,673
Velocity (ft/sec)- calculated	54.6	52.7	50.9	55.0	53.5	53.0	25.9	25.4	29.0

Note: Universal gas constant = 1,542.7 ft-lb(force)/°R; atmospheric pressure = 2,115.4 lb(force)/ft² (@14.671 psia).

Source: GE, 2018; Golder, 2018.

Table A-2: Maximum Emissions for Criteria Pollutants
GE 7HA.02 SS, 1X1 Combined Cycle Combustion Turbnie, HRSG with Duct Burner, Natural Gas Firing, SCR

Parameter	Baseload and DB Firing Ambient Temperature			Baseload Ambient Temperature			MECL Load Ambient Temperature		
	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F
<u>Particulate Matter from CT and DB</u>									
Total HRSG stack emission rate (lb/hr)	14.6	14.4	14.8	12.9	12.8	12.7	10.6	10.4	10.7
<u>Sulfur Dioxide</u>									
$SO_2 \text{ (lb/hr)} = \text{Natural gas (scf/hr)} \times \text{sulfur content (gr/100 scf)} \times 1 \text{ lb/7000 gr} \times (\text{lb } SO_2 \text{ /lb S}) / 100$									
Fuel use (cf/hr)	3,805,015	3,678,827	3,516,697	3,654,240	3,576,434	3,449,554	1,514,067	1,414,835	1,637,097
Sulfur content (grains/ 100 cf)	2	2	2	2	2	2	2	2	1.2
lb SO ₂ /lb S (64/32)	2	2	2	2	2	2	2	2	2
HRSG stack emission rate (lb/hr)	21.7	21.0	20.1	20.9	20.4	19.7	8.7	8.1	5.6
Vendor	21.7	21.0	20.1	20.8	20.4	19.7	8.7	8.1	9.3
<u>Nitrogen Oxides</u>									
$Oxygen \text{ (}\%, \text{ dry)}(O_2 \text{ dry)} = Oxygen \text{ (}\%)/[1\text{-Moisure (}\%)]$									
$NO_x \text{ (ppmv actual)} = NO_x \text{ (ppmd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times [1\text{- Moisture(}\%)/100]$									
$NO_x \text{ (lb/hr)} = NO_x \text{ (ppm actual)} \times Volume \text{ flow (acfm)} \times 46 \text{ (mole. wgt NO}_x) \times 2112.5 \text{ lb/ft}^2 \text{ (pressure) / [1545.4 (gas constant, R) x Actual Temp. (}^\circ\text{R)]} \times 60 \text{ min/hr}$									
Basis, ppm actual	2.7	2.8	2.8	2.6	2.7	2.6	2.3	2.1	2.2
Basis, ppmvd @15% O ₂	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Moisture (%)	9.29	9.97	12.20	8.93	9.86	12.10	7.71	8.04	10.50
Oxygen (%)	10.90	10.70	10.20	11.30	11.00	10.70	12.60	12.90	12.20
Oxygen (%) dry	12.02	11.88	11.62	12.41	12.20	12.17	13.65	14.03	13.63
Turbine Flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585	800,147	782,839	893,673
Turbine Flow (acfm), dry	1,527,125	1,463,256	1,377,068	1,545,229	1,488,128	1,437,679	738,455	719,899	799,837
Turbine Exhaust Temperature (°F)	159.7	161.1	167.3	165.7	166.1	175.0	151.3	151.9	161.6
Calculated HRSG stack emission rate (lb/hr)	28.05	27.21	26.11	26.87	26.48	25.31	11.22	10.36	11.98
Vendor	28.1	27.1	26.0	26.9	26.3	25.4	11.1	10.4	12.0
<u>Carbon Monoxide</u>									
$Oxygen \text{ (}\%, \text{ dry)}(O_2 \text{ dry)} = Oxygen \text{ (}\%)/[1\text{-Moisure (}\%)]$									
$CO \text{ (ppmv wet or actual)} = CO \text{ (ppmvd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times [1\text{- Moisture(}\%)/100]$									
$CO \text{ (lb/hr)} = CO \text{ (ppm actual)} \times Volume \text{ flow (acfm)} \times 28 \text{ (mole. wgt CO)} \times 2112.5 \text{ lb/ft}^2 \text{ (pressure) / [1545.4 (gas constant, R) x Actual Temp. (}^\circ\text{R)]} \times 60 \text{ min/hr}$									
Basis, ppm actual	7.96	8.02	9.02	5.64	5.71	5.59	8.05	7.60	7.83
Basis, ppmvd @15% O ₂	5.8	5.8	6.5	4.3	4.3	4.3	7.1	7.1	7.1
Moisture (%)	9.29	9.97	12.20	8.93	9.86	12.10	7.71	8.04	10.50
Oxygen (%)	10.90	10.70	10.20	11.30	11.00	10.70	12.60	12.90	12.20
Oxygen (%) dry	12.02	11.88	11.62	12.41	12.20	12.17	13.65	14.03	13.63
Turbine Flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585	800,147	782,839	893,673
Turbine Flow (acfm), dry	1,527,125	1,463,256	1,377,068	1,545,229	1,488,128	1,437,679	738,455	719,899	799,837
Turbine Exhaust Temperature (°F)	159.7	161.1	167.3	165.7	166.1	175.0	151.3	151.9	161.6
Calculated HRSG stack emission rate (lb/hr)	49.77	48.28	51.89	35.16	34.66	33.13	24.24	22.38	25.89
Vendor	49.8	48.2	51.6	35.2	34.5	33.2	24.1	22.5	26.0
<u>Volatile Organic Compounds</u>									
$Oxygen \text{ (}\%, \text{ dry)}(O_2 \text{ dry)} = Oxygen \text{ (}\%)/[1\text{-Moisure (}\%)]$									
$VOC \text{ (ppmv wet or actual)} = VOC \text{ (ppmvd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times [1\text{- Moisture(}\%)/100]$									
$VOC \text{ (lb/hr)} = VOC \text{ (ppm actual)} \times Volume \text{ flow (acfm)} \times 16 \text{ (mole. wgt CH}_4) \times 2112.5 \text{ lb/ft}^2 \text{ (pressure) / [1545.4 (gas constant, R) x Actual Temp. (}^\circ\text{R)]} \times 60 \text{ min/hr}$									
Basis, ppm actual	2.73	2.75	2.76	1.40	1.41	1.39	1.41	1.39	1.39
Basis, ppmvd @15% O ₂	2.0	2.0	2.0	1.1	1.1	1.1	1.2	1.3	1.3
Moisture (%)	9.29	9.97	12.20	8.93	9.86	12.10	7.71	8.04	10.50
Oxygen (%) wet	10.90	10.70	10.20	11.30	11.00	10.70	12.60	12.90	12.20
Oxygen (%) dry	12.02	11.88	11.62	12.41	12.20	12.17	13.65	14.03	13.63
Turbine Flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585	800,147	782,839	893,673
Turbine Flow (acfm), dry	1,527,125	1,463,256	1,377,068	1,545,229	1,488,128	1,437,679	738,455	719,899	799,837
Turbine Exhaust Temperature (°F)	159.7	161.1	167.3	165.7	166.1	175.0	151.3	151.9	161.6
Calculated HRSG stack emission rate (lb/hr)	9.76	9.46	9.08	5.00	4.88	4.71	2.42	2.34	2.63
Vendor	9.8	9.5	9.1	5.0	4.9	4.8	2.4	2.4	2.7
<u>Sulfuric Acid Mist</u>									
Sulfuric Acid Mist (lb/hr)= SO ₂ emission (lb/hr) x Conversion to H ₂ SO ₄ (% by weight)/100									
CT SO ₂ emission rate (lb/hr)	21.7	21.0	20.1	20.8	20.4	19.7	8.7	8.1	9.3
Vendor	2.7	2.6	2.5	2.6	2.5	2.4	1.1	1.0	1.2
<u>Ammonia</u>									
$Oxygen \text{ (}\%, \text{ dry)}(O_2 \text{ dry)} = Oxygen \text{ (}\%)/[1\text{-Moisure (}\%)]$									
$NH_3 \text{ (ppmv wet or actual)} = NH_3 \text{ (ppmvd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times [1\text{- Moisture(}\%)/100]$									
$NH_3 \text{ (lb/hr)} = NH_3 \text{ (ppm actual)} \times Volume \text{ flow (acfm)} \times 17 \text{ (mole. wgt NH}_3) \times 2112.5 \text{ lb/ft}^2 \text{ (pressure) / [1545.4 (gas constant, R) x Actual Temp. (}^\circ\text{R)]} \times 60 \text{ min/hr}$									
Basis, ppm actual	6.83	6.88	6.91	6.55	6.64	6.50	5.67	5.36	5.51
Basis, ppmvd @15% O ₂	5	5	5	5	5	5	5	5	5
Moisture (%)	9.29	9.97	12.20	8.93	9.86	12.10	7.71	8.04	10.50
Oxygen (%)	10.90	10.70	10.20	11.30	11.00	10.70	12.60	12.90	12.20
Oxygen (%) dry	12.02	11.88	11.62	12.41	12.20	12.17	13.65	14.03	13.63
Turbine Flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585	800,147	782,839	893,673
Turbine Flow (acfm), dry	1,527,125	1,463,256	1,377,068	1,545,229	1,488,128	1,437,679	738,455	719,899	799,837
Turbine Exhaust Temperature (°F)	159.70	161.10	167.30	165.70	166.10	175.00	151.30	151.90	161.60
Calculated HRSG stack emission rate (lb/hr)	25.91	25.14	24.12	24.82	24.47	23.39	10.36	9.57	11.07
Vendor	25.1	25.1	24.0	24.9	24.4	23.5	10.3	9.6	11.1

Note: ppmvd= parts per million, volume dry; O₂= oxygen.
Source: GE, 2018; Golder, 2018.

Table A-3: Regulated and Hazardous Air Pollutant Emission Factors and Emissions
GE 7HA.02 SS, 1X1 Combined Cycle Combustion Turbine, Natural Gas Firing

Parameter	Hourly Emission Rate firing Natural Gas at Base Load (lb/hr) ⁽¹⁾		Maximum Annual Emissions (TPY) ⁽²⁾
Ambient Temperature (°F):	59 °F	59 °F w/DB	59 °F
CTG Heat Input (MMBtu/hr):	3,622	3,581	1
Duct Burner Heat Input (MMBtu/hr)		145.2	CT/HRSG
<u>HAPs (Section 112(b) of Clean Air Act)</u>			
1,3-Butadiene	0.001558	0.001540	0.007
Acetaldehyde	0.1449	0.1432	0.635
Acrolein	0.0232	0.0229	0.102
Benzene	0.0435	0.0433	0.190
Ethylbenzene	0.1159	0.1146	0.508
Formadehyde	0.807	0.796	3.535
Naphthalene	0.00471	0.00474	0.021
Polycyclic Aromatic Hydrocarbons (PAH) (3)	0.00797	0.00788	0.035
Propylene Oxide	0.1050	0.1038	0.460
Toluene	0.1195	0.1186	0.524
Xylene	0.232	0.229	1.015
Antimony	0.0	0.0	0.00
Arsenic	0.0	0.0	0.00
Beryllium	0.0	0.0	0.00
Cadmium	0.0	0.0	0.00
Chromium	0.0	0.0	0.00
Lead	0.0	0.0	0.00
Manganese	0.0	0.0	0.00
Mercury	3.62E-06	3.58E-06	1.59E-05
Nickel	0.0	0.0	0.00
Selenium	0.0	0.0	0.00
HAPs (Total)	1.605	1.587	7.0

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

(See Table A5 for Duct Firing Emissions using AP-42, Section 1.4, Table 1.4-3)

Emission Factors	Value	Reference
1,3-Butadiene (a)	0.43 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Acetaldehyde	40 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Acrolein	6.4 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Benzene	12 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Ethylbenzene	32 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Formadehyde	0.091 ppmvd @15% O ₂	(see Table A4)
Naphthalene	1.3 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)	2.2 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Propylene Oxide (a)	29 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Toluene	33 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000. Database
Xylene	64 lb/10 ¹² Btu;	AP-42, Table 3.1-3. EPA 2000
Antimony	0.00	
Arsenic	0.00	
Beryllium	0.00	
Cadmium	0.00	
Chromium	0.00	
Lead	0.00	
Manganese	0.00	
Mercury	1.00E-03	
Nickel	0.00	
Selenium	0.00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

(2) Annual emissions based on ambient temperature of 59 °F at maximum hourly emission rate of pollutant and 8,860 hours/year.

Note: Higher hourly rate for CTG/DB CT= 4,760 hr/yr
CT with DB:= 4,000 hr/yr

Table A-4: Formaldehyde Emissions
GE 7HA.02 XX, 1X1 Combined Cycle Combustion Turbine, Natural Gas Firing

Parameter	CT at Baseload and Duct Firing Turbine Inlet Temperature			CT Only at Baseload Turbine Inlet Temperature		
	30 °F	59 °F	95 °F	30 °F	59 °F	95 °F
Formaldehyde (CH ₂ O) MW = 30						
$CH_2O \text{ (lb/hr)} = CH_2O \text{ (ppm actual)} \times \text{Volume flow (acfm)} \times 46 \text{ (mole. wgt NO}_x) \times 2116.8 \text{ lb/ft}^2 \text{ (pressure)} /$ $[1545.7 \text{ (gas constant, R)} \times \text{Actual Temp. (°R)}] \times 60 \text{ min/hr}$						
$CH_2O \text{ (ppm actual)} = CH_2O \text{ (ppmd @ 15\%O}_2) \times [(20.9 - O_2 \text{ dry})/(20.9 - 15)] \times (1 - \text{Moisture}(\%)/100)$						
$Oxygen \text{ (\%, dry)}(O_2 \text{ dry)} = Oxygen \text{ (\%)} / [1 - \text{Moisure (\%)}]$						
Basis, ppm actual- calculated	0.124	0.125	0.126	0.119	0.121	0.118
CT, ppmvd @15% O ₂ ^a	0.091	0.091	0.091	0.091	0.091	0.091
Moisture (%)	9.29	9.97	12.20	8.93	9.86	12.10
Oxygen (%)	10.90	10.70	10.20	11.30	11.00	10.70
Oxygen (%) dry	12.02	11.88	11.62	12.41	12.20	12.17
Exhaust Flow (acfm)	1,683,524	1,625,298	1,568,415	1,696,749	1,650,907	1,635,585
Exhaust Temperature (°F)	160	161	167	166	166	175
CT Emission rate (lb/hr)	0.832	0.807	0.774	0.797	0.786	0.751
CT Emission rate (lb/10 ¹² Btu) (HHV)	224.8	225.4	231.0	519.7	548.2	452.9

Note: ppmvd= parts per million, volume dry; O₂= oxygen.

^a Emission factor based on past PSD projects with GE 7HA combined-cycle combustion turbines.

**Table A-5: Hazardous Air Pollutant Emissions for Auxiliary Boiler
Shady Hills Combined Cycle Facility**

Parameter/Pollutant	Units	Value	Auxiliary Boiler Annual Emission Basis	Duct Firing Hourly Basis
Number			1	1
Heat Input Rate	MMBtu/hr	per unit	60	145.2
Fuel use	scf/hr	per unit	58,824	143,369
Maximum operation/yr	hours	per unit	2,000	4,000
Heat Input Rate/annual	MMBtu/yr	all units	NA	NA
Fuel use/annual	MMscf/yr	all units	117.6	573.5
<u>HAPs [Section 112(b) of Clean Air Act]</u>	<u>Emission Factor ^a</u>		<u>Emissions (TPY)</u>	<u>Emissions (lb/hr)</u>
Benzene	lb/10 ⁶ scf	2.10E-03	1.24E-04	3.01E-04
Formaldehyde	lb/10 ⁶ scf	7.50E-02	4.41E-03	1.08E-02
Naphthalene	lb/10 ⁶ scf	6.10E-04	3.59E-05	8.75E-05
Toluene	lb/10 ⁶ scf	3.40E-03	2.00E-04	4.87E-04
Dichlorobenzene	lb/10 ⁶ scf	1.20E-03	7.06E-05	1.72E-04
Acenaphthene	lb/10 ⁶ scf	1.80E-06	1.06E-07	2.58E-07
Acenaphthylene	lb/10 ⁶ scf	1.80E-06	1.06E-07	2.58E-07
Acetaldehyde	--	NA	NA	NA
Acrolein	--	NA	NA	NA
Anthracene	lb/10 ⁶ scf	2.40E-06	1.41E-07	3.44E-07
Benzo(a)anthracene	lb/10 ⁶ scf	1.80E-06	1.06E-07	2.58E-07
Benzene	lb/10 ⁶ scf	2.10E-03	1.24E-04	3.01E-04
Benzo(g,h,i)perylene	lb/10 ⁶ scf	1.20E-06	7.06E-08	1.72E-07
Chrysene	lb/10 ⁶ scf	1.80E-06	1.06E-07	2.58E-07
Dibenzo(a,h)anthracene	lb/10 ⁶ scf	1.20E-06	7.06E-08	1.72E-07
Ethylbenzene	--	NA	NA	NA
Fluoranthene	lb/10 ⁶ scf	3.00E-06	1.76E-07	4.30E-07
Fluorene	lb/10 ⁶ scf	2.80E-06	1.65E-07	4.01E-07
Indeno(1,2,3-cd)pyrene	lb/10 ⁶ scf	1.80E-06	1.06E-07	2.58E-07
Phenanthrene	lb/10 ⁶ scf	1.70E-05	1.00E-06	2.44E-06
Phenol	--	NA	NA	NA
Pyrene	lb/10 ⁶ scf	5.00E-06	2.94E-07	7.17E-07
Xylene	--	NA	NA	NA
1,3-Butadiene	--	NA	NA	NA
Polycyclic Aromatic Hydrocarbons (PAH)	--	NA	NA	NA
Propylene Oxide	--	NA	NA	NA
Arsenic	lb/10 ⁶ scf	2.00E-04	1.18E-05	2.87E-05
Beryllium	lb/10 ⁶ scf	1.20E-05	7.06E-07	1.72E-06
Cadmium	lb/10 ⁶ scf	1.10E-03	6.47E-05	1.58E-04
Chromium	lb/10 ⁶ scf	1.40E-03	8.24E-05	2.01E-04
Cobalt	lb/10 ⁶ scf	8.40E-05	4.94E-06	1.20E-05
Mercury	lb/10 ⁶ scf	2.60E-04	1.53E-05	3.73E-05
Manganese	lb/10 ⁶ scf	3.80E-04	2.24E-05	5.45E-05
Nickel	lb/10 ⁶ scf	2.10E-03	1.24E-04	3.01E-04
Selenium	lb/10 ⁶ scf	2.40E-05	1.41E-06	3.44E-06
HAPs (Total; TPY for auxiliary boiler and lb/hr for duct burner)			5.29E-03	1.29E-02

^a EPA AP-42, Section 1.4, Table 1.4-3, Natural Gas Combustion (March 1998).

**Table A-6: Hazardous Air Pollutant Emissions for Diesel-Fired Engines
Shady Hills Combined Cycle Facility**

Parameter	Units	Value	Annual Emission Basis	
			Fire Pump Engine	Emergency Generator
Number of Units			1	1
Heat Input Rate	MMBtu/hr	per unit	2.46	14.8
Maximum operation/yr	hours	per unit	500	500
Heat Input Rate/annual	MMBtu/yr	all units	1232.5	7,409.1
<u>HAPs [Section 112(b) of Clean Air Act]</u>	<u>Emission Factor ^{a, b}</u>		<u>Emissions (TPY)</u>	
Acrolein	lb/MMBtu	7.88E-06	4.86E-06	2.92E-05
Acetaldehyde	lb/MMBtu	2.52E-05	1.55E-05	9.34E-05
Benzene	lb/MMBtu	7.76E-04	4.78E-04	2.87E-03
Formaldehyde	lb/MMBtu	7.89E-05	4.86E-05	2.92E-04
Naphthalene	lb/MMBtu	1.30E-04	8.01E-05	4.82E-04
Toluene	lb/MMBtu	2.81E-04	1.73E-04	1.04E-03
Xylene	lb/MMBtu	1.93E-04	1.19E-04	7.15E-04
Acenaphthene	lb/MMBtu	4.68E-06	2.88E-06	1.73E-05
Acenaphthylene	lb/MMBtu	9.23E-06	5.69E-06	3.42E-05
Anthracene	lb/MMBtu	1.23E-06	7.58E-07	4.56E-06
Benzo(a)anthracene	lb/MMBtu	6.22E-07	3.83E-07	2.30E-06
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	6.84E-07	4.11E-06
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	1.34E-07	8.08E-07
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	3.43E-07	2.06E-06
Benzo(a)pyrene	lb/MMBtu	2.57E-07	1.58E-07	9.52E-07
Chrysene	lb/MMBtu	1.53E-06	9.43E-07	5.67E-06
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	2.13E-07	1.28E-06
Fluoranthene	lb/MMBtu	4.03E-06	2.48E-06	1.49E-05
Fluorene	lb/MMBtu	4.47E-06	2.75E-06	1.66E-05
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	2.55E-07	1.53E-06
Phenanthrene	lb/MMBtu	1.05E-06	6.47E-07	3.89E-06
Pyrene	lb/MMBtu	3.71E-06	2.29E-06	1.37E-05
Arsenic	lb/10 ¹² Btu	4.0	2.46E-06	1.48E-05
Beryllium	lb/10 ¹² Btu	3.0	1.85E-06	1.11E-05
Cadmium	lb/10 ¹² Btu	3.0	1.85E-06	1.11E-05
Chromium	lb/10 ¹² Btu	3.0	1.85E-06	1.11E-05
Lead	lb/10 ¹² Btu	9.0	5.55E-06	3.33E-05
Mercury	lb/10 ¹² Btu	3.0	1.85E-06	1.11E-05
Manganese	lb/10 ¹² Btu	6.0	3.70E-06	2.22E-05
Nickel	lb/10 ¹² Btu	3.0	1.85E-06	1.11E-05
Selenium	lb/10 ¹² Btu	15.0	9.24E-06	5.56E-05
HAPs (Total)			9.70E-04	5.83E-03

^a EPA AP-42, Section 3.4, Large Stationary Diesel And All Stationary Dual-fuel Engines (October 1996)

^b EPA AP-42, Section 1.3, Fuel Oil Combustion for metals (September 1998).

Table A-7: Greenhouse Gas (GHG) Emissions
GE 7HA.02 SS, 1X1 Combined Cycle Combustion Turbine, Natural Gas Firing
Shady Hills Combined Cycle Facility

Pollutant	Emission Rate firing Natural Gas at Base Load (lb/hr) ⁽¹⁾		Annual Emissions (TPY) ⁽²⁾	Annual Emissions (TPY of CO ₂ e) ⁽³⁾
	59 °F	59 °F w/DB	59 °F	59 °F
Ambient Temperature (°F):	59 °F	59 °F w/DB	59 °F	59 °F
HIR (MMBtu/hr):	3,622	3,726	CT/HRSG	CT/HRSG
CO ₂	430,512	442,837	1,910,293	1,910,293
CH ₄	7.98	8.21	35.42	886
N ₂ O	0.80	0.82	3.54	1056
Total GHGs =		442,846	1,910,332	1,912,234

(1) CO₂ based on 40 CFR Part 75 Appendix G, Section 2.3.

CH₄ and N₂O based on Table C-2, Subpart C, 40 CFR 98. Emission factors in lb/MMBtu

Pollutant	Natural Gas
CO ₂	118.9
CH ₄	0.002204
N ₂ O	0.0002204

(2) Annual emissions based on ambient temperature of 59 °F firing natural gas for following hours:

CT:	4,760 hr/yr
CT with DB:	4,000 hr/yr

(3) CH₄ and N₂O are multiplied by CO₂e factor based on 40 CFR Part 98.

Pollutant	CO ₂ e Factor
CH ₄	25
N ₂ O	298

**Table A-8: Greenhouse Gas (GHG) Emissions - Aux Boiler, Emergency Generator, Fire Pump Engine
Shady Hills Combined Cycle Facility**

Emission Unit/ Pollutant	Maximum Heat Input (MMBtu/hr)	Emission Factor ^a (lb/MMBtu)	Hourly GHG Emissions (lb/hr)	Operating Hours	Annual GHG Emissions (TPY)	Annual GHG Emissions ^b (TPY of CO ₂ e)
Auxiliary Boiler (Natural Gas)						
CO ₂	60.0	116.9	7,011.4	2,000	7,011.4	7,011.4
CH ₄	60.0	0.002204	0.132	2,000	0.132	3.306
N ₂ O	60.0	0.0002204	0.0132	2,000	0.013	3.941
						<u>7,018.6</u>
Emergency Generator (Fuel Oil)						
CO ₂	14.82	163.0	2,415.5	500	603.9	603.9
CH ₄	14.82	0.006612	0.098	500	0.024	0.61
N ₂ O	14.82	0.001322	0.020	500	0.0049	1.46
						<u>605.9</u>
Fire Pump Engine (Fuel Oil)						
CO ₂	2.46	163.0	401.8	500	100.5	100.5
CH ₄	2.46	0.006612	0.0163	500	0.00407	0.10
N ₂ O	2.46	0.001322	0.0033	500	0.00081	0.24
						<u>100.80</u>

^a Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu

Pollutant	Natural Gas	Distillate Fuel Oil
CO ₂	53.02	73.96
CH ₄	0.001	0.003
N ₂ O	0.0001	0.0006

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

^b CH₄ and N₂O are multiplied by CO₂e factor

Pollutant	CO ₂ e Factor
CH ₄	25
N ₂ O	298

**Table A-9: Estimated Greenhouse Gas (GHG) Emissions from Leaks of Natural Gas Piping Supporting the Project
Shady Hills Combined Cycle Facility**

Natural Gas Pipe Components ^a	Source Type	40 CFR Part 98 Component Equivalent (Eastern US)	Count (No.) ^a	Whole Gas Emissions ^b (scf/hr/comp)	CO ₂ ^c (TPY)	Methane ^d (TPY)	Total CO ₂ ^e (TPY) ^e
Piping to CTG	Valves & Connectors	Valve	10	0.027	1.6E-03	5.1E-02	1.29
	Instrument/Drain/Vent Valves	Pressure Relief Valve	78	0.04	1.8E-02	5.9E-01	14.87
HRSG Duct Burner Skid	Valves & Connectors	Valve	45	0.027	7.2E-03	2.3E-01	5.79
	Instrument/Drain/Vent Valves	Pressure Relief Valve	27	0.04	6.4E-03	2.1E-01	5.15
Auxiliary Boiler Burner Skid	Valves & Connectors	Valve	30	0.027	4.8E-03	1.5E-01	3.86
	Instrument/Drain/Vent Valves	Pressure Relief Valve	20	0.04	4.7E-03	1.5E-01	3.81
DB/Auxiliary Boiler PRV Skid	Valves & Connectors	Valve	6	0.027	9.6E-04	3.1E-02	0.77
	Instrument/Drain/Vent Valves	Pressure Relief Valve	14	0.04	3.3E-03	1.1E-01	2.67
Subtotal =					0.05	1.53	38.22
Natural Gas Venting ^f	Gas Vented / Event / CT (scf)	No. of Events / CT (Events/yr)	No. CTs	Total Gas Vented (scf/yr)	CO ₂ (TPY)	Methane (TPY)	Total CO ₂ ^e (TPY) ^e
	226	150	1	33900	2.29E-02	0.737	18.45
Total					0.07	2.26	56.67

Notes:

^a Estimated based on two 7F CTs with margin for design uncertainty.

^b 40 CFR Part 98 Table W-1A, Eastern US

^c Concentration of CO₂ in natural gas is defined equal to 1.1×10^{-2} (40 CFR Part 98.233). CO₂ TPY = Count x (scf/hr/comp) x 1.1×10^{-2} x (1 mol/0.7909 scf) x (44.01 g/ 1mol CO₂) x (1 lb/ 453.6 g) x 8760 hr/yr x (1 ton/2000 lb)

^d Concentration of CH₄ (Methane) in natural gas is defined equal to 0.975 (40 CFR Part 98.233)

CH₄ TPY = Count x (scf/hr/comp) x 0.975 x (1 mol/0.7909 scf) x (16 g/ 1mol CH₄) x (1 lb/ 453.6 g) x 8760 hr/yr x (1 ton/2000 lb)

^e Global Warming Potential Factors: CO₂ = 1 and CH₄ = 25

^f Based on one per month per CT.

APPENDIX B

BACT DETERMINATIONS FROM EPA RBL CLEARINGHOUSE

Table B-1: Summary of CO BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Florida							
FPL Dania Beach Energy Center	FL	12/4/2017	2-on-1 Combined Cycle with HRSG	4,015 MMBtu/hr	GCP	4.3 ppmvd @ 15% O ₂	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined Cycle CT with HRSG	3,096 MMBtu/hr	GCP	4.3 ppmvd @ 15% O ₂	BACT-PSD
Duke Energy - Citrus Combined Cycle	FL	12/1/2014	2-on-1 Combined Cycle with HRSG	270 MW	GCP	4.0 ppmvd @ 15% O ₂	AC Permit
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined Cycle CT with HRSG	250 MW	GCP	9.0 ppmvd @ 15% O ₂	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	5.0 ppmvd @ 15% O ₂	AC Permit
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	7.6 ppmvd @ 15% O ₂	AC Permit
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined Cycle CT with HRSG	265 MW	GCP	7.6 ppmvd @ 15% O ₂	AC Permit
Shady Hills GE	FL	11/13/2008	(3) GE7FA CTs	170 MW (EACH)	GCP, Clean Fuels	12.0 ppmvd	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	GCP	4.1 ppmvd @ 15% O ₂	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	05/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	GCP	8.0 ppmvd @ 15% O ₂	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	GCP	8.0 ppmvd	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	01/10/2007	Combined Cycle CT - 6 Units	2,333 MMBtu/hr	GCP	8.0 ppmvd @ 15% O ₂	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
NRG Wholesale Generation LLC	MS	4/28/2017	Combustion turbines with DB	2,126 MMBtu/hr	GCP, Catalytic Oxidation	10.0 ppmv @ 15% O ₂	BACT-PSD
Riverside Generating CO LLC	KY	9/30/2016	5 Combined Cycle Generation Turbines with DB and HRSG	2,076 MMBtu/hr	Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339 MMBtu/hr	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG	180 MW	GCP, Catalytic Oxidation	2.0 ppmvd @ 15% O ₂	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	600 MW	Oxidation Catalyst	2.0 ppmvd @ 15% O ₂	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	600 MW	Oxidation Catalyst	3.2 ppmvd @ 15% O ₂	BACT-PSD
McDonough Combined Cycle Plant	GA	1/7/2008	(6) CTs (Mitsubishi M501G) w/ DB	254 MW	Oxidation Catalyst	1.8 ppm @ 15% O ₂	BACT-PSD
Other States							
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam Generato	426 MW	GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
ST. CHARLES POWER STATION	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBtu/hr	Oxidation Catalyst, GCP	2.0 ppm @ 15% O ₂	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for DB	3961 mmBtu/hr	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED	3227 mmBtu/hr	Oxidation Catalyst	1.6 ppmvd	Unknown
Wallingford Energy, LLC	CT	5/6/2016	GE LM6000 Simplr Cycle Jet Turbine 6		Oxidation Catalyst	5.7 lb/hr	CASE-BY-CASE
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	4.0 ppm	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	Oxidation Catalyst	4.0 ppm	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	Oxidation Catalyst	0.9 ppmvd @ 15% O ₂	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	Oxidation Catalyst	1.7 ppmvd @ 15% O ₂	BACT-PSD
Colorado Bend Energy Center	TX	4/1/2015	Combined Cycle Turbine	1100 MW	Oxidation Catalyst	4.0 ppmvd @ 15% O ₂	BACT-PSD
Cedar Bayou Electric Generating Station	TX	3/31/2015	Combined Cycle Turbine	187 MW each	Oxidation catalyst	15.0 ppmvd	BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	(2) Combined Cycle Turbine	240 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Victoria Power Station	TX	12/1/2014	Combined Cycle Turbine	197 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	Combined Cycle Turbine	497 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Cedar Bayou Electric Generation Station	TX	8/29/2014	Combined Cycle Turbine	225 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	(2) Combined Cycle Turbine	274 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #1 - combined cycle	2258 MMBtu/hr	catalytic oxidizer	2.0 ppmvd	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #2 - combined cycle	2258 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Fge Texas Power I And Fge Texas Power Ii	TX	3/24/2014	Alstom Turbine	230.7 MW	Oxidation catalyst	2.0 ppmvd	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle Turbine w/ DB	2988 MMBtu/hr	Oxidation catalyst	3.3 ppmvd AT 15% O ₂	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, COMBINED CYCLE UNIT (Siemens 5000)	2267 MMBtu/hr	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Combined Cycle Turbine w/ DB	647 MMBtu/hr each	Oxidation Catalyst, GCP	4.0 ppmvd	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Combined Cycle Turbine	700 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Sand Hill Energy Center	TX	9/13/2013	Combined Cycle Turbine	173.9 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Thetford Generating Station	MI	7/25/2013	Combined Cycle Turbine w/ DB	2,587 MMBtu/hr each	Oxidation catalyst	4.0 ppmvd	BACT-PSD

Table B-1: Summary of CO BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	CO Limit	Basis
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/o DB	2,237 MMBtu/hr	GCP	9.0 ppmvd	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/ DB	2,486 MMBtu/hr	GCP	10.5 ppmvd	BACT-PSD
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	Combined Cycle Turbine w/ DB (3)	2,538 MMBtu/hr	Oxidation Catalyst	2.0 ppmvd	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	COMBUSTION TURBINE GENERATORS, (3)	3,442 MMBtu/hr	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
La Paloma Energy Center	TX	2/7/2013	(2) Combined Cycle Turbine	650 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Moxie Energy Llc/Patriot Generation Plt	PA	1/31/2013	Combined Cycle Power Blocks (2)	472 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle Turbine	180 MW	GCP	4.0 ppmvd	BACT-PSD
Deer Park Energy Center	TX	9/26/2012	Combined Cycle Turbine	180 MW	GCP	4.0 ppmvd	BACT-PSD
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	GCP	4.0 ppmvd	BACT-PSD
Palmdale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390 MW	Oxidation Catalyst, GCP	4.0 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 (w/o DB)	180 MW	Oxidation Catalyst	1.5 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 (w/ DB)	180 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Colusa Generating Station	CA	3/11/2011	Combustion Turbines (Normal Operation)	172 MW	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
Nelson Energy Center	IL	12/28/2010	Electric Generation Facility	220 MWe each		5.0 ppmvd @ 15% O ₂	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2996 MMBTU/H	Oxidation Catalyst, GCP	1.5 ppmvd	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1350 MW	Oxidation Catalyst, GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
Langley Gulch Power Plant	ID	6/25/2010	Combustion Turbine, Combined Cycle W/ Duct Burner	2375.28 MMBTU/H	Oxidation Catalyst, GCP	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 (w/o DB)	154 MW	Oxidation Catalyst	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 (w/ DB)	154 MW	Oxidation Catalyst	3.0 ppmvd	BACT-PSD
High Desert Power Project	CA	3/11/2010	Combustion Turbine Generators (Normal Operation)	190 MW	Oxidation Catalyst	4.0 ppmvd	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP	9.0 ppmvd	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		Oxidation Catalyst	2.0 ppmvd @15% O ₂	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBtu/hr	GCP	4.0 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	Oxidation Catalyst	4.0 ppmvd @ 15% O ₂	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	Oxidation Catalyst	3.0 ppmvd @ 15% O ₂	BACT-PSD
Arsenal Hill Power Plant	LA	03/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Proper Operating Practices	143.3 lb/hr	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,136 MMBtu/hr	Oxidation Catalyst	0.9 ppmvd @ 15% O ₂	BACT-PSD
Kleen Energy Systems, LLC	CT	02/25/2008	(2) CT (Siemens SGT6-5000f), DB	2,581 MMBtu/hr	Oxidation Catalyst	1.7 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC.	VA	01/14/2008	Electric Generation - Secenario 3	2,204 MMBtu/hr	GCP and Oxidation Catalyst.	1.8 ppmvd	BACT-PSD
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	Oxidation Catalyst	4.0 ppmvd @ 15% O ₂	BACT-PSD
Fairbault Energy Park	MN	06/05/2007	Combined Cycle CT W/ DB	1,758 MMBtu/hr	GCP	9.0 ppmvd	BACT-PSD
Blythe Energy Project II, LLC	CA	04/25/2007	(2) Combustion Turbines	170 MW		4.0 ppmvd	BACT-PSD
Pso Southwestern Power Plt	OK	02/09/2007	Gas-Fired Turbines		Combustion Control	25.0 ppmvd	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

Note: DB = duct burner; DLN= dry low NOx; GCP= good combustion practices

Table B-2: Summary of PM BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	PM/PM ₁₀ /PM _{2.5} Limit	Equivalent PM/PM ₁₀ /PM _{2.5} Emissions Rate	Basis
Florida								
FPL Dania Beach Energy Center	FL	12/4/2017	2-on-1 Combined Cycle with HRSG	4,015 MMBtu/hr	NG Fuel	2 gr S/100 scf		BACT-PSD
City of Tallahassee - Hopkins Generating Station	FL	9/26/2017	4 Spark ignition RICE	18.82 MW	NG Fuel	2 gr S/100 scf		BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	3-on-1 Combined-cycle CT with HRSG	3,096 MMBtu/hr	Clean fuels	2 gr S/100 scf		BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	3-on-1 Combined-cycle CT with HRSG	250 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	3-on-1 Combined-cycle CT with HRSG	265 MW	NG Fuel and GCP	2 gr S/100 scf		BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	NG Fuel	2 gr S/100 scf	0.0015 lb/MMBtu	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1765 MMBtu/hr	NG Fuel			BACT-PSD
FPL West County Energy Center	FL	1/10/2007	CC CTs - 6 Units	2,333 MMBtu/hr	NG only, GCP	2 gr S/100 scf	0.0015 lb/MMBtu	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
NRG Wholesale Generation LLC	MS	4/28/2017	Combustion turbines with DB	2,126 MMBtu/hr	NG Fuel	0.8 % by weight	20.59 lb/hr	BACT-PSD
Riverside Generating CO LLC	KY	9/30/2016	5 Combined Cycle Generation Turbines with DB and I	2,076 MMBtu/hr	NG Fuel	1 gr S/100 scf	19.09 lb/hr	BACT-PSD
Johnsonville Cogeneration	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1,339 MMBtu/hr	GCP	0.005 lb/MMBtu		BACT-PSD
Effingham County Power (current project)	GA	5/30/2012	(2) Combined Cycle CT (GE 7FA)/HRSG w/ DB	180 MW	Low Sulfur Fuel	0.5 gr S/100 scf		BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/o DB	200 MW	Low Sulfur Fuel	0.5 gr S/100 scf	0.0064 lb/MMBtu	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	200 MW	Low Sulfur Fuel	0.5 gr S/100 scf	0.0054 lb/MMBtu	BACT-PSD
Other States								
St. Charles Power Station	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBTU/hr	GCP, Clean Fuels	17.52 lb/hr	0.0080 lb/MMBtu	BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	Clean fuel	11.7 lb/hr		BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for I	3961 mmBtu/hr	Clean fuel	18.3 lb/hr		BACT-PSD
Greensville Power Station	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT	3227 mmBtu/hr	LSF, GCP	0.0039 LB/MMBTU		Unknown
Wallingford Energy, LLC	CT	5/6/2016	GE LM6000 Simplr Cycle Jet Turbine 6			6 lb/hr	0.023 lb/MMBtu	BACT-PSD
Neches Station	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	GCP, LSF	19.35 lb/hr		BACT-PSD
Decordova Steam Electric Station	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	GCP, LSF	35.47 lb/hr		BACT-PSD
CPV Towantic, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	N/A	9.73 lb/hr		BACT-PSD
CPV Towantic, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	N/A	20.4 lb/hr		BACT-PSD
Colorado Bend Energy Center	TX	4/1/2015	Combined-Cycle Gas Turbine	1,100 MW	GCP, Clean Fuels	43 lb/hr		BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Combined Cycle Turbine w/ DB	2,159 MMBtu/hr	GCP, Clean Fuels	7.6 lb/hr	0.0035 lb/MMBtu	BACT-PSD
Freeport Lng Pretreatment Facility	TX	7/16/2014	Combustion Turbine	87 MW		15.22 lb/hr		BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion Turbine #1 - Combined Cycle	2,258 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion Turbine #2 -Combined Cycle	2,258 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Fge Texas Power I And Fge Texas Power ii	TX	3/24/2014	Alstom Turbine	231 MW	GCP, Clean Fuels	2 PPMVD		BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle Turbine w/ DB	2,988 MMBtu/hr	GCP, Clean Fuels	23.6 LB/HR TOTAL PM		BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, Combined Cycle Unit (Siemens 5000)	2,267 MMBtu/hr		10.4 lb/hr	0.0046 lb/MMBtu	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Turbine, Combined Cycle Unit (Siemens 5000)	2,267 MMBtu/hr		15.6 lb/hr	0.0069 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Turbine, Combined Cycle, #1 And #2	3,046 MMBtu/hr		48.56 TPY		BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Combined Cycle Turbine w/ DB	647 MMBtu/hr each	GCP, Clean Fuels	0.014 lb/MMBtu	0.0140 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Combined Cycle Turbine	700 MW	GCP, Clean Fuels	26.2 lb/hr		BACT-PSD
Theftord Generating Station	MI	7/25/2013	Combined Cycle Turbine w/ DB	2,587 MMBtu/hr each	GCP, Clean Fuels	0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/o DB	2,237 MMBtu/hr	GCP, Clean Fuels	0.006 lb/MMBtu	0.0060 lb/MMBtu	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	Combined Cycle Turbine w/ DB	2,486 MMBtu/hr	GCP, Clean Fuels	0.008 lb/MMBtu	0.0080 lb/MMBtu	BACT-PSD
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	Combined Cycle Turbine w/ DB (3)	2,538 MMBtu/hr		0.0088 lb/MMBtu	0.0088 lb/MMBtu	OTHER CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Combustion Turbine Generators, (3)	3,442 MMBtu/hr	GCP, Clean Fuels	0.0033 lb/MMBtu		BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle Turbine	180 MW	GCP, Clean Fuels	27 lb/hr		BACT-PSD
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	GCP, Clean Fuels	18 lb/hr	lb/MMBtu	OTHER CASE-BY-CASE
Sumpter Power Plant	MI	11/17/2011	Combined Cycle Combustion Turbine W/ Hrsg	130 MW electrical output		0.0066 lb/MMBtu	0.0066 lb/MMBtu	BACT-PSD
Palmdale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	Use of NG	0.0048 lb/MMBtu	0.0048	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 w/o DB	180 MW	Use of NG	8.91 lb/hr		BACT-PSD

Table B-2: Summary of PM BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	PM/PM ₁₀ /PM _{2.5} Limit	Equivalent PM/PM ₁₀ /PM _{2.5} Emissions Rate	Basis
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #1 and #2 w/ DB	180 MW	Use of NG	11.78 lb/hr		BACT-PSD
Colusa Generating Station	CA	3/11/2011	Combustion Turbines (Normal Operation)	172 MW	Use of NG	13.5 lb/hr	lb/MMBtu	BACT-PSD
Nelson Energy Center	IL	12/28/2010	Electric Generation Facility	220 MWe each		0.012 lb/MMBtu	0.012 lb/MMBtu	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2,996 MMBtu/hr	Natural Gas only, fuel has maxim	8 lb/hr	0.0027	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1,350 MW	use low ash fuel (natural gas or k	11.1 lb/hr		BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 w/ DB	154 MW	PUC QUALITY NATURAL GAS	12 lb/hr		BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #1 and #2 w/ DB	154 MW	PUC QUALITY NATURAL GAS	18 lb/hr	lb/MMBtu	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	GCP, NG as Fuel	0.01 lb/MMBtu	0.01 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines			0.012 lb/MMBtu	0.012	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	NG with 0.75 gr/100 scf S			BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW		20 lb/hr	lb/hr	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	24.23 lb/MMBtu	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Two CC Gas Turbines	2,110 MMBtu/hr	GCP, NG as Fuel	24.23 lb/hr	0.0000 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f) w/o DB	2,136 MMBtu/hr	NG Fuel	11 lb/hr	0.0051 lb/MMBtu	BACT-PSD
Kleen Energy Systems, LLC	CT	2/25/2008	(2) CT (Siemens SGT6-5000f) w/ DB	2,581 MMBtu/hr	NG Fuel	15.2 lb/hr	0.0059 lb/MMBtu	N/A
CPV Warren	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	GCP	0.013 lb/MMBtu	0.0130 lb/MMBtu	N/A
Russell City Enery Center	CA	6/19/2007	(2) CTs (Westinghouse 501F)/HRSG	600 Net MW	NG with 0.25 gr/100 scf S		lb/MMBtu	BACT-PSD
Fairbault Energy Park	MN	6/5/2007	CC CT w/DB	1,758 MMBtu/hr		0.01 lb/MMBtu	0.0100 lb/MMBtu	BACT-PSD
Blythe Energy Project II, LLC	CA	4/25/2007	2 CTs	1,776 MMBtu/hr ea.	NG with 0.5 gr S/100 SCF	6 lb/hr	0.0034 lb/MMBtu	BACT-PSD
PSO Southwestern Power Plant	OK	2/9/2007	Gas-Fired Turbines		NG and Efficient Combustion	0.0093 lb/MMBtu	0.0093 lb/MMBtu	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

Note: GCP= good combustion practices; LSF= low sulfur fuel; NG = natural gas; CC = combined cycle; CT = combustion turbine; DB = duct burner; HRSG = heat recovery steam generator.

Table B-3: Summary of SO₂ BACT Determinations for CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	SO ₂ Limit	Basis
FPL Dania Beach Energy Center	FL	12/4/2017	2-on-1 Combined Cycle with HRSG	4,015 MMBtu/hr	Use of natural gas fuel	2 gr/100 scf	BACT-PSD
NRG Wholesale Generation LLC	MS	4/28/2017	Combustion turbines with DB	2,126 MMBtu/hr	Use of natural gas fuel	0.8 % S by weight	BACT-PSD
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle Turbine with Heat Recovery Steam C	426 MW	Pipeline quality natural gas	1.54 lb/hr	BACT-PSD
Riverside Generating CO LLC	KY	9/30/2016	5 Combined Cycle Generation Turbines with DB and I	2,076 MMBtu/hr		7.82 lb/hr	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine - 7HA.02	380 MW	LSF	5.62 lb/hr	CASE-BY-CASE
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle CT w/DB -3462 MMBtu/hr + 499 for I	3961 mMBtu/hr	LSF	6.64 lb/hr	CASE-BY-CASE
GREENSVILLE POWER STATION	VA	6/17/2016	COMBUSTION TURBINE GENERATOR WITH DUCT	3227 mMBtu/hr	LSF	0.0011 lb/mmbtu	Unkown
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	LSF, GCP	1 gr/100 scf	
OKEECHOBEE CLEAN ENERGY CENTER	FL	3/9/2016	Combined-cycle electric generating unit	3,096 MMBtu/hr	LSF	2 gr/100 scf	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	LSF, GCP	5 gr/100 scf	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w/o DB	805 MW	LSF	4.49 LB/HR	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant - w DB	805 MW	LSF	6.2 LB/HR	BACT-PSD
Colorado Bend Energy Center	TX	4/1/2015	Combined-cycle gas turbine	1100 MW	LSF, GCP	2 gr/100 scf	BACT-PSD
West Deptford Energy Station	NJ	7/18/2014	Combined Cycle Combustion Turbine w/o DB	2,308 MMBtu/hr	LSF	0.00214 lb/MMbtu	BACT-PSD
West Deptford Energy Station	NJ	7/18/2014	Combined Cycle Combustion Turbine with Duct Burne	20,282 MMCF/YR	Use of natural gas fuel	6.56 LB/H	BACT-PSD
FGE Texas Power I And Fge Texas Power II	TX	3/24/2014	Alstom Turbine	231 MW	LSF, GCP	1.00000 GR S / 100 DSCF	BACT-PSD
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined Cycle Combustion Turbine w/ DB	3846.0046 MMBtu/hr	LSF	0.00130 lb/MMbtu	CASE-BY-CASE
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined Cycle Combustion Turbine w/ DB	3,846 MMBtu/hr	LSF	0.00133 lb/MMbtu	CASE-BY-CASE
PSEG Fossil LLC Sewaren Generating Station	NJ	3/7/2014	Combined-cycle gas turbine w/ DB	3846.0046 MMBtu/hr	LSF	0.00135 lb/MMbtu	CASE-BY-CASE
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	Combined-cycle gas turbine	2,267 MMBtu/hr		0.00229 lb/MMbtu	BACT-PSD
Berks Hollow Energy Assoc LLC/Ontelaunee	PA	12/17/2013	Turbine, Combined Cycle, #1 and #2	3046 MMBtu/hr		0.00148 lb/MMbtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/o DB	5,886 MMBtu/hr	LSF	0.00140 lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/ DB	5,886 MMBtu/hr		0.00140 lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/o DB	5,470 MMBtu/hr	LSF	0.00140 lb/MMbtu	N/A
Oregon Clean Energy Center	OH	6/18/2013	Combined Cycle Combustion Turbine w/ DB	5,470 MMBtu/hr	LSF	0.00140 lb/MMbtu	N/A
Sunbury Generation LP/Sunbury SES	PA	4/1/2013	Combined Cycle Combustion Turbine w/ DB	2,538 MMBtu/hr		0.00240 lb/MMbtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Combustion Turbine	3442 MMBtu/hr	LSF	0.00110 lb/MMbtu	BACT-PSD
Woodbridge Energy Center	NJ	7/25/2012	Combined Cycle Combustion Turbine w/ DB	4600 MMBtu/hr	LSF, GCP	0.00107 lb/MMbtu	CASE-BY-CASE
Woodbridge Energy Center	NJ	7/25/2012	Combined Cycle Combustion Turbine w/o DB	4600 MMBtu/hr	LSF	0.00089 lb/MMbtu	CASE-BY-CASE
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390 MW	LSF	27.1 lb/r	BACT-PSD
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2996 MMBtu/hr	LSF, GCP	0.00033 lb/MMbtu	CASE-BY-CASE

Source: EPA 2017 (RBLC database); Golder, 2017

Note: LSF=low sulfur fuel, GCP= good combustion practices.

Table B-4: Summary of NO_x BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO _x Limit	Basis
Florida							
FPL Dania Beach Energy Center	FL	12/4/2017	2-on-1 Combined Cycle with HRSG	4,015 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Combined-cycle electric generating unit	3,096 MMBtu/hr	DLN, SCR, WI	2.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Port Everglades Power Plant	FL	5/9/2012	(3) Combined Cycle CT with HRSG	250 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Cape Canaveral Energy Center	FL	7/23/2009	(3) Combined Cycle CT with HRSG	265 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	(3) Combined Cycle CT with HRSG	265 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
FPL West County Energy Center Unit 3	FL	7/30/2008	Combined Cycle CTs - 3 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
OUC Curtis H. Stanton Energy Center	FL	5/12/2008	300 MW Combined Cycle CT	1,765 MMBtu/hr	LNB and SCR	8.0 ppmvd @ 15% O ₂	BACT-PSD
Progress Bartow Power Plant	FL	1/29/2007	Combined Cycle CT (4-On-1)	1,972 MMBtu/hr	DLN	15.0 ppmvd uncorrected	BACT-PSD
FPL West County Energy Center Units 1 & 2	FL	1/10/2007	Combined Cycle CTs - 6 Units	2,333 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
NRG Wholesale Generation LLC	MS	4/28/2017	Combustion turbines with DB	2,126 MMBtu/hr	SCR	3.0 ppmv @ 15% O ₂	BACT-PSD
Riverside Generating CO LLC	KY	9/30/2016	5 Combined Cycle Generation Turbines with DB and HRSG	2,076 MMBtu/hr	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
JOHNSONVILLE COGENERATION	TN	4/19/2016	Natural Gas-Fired Combustion Turbine with HRSG	1339 MMBtu/hr	SCR, GCP	2.0 ppmvd @ 15% O ₂	BACT-PSD
Effingham County Power (current project)	GA	5/30/2012	Combined Cycle CT (GE 7FA)HRSG	180 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Live Oaks Power Project	GA	4/8/2010	(2) CTs (Siement SGT6-5000F) w/ DB	600 MW	DLN and SCR	2.5 ppmvd @ 15% O ₂	BACT-PSD
Other States							
GAINES COUNTY POWER PLANT	TX	4/28/2017	Combined Cycle CT with HRSG, Duct Burners, and Steam Turbine	426 MW	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
ST. CHARLES POWER STATION	LA	8/31/2016	(2) SCPS Combined Cycle (Unit 1A & 1B)	3625 MMBTU/hr	DLN, GCP and SCR	2.0 ppm @ 15% O ₂	BACT-PSD
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine	8040 h/yr	DLN, SCR	2.0 ppmvd @ 15% O ₂	LAER
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	Combined Cycle Combustion Turbine w/DB	4000 h/yr	DLN, SCR	2.0 ppmvd @ 15% O ₂	LAER
GREENSVILLE POWER STATION	VA	6/17/2016	CT with duct fired HRSG (3)	3227 mmBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	Unknown
Wallingford Energy, LLC	CT	5/6/2016	GE LM6000 Simplr Cycle Jet Turbine 6		SCR	2.5 ppmvd @ 15% O ₃	CASE-BY-CASE
NECHES STATION	TX	3/24/2016	Combined Cycle & Cogeneration	231 MW	SCR	2 ppm	BACT-PSD
DECORDOVA STEAM ELECTRIC STATION	TX	3/8/2016	Combined Cycle & Cogeneration	231 MW	SCR	2.0 PPM	BACT-PSD
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Refrigeration Compression Turbines	10 M TONNES/YR	DLN, GCP	9.0 PPM	BACT-PSD
PORT ARTHUR LNG EXPORT TERMINAL	TX	2/17/2016	Simple Cycle Electrical Generation Gas Turbines	34 MW	SCR	5.0 PPM	BACT-PSD
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	21200000 MMBtu/12 month	SCR	5.0 ppmvd @ 15% O ₂	LAER
CPV TOWANTIC, LLC	CT	11/30/2015	Combined Cycle Power Plant	1720000 gal/ 12 months			
Colorado Bend Energy Center	TX	4/1/2015	COMBINED CYCLE CT	1,100 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	(2) combined cycle turbines	240 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Victoria Power Station	TX	12/1/2014	combined cycle turbine	197 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	combined cycle turbine	497 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Cedar Bayou Electric Generation Station	TX	8/29/2014	Combined cycle natural gas turbines	225 MW	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	(2) combined cycle turbines	274 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #1 - combined cycle	2,258 mmBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Combustion turbine #2 - combined cycle	2,258 mmBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Fge Texas Power I And Fge Texas Power II	TX	3/24/2014	Alstom Turbine	231 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Combined Cycle CT w/ DB	2,988 MMBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Future Power Pa/Good Springs Ngcc Facility	PA	3/4/2014	COMBINED CYCLE CT	2,267 MMBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	COMBINED CYCLE CT	700 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Sand Hill Energy Center	TX	9/13/2013	COMBINED CYCLE CT	174 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	COMBINED CYCLE CT	2,237 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Midland Cogeneration Venture	MI	4/23/2013	COMBINED CYCLE CT w/DB	2,486 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	COMBINED CYCLE UNITS #1 and #2	3,000 MMBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	CASE-BY-CASE
Sunbury Generation Lp/Sunbury Ses	PA	4/1/2013	COMBINED CYCLE CTs w/DB (3)	2,538 MMBtu/hr	SCR	2.0 ppmvd @ 15% O ₂	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	COMBINED CYCLE CTs (3)	3,442 MMBtu/hr	DLN, SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
La Paloma Energy Center	TX	2/7/2013	COMBINED CYCLE CTs (2)	650 MW	SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Channel Energy Center Llc	TX	10/15/2012	Combined Cycle CT	180 MW	SCR	2.0 ppmvd	LAER
Deer Park Energy Center	TX	9/26/2012	Combined Cycle CT	180 MW	SCR	2.0 ppmvd	LAER
Es Joslin Power Plant	TX	9/12/2012	Combined Cycle Gas Turbine	195 MW	SCR	2.0 ppmvd	BACT-PSD
Palmale Hybrid Power Project	CA	10/18/2011	Combustion Turbines (Normal Operation)	154 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Thomas C. Ferguson Power Plant	TX	9/1/2011	Natural Gas-Fired Turbines	390 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Combustion Turbine #2 w/DB	180 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Carty Plant	OR	12/29/2010	Combined Cycle Natural Gas-Fired Electric Generating Unit	2,866 MMBTU/H	SCR	2.0 PPM@15%O2	BACT-PSD

Table B-4: Summary of NO_x BACT Determinations for Natural Gas-Fired CTs (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	NO _x Limit	Basis
Warren County Power Plant - Dominion	VA	12/17/2010	Combined Cycle Turbine & Duct Burner, 3	2,996 MMBTU/H	DLN and SCR	2.0 ppmvd@15%O ₂	BACT-PSD
King Power Station	TX	8/5/2010	Turbine	1,350 MW	DLN and SCR	2.0 ppmvd AT 15% O ₂	LAER
Langley Gulch Power Plant	ID	6/25/2010	Combined Cycle CT W/ DB	2,375 MMBTU/H	DLN, SCR, GCP	2.0 ppmvd	BACT-PSD
Colusa Generating Station	CA	3/11/2010	Combustion Turbines	172 MW	DLN and SCR	2.0 ppmvd	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	Combustion Turbine #2 w/DB	154 MW	SCR	2.0 ppmvd	BACT-PSD
High Desert Power Project	CA	3/11/2010	Combustion Turbine Generators	190 MW	DLN and SCR	2.5 ppmvd	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electric Generation	170 MW	DLN	9.0 ppmvd @ 15% O ₂	BACT-PSD
CPV St. Charles	MD	11/12/2008	(2) Combustion Turbines		DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2,169 MMBtu/hr	DLN	9.0 ppm	BACT-PSD
Gateway Generating Station	CA	7/1/2008	(2) Combined Cycle CT (GE 7FA)/HRSG	530 Net MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Colusa Generating Station	CA	5/1/2008	(2) Combined Cycle CT/HRSG	172 MW	DLN and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	Low Nox Turbines, SCR	30.15 lb/hr	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	(2) Combined Cycle Gas Turbines	2,110 MMBtu/hr	DLN and SCR	30.15 lb/hr	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 1	1,717 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 2	1,944 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD
CPV Warren, LLC	VA	1/14/2008	Electric Generation - Scenario 3	2,204 MMBtu/hr	DLN, GCP and SCR	2.0 ppmvd @ 15% O ₂	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

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

Table B-5: Summary of CO, VOC, PM, and SO₂ BACT Determinations for Auxiliary Boilers (2007-2017)

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Nitrogen Oxides (NO_x)								
FPL Dania Beach Energy Center	FL	12/4/2017	Auxiliary Boiler	NG	99.8 MMBtu/hr	LNB	0.050 lb/MMBtu	BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	LNB and FGR	0.010 lb/MMBtu	LAER
Lakes Charles Methanol Facility	LA	6/30/2016	Auxiliary Boiler	NG	225 MMBtu/hr	SCR	0.015 lbs/MMBtu	BACT-PSD
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	LNB and FGR	0.010 lb/MMBtu	LAER
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	LNB	0.050 lb/MMBtu	BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	LNB and FGR	0.020 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	auxiliary boiler	NG	60.1 MMBtu/hr		0.013 lb/MMBtu	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Auxiliary boiler	NG	39.8 MMBtu/hr	LNB and FGR	0.035 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr		0.006 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B	NG	95 MMBtu/hr	LNB and FGR	0.050 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A	NG	55 MMBtu/hr	LNB and GCP	0.050 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	LNB	16 PPMVD	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxiliary Boiler	NG	99 MMBtu/hr	LNB and FGR	0.020 lb/hr	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr		0.011 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	LNB	9 PPMVD	BACT-PSD
Effingham County Power (current project)	GA	5/30/2012	Auxiliary Boiler	NG	17 MMBtu/hr	LNB and Clean Fuel	0.098 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	NG	46 MMBtu/hr	LNB and FGR	0.036 lb/MMBtu	BACT-PSD
Avenal Energy Project	CA	6/21/2011	Auxiliary Boiler	NG	37.4 MMBtu/hr	LNB and Clean Fuel	9 ppmvd	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	NG	99 MMBtu/hr	LNB and/or CSR	0.040 lb/MMBtu	BACT-PSD
Carly Plant	OR	12/29/2010	NATURAL GAS-FIRED BOILER	Diesel	91 MMBtu/hr	LNB	0.049 lb/hr	BACT-PSD
Lake Charles Chemical Complex - Lab Unit	LA	11/29/2010	EQT0027 - PACOL CHARGE HEATER H-201	NG	87.3 MMBtu/hr	Low NOX Burners	0.082 LB/H	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	NG	35 MMBtu/hr	Restricted hours	9 ppmvd	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS	NG	41.64 MMBtu/hr	LNB and FGR	0.011 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	LNB and FGR	0.035 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	LNB and FGR	0.030 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	LNB	0.031 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	LNB	0.035 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	NG	33.48 MMBtu/hr	LNB	0.037 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT PA15	Diesel Oil	21 MMBtu/hr	LNB	0.037 lb/MMBtu	BACT-PSD
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	Diesel Oil	16.7 MMBtu/hr	LNB	0.049 lb/MMBtu	LAER
FPL Cape Canaveral Energy Center	FL	7/23/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.050 lb/MMBtu	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.050 lb/MMBtu	BACT-PSD
Concord Steam Corporation	NH	2/27/2009	BOILER 2 and 3 (AUXILIARY)	NG	76.8 MMBtu/hr	LNB and FGR	0.049 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr	LNB with FGR	0.011 lb/MMBtu	N/A
CPV Warren LLC	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	CEM System	0.011 lb/MMBtu	N/A
CPV Warren LLC	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	CEM System	0.011 lb/MMBtu	BACT-PSD
Carbon Monoxide (CO)								
FPL Dania Beach Energy Center	FL	12/4/2017	Auxiliary Boiler	NG	99.8 MMBtu/hr	GCP	0.080 lb/MMBtu	BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Clean Fuel and GCP	0.037 lb/MMBtu	BACT-PSD
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Clean Fuel and GCP	0.036 lb/MMBtu	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	GCP	0.080 lb/MMBtu	BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr	CO catalytic oxidizer	0.02 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr		0.04 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAUXBOILERB)	NG	95 MMBtu/hr		0.01 lb/MMBtu	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAUXBOILER A)	NG	55 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxiliary Boiler	NG	99 MMBtu/hr	GCP	75.00 PPMVD	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr	GCP	0.14 lb/MMBtu	BACT-PSD
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr		0.04 lb/MMBtu	CASE-BY-CASE
Effingham County Power (current project)	GA	5/30/2012	Auxiliary Boiler	NG	17 MMBtu/hr	GCP	50.00 PPMVD	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	NG	46 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Biomass-Fuel Boilers (2)	NG	120 MMBtu/hr	GCP	0.40 lb/MMBtu	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	N/A	99 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Flopam Inc.	LA	6/14/2010	Boilers	N/A	25.1 MMBtu/hr	GCP	0.04 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	Natural Gas	35 MMBtu/hr	Operational limit - 500 hr/yr	50.00 ppmvd	BACT-PSD
Flakeboard America Limited - Bennettsville Mdf	SC	12/22/2009	SANDERDUST BOILER	Diesel	99 MMBtu/hr	GCP	0.30 lb/MMBtu	BACT-PSD
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	NG	41.64 MMBtu/hr	GCP	0.02 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	NG	4.2 MMBtu/hr	GCP	0.02 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILER - UNIT MB090 AT Mandalay Bay		4.3 MMBtu/hr	FGR and GCP	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO		2 MMBtu/hr	GCP	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILER - UNIT BE111 AT BELLAGIO	Low Sulfur Diese	2.1 MMBtu/hr	GCP, Low-Sulfur NG	0.04 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER		44 MMBtu/hr	GCP	0.01 lb/MMBtu	LAER
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK	NG	2 MMBtu/hr	GCP	0.04 lb/MMBtu	LAER
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT HA08	Diesel Oil	8.37 MMBtu/hr	GCP	0.04 lb/MMBtu	CASE-BY-CASE
Source: EPA 2015 (RBL database); Golder, 2015	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	FGR and GCP	0.07 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	FGR and GCP	0.02 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	GCP	0.02 lb/MMBtu	CASE-BY-CASE

Table B-5: Summary of CO, VOC, PM, and SO₂ BACT Determinations for Auxiliary Boilers (2007-2017)

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	NG	33.48 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP26	Diesel Oil	24 MMBtu/hr	GCP	0.04 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT PA15	Diesel Oil	21 MMBtu/hr	GCP	0.85 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	NG	16.7 MMBtu/hr	GCP	0.01 lb/MMBtu	CASE-BY-CASE
FPL Cape Canaveral Energy Center	FL	7/23/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.08 lb/MMBtu	BACT-PSD
FPL Riviera Beach Energy Center	FL	6/10/2009	Auxiliary Boiler	NG	99.8 MMBtu/hr	Oxidation Catalyst	0.08 lb/MMBtu	BACT-PSD
Medicine Bow Igl Plant	WY	3/4/2009	AUXILIARY BOILER	NG	66 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	BOILERS #1 AND #2	NG	80 MMBtu/hr	GCP	0.08 lb/MMBtu	BACT-PSD
Ponca City Refinery	OK	2/9/2009	TB-1 Leased Boiler No. 1	NG	95 MMBtu/hr	LNB, GCP, Low-Sulfur NG	0.04 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	AUXILIARY BOILER	NG	33.5 MMBtu/hr	GCP	0.15 lb/MMBtu	N/A
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.02 lb/MMBtu	BACT-PSD
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.04 lb/MMBtu	CASE-BY-CASE
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	GCP	0.04 lb/MMBtu	N/A
CPV Warren, LLC.	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	GCP	0.04 lb/MMBtu	N/A
<u>Volatile Organic Compounds (VOC)</u>								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	GCP and use of clean fuel	0.005 lb/MMBtu	LAER
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Troutdale Energy Center, Llc	OR	3/5/2014	Auxiliary boiler	NG	39.8 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr	GCP	0.0008 lb/MMBtu	
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAXBOILERB)	NG	95 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAXBOILER A)	NG	55 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxiliary Boiler	NG	99 MMBtu/hr	GCP	0.0060 lb/MMBtu	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr	GCP	0.0015 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	GCP	0.0050 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	Diesel	46 MMBtu/hr	GCP	0.0030 lb/MMBtu	BACT-PSD
Republic Steel	OH	7/18/2012	Steam Boiler	NG	65 MMBtu/hr	Proper burner design and GC	0.0054 lb/MMBtu	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0323 - Boiler 401F	N/A	99 MMBtu/hr	Proper burner design and GC	0.0054 lb/MMBtu	BACT-PSD
Archer Daniels Midland-Mexico	MO	10/5/2010	DUAL-FIRED 85.6 MMBTU/HR WATER-TUBE BOILER	NG	85.6 MMBtu/hr	GCP	0.0055 lb/MMBtu	LAER
Flopam Inc.	LA	6/14/2010	Boilers	NG	25.1 MMBtu/hr	GCP	0.0030 lb/MMBtu	BACT-PSD
Flakeboard America Limited - Bennettsville Mdf	SC	12/22/2009	SANDERDUST BOILER	Diesel	99 MMBtu/hr	GCP	0.1000 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	N/A	41.64 MMBtu/hr	GCP	0.0024 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	NG	4.2 MMBtu/hr	GCP	0.0048 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILER - UNIT MB090 AT MANDALAY BAY	NG	4.3 MMBtu/hr	GCP and FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO	2 MMBtu/hr	GCP, Low-Sulfur NG		0.0054 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILER - UNIT BE111 AT BELLAGIO	2 MMBtu/hr	GCP, Low-Sulfur NG		0.0048 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER	NG	44 MMBtu/hr	GCP, Low-Sulfur NG	0.0055 lb/MMBtu	CASE-BY-CASE
Mgm Mirage	NV	11/30/2009	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK	NG	2 MMBtu/hr	GCP	0.0050 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT HA08	Diesel Oil	8.37 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT FL01	Diesel Oil	14.34 MMBtu/hr	FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA01	NG	16.8 MMBtu/hr	FGR	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT BA03	NG	31.38 MMBtu/hr	Operate per Manufac. Spec	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP01	NG	35.4 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP03	N/A	33.48 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT CP26	Diesel Oil	24 MMBtu/hr	GCP	0.0054 lb/MMBtu	CASE-BY-CASE
Harrah's Operating Company, Inc.	NV	8/20/2009	BOILER - UNIT IP04	Diesel Oil	16.7 MMBtu/hr	GCP	0.0053 lb/MMBtu	LAER
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.0020 lb/MMBtu	CASE-BY-CASE
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.0094 lb/MMBtu	N/A
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 2	NG	97 MMBtu/hr	CEM System	0.0060 lb/MMBtu	N/A
Cpv Warren	VA	1/14/2008	Auxiliary Boiler - Scenario 3	NG	62 MMBtu/hr	CEM System	0.0060 lb/MMBtu	BACT-PSD
<u>Particulate Matter (PMPM₁₀/PM_{2.5})</u>								
FPL Dania Beach Energy Center	FL	12/4/2017	Auxiliary Boiler	NG	99.8 MMBtu/hr	GCP	2 gr S/100 scf	BACT-PSD
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Use of clean fuel	0.005 lb/MMBtu	BACT-PSD
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Clean Fuel and GCP	0.005 lb/MMBtu	BACT-PSD
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	Clean Fuel and GCP	2 gr S/100 scf	BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Auxiliary Boiler	NG	100 MMBtu/hr	GCP	0.005 lb/MMBtu	BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Auxiliary Boiler	NG	60.1 MMBtu/hr		0.008 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr		0.46 TPy	CASE-BY-CASE
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler B (EUAXBOILERB)	NG	95 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Auxiliary Boiler A (EUAXBOILER A)	NG	55 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Pinecrest Energy Center	TX	11/12/2013	Auxiliary boiler	NG	150 MMBtu/hr	GCP	0.0076 lb/MMBtu	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Auxiliary Boiler	NG	99 MMBtu/hr	GCP	0.0080 lb/MMBtu	BACT-PSD
Hickory Run Energy Station	PA	4/23/2013	AUXILIARY BOILER	NG	40 MMBtu/hr		0.005 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	AUXILIARY BOILER	NG	66.7 MMBtu/hr	GCP	0.007 lb/MMBtu	BACT-PSD
Suwannee Mill	FL	9/5/2012	Natural Gas Boilers (4)	Diesel	46 MMBtu/hr	GCP	2 gr S/100 scf	RACT
Suwannee Mill	FL	9/5/2012	Biomass-Fuel Boilers (2)		120 MMBtu/hr	ESP	0.015 lb/MMBtu	BACT-PSD

Table B-5: Summary of CO, VOC, PM, and SO₂ BACT Determinations for Auxiliary Boilers (2007-2017)

Facility Name	State	Permit Issued	Process Info	Fuel	MW/Heat Input	Control Method	Pollutant Limit	Basis
Avenal Energy Project	CA	6/21/2011	AUXILIARY BOILER	Natural Gas	37.4 MMBtu/hr	Use of pipeline NG	0.0034 GR/DSCF	BACT-PSD
Flopam Inc.	LA	6/14/2010	Boilers	N/A	25.1 MMBtu/hr	GCP, Use of NG	0.0052 lb/MMBtu	BACT-PSD
Victorville 2 Hybrid Power Project	CA	3/11/2010	AUXILIARY BOILER	Natural Gas	35 MMBtu/hr	Use of pipeline NG	0.2 gr S/100 scf	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	BOILERS #1 AND #2	Natural Gas	80 MMBtu/hr		0.0075 lb/MMBtu	BACT-PSD
CPV St. Charles	MD	11/12/2008	Boiler	NG	93 MMBtu/hr		0.005 lb/MMBtu	CASE-BY-CASE
Nellis Air Force Base	NV	2/26/2008	Boilers/Heaters	Diesel Oil		GCP	0.019 lb/MMBtu	BACT-PSD
Caithnes Bellport Energy Center	NY	5/10/2006	Auxiliary Boiler	NG	29.4 MMBtu/hr	Low-Sulfur Fuel	0.0033 lb/MMBtu	BACT-PSD
<u>Sulfur Dioxide (SO₂)</u>								
Middlesex Energy Center, LLC	NJ	7/19/2016	Auxiliary Boiler	NG	97.5 MMBtu/hr	Low sulfur fuel	0.001 lb/MMBtu	CASE-BY-CASE
SEG FOSSIL LLC SEWAREN GENERATING STATION	NJ	3/10/2016	Auxiliary Boiler	NG	80 MMBtu/hr	Low sulfur fuel	0.002 lb/MMBtu	CASE-BY-CASE
Okeechobee Clean Energy Center	FL	3/9/2016	Auxiliary Boiler	NG	99.8 MMBtu/hr	2 gr S/100 scf	0.080 lb/MMBtu	BACT-PSD
Berks Hollow Energy Assoc Llc/Ontelaunee	PA	12/17/2013	Auxiliary Boiler	NG	40 MMBtu/hr	Low sulfur fuel	0.0011 lb/MMBtu	
Hickory Run Energy Station	PA	4/23/2013	Auxiliary Boiler	NG	40 MMBtu/hr	Low sulfur fuel	0.0021 lb/MMBtu	CASE-BY-CASE
Brunswick County Power Station	VA	3/12/2013	Auxiliary Boiler	NG	66.7 MMBtu/hr	Low sulfur fuel	0.0011 lb/MMBtu	BACT-PSD
Lake Charles Gasification Facility	LA	6/22/2009	Auxiliary Boiler	NG	938.3 MMBtu/hr	Low sulfur fuel	0.0003 lb/MMBtu	BACT-PSD
Chouteau Power Plant	OK	1/23/2009	Auxiliary Boiler	NG	33.5 MMBtu/hr	Low sulfur fuel	0.0009 lb/MMBtu	N/A

Source: EPA 2017 (RBLC database); Golder, 2017

Note: LNB= dry low NOx; GCP= good combustion practices; LNB= low NOx burner; FGR= flue gas recirculation

Table B-6: Summary of BACT Determinations for Cooling Towers (2007-2017)

Facility Name	State	Permit Issued	Process Info	MW/Heat Input	Control Method	Pollutant Limit	Basis
Midwest Fertilizer Company LLC	IN	3/23/2017	18 Cell Cooling Tower		Drift eliminators	2000 MG/L	BACT-PSD
Port Arthur Ethane Side Cracker	TX	1/17/2017	Cooling Tower		Drift eliminators		BACT-PSD
METHANEX - GEISMAR METHANOL PLANT	LA	12/22/2016	Cooling Tower	66000 gal/min	Drift eliminators 0.0010%		BACT-PSD
NUCOR STEEL	IN	9/21/2016	Hot Mill Contact Cooling Tower	25000 gal/min	Drift eliminators	0.38 lb/hr	BACT-PSD
ST. Charles Power Station	LA	8/31/2016	Cooling Tower	164,400 gal/min			
Okeechobee Clean Energy Center	FL	3/9/2016	Cooling Tower	465,815 gal/min	Drift Eliminators 0.0005% DR		BACT-PSD
CMC Steel Oklahoma	OK	1/19/2016	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Flopam, Inc.	TX	1/7/2016	Cooling Tower		Drift Eliminators 0.0010%		BACT-PSD
The Empire District Electric Co.	KS	7/14/2015	Cooling Tower	gal/min	integrated drift eliminators		BACT-PSD
S R Bertron Electric Generating Station	TX	12/19/2014	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Victoria Power Station	TX	12/1/2014	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Moundsville Combined Cycle Power Plant	WV	11/21/2014	Cooling Tower	159,000 gal/min		0.50 lb/hr	BACT-PSD
Trinidad Generating Facility	TX	11/20/2014	Cooling Tower		Drift Eliminators 0.001% DR		BACT-PSD
Tenaska Brownsville Generating Station	TX	4/29/2014	Cooling Tower		Drift Eliminators 0.0005% DR		BACT-PSD
Marshalltown Generating Station	IA	4/14/2014	Cooling Tower	160,000 gal/min	Mist/drift eliminators.	1.20 lb/hr	BACT-PSD
Pseg Fossil Llc Sewaren Generating Station	NJ	3/7/2014	3 Cell Wet Mechanical Cooling Tower	13,000 gal/min		0.16 lb/hr	BACT-PSD
Holland Board Of Public Works - East 5th Street	MI	12/4/2013	Cooling Tower -- Wet Mechanical Draft		Mist/drift eliminators.	0.54 lb/hr	BACT-PSD
Oregon Clean Energy Center	OH	6/18/2013	Mechanical draft wet cooling tower, 16 cell	322,000 gal/min		1.03 lb/hr	BACT-PSD
Cf Industries Nitrogen, Llc - Port Neal Nitrogen Complex	IA	7/12/2013	Cooling Towers		Drift Eliminators 0.0005% DR		BACT-PSD
Effingham County Power	GA	5/30/2012	Cooling Towers		Drift Eliminators 0.0005% DR		BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0010 - Cooling Tower 403	61,250 gal/min	Drift eliminators	1.20 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0035 - Cooling Tower CT-600	45,000 gal/min	Drift eliminators	0.09 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0243 - HCU Cooling Tower	50,000 gal/min	Drift eliminators	0.10 lb/hr	BACT-PSD
St. Charles Refinery	LA	12/31/2010	EQT0244 - New West Cooling Tower	40,000 gal/min	drift eliminators	0.08 lb/hr	BACT-PSD
Sabina Petrochemicals Llc	TX	8/20/2010	COOLING TOWER	73,000 gal/min	Monitoring VOC concentration in cooling water	3.07 lb/hr	BACT-PSD
Live oaks Power Project	GA	4/8/2010	Cooling Tower	140,000 gal/min			BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	COOLING TOWER #2	40,000 gal/min	MIST ELIMINATORS	1.92 lb/hr	BACT-PSD
Pryor Plant Chemical	OK	2/23/2009	COOLING TOWER #1	24,500 gal/min	MIST ELIMINATORS	1.18 lb/hr	BACT-PSD
CPV St. Charles	MD	11/12/2008	Cooling Tower		Drift Eliminators, Max 0.0005% DR		BACT-PSD
FPL West County Energy Center Unit 3	FL	4/25/2008	Mechanical Draft Cooling Tower (26 Cell)	304,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.20 lb/hr	
Arsenal Hill Power Plant	LA	3/20/2008	Cooling Tower	140,000 gal/min	Use Of Mist Eliminators	1.40 lb/hr	BACT-PSD
FPL West County Energy Center	FL	1/10/2007	(2) Cooling Tower (26 Cell Mechanical Draft)	306,000 gal/min	Drift Eliminators, Max 0.0005% DR	1.20 lb/hr	
Forsyth Energy Plant	NC	9/29/2005	Cooling Tower	3,834 gal/min		0.007 lb/hr	BACT-PSD

Source: EPA 2017 (RBLC database); Golder, 2017

Note: DR = Drift rate

Table B-7: Summary of Greenhouse Gas BACT Determinations for Natural Gas Combined-Cycle CTs

Facility Name	State	Permit Issued	CO ₂ e Limit (mass)	CO ₂ e Limit (lb/MWH)	Heat Rate (Btu/kWH)	Note
FPL Dania Beach Energy Center	FL	12/4/2017	NA	850 (gas), 1,210 (oil)	NA	2-on-1 GE 7HA.02, 12-month rolling
GAINES COUNTY POWER PLANT	TX	4/28/2017	NA	960	NA	Siemens SGT6-5000F
Riverside Generating CO LLC	KY	9/30/2016	NA	1,069	NA	Rated 2,076 MMBtu/hr each ; Throughput 1700 MW
MIDDLESEX ENERGY CENTER, LLC	NJ	7/19/2016	NA	888	NA	12-month rolling average; 560 MW
Okeechobee Clean Energy Center	FL	3/9/2016	NA	850 (gas), 1,210 (oil)	NA	3-on-1 GE 7HA.02, 12-month rolling
FGE Eagle Pines Project	TX	11/4/2015	NA	886	NA	3, 2-on-1 Alstom GT36
Colorado Bend Energy Center	TX	4/1/2015	MA	880 *	7,395	2-on-1 GE 7HA.02
West Deptford Energy Station	NJ	7/18/2014	1,237,923 TPY	947	NA	2-on-1; lb/MWh is 1-month rolling
Mounds Power, LLC	WV	11/21/2014	254,315 lb/hr	793 **	NA	2-on-1; GE 7F.04
Golden Spread Electric Cooperative Inc.	TX	6/2/2014	NA	1,304	NA	202 MW GE 7F 5-series
CPV Maryland, LLC	MD	4/23/2014	NA	905 *	7,605	2-on-1; GE 7F 57% Efficiency (ISO)
Apex Matagorda Energy Center	TX	4/14/2014	NA	558	NA	Throughput : 7807409 MMBtu/yr
Apex Matagorda Energy Center	TX	4/14/2014	456296 TPY	NA	NA	Throughput : 8600 scf/hr
Apex Bethel Energy Center	TX	3/13/2014	NA	558	4,390 (Max load)	4773 Btu/KWh at low load (HHV)
Old Dominion Wildcat Point Facility	MD	6/9/2014	NA	946	7,500	2-on-1; MPS G, heat rate at all times, excludes SU/SD
FGE Power LLC	TX	4/28/2014	NA	889	7,625	2-on-1; 4-Alstom GT24, heat rate is net; SU/SD 48 t/h
Marshalltown Generating Station	IA	4/14/2014	1,318,647	951	NA	2-on-1; Siemens SGT6-5000F; Limit 12-month rolling
Troutdale Energy Center, LLC	OR	3/5/2014	NA	1,000	NA	2-on-1; MPS M501-GAC; 365 day rolling average
Holland Board of Public Works	MI	12/4/2013	339,125 TPY	995 **	8,361	2-on-1 (115 MW); 12-month rolling average; heat rate is gross; SU/SD 635 hrs/yr
Thetford generating Station	MI	7/25/2013	1,386,268 TPY	NA	NA	2-on-1; 4 F-Class CTs, 12-month rolling average
Orgeon Clean Energy Center	OH	6/18/2013	1,394,611 TPY	840	NA	2-on-1; MPS or Siemens F-Class; 12-month rolling average
Hickory Run Energy Center, LLC	PA	4/23/2013	3,665,974 TPY	NA	NA	2-on-1; F-Class CTs; 12-month rolling
Calpine Garrison Energy Center	DE	1/30/2013	1,006,304	NA	NA	2-on-1; GE F-Class CTs; 12-month rolling average
Calpine Deer Park	TX	11/29/2012	1,063,650	920	7,730	2-on-1; Siemens F-Class CTs; 12-month rolling average
Calpine Channel	TX	11/29/2012	1,063,650	920	7,730	2-on-1; Siemens F-Class CTs; 12-month rolling average
Hess Newark	NJ	10/13/2012	2,000,268	887	7,522	without Duct Burner
Criquet Valley	NY	9/27/2012	3,576,943	913	7,605	without Duct Burner
Gibson County	TN	9/4/2012	1,679,459	NA	NA	2-on-1; GE F-Class
Woodbridge	NJ	8/24/2012	312,885	925	7,605	2-on-1; GE F-Class

* Calculated from heat rate using EPA Part 75 procedures. ** Design value at 59 oF.

Source: EPA RBLC, 2017.

Note: NA = not applicable.

APPENDIX C

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



Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM DEP FORM No. 62-210.900(1) and INSTRUCTIONS

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

Identification of Facility

1. Facility Owner/Company Name: Shady Hills Energy Center, LLC	
2. Site Name: Shady Hills Combined Cycle Facility	
3. Facility Identification Number: 1010373 ☐ Unknown	
4. Facility Location 14240 Merchant Energy Way Street Address or Other Locator: City: Shady Hills County: Pasco Zip Code: 36410	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Roy S. Belden Title:	
2. Application Contact Mailing Address Organization/Firm: Shady Hills Energy Center, LLC Street Address: 901 Main Avenue City: Norwalk State: CT Zip Code: 06851	
3. Application Contact Telephone Numbers Telephone: (203) 357-6820 ext. Fax: (203) 961-5116	
4. Application Contact E-mail Address: roy.belden@ge.com	

Application Processing Information (DEP Use Only)

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

I. 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 for the construction of a 1x1 combined-cycle electric power generating facility consisting of one GE 7HA.02 CTG with duct firing and a Heat Recovery Steam Generator, auxiliary boiler, emergency generator, fire pump engine, and a 6-cell cooling tower.

I. APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
N/A	Combined-cycle combustion turbine generator (CTG) and HRSG	AC1A	
N/A	Auxiliary Boiler	AC1A	
N/A	6-Cell Cooling Tower	AC1A	
N/A	Emergency Diesel Generator (2,206 hp)	AC1A	
N/A	Diesel Fire Pump Engine (347 hp)	AC1A	

Application Processing Fee

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

I. APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name: Roy S. Belden Title: Vice President	
2. Owner/Authorized Representative Mailing Address Organization/Firm: Shady Hills Energy Center, LLC Street Address: 901 Main Avenue City: Norwalk State: CT Zip Code: 06851	
3. Owner/Authorized Representative Telephone Numbers Telephone: (203) 357 - 6820 ext. Fax:	
4. Owner/Authorized Representative E-mail Address: roy.belden@ge.com	
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative* of the facility 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 (Department) and revisions thereof. 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 any permitted emissions unit.</i> Signature <u>Roy S. Belden</u> Date <u>2/16/18</u>	

* Attach letter of authorization if not currently on file.

I. APPLICATION INFORMATION

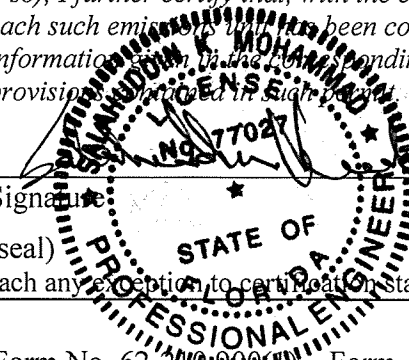
Application Responsible Official Certification

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

1. Application Responsible Official Name: _____ Title: _____			
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 _____			

I. APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Salahuddin K. Mohammad Florida License Number: 77027	
2. Professional Engineer Mailing Address Organization/Firm: Golder Associates Inc. Street Address: 6026 NW 1st Place City: Gainesville State: FL Zip Code: 32606	
3. Professional Engineer Telephone Numbers Telephone: (352) 336 - 5600 ext. Fax: (352) 336 - 6603	
4. Professional Engineer E-mail Address: smohammad@golder.com	
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>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</i> <i>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.</i> <i>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.</i> <i>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.</i> <i>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 following application for air construction permit and with all provisions contained in such permit.</i> Signature _____ (seal)  2/16/2018 Date _____ * Attach any exception to certification statement.	

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates Zone: East (km): 347.0 North (km): 3139.0		2. Facility Latitude/Longitude Latitude (DD/MM/SS): 28/22/00 Longitude (DD/MM/SS): 82/33/30	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Primary Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Primary NAICS 2-digit Code: 22		8. Facility NAICS(s) 6-digit Code(s): 221112	
9. Facility Comment:			

Facility Contact

1. Facility Contact Name: Roy S. Belden Title:
2. Facility Contact Mailing Address Organization/Firm: Shady Hills Energy Center, LLC Street Address: 901 Main Avenue City: Norwalk State: CT Zip Code: 06851
3. Facility Contact Telephone Numbers: Telephone: (203) 357 - 6820 ext. Fax: () -
4. Facility Contact E-mail Address: roy.belden@ge.com

Facility Primary Responsible Official

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

1. Facility Primary Responsible Official Name: Title:
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:

II. 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: The combined-cycle CTG is subject to 40 CFR 60 Subpart KKKK—Standards of Performance for Stationary Combustion Turbines and 40 CFR 60 Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. The auxiliary boiler is subject to 40 CFR 60 Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and Subpart A - General Provisions. The standby generator and the emergency fire pump engine are subject to 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.

Potential Greenhouse Gas Emissions (For PSD applications only.)

1. List the potential emissions, in tons per year, of the following greenhouse gases:

Greenhouse Gas	Tons/year	2. x GWP =	CO2e (Tons/year)
carbon dioxide		1	See PSD Report
nitrous oxide		298	
methane		25	
sulfur hexafluoride		22,800	
hydrofluorocarbons			
perfluorocarbons			
3. Total carbon dioxide equivalents			

4. Greenhouse Gases Comments:

See Table 2-7, A-7, A- 8 and A-9 in PSD Report

II. FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM10	A	N
CO	A	N
VOC	A	N
SO2	A	N
NOx	A	N

II. FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

II. FACILITY INFORMATION

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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location ☒ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL) ☐ Attached, Document ID: <u>See PSD Report</u>
3. Rule Applicability Analysis ☐ Attached, Document ID: <u>See PSD Report</u>
4. List of Exempt Emissions Units ☒ Attached, Document ID: <u>SH-FI-C4</u> ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification ☐ Attached, Document ID: _____ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.) ☐ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.) ☐ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.) ☐ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.) ☐ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.) ☐ Attached, Document ID: _____ ☒ Not Applicable

II. FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirement for FESOP Applications

List of Exempt Emissions Units

☐ Attached, Document ID: _____ ☒ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only)

☐ Attached, Document ID: _____ ☒ Not Applicable (revision application)

2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought. For federal regulations where applicability is dependent on the specific type of facility, provide the level of detail required to determine which specific set of regulations apply.)

☐ 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

II. FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain or CAIR Program

1. **Acid Rain Program Forms:**

Acid Rain Part Application (DEP Form No. 62-210.900(1)(a))

☒ Attached, Document ID: **SH-FI-AR** ☐ 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

ATTACHMENT SH-FI-AR

ACID RAIN FORM

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name Shady Hills Combined Cycle Facility	State FL	ORIS Plant Code 55414
--	-----------------	------------------------------

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO₂ Opt-in unit, enter "yes" in column "b".

For new units or SO₂ Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO ₂ Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO ₂ Opt-in Units Commence Operation Date	New or SO ₂ Opt-in Units Monitor Certification Deadline
CTG01	NO	Yes	TBD	TBD
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

STEP 3

Read the standard requirements.

Shady Hills Combined Cycle Facility

Plant Name (from STEP 1)

Acid Rain Part Requirements.

- (1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
 - (ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
- (2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
 - (ii) Have an Acid Rain Part.

Monitoring Requirements.

- (1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
- (4) For applications including a SO₂ Opt-in unit, a monitoring plan for each SO₂ Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO₂ Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

- (1) The owners and operators of each source and each Acid Rain unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

- (1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
- (2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
 - (i) Pay without demand and the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
 - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

- (1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
 - (i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 - (iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

Plant Name (from STEP 1)

Shady Hills Combined Cycle Facility

Recordkeeping and Reporting Requirements (cont)

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.

(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4

For SO₂ Opt-in units only.

In column "f" enter the unit ID# for every SO₂ Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

Plant Name (from STEP 1)
Shady Hills Combined Cycle Facility

STEP 5

For SO₂ Opt-in units only.
 (Not required for SO₂ Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO₂ Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO ₂ Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO ₂ Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO ₂ Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO ₂ Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO₂ Opt-in units only.

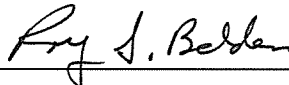
Attach additional requirements, certify and sign.

- If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
- A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
- A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
- Attach a complete compliance plan for SO₂ under 40 CFR 72.40.
- The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
- The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature	Date
-----------	------

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)	
I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.	
Name Roy S. Belden	Title Vice President
Owner Company Name Shady Hills Energy Center, LLC	
Phone (203)-357-6820	E-mail address roy.belden@ge.com
Signature 	Date 2/16/18

ATTACHMENT SH-FI-C4
LIST OF EXEMPT EMISSIONS UNITS

ATTACHMENT SH-FI-C4

LIST OF TYPICAL INSIGNIFICANT ACTIVITIES

The project will contain facilities, emissions units, or pollutant-emitting activities that will meet the Categorical Exemptions criteria in Rule 62-210.300(3)(a), F.A.C., or Generic Emission Unit Exemptions criteria in Rule 62-210.300(3)(b)1., F.A.C. A typical list of these exempt and insignificant units is summarized below. These emission unit are common to combined cycle units and will not have a specific unit applicable requirement or affect the facilities regulatory status (i.e., potential-to-emit, PSD review or HAPs thresholds). The list of exempt emission units for the Project will be finalized upon construction and submitted with the Title V Air Operating Permit Application

- Diesel storage tanks for fire pump and emergency generator
- Miscellaneous new and used oil drums in storage building
- Portable diesel generators (wheel mounted)
- Internal combustion engines of vehicles used for transportation of passengers or freight
- Vacuum pumps in laboratory operations
- Equipment used for steam cleaning
- Belt or drum sanders having a total sanding surface of 5 square feet or less
- Laboratory equipment used exclusively for chemical or physical analyses
- Brazing, soldering, or welding equipment
- Fire and safety equipment
- Petroleum lubrication systems
- Degreasing units
- Non-halogenated solvent storage and cleaning operations
- Surface coating operations
- Combustion turbine lube oil vents
- Steam turbine lube oil vents
- Miscellaneous steam and condensate vents
- Aqueous ammonia (19-percent) storage tank(s)
- Sealed drums and containers
- Natural gas metering station
- Compressed nitrogen bottles
- Compressed air systems
- Storage & use of water treatment chemicals
- Water treatment systems
- Parts washer (aliphatic hydrocarbon solvent)
- Miscellaneous painting activities

- Oil/water separators
- Water treatment chemicals
- Miscellaneous electrical equipment
- Miscellaneous enclosed oil filled equipment
- Enclosed transformers
- Storage of bottled gases
- Lube oil storage area (55-gallon lube oil drums)
- Lube oil storage tank(s)
- Mineral oil storage tank(s)
- Hydraulic oil skids for the CTs
- Steam turbine electro-hydraulic control unit skid
- New and used oil drum storage
- Condensate storage tank(s)
- Various oily wastewater tanks

EMISSIONS UNIT INFORMATION

Section [1] of [5]
Combined-cycle CTG with HRSG

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION

Section [1] of [5]
Combined-cycle CTG with HRSG

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

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 GE 7HA.02 Combustion Turbine Generator (CTG) and Heat Recovery Steam Generator (HRSG) with duct burner.

3. Emissions Unit Identification Number: N/A

**4. Emissions Unit
Status Code:**

C

**5. Commence
Construction
Date:**

**6. Initial Startup
Date:**

**7. Emissions Unit
Major Group
SIC Code:**

49

8. NAICS Code: 221112**9. Federal Program Applicability: (Check all that apply)**

- ☒ Acid Rain Unit
- ☒ CAIR Unit

10. Package Unit

Manufacturer: General Electric (GE)

Model Number: GE 7HA.02 SS

11. Generator Nameplate Rating: 573 MW nominal net (winter)

12. Emissions Unit Comment:

1x1 Combined-cycle unit with duct firing in the HRSG firing only natural gas

EMISSIONS UNIT INFORMATION

Section [1] of [5]

Combined-cycle CTG with HRSG

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description:

Dry Low NOX (DLN) combustion for NOx control

2. Control Device or Method Code: 25

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description:

Selective Catalytic Reduction (SCR) for NOx control

2. Control Device or Method Code: 107

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 INFORMATION

Section [1] of [5]
Combined-cycle CTG with HRSG

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: 3,795.2 mmBtu/hr (HHV)		
4. Maximum Incineration Rate: lbs/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 Capacity of the HRSG Duct burner is 210 MMBtu/hr		
Maximum heat input rate at HHV based on baseload and 59 degrees ambient temperature		

EMISSIONS UNIT INFORMATION

Section [1] of [5]

Combined-cycle CTG with HRSG

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: 5		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: CTG Exhausts through HRSG Stack		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height (feet): 149	7. Exit Diameter (feet): 25.6
8. Exit Temperature (°F): 162.9	9. Actual Volumetric Flow Rate (acfm): 1,725,580	10. Water Vapor (%):
11. Maximum Dry Standard Flow Rate (dscfm):		12. Nonstack Emission Point Height (feet):
13. Emission Point UTM Coordinates Zone: East (km): 347.0 North (km): 3,139.0		14. Emission Point Latitude/Longitude Latitude (DD/MM/SS): 28/22/00 Longitude (DD/MM/SS): 82/33/30
15. Emission Point Comment: Stack parameters for ambient temperature of 59 degree F at baseload with duct firing. See Table 2-1 for stack parameters and Table A1 for volumetric flow rates as a function of ambient temperatures and loads.		

EMISSIONS UNIT INFORMATION

Section [1] of [5]
Combined-cycle CTG with HRSG

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Internal Combustion Engines; Electric Generation; Natural gas; Turbine		
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million Cubic feet
4. Maximum Hourly Rate: 3.58	5. Maximum Annual Rate: 31,360.8	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 2 gr/100 scf	8. Maximum % Ash:	9. Million Btu per SCC Unit: 913 (LHV)
10. Segment Comment: Fuel Usage Rate = Heat input (MMBtu/hr) / Heat content (Btu/lb) x 106 fuel Usage Rate = 3266.9 MMBtu/hr / 913 MMBtu/106 ft3 = 3.58 x 106 ft3/hr Annual rate = 3.58 Million ft3/hr x 8760 hrs/yr = 31,360.8 Million ft3/yr Based on base load at 59oF ambient temperature		

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:		

Section [1] of [5]
Combined-cycle CTG with HRSG

List of Pollutants Emitted by Emissions Unit

DEP Form No. 62-210.900(1) – Form
Effective: 6/2017

EMISSIONS UNIT INFORMATION

Section [1] of [5]
 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

Page [1] of [7]
 Particulate Matter Total - PM/PM10/PM2.5

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter Total - PM/PM10/PM2.5		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1, 2-2 and Table A2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

Page [1] of [7]
 Particulate Matter Total - PM/PM10/PM2.5

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

Page [2] of [7]
 Sulfur Dioxide - SO₂

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Sulfur Dioxide - SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1, 2-2 and Table A2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Sulfur Dioxide - SO₂

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

Page [3] of [7]
 Nitrogen Oxides - NOx

**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: Nitrogen Oxides - NOx		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1, 2-2 and Table A2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Nitrogen Oxides - NOx

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Carbon Monoxide - CO

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Monoxide - CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1, 2-2 and Table A2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Carbon Monoxide - CO

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Volatile Organic Compounds - VOC

**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: Volatile Organic Compounds - VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1, 2-2 and Table A2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Volatile Organic Compounds - VOC

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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Carbon Dioxide Equivalent - CO₂e**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Dioxide Equivalent - CO ₂ e		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Table 2-7 and Table A7 CT-GHG in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Carbon Dioxide Equivalent - CO₂e

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Sulfuric Acid Mist - SAM

**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: Sulfuric Acid Mist - SAM		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Tables 2-1 and 2-2 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [5]
 Combined-cycle CTG with HRSG

POLLUTANT DETAIL INFORMATION

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 Sulfuric Acid Mist - SAM

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report bs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [1] of [5]
Combined-cycle CTG with HRSG

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE20	2. Basis for Opacity Limit: ☐ Rule ☒ Other
3. Opacity Limit Normal Conditions: 20 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: Exceptional condition allowed for 10 6-minute periods/day Proposed secondary BACT limit applies during startup and shutdown (See Table 4-1)	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE10	2. Basis for Opacity Limit: ☐ Rule ☒ Other
3. Opacity Limit Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: See PSD Report, Section 4.2 and Table 4-1 Proposed primary BACT limit applies during normal operation	

EMISSIONS UNIT INFORMATION

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Combined-cycle CTG with HRSG

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 1

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	
4. Monitor Manufacturer: TBD Model Number: Serial Number: TBD	
5. Installation Date: TBD	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: CEM meeting 40 CFR Part 75 requirements NOx CEM will also include diluent monitor (O2 or CO2)	

Continuous Monitoring System: Continuous Monitor ____ of ____

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

EMISSIONS UNIT INFORMATION

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Combined-cycle CTG with HRSG

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)**Continuous Monitoring System:** Continuous Monitor ____ of ____

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

EMISSIONS UNIT INFORMATION

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Combined-cycle CTG with HRSG

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: <u>See PSD report</u> ☐ 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: <u>See PSD report</u> ☐ 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: <u>See PSD report</u> ☐ 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: <u>See PSD report</u> ☐ 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: <u>See PSD report</u> ☐ 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

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Combined-cycle CTG with HRSG

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: <u>See PSD Report</u>	☐ Not Applicable
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: <u>See PSD Report</u>	☐ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	☒ Attached, Document ID: <u>See PSD Report</u>	☐ Not Applicable

1. Identification of Applicable Requirements (For federal regulations where applicability is dependent on the specific type of emissions unit and/or emissions unit subgroup, provide the level of detail required to determine which specific set of regulations apply.): ☐ 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

[illegible]

EMISSIONS UNIT INFORMATION

Section [2] of [5]

Auxiliary Boiler

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION

Section [2] of [5]

Auxiliary Boiler

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

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: 60 MMBtu/hr natural gas firing Auxiliary Boiler**3. Emissions Unit Identification Number:****4. Emissions Unit Status Code:****C****5. Commence Construction Date:****6. Initial Startup Date:****7. Emissions Unit Major Group SIC Code:****49****8. NAICS Code: 221112****9. Federal Program Applicability: (Check all that apply)**

- ☐ Acid Rain Unit
- ☐ CAIR Unit

10. Package Unit**Manufacturer: TBD****Model Number: TBD****11. Generator Nameplate Rating: MW****12. Emissions Unit Comment:**

Auxiliary boiler will be used to provide steam and steam cleaning during construction and initial startup of the CTG/HRSG/STG combined cycle unit. The Auxiliary boiler will also provide steam to the combined cycle unit during cold, warm and hot startups and when the combined cycle unit is being shut down

EMISSIONS UNIT INFORMATION

Section [2] of [5]

Auxiliary Boiler

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description:

Low NOX burners

2. Control Device or Method Code: 205

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:

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

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: 60.0 mmBtu/hr		
4. Maximum Incineration Rate: lbs/hr tons/day		
5. Requested Maximum Operating Schedule		
24 hours/day:		7 days/week:
52 weeks/year:		2000 hours/year:
6. Operating Capacity/Schedule Comment:		
The auxiliary boiler will be used only during the cold, warm and hot startups and when the combined cycle unit is being shutdown		

EMISSIONS UNIT INFORMATION

Section [2] of [5]

Auxiliary Boiler

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: 16		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Auxiliary Boiler		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: 		
5. Discharge Type Code: V	6. Stack Height (feet): 50	7. Exit Diameter (feet): 3.0
8. Exit Temperature (°F): 309	9. Actual Volumetric Flow Rate (acfm): 25,447	10. Water Vapor (%):
11. Maximum Dry Standard Flow Rate (dscfm):		12. Nonstack Emission Point Height (feet):
13. Emission Point UTM Coordinates Zone: East (km): North (km):		14. Emission Point Latitude/Longitude Latitude (DD/MM/SS): Longitude (DD/MM/SS):
15. Emission Point Comment: See Table 2-3 in the PSD report		

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): External Combustion Boilers; Electric Generation; Natural Gas; Boilers >100 MMBtu/hr		
2. Source Classification Code (SCC): 10100601		3. SCC Units: MMscf
4. Maximum Hourly Rate: 0.058	5. Maximum Annual Rate: 117.64	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 1,020
10. Segment Comment: Maximum hourly rate = Heat input (MMBtu/hr) / heat content (Btu/scf) Maximum hourly rate = 60 (MMBtu/hr) (HHV) / 1020 MMBtu/10 ⁶ scf = 0.058 Million ft ³ /hr Maximum annual rate = 0.058 Million ft ³ /hr * 2000 hrs/yr = 117.64 Million ft ³ /yr		

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:		

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Auxiliary Boiler

List of Pollutants Emitted by Emissions Unit

[illegible]

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Particulate Matter Total - PM/PM10/PM2.5

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter Total - PM/PM10/PM2.5		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.42 lbs/hour 0.42 tons/year		4. Synthetically-Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0070 lb/MMBtu Reference: Emissions based on AP-42		7. Emissions Method Code: 3B	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Potential emissions (lb/hr) = 0.007 lb/MMBtu x 60.0 MMBtu/hr = 0.42 lb/hr Potential emissions (TPY) = 0.42 (lb/hr) x 2000 hr x ton/2000 lb = 0.42 TPY			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Particulate Matter Total - PM/PM10/PM2.5

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units:	4. Equivalent Allowable Emissions: 0.42 lbs/hour 0.42 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Sulfur Dioxide - SO₂**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Sulfur Dioxide - SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.34 lbs/hour 0.34 tons/year		4. Synthetically-Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 2 grains S/100 scf Reference: Maximum sulfur content for natural gas		7. Emissions Method Code:	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Hourly: 2 grains S/100 scf x 64/32 (MW SO ₂ /S) x 1 lb/7000 gr x 58,824 scf/hr = 0.34 lb/hr Annual: 0.34 lb/hr x 2000 hr/ 2000 lb = 0.34 TPY			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Sulfur Dioxide - SO₂**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 2 grains S/100 scf gas	4. Equivalent Allowable Emissions: 0.34 lbs/hour 0.34 tons/year
5. Method of Compliance: Fuel Sampling and Analysis	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Nitrogen Oxides - NOX

**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: Nitrogen Oxides - NOX		2. Total Percent Efficiency of Control:	
3. Potential Emissions 3 lbs/hour 3 tons/year		4. Synthetically-Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.050 lb/MMBtu Reference: Emissions based on AP-42		7. Emissions Method Code: 3B	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Hourly : 0.05 lb/MMBtu x 60.0 MMBtu/hr = 3.0 lb/hr Annual: 3.0 lb/hr x 2000 hr/ 2000 lb = 3.0 TPY			
11. Potential, Fugitive, and Actual Emissions Comment:			

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Auxiliary Boiler

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Nitrogen Oxides - NOX

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units:	4. Equivalent Allowable Emissions: 3.0 lbs/hour 3.0 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Carbon Monoxide - CO

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Monoxide - CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions 4.8 lbs/hour 4.8 tons/year		4. Synthetically-Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.080 lb/MMBtu Reference: Emissions based on AP-42		7. Emissions Method Code: 3B	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Hourly : 0.080 lb/MMBtu x 60.0 MMBtu/hr = 4.8 lb/hr Annual: 4.8 lb/hr x 2000 hr/ 2000 lb = 4.8 TPY			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Carbon Monoxide - CO

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units:	4. Equivalent Allowable Emissions: 4.8 lbs/hour 4.8 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Volatile Organic Compounds - VOC

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: Volatile Organic Compounds - VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions 4.8 lbs/hour 4.8 tons/year		4. Synthetically-Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0050 lb/MMBtu Reference: Emissions based on AP-42		7. Emissions Method Code: 3B	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Hourly : 0.0050 lb/MMBtu x 60.0 MMBtu/hr = 0.30 lb/hr Annual: 0.3 lb/hr x 2000 hr/ 2000 lb = 0.3 TPY			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Volatile Organic Compounds - VOC

**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 Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

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Carbon Dioxide Equivalent - CO₂e**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –****POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Dioxide Equivalent - CO ₂ e		2. Total Percent Efficiency of Control:	
3. Potential Emissions See PSD report lbs/hour See PSD report tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: See PSD report Reference:		7. Emissions Method Code: 3B	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Table 2-7 and Table A7 in PSD report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

POLLUTANT DETAIL INFORMATION

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Carbon Dioxide Equivalent - CO₂e**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: See PSD report, Table 4-1	4. Equivalent Allowable Emissions: See PSD report lbs/hour See PSD report tons/year
5. Method of Compliance: See PSD report, Table 4-1	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

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Auxiliary Boiler

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: VE20	2. Basis for Opacity Limit: ☒ Rule ☐ Other
3. Opacity Limit Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: FDEP Rule 62-296.320(4)(b)1, F.A.C., requires 20% opacity.	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Opacity Limit: ☐ Rule ☐ Other
3. Opacity Limit Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION (CONTINUED)**Continuous Monitoring System:** Continuous Monitor ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [2] of [5]

Auxiliary Boiler

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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ Not Applicable

Section [2] of [5]
Auxiliary Boiler

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: <u>See PSD Report</u> ☐ Not Applicable
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: <u>See PSD Report</u> ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: <u>See PSD Report</u> ☐ Not Applicable

1. Identification of Applicable Requirements (For federal regulations where applicability is dependent on the specific type of emissions unit and/or emissions unit subgroup, provide the level of detail required to determine which specific set of regulations apply.): ☐ 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

[illegible]

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

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:
Mechanical Draft Cooling tower**3. Emissions Unit Identification Number:**

4. Emissions Unit Status Code:
C

5. Commence Construction Date:
TBD

6. Initial Startup Date:
TBD

7. Emissions Unit Major Group SIC Code:
49

8. NAICS Code: 221112**9. Federal Program Applicability: (Check all that apply)**

- ☐ Acid Rain Unit
- ☐ CAIR Unit

10. Package Unit Manufacturer:**Model Number:****11. Generator Nameplate Rating:** MW**12. Emissions Unit Comment:**

6 cell wet mechanical draft cooling tower.

EMISSIONS UNIT INFORMATION

Section [3] of [5]

Mechanical Draft Cooling Tower

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description:

High Efficiency Mist Eliminators

2. Control Device or Method Code: 014

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:

Section [3] of [5] Mechanical Draft Cooling Tower

(Optional for unregulated emissions units.)

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:	mmBtu/hr	
4. Maximum Incineration Rate:	lbs/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:		

EMISSIONS UNIT INFORMATION

Section [3] of [5]

Mechanical Draft Cooling Tower

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: 6 Cooling Tower Cells		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height (feet): 51.2	7. Exit Diameter (feet): 33
8. Exit Temperature (°F): 91.0	9. Actual Volumetric Flow Rate (acfm): 1,659,000	10. Water Vapor (%):
11. Maximum Dry Standard Flow Rate (dscfm):		12. Nonstack Emission Point Height (feet):
13. Emission Point UTM Coordinates Zone: East (km): North (km):		14. Emission Point Latitude/Longitude Latitude (DD/MM/SS): Longitude (DD/MM/SS):
15. Emission Point Comment: Stack dimensions are per cell		

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

D. SEGMENT (PROCESS/FUEL) INFORMATION

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:		

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:		

Section [3] of [5] Mechanical Draft Cooling Tower

List of Pollutants Emitted by Emissions Unit

[illegible]

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [1] of [3]
Particulate Matter Total - PM

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter Total - PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions 3.7 lbs/hour 16.1 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.001 % Drift rate Reference:		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Table 2-6 in PSD Report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [1] of [3]
Particulate Matter Total - PM

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.001 percent of CW	4. Equivalent Allowable Emissions: 3.7 lbs/hour 16.1 tons/year
5. Method of Compliance: Design Certification from Manufacturer	
6. Allowable Emissions Comment (Description of Operating Method): CW = circulating water	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [2] of [3]
Particulate Matter - PM10

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter - PM10		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.72 lbs/hour 3.17 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0010 % Drift rate Reference:		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Table 2-6 in PSD Report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [2] of [3]
Particulate Matter - PM10

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.0010 percent of CW	4. Equivalent Allowable Emissions: 0.72 lbs/hour 3.17 tons/year
5. Method of Compliance: Design Certification from Manufacturer	
6. Allowable Emissions Comment (Description of Operating Method): CW = circulating water	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [3] of [3]
Particulate Matter - PM2.5

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)**

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter - PM2.5		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.01 lbs/hour 0.044 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0010 % Drift rate Reference:		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: See Table 2-6 in PSD Report			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

POLLUTANT DETAIL INFORMATION

Page [3] of [3]
Particulate Matter - PM2.5

**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 Numerical Emissions Limitation **1** of **1**

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.0010 percent of CW	4. Equivalent Allowable Emissions: 0.01 lbs/hour 0.044 tons/year
5. Method of Compliance: Design Certification from Manufacturer	
6. Allowable Emissions Comment (Description of Operating Method): CW = circulating water	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [3] of [5]

DEP Form No. 62-210.900(1) – Form

Effective: 6/2017

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype: VE20	2. Basis for Opacity Limit: ☒ Rule ☐ Other
3. Opacity Limit Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9	
5. Visible Emissions Comment: FDEP Rule 62-296.320(4)(b)1, F.A.C., requires 20% opacity.	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Opacity Limit: ☐ Rule ☐ Other
3. Opacity Limit Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [3] of [5]
Mechanical Draft Cooling Tower

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: _____ ☐ 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: _____ ☐ 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: <u>See PSD Report</u> ☐ 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

Section [3] of [5] Mechanical Draft Cooling Tower

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: <u>See PSD Report</u>	☐ Not Applicable
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: _____	☒ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____	☒ Not Applicable

1. Identification of Applicable Requirements (For federal regulations where applicability is dependent on the specific type of emissions unit and/or emissions unit subgroup, provide the level of detail required to determine which specific set of regulations apply.): ☐ 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

[illegible]

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

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:**Emergency diesel generator****3. Emissions Unit Identification Number:****4. Emissions Unit Status Code:****C****5. Commence Construction Date:****TBD****6. Initial Startup Date:****TBD****7. Emissions Unit Major Group SIC Code:****49****8. NAICS Code: 221112****9. Federal Program Applicability: (Check all that apply)**

- ☐ Acid Rain Unit
- ☐ CAIR Unit

10. Package Unit**Manufacturer: Caterpillar****Model Number: 3512-C or equivalent****11. Generator Nameplate Rating: 1.5 MW****12. Emissions Unit Comment:**

1400 KW Emergency diesel generator will be used to provide electrical power during an emergency situation when electric power from the grid is interrupted onto ensure the safe shutdown of the CTG and for maintenance checks and readiness testing.

Tier 2 certified, 3.238 liters/cylinder displacement

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

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:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

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: 14.82 mmBtu/hr		
4. Maximum Incineration Rate: lbs/hr tons/day		
5. Requested Maximum Operating Schedule		
24 hours/day:		7 days/week:
52 weeks/year:		100 hours/year:
6. Operating Capacity/Schedule Comment:		
The emergency generator will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation. There are no limits for emergency operation. The emergency generator will meet the requirements of 40 CFR 60 Subpart IIII and Part 89.		

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height (feet): 25	7. Exit Diameter (feet): 1.0
8. Exit Temperature (°F): 756.7	9. Actual Volumetric Flow Rate (acfm): 11,734	10. Water Vapor (%):
11. Maximum Dry Standard Flow Rate (dscfm):		12. Nonstack Emission Point Height (feet):
13. Emission Point UTM Coordinates Zone: East (km): North (km):		14. Emission Point Latitude/Longitude Latitude (DD/MM/SS): Longitude (DD/MM/SS):
15. Emission Point Comment: See Table 2-4 in PSD Report		

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Ultra Low Sulfur Diesel Fuel Combustion		
2. Source Classification Code (SCC):		3. SCC Units: 1,000 gallons
4. Maximum Hourly Rate: 0.105	5. Maximum Annual Rate: 52.3	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: Annual rate = 104.6 gal/hr x 500 hr/yr = 52,300 gal/yr		

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:		

Section [4] of [5]
Emergency Diesel Generator

List of Pollutants Emitted by Emissions Unit

[illegible]

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [1] of [5]
Carbon Monoxide - CO

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Monoxide - CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions 12.7 lbs/hour 3.2 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 3.5 g/KW-hr Reference: Manufacture certification		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 3.5 g/KW-hr x 1645 KW x 1 lb/453.6 g = 12.7 lb/hr 12.7 lb/hr x 500 hr x ton/2000 lb = 3.2 TPY			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual annual operation of 500 hrs/yr, which includes 100 hrs/yr maintenance checks, readiness testing, and non-emergency operation See Table 2-4 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [1] of [5]
Carbon Monoxide - CO

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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 3.5 g/KW-hr	4. Equivalent Allowable Emissions: 12.7 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII standards.	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [2] of [5]
Nitrogen Oxides - NOX

**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: Nitrogen Oxides - NOX		2. Total Percent Efficiency of Control:	
3. Potential Emissions 23.2 lbs/hour 5.8 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 6.4 g/KW-hr Reference: Manufacture certification		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 7.3 g/KW-hr x 1,645 KW x lb/453.6 = 26.4 lb/hr 23.2 lb/hr x 500 hr x ton/2000 lb = 5.8 TPY			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual annual operation of 500 hrs/yr, which includes 100 hrs/yr maintenance checks, readiness testing, and non-emergency operation See Table 2-4 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [2] of [5]
Nitrogen Oxides - NOX

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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 6.4 g/KW-hr	4. Equivalent Allowable Emissions: 23.2 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII standards.	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [3] of [5]
Sulfur Dioxide - SO₂

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Sulfur Dioxide - SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.023 lbs/hour 0.0058 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0015% S fuel oil Reference: 40 CFR 60 Subpart IIII			7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: $0.0015\% \text{ S} \times 64/32 \text{ (MW SO}_2\text{/S)} \times 7.39 \text{ lb/gal} \times 104.6 \text{ gal/hr} = 0.023 \text{ lb/hr}$ $0.023 \text{ lb/hr} \times 500 \text{ hr} \times \text{ton}/2000 \text{ lb} = 0.0058 \text{ TPY}$			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual annual operation of 500 hrs/yr, which includes 100 hrs/yr maintenance checks, readiness testing, and non-emergency operation See Table 2-4 E Gen in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [3] of [5]
Sulfur Dioxide - SO₂

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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.0015% S fuel oil	4. Equivalent Allowable Emissions: 0.023 lbs/hour tons/year
5. Method of Compliance: Fuel Vendor Information	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [4] of [5]
Particulate Matter - PM/PM10/PM2.5

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter - PM/PM10/PM2.5		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.7 lbs/hour 0.18 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.20 g/KW-hr Reference: Manufacturer certification		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 0.20 g/KW-hr x 1,645 x 1 lb/453.6 g = 0.7 lb/hr 0.7 lb/hr x 500 hr x ton/2000 lb = 0.18 TPY			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual annual operation of 500 hrs/yr, which includes 100 hrs/yr maintenance checks, readiness testing, and non-emergency operation See Table 2-4 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [4] of [5]
Particulate Matter - PM/PM10/PM2.5

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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.2 g/KW-hr	4. Equivalent Allowable Emissions: 0.7 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII Standards.	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [5] of [5]
Volatile Organic Compounds - VOC

**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: Volatile Organic Compounds - VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions 3.6 lbs/hour 0.91 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 1 g/kW-hr Reference: Manufacturer certification		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: $1 \text{ g/kW-hr} \times 1,645 \text{ kW} \times 1 \text{ lb}/453.6 \text{ g} = 3.6 \text{ lb/hr}$ $3.6 \text{ lb/hr} \times 500 \text{ hr} \times \text{ton}/2000 \text{ lb} = 0.91 \text{ TPY}$			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual annual operation of 500 hrs/yr, which includes 100 hrs/yr maintenance checks, readiness testing, and non-emergency operation See Table 2-4 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [4] of [5]
Emergency Diesel Generator

POLLUTANT DETAIL INFORMATION

Page [5] of [5]
Volatile Organic Compounds - VOC

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 Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype: VE20	2. Basis for Opacity Limit: ☒ Rule ☐ Other
3. Opacity Limit Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20 percent opacity.	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Opacity Limit: ☐ Rule ☐ Other
3. Opacity Limit Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [4] of [5]

Emergency Diesel Generator

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: <u>See PSD Report</u> ☐ 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: <u>See PSD Report</u> ☐ 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: _____ ☐ 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

Section [4] of [5] Emergency Diesel Generator

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

--

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

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:
Diesel fire pump engine**3. Emissions Unit Identification Number:****4. Emissions Unit Status Code:**

C

5. Commence Construction Date:
TBD**6. Initial Startup Date:**

TBD

7. Emissions Unit Major Group SIC Code:

49

8. NAICS Code: 221112**9. Federal Program Applicability: (Check all that apply)**

- ☐ Acid Rain Unit
- ☐ CAIR Unit

10. Package Unit

Manufacturer: Cummins Model Number: CFP9E-F40 or equivalent

11. Generator Nameplate Rating: MW**12. Emissions Unit Comment:**

One diesel fired pump rated at approximately 347 hp, which will be used to provide power to pump water for fire suppression or protection
Tier 3 certified, 1.483 liters/cylinder displacement

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

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:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [5] of [5]

Diesel Fire Pump Engine

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: 2.46 mmBtu/hr
4. Maximum Incineration Rate: lbs/hr tons/day
5. Requested Maximum Operating Schedule 24 hours/day: 7 days/week: 52 weeks/year: 100 hours/year:
6. Operating Capacity/Schedule Comment: The emergency fire pump engine will operate a combined total of 100 hr/yr for maintenance checks, and readiness testing, which includes a maximum 50 hr/yr for non-emergency operation. There are no limits for emergency operation. The fire pump engine will meet the requirements of 40 CFR Part 98 Tier III engines.

EMISSIONS UNIT INFORMATION

Section [5] of [5]

Diesel Fire Pump Engine

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: 28		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height (feet): 15	7. Exit Diameter (feet): 0.50
8. Exit Temperature (°F): 1,088	9. Actual Volumetric Flow Rate (acfm): 2,036	10. Water Vapor (%):
11. Maximum Dry Standard Flow Rate (dscfm):		12. Nonstack Emission Point Height (feet):
13. Emission Point UTM Coordinates Zone: East (km): North (km):		14. Emission Point Latitude/Longitude Latitude (DD/MM/SS): Longitude (DD/MM/SS):
15. Emission Point Comment: See Table 2-5 in PSD Report		

EMISSIONS UNIT INFORMATION

Section [5] of [5]

Diesel Fire Pump Engine

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Diesel Fuel Combustion		
2. Source Classification Code (SCC):		3. SCC Units: 1,000 gallons
4. Maximum Hourly Rate: 0.0174	5. Maximum Annual Rate: 8.7	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: Hourly rate = 17.4 gal/hr Annual rate = 17.4 gal/hr x 500 hr/yr = 8,700 gal/yr		

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:		

**Section [5] of [5]
Diesel Fire Pump Engine**

List of Pollutants Emitted by Emissions Unit

DEP Form No. 62-210.900(1) – Form
Effective: 6/2017

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [1] of [5]
 Carbon Monoxide - CO

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Carbon Monoxide - CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions 1.99 lbs/hour 0.5 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 2.60 g/hp-hr Reference: Manufacturer certification		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: $2.6 \text{ g/hp-hr} \times 347 \text{ hp} \times 1 \text{ lb}/453.6 \text{ g} = 1.99 \text{ lb/hr}$ $1.99 \text{ lb/hr} \times 500 \text{ hr/yr} \times 1 \text{ ton}/2,000 \text{ lb} = 0.5 \text{ TPY}$			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual operation of 500 hrs/yr, which includes 100 hrs/yr for maintenance checks, readiness testing and non-emergency operation See Table 2-5 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [1] of [5]
 Carbon Monoxide - CO

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions: 1.99 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII standards	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [2] of [5]
Nitrogen Oxides - NOX

**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: Nitrogen Oxides - NOX		2. Total Percent Efficiency of Control:	
3. Potential Emissions 2.29 lbs/hour 0.57 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 3.0 g/hp-hr Reference: Manufacturer certification			7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 3.0 g/hp-hr x 347 hp x 1 lb/453.6 g = 2.29 lb/hr 2.29 lb/hr x 500 hr/yr x 1 ton/2,000 lb = 0.57 TPY			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual operation of 500 hrs/yr, which includes 100 hrs/yr for maintenance checks, readiness testing and non-emergency operation See Table 2-5 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [2] of [5]
Nitrogen Oxides - NOX

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 3.0 g/hp-hr	4. Equivalent Allowable Emissions: 2.29 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII standards	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [3] of [5]
 Sulfur Dioxide - SO₂

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
 POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
 (Optional for unregulated emissions units.)**

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Sulfur Dioxide - SO ₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.0039 lbs/hour 0.00096 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.0015% S fuel oil Reference: 40 CFR 60 Subpart IIII			7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: $0.0015\% \text{ S} \times 64/32 \text{ (MW SO}_2\text{/S)} \times 7.39 \text{ lb/gal} \times 17.4 \text{ gal/hr} = 0.0039 \text{ lb/hr}$ $0.0039 \text{ lb/hr} \times 500 \text{ hr/yr} \times 1 \text{ ton}/2,000 \text{ lb} = 0.00096 \text{ TPY}$			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual operation of 500 hrs/yr, which includes 100 hrs/yr for maintenance checks, readiness testing and non-emergency operation See Table 2-5 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [3] of [5]
 Sulfur Dioxide - SO₂

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: OTHER	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: 0.0039 lbs/hour tons/year
5. Method of Compliance: Fuel Vendor Information	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [4] of [5]
 Particulate Matter - PM/PM10/PM2.5

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
 POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
 (Optional for unregulated emissions units.)**

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: Particulate Matter - PM/PM10/PM2.5		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.11 lbs/hour 0.029 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.15 g/hp-hr Reference: Manufacturer certification			7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: $0.15 \text{ g/hp-hr} \times 347 \text{ hp} \times 1 \text{ lb}/453.6 \text{ g} = 0.11 \text{ lb/hr}$ $0.11 \text{ lb/hr} \times 500 \text{ hr/yr} \times 1 \text{ ton}/2,000 \text{ lb} = 0.029 \text{ TPY}$			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual operation of 500 hrs/yr, which includes 100 hrs/yr for maintenance checks, readiness testing and non-emergency operation See Table 2-5 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [4] of [5]
 Particulate Matter - PM/PM10/PM2.5

**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 Numerical Emissions Limitation 1 of 1

1. Basis for Numerical Emissions Limitation Code: RULE	2. Future Effective Date of Numerical Emissions Limitation:
3. Numerical Emissions Limitation and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: 0.11 lbs/hour tons/year
5. Method of Compliance: Manufacturer certification of Subpart IIII standards	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
 Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [5] of [5]
 Volatile Organic Compounds - VOC

**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: Volatile Organic Compounds - VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions 0.57 lbs/hour 0.143 tons/year		4. Synthetically-Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): _____ to _____ tons/year			
6. Emission Factor: 0.75 g/hp-hr Reference: Manufacturer certification			7. Emissions Method Code: 2
8.a. Baseline Actual Emissions (if required): tons/year		8.b. Baseline 24-month Period: From: To:	
9.a. Projected Actual Emissions (if required): tons/year		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: 0.75 g/hp-hr x 347 hp x 1 lb/453.6 g = 0.57 lb/hr 0.57 lb/hr x 500 hr/yr x 1 ton/2,000 lb = 0.143 TPY			
11. Potential, Fugitive, and Actual Emissions Comment: Annual emissions based on assumed actual operation of 500 hrs/yr, which includes 100 hrs/yr for maintenance checks, readiness testing and non-emergency operation See Table 2-5 in the PSD Report			

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

POLLUTANT DETAIL INFORMATION

Page [5] of [5]
Volatile Organic Compounds - VOC

**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 Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

Allowable Emissions Numerical Emissions Limitation ____ of ____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

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: VE20	2. Basis for Opacity Limit: ☒ Rule ☐ Other
3. Opacity Limit Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20 percent opacity.	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Opacity Limit: ☐ Rule ☐ Other
3. Opacity Limit Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor _____ of _____

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

EMISSIONS UNIT INFORMATION

Section [5] of [5]
Diesel Fire Pump Engine

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: See PSD Report ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: See PSD Report ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: See PSD Report ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

**Section [5] of [5]
Diesel Fire Pump Engine**

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: <u>See PSD Report</u> ☐ Not Applicable
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: _____ ☒ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☒ Not Applicable

1. **Identification of Applicable Requirements** (For federal regulations where applicability is dependent on the specific type of emissions unit and/or emissions unit subgroup, provide the level of detail required to determine which specific set of regulations apply.):
☐ 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

APPENDIX 10.2.66

COASTAL ZONE MANAGEMENT CERTIFICATIONS

NOTE: The Florida Coastal Management Act (§380.205-380.27, Florida Statutes) requires that the Coastal Zone Management Section of FDEP be responsible for certification of consistency with the Florida Coastal Management Program (FCMP) for all federal licenses, permits, activities, and projects listed in §380.23(3)(c), Florida Statutes, when such activities are subject to federal consistency review and affect land or water use, are seaward of the jurisdiction of the state, or there is no state agency with sole jurisdiction for such consistency review. The issuance of federal permits listed in §380.23(3)(c), Florida Statutes is not required for this Project. Nonetheless, issuance of the final Site Certification constitutes consistency with the Federal Coastal Zone Management Act.

APPENDIX 10.2.77

OTHER FEDERAL PERMITS OR APPROVALS

NOTE: There are no federal permits or approvals required for the SHCCF Project.

APPENDIX 10.2.8
USFWS CONCURRENCY LETTER

Bullock, Karl

From: Nguyen, Tina <tina_nguyen@fws.gov>
Sent: Friday, February 16, 2018 11:35 AM
To: Bullock, Karl
Cc: Zions, Adam; Phillips, Luna; Moultrie, Manitia
Subject: Re: request for environmental review - Shady Hills Combined Cycle Facility
Attachments: 20180216_ltr_FWS_Shady Hills Combined Cycle Facility.pdf

Dear Mr. Karl Bullock,

Please see the following attachment regarding the Service's concurrence on the Shady Hills Combined Cycle Facility project in Pasco County. At least **30 days prior** to any clearing/land alteration activities, the applicant shall notify the appropriate USFWS Field Office via e-mail (jaxregs@fws.gov) that the Eastern Indigo Snake Standard Protection Measures will be implemented. Feel free to contact me if you have any additional questions or concerns. Thank you for contacting the USFWS North Florida Ecological Services Office for consultation.

Best,

Tina

On Mon, Feb 5, 2018 at 10:43 AM, Bullock, Karl <Karl_Bullock@golder.com> wrote:

Thank you Tina!



Karl Bullock
Associate and Senior Scientist

[6026 NW 1st Place, Gainesville, Florida, USA 32607](#)

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Work Safe, Home Safe

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February 2, 2018

US Fish and Wildlife Service
North Florida Ecological Services Office
Attn: Ms. Tina Nguyen
7915 Baymeadows Way, Suite 200
Jacksonville, FL 32256-7517
Tina_Nguyen@fws.gov



FWS Log No 18-TA-0317

Based on the submitted information, the proposed action is not expected to cause "take" of the listed species as defined under section 9 of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.).

Annie Dyer gws

2-14-18

RE: SHADY HILLS COMBINED CYCLE FACILITY *per* Jay B. Herrington
Field Supervisor

Date

Dear Ms. Nguyen:

On behalf of Shady Hills Energy Center, LLC, Golder is preparing a Site Certification Application under the Florida Power Plant Siting Act for the proposed Shady Hills Combined Cycle Facility (Project), a 573 megawatt (winter) combined cycle natural gas unit to be constructed on the existing Shady Hills Power Plant site in Pasco County, FL (Figure 1). The Project is proposed upon previously disturbed areas of the Shady Hills Power Plant site comprising approximately 14 acres (Site) of the existing 30-acre parcel. The Site is surrounded by industrial, utility, and commercial uses. The Project includes an approximately 0.6-mile interconnection tie-line heading west to an existing high voltage transmission line right-of-way and an approximately 20-acre temporary construction laydown and parking area to the immediate east of the Site (Figure 2).

Golder has conducted field and desktop habitat evaluations, listed species surveys, and database reviews to evaluate the potential for threatened, endangered, or candidate (listed) species occurrences within the Project Area, which comprises the 14-acre Site, the interconnection tie-line corridor, and the temporary construction laydown and parking area. A summary of the analysis is provided below for review and concurrence by the U.S. Fish and Wildlife Service (USFWS).

Habitat Classification

Characteristic vegetative communities were classified utilizing the Florida Land Use, Cover and Forms Classification System (FLUCFCS) data from the Southwest Florida Water Management District (SWFWMD) that were updated based on field reconnaissance conducted in October 2017 and January 2018. As illustrated on Figure 3, the Site is dominated by approximately 12 acres of vacant land (FLUCFCS 190) and utilities (FLUCFCS 830) that was previously cleared and utilized as a temporary laydown and equipment storage area associated with construction of the existing Shady Hills Power Plant in 2001. Vegetation present in this area is dominated by ruderal native and non-native invasive/exotic groundcover species such as bahia grass (*Paspalum notatum*), beggar ticks (*Bidens* sp.), cogon grass (*Imperata cylindrica*), Durban crowfoot grass (*Dactyloctenium aegyptium*), and annual phlox (*Phlox drummondii*). An approximately 2-acre area of pine plantation occurs in the northern portion of the Site, with a canopy dominated by planted slash pine (*Pinus elliotii*) and a variety of subdominant native and non-native invasive/exotic species such as planted southern red cedar, laurel oak (*Quercus laurifolia*), beautyberry (*Callicarpa americana*), caesarweed (*Urena lobata*), slender flattop goldenrod (*Euthamia caroliniana*), dogfennel (*Eupatorium capillifolium*), prickly pear cactus (*Opuntia humifusa*), Virginia creeper (*Parthenocissus quinquefolia*), cogon grass, bahia grass, beggar ticks, and grapevine.

The interconnection tie-line will be installed within a portion of a 200-ft-wide corridor that traverses approximately 0.6-mile across existing disturbed lands located adjacent to the Shady Hills Power Plant. An approximately 3-acre area of mixed pine and oak (FLUCFCS 434) occurs on the eastern edge of the corridor, with a canopy of live oak (*Quercus virginiana*), laurel oak, and slash pine and a sparse understory

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of saplings, muscadine (*Vitis rotundifolia*), and catbrier (*Smilax* sp.). Although the width of the corridor is 200 ft, the actual width of the interconnection tie-line right-of-way (ROW) to be constructed within the corridor will be approximately 100 ft. Following removal of canopy species, only small areas within the ROW will be disturbed for construction of transmission structure foundations.

The temporary construction laydown and parking area is dominated by pine plantation and improved pasture, with a small area (approximately 2.3 acres) of live oak (FLUCFCS 427) in the northern corner that has historically been utilized for cattle grazing and supports a sparse understory of beautyberry, caesarweed, muscadine, and dogfennel.

Listed Species Assessment

Prior to field reconnaissance, Golder obtained county-specific lists of threatened and endangered species from the Florida Natural Areas Inventory (FNAI, 2017). In addition, geographic information system (GIS) data were obtained from the FNAI, which maintains a database of documented occurrences of listed species throughout the State of Florida. Golder conducted field surveys in August and October 2017 and January 2018. The only listed species that Golder observed within the Project Area during its field surveys were burrows of the gopher tortoise (*Gopherus polyphemus*), a state-listed threatened species that is a candidate for listing by the USFWS.

A list of threatened and endangered species known to occur in Pasco County and their probability of occurrence within the Project Area is provided in Table 1. The potential for utilization by most terrestrial listed species for foraging, roosting, or breeding is limited due to the significant alteration of the upland habitats present, as well as the surrounding industrial, utility, commercial, and limited residential development. The FNAI database did not include any documented occurrences of federally listed species within 5 miles of the Project (Figure 4).

Table 1. Federally Listed Species known to occur in Pasco County and Probability of Occurrence on Shady Hills Combined Cycle Project Area

Common Name	Scientific Name	Federal Status	Likelihood of Occurrence
Plants			
Britton's beargrass	<i>Nolina brittoniana</i>	Endangered	None
Reptiles			
Eastern Indigo Snake	<i>Drymarchon corais couperi</i>	Threatened	Low
Gopher Tortoise	<i>Gopherus polyphemus</i>	Candidate	Observed (burrows)
Green Sea Turtle	<i>Chelonia mydas</i>	Threatened	None
Kemp's Ridley Sea Turtle	<i>Lepidochelys kempi</i>	Endangered	None
Leatherback Sea Turtle	<i>Dermochelys coriacea</i>	Endangered	None
Loggerhead Sea Turtle	<i>Caretta caretta</i>	Threatened	None
Mammals			
West Indian Manatee	<i>Trichechus manatus</i>	Threatened	None
Birds			
Florida Scrub-Jay	<i>Aphelocoma coerulescens</i>	Threatened	None
Piping Plover	<i>Charadrius melodus</i>	Threatened	None
Wood Stork	<i>Mycteria americana</i>	Threatened	None

Flora – One federally-listed plant species is known to occur in Pasco County, Britton's beargrass (*Nolina brittoniana*). The FNAI database review did not indicate any reported occurrences of listed plant species in the vicinity of the Project, and no listed plant species were observed within the Project Area during field surveys. Britton's beargrass prefers scrub, sandhill, scrubby flatwoods, and xeric hammock habitats, which are not present within the Project Area. It is unlikely that the Project will affect federally listed plant species.

Fauna – The majority of federally listed species known to occur within Pasco County occur within aquatic or xeric habitats, which are not present within the Project Area. The FNAI database review did not indicate any reported occurrences of listed animal species in the vicinity of the Project.

The closest wood stork (*Mycteria americana*) colony (Embassy – Shoppers Way) is located approximately 10 miles to the southwest of the Project; no wetland impacts are proposed and no effect upon the wood stork is anticipated. A completed USFWS *Effect Determination Key for the Wood Stork in Central and North Peninsular Florida* is provided in Attachment A.

According to the Florida Fish and Wildlife Conservation Commission (FWC) bald eagle (*Haliaeetus leucocephalus*) nest location database, the closest documented bald eagle nests (nest ID #PS008 and PS031) are approximately 3 miles to the northeast and southwest of the Project, respectively (Figure 4). No adverse effect upon bald eagles is anticipated as a result of the Project.

Several burrows of the gopher tortoise were observed within the Project Area, as illustrated in Figure 5. A 25-foot buffer from construction will be maintained around burrows, where feasible. The majority of burrows are located on the southern edge of the interconnection tie-line corridor; it is likely that installation of transmission structures may be achieved without encroaching into the 25-foot buffer around most of these burrows. A permit will be obtained from FWC to excavate unavoidable burrows, and any captured tortoises will be relocated to an approved recipient site in accordance with FWC gopher tortoise permit guidelines.

The federally-threatened eastern indigo snake (*Drymarchon corais couperi*) occasionally utilizes gopher tortoise burrows as refugia, especially during the winter months in the northern portion of the state. In accordance with the USFWS *Eastern Indigo Snake Programmatic Effect Determination Key* (Attachment A), the Project may affect, but is not likely to adversely affect the eastern indigo snake because construction will be conducted in compliance with the USFWS *Standard Protection Measures for the Eastern Indigo Snake* (August 12, 2013), will require excavation of fewer than 25 gopher tortoise burrows, and will not impact xeric habitat.

Golder respectfully requests that the USFWS conduct an environmental review of the proposed Project and provide us with any comments to aid in the avoidance and minimization of potential impacts to federally listed species. In addition, to the extent appropriate, we request the USFWS's concurrence with Golder's determination that the Project is not likely to adversely affect federally listed species. If you have any questions or need additional information, please contact Adam Zions at 352-336-5600 or azions@golder.com. Golder appreciates the Service's assistance.

GOLDER ASSOCIATES INC.



Adam Zions
Senior Ecologist



Karl Bullock
Associate and Senior Scientist

cc: Manitia Moultrie, Golder Associates
Luna Phillips, Gunster

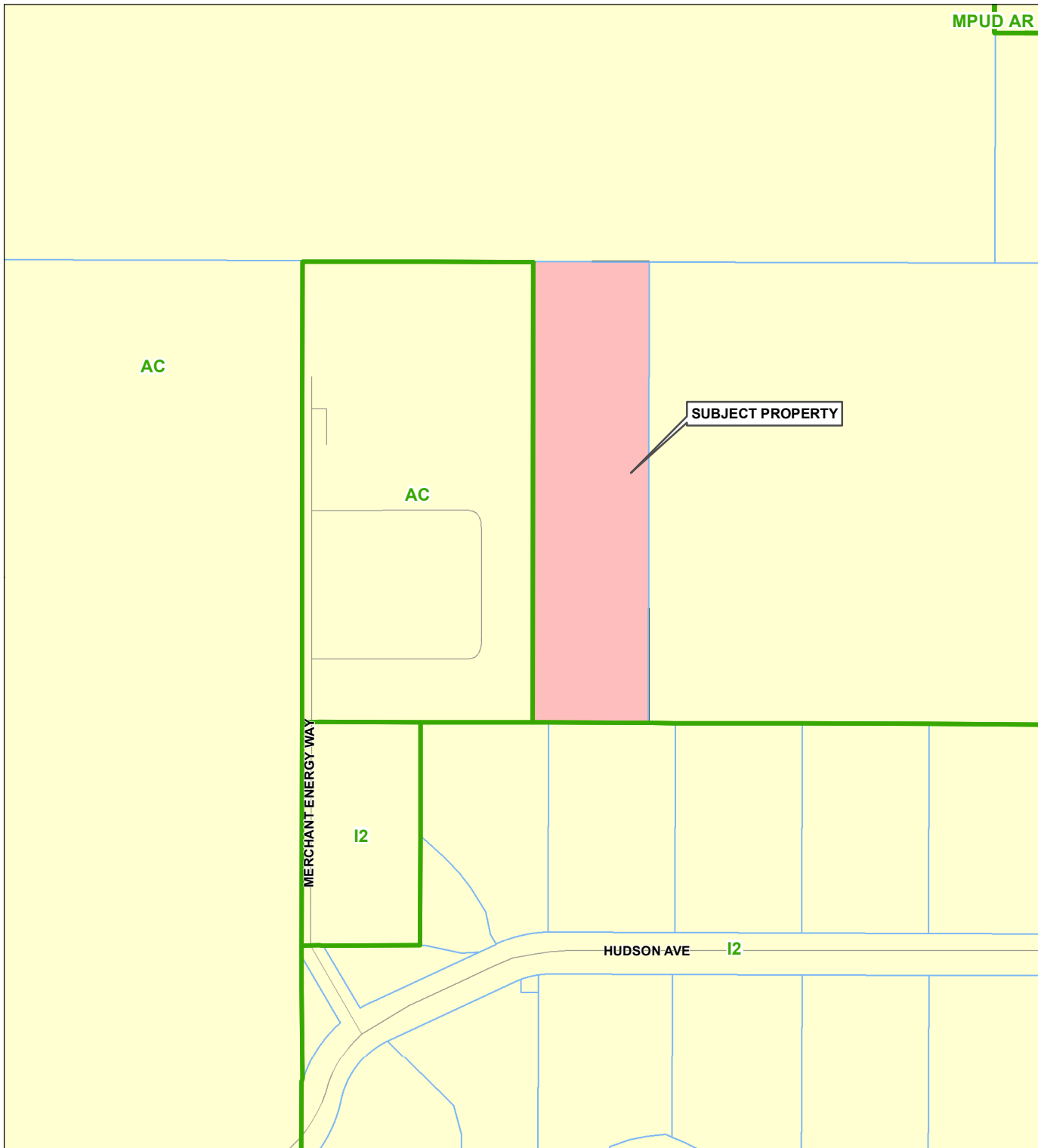
Figure 1 – Location Map
Figure 2 – Site Plan
Figure 3 – Land Use and Cover Map
Figure 4 – Documented Listed Species Occurrence within 5 Miles
Figure 5 – Gopher Tortoise Burrow Map

Attachment A – USFWS Effect Determination Keys

APPENDIX 10.3
ZONING DESCRIPTIONS

APPENDIX 10.3.1

PASCO COUNTY, ZONING MAP



SE-7295 PRIVATE UTILITY FACILITY IN A-C

PORTION OF:
25-24-17-0000-00100-0011

SHADY HILLS POWER CO.,LLC
14240 MERCHANT ENERGY WAY
SPRING HILL, FL 34610

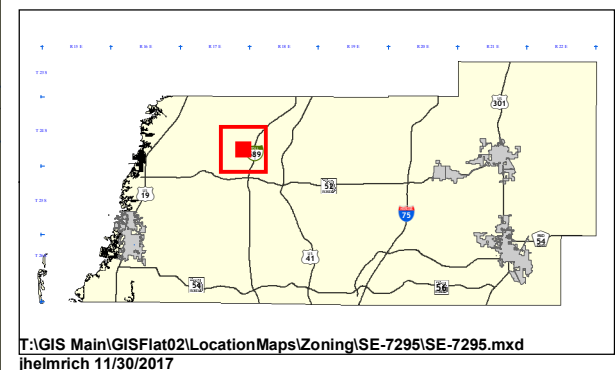
PHYSICAL ADDRESS:
14240-14350 MERCHANT ENERGY
WAY

TAZ-16
COMMISSION DISTRICT: 5

 SUBJECT PROPERTY
 EXISTING ZONING



0 500 1,000
Feet



APPENDIX 10.3.2
SECTION 503 OF THE PASCO
COUNTY LDC

CHAPTER 500. ZONING STANDARDS

SECTION 503. A-C AGRICULTURAL DISTRICT

503.1. Purpose

The purpose of the A-C Agricultural District is to preserve the rural and open character of various lands within the County. These lands are agricultural lands; sites of vital, natural water resource functions; areas with highly productive, natural plant and animal communities; and areas with valuable topographic and/or subsurface features, all of which are necessary to sustain and enhance the quality of life in the County.

Those uses will be allowed which are compatible with these overall objectives.

503.2. Permitted Uses

A. Principal Uses

1. Agriculture, general farming, and horticulture to include animal feedlots; the commercial hatching or raising of poultry; the production of eggs; the raising of hogs; pasturage of animals, such as cattle and horses; citrus groves (as well as other fruits); forestry; plant nurseries; sheds; stables; barns; truck farms; fish hatcheries; fish pools, and other structures devoted to the on-site farm uses.
2. Dwellings. Single-family detached dwellings on individual lots and single-family mobile homes on individual lots, where they are securely anchored as required by the County Building Code.
3. Home occupations.
4. Temporary roadside stands used on a seasonal basis for the sale of fruits, vegetables, and other agriculturally related products.
5. Public and private parks and playgrounds.
6. Noncommercial boat slips and piers or private docking facilities with the approval of the various State and/or Federal agencies where mandatory.
7. Noncommercial recreation facilities including parks, playgrounds, and camps for youths and adults.
8. Public and semipublic buildings and facilities to include the following: County, State, or Federal structures and uses; churches; civic organizations; and schools.
9. Residential treatment and care facilities, subject to a minimum site area of ten (10) acres.

B. Accessory Uses

1. Private garages and parking areas.
2. Private swimming pools and cabanas in accordance with this Code.
3. Signs in accordance with this Code.
4. Other accessory uses customarily incidental to an allowed principal use.

503.3. Conditional Uses

- A. Gun and archery range clubs and indoor or outdoor firing and archery ranges, subject to a minimum site area of ten (10) acres.
- B. Aircraft and helicopter landing fields, subject to approval by the Federal Aviation Administration and compliance with appropriate State and local laws, provided that no aircraft landing field or helicopter pad be located closer than 1,000 feet from the closest property line of a school that provides a curriculum of elementary or secondary academic instruction, including kindergarten, elementary, middle, or high schools.
- C. Parachute drops.
- D. Amusement parks.
- E. Automobile race tracks.
- F. Medical waste disposal facilities.
- G. Auction houses.
- H. Flea markets.
- I. Drive-in theaters.
- J. Construction and demolition debris dumps, subject to all local, State, and Federal regulations.
- K. Sanitary landfills, subject to all local, State, and Federal regulations.
- L. Yard trash disposal facilities.
- M. Mining and/or reclamation including, but not limited to, mining or extraction of limestone, clay, sand, natural gas, oil, and organic soils, subject to all local, State, and Federal regulations.
- N. Sludge, septage, and other waste disposal sites.

- O. Wastewater treatment plants, except when accessory to a development.
- P. Fertilizer manufacturing.
- Q. Saw mills.

503.4. **Performance Standards for Conditional and Special Exception Uses**

All activities shall be in conformance with standards established by the County, State, and Federal government.

503.5. **Special Exception Uses**

- A. Bed and breakfast, tourist homes.
- B. Country clubs and golf courses.
- C. Day-care centers.
- D. Public and private utility facilities to include the following:
 - 1. County, State, or Federal structures and uses.
 - 2. Water pumping plants; transmission lines for gas, electric, and telephones or for broadcasting or communication towers and facilities.
 - 3. Other conforming uses which do not cause an undue nuisance or adversely affect existing structures, uses, and residents.
- E. Storage and repair facilities for essential public services.
- F. Cemeteries, mausoleums, and crematoriums.
- G. Animal hospitals or veterinarian clinics and dog kennels.
- H. Accessory uses customarily incidental to an allowed special exception use.
- I. **Farm Feed and Supplies Establishments**

The following criteria and requirements shall apply to all farm feed and supplies establishments:

 - 1. Feed—livestock, poultry, and pets.
 - 2. Animal health products.
 - 3. Lawn and garden supplies.
 - 4. Fertilizer, insecticides, and pesticides.

5. Leather goods and tack.
6. Fence posts and supplies to be enclosed in an opaque buffer.
7. No equipment, such as lawn mowers, tractors, and accessories, shall be stored or repaired on this site.
8. There shall be a minimum fifty (50) foot setback from all property lines for the building and storage areas, except as incidental to the above uses.

J. Duplexes.

K. Private schools.

503.6. **Area, Density, and Lot Width Requirements**

A. **Single-Family Detached Dwellings and Mobile Homes**

1. Minimum lot area: ten (10) acres.
2. Maximum possible gross density: 0.10 (nonfarm) dwelling units per acre, subject to compliance with the Comprehensive Land Use Map Classification.
3. Minimum lot width: 250 feet.
4. Single-family detached dwellings and mobile homes in the A-C Agricultural District are required to meet all of the standards above, except when such units are developed in a CS-MPUD Conservation Subdivision Master Planned Unit Development in accordance with this Code, the minimum lot area requirements and lot width requirements shall not apply.

B. **All Other Uses**

No minimum lot areas are required, subject to meeting minimum yard and coverage regulations.

503.7. **Coverage Regulations**

All buildings, including accessory buildings, shall not cover more than fifteen (15) percent of the total lot area.

503.8. **Yard Regulations**

The following minimum building line setbacks measured from the right-of-way or edge of ingress/egress easement (where there is no right-of-way) are required in front yard areas. All other yard areas shall be measured from the property line.

- A. Front: Fifty (50) Feet
- B. Side: Twenty-five (25) Feet
- C. Rear: Fifty (50) Feet
- D. Single-family detached dwellings and mobile homes in the A-C Agricultural District are required to meet all of the standards above, except when such units are developed in a CS-MPUD in accordance with this Code, the minimum lot area requirements and lot width requirements shall not apply.

503.9. **Height Regulations**

Building height. Thirty-five (35) feet maximum; however, no dwelling shall be less than ten (10) feet in height. For exceptions, see this Code, Chapter 500, Supplemental Regulations.

503.10. **On-Site Parking Regulations**

On-site parking shall be provided in accordance with this Code.

503.11. **Development Plan**

A development plan shall be submitted in accordance with this Code.

APPENDIX 10.3.3
SECTION 530.1 OF THE
PASCO COUNTY LDC

CHAPTER 500. ZONING STANDARDS

SECTION 530. SUPPLEMENTAL REGULATIONS

The provisions of this chapter shall be subject to such exceptions, additions, or modifications as provided by the following supplemental regulations.

530.1. Height Regulations Exceptions

- A. Public, semipublic, or public services buildings; hospitals; public institutions; or schools may not exceed sixty (60) feet in height. Churches or temples may not exceed seventy-five (75) feet in height, and the building shall be set back from each yard line at least one (1) foot for each additional two (2) feet of building height above the height limit otherwise provided in the district in which the building is located. Spires, flagpoles, chimneys, residential antennas, towers, tanks, belfries, and similar projections are exempt from the height regulations.
- B. Special industrial and commercial structures, such as cooling towers, elevator bulkheads, fire towers, tanks, water towers, and broadcasting towers which require a greater height than provided in the district in which the structure is located may be erected to a greater height than permitted provided:
 - 1. The structure shall not occupy more than twenty-five (25) percent of the lot area; and
 - 2. The setbacks of the district in which the structure is erected shall be increased by one (1) foot for each three (3) feet of height over the maximum height permitted. However, in no case shall setbacks be less than one-third of the total height of the broadcasting tower, including antennas.

530.2. Yard Requirements

All yards required by this Code to be provided shall be open to the sky and unobstructed by any structure, except for accessory structures and fences. Accessory structures, however, shall not be constructed within five (5) feet of any rear or side lot line.

- A. The following may project into the required yards:
 - 1. Steps, porches, decks, balconies, and stoops may project to within three (3) feet of the side or rear property line, but may not project more than four (4) feet into the required front yard area.
 - 2. Open or lattice-enclosed fire escapes, fireproof outside stairways and balconies, and the ordinary projection of chimneys and flues not exceeding 3.5 feet in width and placed so as not to obstruct light or ventilation.

APPENDIX 10.3.4
SECTION 902 OF THE PASCO COUNTY
LDC

CHAPTER 900. DEVELOPMENT STANDARDS

SECTION 902. STORMWATER

902.2. Stormwater Management Requirements

A. Intent and Purpose

It is the intent and purpose of this section to reduce existing and future flooding problems, improve surface water quality in the County, and protect the functions of natural features and surficial aquifer recharge.

B. Applicability

This section shall apply to all development where any portion of the development is within the jurisdiction of unincorporated Pasco County.

C. General Standards and Alternative Approaches

1. General Standards

The stormwater management methodologies and requirements shall be in accordance with this section.

The developer shall be responsible for obtaining any necessary permits for the stormwater management system required by local, State, or Federal agencies.

In addition to the specific standards of this section, stormwater management systems shall be designed to ensure:

- a. Site alteration shall not contribute to water becoming a health hazard or encourage the breeding of mosquitoes;
- b. The drainage area used in runoff calculation shall be the total watershed area, which may include areas beyond the site limits;
- c. Flood, safety hazards, and health hazards are reduced; and
- d. Groundwater recharge is enhanced where applicable; however, in an area designated as a groundwater recharge area, the developer shall limit runoff from the proposed site to no more than the predevelopment discharge.

2. Alternative and Innovative Approaches:

Alternative and innovative approaches to the design of water retention or detention structures and flow devices may be proposed.

If alternate and innovative stormwater management plans are proposed, it must be demonstrated to the satisfaction of the County Administrator or his designee that the proposed development activity has been planned, designed, and will be constructed and maintained to meet each of the standards of this section.

D. Performance and Design Standards

To ensure attainment of the intent and purpose of this section and to ensure that standards will be met, the design, performance, construction, and maintenance of the drainage system shall be consistent with the following:

1. All new developments shall be required to provide a detention/retention system in order to detain/retain increased runoff caused by the development. Where public or private lakes, ponds, borrow pits, or similar type water detention/retention areas are incorporated in a comprehensive drainage plan, drainage calculations shall demonstrate that the facilities have sufficient capacity for the design storm. In the design of detention/retention facilities, the effective volume shall be based on the pond bottom or the seasonal high groundwater level, whichever is higher, as a minimum starting elevation of the stage/storage computations.
2. The rate of stormwater discharge from new developments shall be limited to amounts which are equal to or less than the rate of discharge which existed prior to development in accordance with Rules 40D-4 and 40D-40, Florida Administrative Code (FAC), administered by the Southwest Florida Water Management District (SWFWMD), provided, however, that Drainage Basins of Special Concern shall be subject to the requirements of this Code, Section 902.2.N.
3. The volume of stormwater discharge shall be in accordance with Rules 40D-4 and 40D-40, FAC, administered by the SWFWMD, provided; however, that Drainage Basins of Special Concern shall also be subject to the requirements of this Code, Section 902.2.N.
4. Protect or improve the quality of ground and surface water.
5. Maintain groundwater levels and enhance groundwater recharge where applicable.
6. Protect the wetlands for the storage of surface waters and the biological and physical reduction and assimilation of pollutants.

7. Prevent saltwater intrusion, where applicable, by adhering to Best Management Practices.
8. Prevent damages due to increased flooding.
9. Encourage the maintenance of the natural levels of salinity in estuarine areas.
10. Minimize adverse impacts to flora, fauna, fish, and wildlife habitats.
11. To otherwise further the objectives of this Code.
12. Channeling runoff directly into natural water bodies shall be prohibited, unless permitted by appropriate regulatory agencies. Runoff shall be routed through swales and other systems designed to increase time of concentration, decrease velocity, increase infiltration, allow suspended solids to settle, and otherwise remove pollutants.
13. Natural water courses shall not be dredged, cleared of vegetation, deepened, widened, straightened, stabilized, or otherwise altered without specific approval of the appropriate regulatory agencies. Water shall be retained or detained before it enters any natural water course in order to preserve the natural flow characteristics of the water course and to decrease siltation and other pollutants.
14. The area of land disturbed by development shall be as small as practicable. Those areas which are not to be disturbed shall be protected by an adequate barrier from construction activity. Whenever possible, natural vegetation shall be retained and protected.
15. No grading, cutting, or filling shall be commenced until erosion and sedimentation control devices have been installed between the disturbed area and water bodies, water courses, and wetlands.
16. Land which has been cleared for development and upon which construction has not been commenced shall be protected from erosion by appropriate techniques designed to revegetate the area.
17. The drainage system shall be designed so that sediment shall be retained on the site of the development.
18. Wetlands and other water bodies shall not be used as sediment traps.
19. Erosion and sedimentation facilities shall be regularly maintained to ensure proper function.

20. Artificial water courses shall be designed, considering soil type and side bank stabilization, so that the velocity flow does not cause erosion.
21. Vegetated buffer strips shall be provided or, where practicable, retained in their natural state along the banks of all water courses, water bodies, and/or wetlands.
22. Intermittent water courses, such as swales, shall be vegetated, except where flows exceed five (5) feet per second (fps), then they shall be concreted or otherwise sufficiently stabilized.
23. Although the use of wetlands for storing and purifying water is encouraged, care must be taken not to overload their capacity, thereby harming the wetlands and transitional vegetation. Wetlands should not be damaged by the construction of detention ponds.
24. Runoff shall be retained or detained on site in accordance with the applicable SWFWMD rules.
25. Runoff from streets and parking lots shall be treated to reduce the quantity of oil and sediment entering receiving waters.
26. The banks of detention and retention areas shall slope at a gentle grade into the waters in accordance with the applicable County and SWFWMD rules as a safeguard against drowning, personal injury, or other accidents, to encourage the growth of vegetation, and to allow the alternate flooding and exposure of areas along the shore as water levels periodically rise and fall.
27. The use of drainage detention and retention facilities and vegetated buffer zones as open space, recreation, and conservation areas shall be encouraged except where this Code is more stringent.
28. Development, including grading, shall take place in a manner that protects the roots and stability of trees.
29. General stormwater conveyance facilities include swales, ditches, channels, culverts, storm sewers, inlets, and weirs. The collection of stormwater runoff should be by positive gravity means without the use of siphons, pumps, or similar devices, unless specific approval is obtained.
30. Unless otherwise approved by the County, standard details and specifications for the construction of storm drainage systems shall conform to applicable sections of the latest editions of the following:
 - a. Florida Department of Transportation (FDOT), *Roadway and Traffic Design Standards*, latest edition.

- b. *FDOT, Standard Specifications for Road and Bridge Construction*, latest edition.

E. System Designs (Frequency of Design Storms)

The drainage systems shall be designed for "design storms" resulting from rainfall of the following minimum frequencies:

1. Ten (10) Year: All storm sewers and culverts, except those crossing arterial roads. A minimum time of concentration of fifteen (15) minutes to the first inlet may be utilized in determining design flows.
2. Twenty-Five (25) Year/Twenty-Four (24) Hour: All floodways, ditches, channels, and detention/retention areas with outfalls (open drainage basin).
3. Fifty (50) Year: All storm sewers and culverts crossing arterial roads.
4. 100-Year/Twenty-Four (24) Hour: All retention areas without outfalls (closed drainage basin).

Rainfall intensity factors shall come from accepted meteorological and rainfall sources applicable to the County.

F. Runoff

Runoff and routing analysis shall be based on current hydrological design procedures. Computations shall include a tabulation of inflow, discharge, storage capacity, minimum and maximum water elevations, and retention/detention time to peak.

Basic hydrological calculations shall be based on commonly accepted procedures, such as those of:

1. Natural Resources Conservation Service
 - a. *A Method for Estimating Volume and Rate of Runoff in Small Watersheds*, U.S. Department of Agriculture, Natural Resources Conservation Service (NRCS), Technical Paper No. 149.
 - b. *Urban Hydrology for Small Watersheds*, USDA, NRCS Technical Release No. 55.
 - c. *National Engineering Handbook*, Section 4, *Hydrology*, U.S. Department of Agriculture, NRCS, latest edition.

The NRCS, Type II, Florida Modified Rainfall Distribution, with antecedent moisture Condition II will be used. Other rainfall distributions may be utilized for design with prior approval of the County. The same shape factor shall be used for predevelopment and postdevelopment calculations unless otherwise approved by the County.

2. Rational Method:

- a. *Drainage Manual*, FDOT, Volume 2A, latest edition.
- b. Standard Engineering Texts: The rational method of routing analysis may be used for systems serving projects with less than five (5) acres total contributing area.

The rational method of routing analysis may be used for systems serving projects with less than five (5) acres total contributing area.

3. Others Alternatives as Approved by the County:

Ultimate land usage shall be assumed for the selection of proper runoff coefficients or curve numbers within the basins involved. Weighted runoff coefficients or curve numbers shall be utilized where different coefficients or curve numbers exist within the areas comprising the basin.

G. Standards for Detention/Retention, Stormwater Runoff Storage/Discharge, and Floodplain Encroachment

1. The detention/retention of cumulative stormwater runoff in excess of predevelopment release rates shall be provided by sufficient storage capacity constructed on the property to be developed or within approved off-site drainage areas. Detention/retention storage capacity shall be based on a twenty-five (25) year/twenty-four (24) hour design for open basins. Design high water elevations shall be established in consideration of adjacent properties and facilities such that off-site drainage impacts are minimized.
2. The detention/retention facilities designed for the storage of stormwater to control runoff rates shall:
 - a. Be designed in accordance with requirements of the SWFWMD, the FDOT, or other agencies with jurisdiction.
 - b. Be identified as a drainage easement on the final plat of a subdivision or duly recorded as such in other developments.
 - c. Have bank slope grades not steeper than four (4) feet horizontal to one (1) foot vertical which shall be sodded to the

seasonal high water elevation. Slopes steeper than 4:1 may be submitted for review and may be approved by the County. Wet ponds with slopes steeper than 4:1 may require the installation of a security fence.

- d. Include an outlet structure in detention facilities sized to release, as a maximum, the predevelopment runoff rate, and designed to provide water quality treatment of the runoff from the contributing area, in accordance with applicable standards of the respective agencies (the SWFWMD, the Florida Department of Environmental Protection, and the FDOT) having jurisdiction.
 - e. Be constructed to provide a minimum of six (6) inches of freeboard between the design high water elevation and the lowest berm elevation surrounding the detention/retention area.
 - f. Where practicable, include in detention areas an emergency overflow spillway or other structure acceptably protected from erosion with the invert no lower than the design high water level.
 - g. Have the discharge of controlling and overflow structures flow through an abutting drainage easement or public right-of-way in order to convey stormwater runoff away from the detention area.
 - h. Include special engineering features, such as skimmers, designed to remove oils and other objectionable materials, in accordance with criteria established by the SWFWMD.
3. Off-site discharge is limited to amounts which will not cause adverse off-site impacts.
- a. For a project or portion of a project located within an open drainage basin, the allowable discharge shall not exceed the historic discharge, which is the peak rate at which runoff leaves a parcel of land under existing site conditions. These criteria shall not apply to projects which have been discharging stormwater runoff directly to the Gulf of Mexico.
 - b. For a project or portion of a project located within a closed drainage basin, the required retention volume shall be the postdevelopment runoff volume, less the predevelopment runoff volume, computed using the SWFWMD's twenty-four (24) hour/100-year rainfall map, and the SCS, Type II, Florida modified twenty-four (24) hour rainfall distribution with an antecedent moisture Condition II. The total postdevelopment

volume leaving the site shall be no more than the total predevelopment volume leaving the site for the design 100-year storm, unless otherwise approved by the County.

4. Maintenance of predevelopment, off-site low flow may be required in hydrologically sensitive areas.

5. Floodplain Encroachment

No net encroachment into the floodplain, up to that encompassed by the 100-year event, which will adversely affect either conveyance, storage, water quality, or adjacent lands will be allowed. Any required compensating storage shall be equivalently provided between the seasonal high water level and the 100-year flood level to allow storage function during all lesser flood events. A detailed flood study performed by a registered engineer which indicates no adverse impact to off-site flood elevations may be approved by the County to lessen or remove the flood plain compensation requirements.

6. Off-Site Lands

Adequate provisions shall be made to allow drainage from off-site, upstream areas to downstream areas without adversely affecting the upstream or downstream areas.

7. Exfiltration systems and percolation designed in conjunction with detention/retention systems:

- a. The detention/retention facilities must have the capacity to retain the volume required for water quality treatment without considering discharges.
- b. The seasonal high water level must be at least one (1) foot below the bottom of the exfiltration pipe.
- c. Exfiltration should not be proposed for systems to be operated and maintained by the County, unless otherwise approved by the BCC.
- d. Double ring infiltrometer tests shall be performed at each detention/retention facility. The said test shall be performed at the approximate elevation of infiltration.
- e. A safety factor of 2.0 or more shall be applied in the exfiltration design to allow for geological uncertainties by dividing the percolation rate by the safety factor.

H. Storm Sewer Systems

The capacity of inlets, with the allowable head conditions, should equal or exceed the runoff from their individual drainage areas. The size, type, and location of storm sewer inlets, gratings, or other openings into an enclosed storm drainage system shall be in accordance with the FDOT *Drainage Manual*, latest edition, unless otherwise approved by the County.

1. Drainage Structures

a. Roadway Inlets: Roadway inlets in curb and gutter construction shall be designed and constructed to:

- (1) Avoid abrupt changes in hydraulic slope and velocity.
- (2) Limit the quantity of stormwater flowing in a street to a depth not to exceed two (2) inches below the crown of collector streets and arterial streets, unless otherwise approved in writing by the County, but in no case shall more than one-half the width of the outside lane be flooded at design flow. Limit the quantity of stormwater flowing in local residential streets to a depth not to exceed six (6) inches deep at the inlet at the design flow.
- (3) Prevent design flows across street intersections unless concrete valley gutters are approved by the County.
- (4) Have formed inverts a minimum of six (6) inches above the flow line to properly drain inlet bottoms.
- (5) Have pipes cut flush with the inside wall.
- (6) Provide for ease of maintenance.

b. Commercial Parking Lot Inlets: Commercial parking lot inlets shall be designed and constructed to:

- (1) Accommodate a ten (10) year/twenty-four (24) hour storm.
- (2) Have the hydraulic gradient at or below the inlet elevation.

I. Pipe Standards

1. The piping and appurtenances used in the stormwater collection system shall be designed to convey the runoff of a ten (10) year storm with a minimum time of concentration of not less than fifteen (15) minutes to the first inlet.
2. Unless otherwise approved by the County, reinforced concrete pipe (RCP) shall be used in all easements and street rights-of-way with the exception of residential driveways. All storm sewer pipes and culverts

shall have a minimum of six (6) inches of cover from outside crown of pipe to bottom of roadway base course. The minimum cover of pipe in swale areas shall be one (1) foot, unless otherwise approved by the County.

3. Minimum pipe sizes, not including driveway culverts, shall be as follows:

<u>Type</u>	<u>Minimum Size</u>
Under Drains	6"
Pipe Culvert	18"
Box Culvert	3' X 3'

Application of these values to oval or elliptical pipe shall be based on equivalent round diameter.

4. Roughness coefficients for use in Manning's Formula for storm pipe and box culverts shall be as follows:

a.	<u>Concrete Pipe and Box Culverts</u>	<u>N</u>
	18-30", inclusive	0.013
	36-48", inclusive	0.012
	54" and up, including smooth concrete boxes of 15 square feet and up	0.011
b.	<u>Corrugated Metal Pipe (CMP) or Aluminum Pipe</u>	0.023
	Asphalt Coated	0.018

Applications of these values to oval or elliptical pipe shall be based on equivalent round diameter.

5. The slopes for culverts used as storm sewers shall produce a velocity within the following limits, unless otherwise approved by the County:

<u>Maximum</u>	<u>Minimum</u>
RCP 12 fps	2 fps
CMP 10 fps	3 fps

6. The maximum length of pipe without an access structure shall be:
 - a. 18"-36" pipes: 400'
 - b. 42" and over, and all box culverts: 500'
7. The minimum and maximum allowable hydraulic slopes shall be those that produce the aforementioned minimum and maximum velocities.

Manholes may be used as drop structures where necessary to lessen slopes in storm sewers.

8. Culvert capacity shall be based on sound engineering practice. Detailed analysis and design shall be based on either inlet or outlet control, whichever is applicable, using appropriate entrance loss coefficients and culvert nomographs. Backwater curve data, flood profiles, and other hydraulic information along a watershed reach shall be used to establish design water elevations and set the culvert crown elevations.
9. When required to control high groundwater conditions, underdrains shall be designed to maintain the groundwater table elevation at least twenty-four (24) inches below the edge of the pavement.
10. Unless otherwise approved by the County, driveways across roadside swales will require the placement of a drainage culvert (side drain) under the driveway in order not to impede flow in the swale resulting in an increase of backwater onto upstream property. Culverts in residential areas may be CMP or RCP with a minimum diameter of fifteen (15) inches. Culverts in commercial areas shall be RCP with a minimum diameter of eighteen (18) inches.

J. Scour and Erosion

It shall be the responsibility of the developer to control soil erosion by wind or water from the date of ground breaking until such time as the responsibility is transferred to an acceptable entity in accordance with this Code.

The developer's engineer must provide for use of sediment basins, straw bale dams, velocity checks, hydroseeding applications, etc., to minimize erosion within the limits of the site being developed and prevent damage to wetland systems which are to remain in the development.

The design of canals, streams, ditches, and other waterways shall be based on current open channel design procedures using the Chezy, Talbot, and/or Manning's Formula. Design velocities without erosion protection shall not exceed the maximums for soil types as shown below. Where design levels exceed the top of banks for the required design storm; i.e., twenty-five (25) year for major waterways and berms are not provided, the extent of flooding in the flood plain shall be shown. Runoff and roughness coefficients, safe velocities, nomographs, erosion control, and practical limitations on use of design formulas shall be based on current practice in the field of hydraulics, notwithstanding any requirements of this section.

Conditions such as alignment and presence of severe irregularities in smoothness will alter the allowable velocities. Maximum flow velocities for various soil types without erosion protection are as follows:

<u>Type of Soil</u>	<u>Allowable Velocity</u>
Fine Sand	1.50 fps
Sandy Loam	1.75 fps
Silt Loam	2.00 fps
Firm Loam	2.50 fps
Fine Gravel	2.50 fps

The above allowable velocities may be increased if appropriate erosion protection devices are provided and approved.

Where erosion protection structures are constructed in floodway banks and bottoms, the design section shall be selected to provide a maximum velocity of ten (10) fps with energy dissipation structures at flow discharges to unprotected floodways. Check dams designed to control velocities in open channels shall be detailed in the plans of the proposed development to provide acceptable erosion protection.

K. Lot Drainage

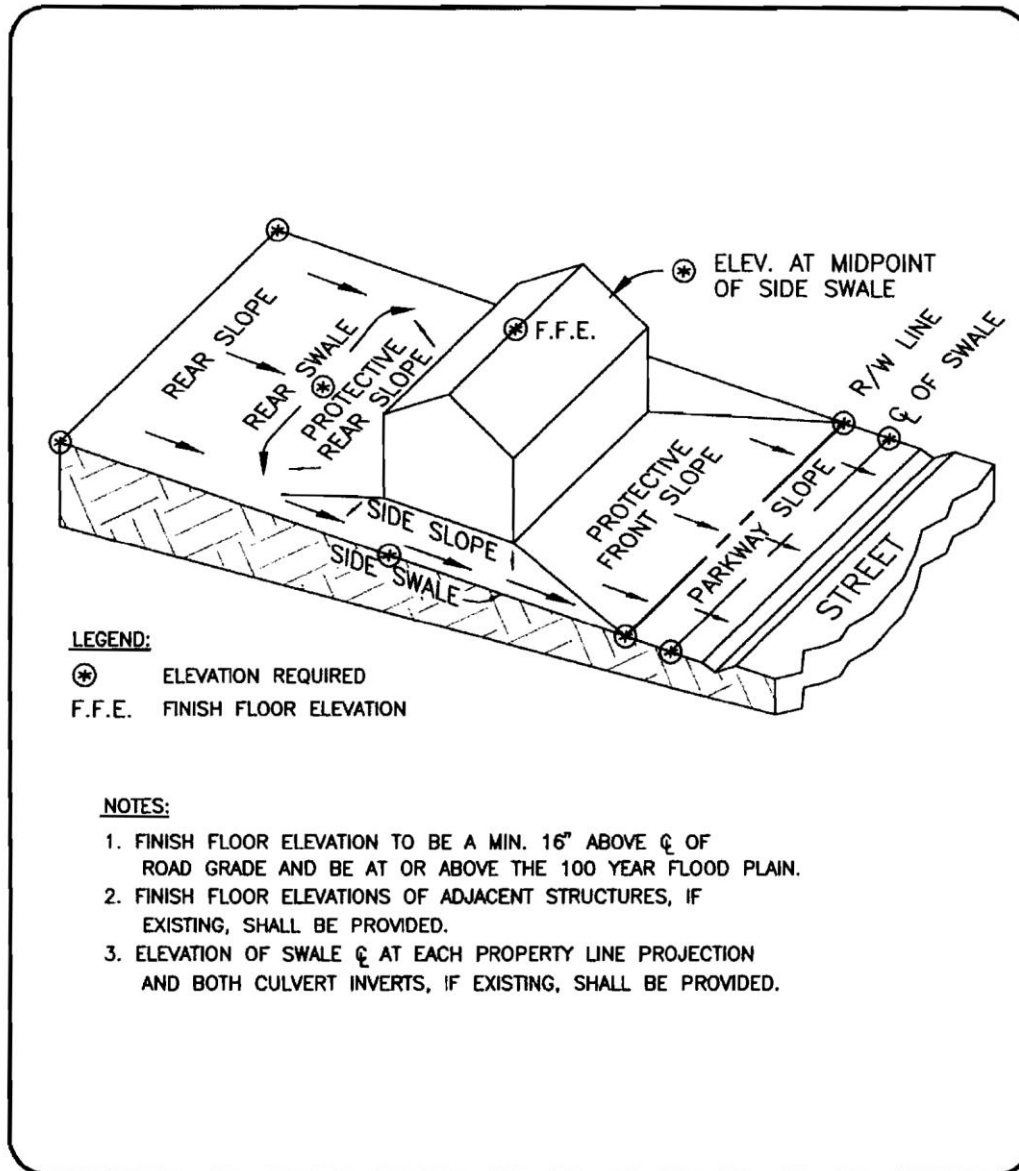
1. Drainage Plan

The finished grade of individual lots shall be shown on the construction plans. Generally, lots shall be graded in accordance with Types A, B, or C Typical Grading Plans as shown in Figures 902.2.A, 902.2.B, and 902.2.C. When topography or other features make such lot grading impractical, alternate standards may be presented for the County Administrator's or his designee's review and approval.

The proposed minimum, finished floor elevation of all structures which may be constructed shall be included on the construction plans. As a minimum, the finished floor elevation shall be at least sixteen (16) inches above the highest crown line of the street lying between the projection of the side building lines, unless otherwise approved by the County Administrator or his designee. In no case shall finished floor elevations be specified below the 100-year flood plain as designated by the Federal Insurance Administration Flood Hazard Boundary Maps. When a detailed study from the Federal Emergency Management Agency (FEMA) has not been provided, the engineer shall submit the best available data for the 100-year base flood elevation for review and approval by the County Administrator or his designee.

FIGURE 902.2.A

TYPE A TYPICAL GRADING PLAN



PASCO COUNTY
 DEVELOPMENT SERVICES

STORM DRAINAGE DETAIL

**TYPICAL LOT GRADING
 TYPE "A"**

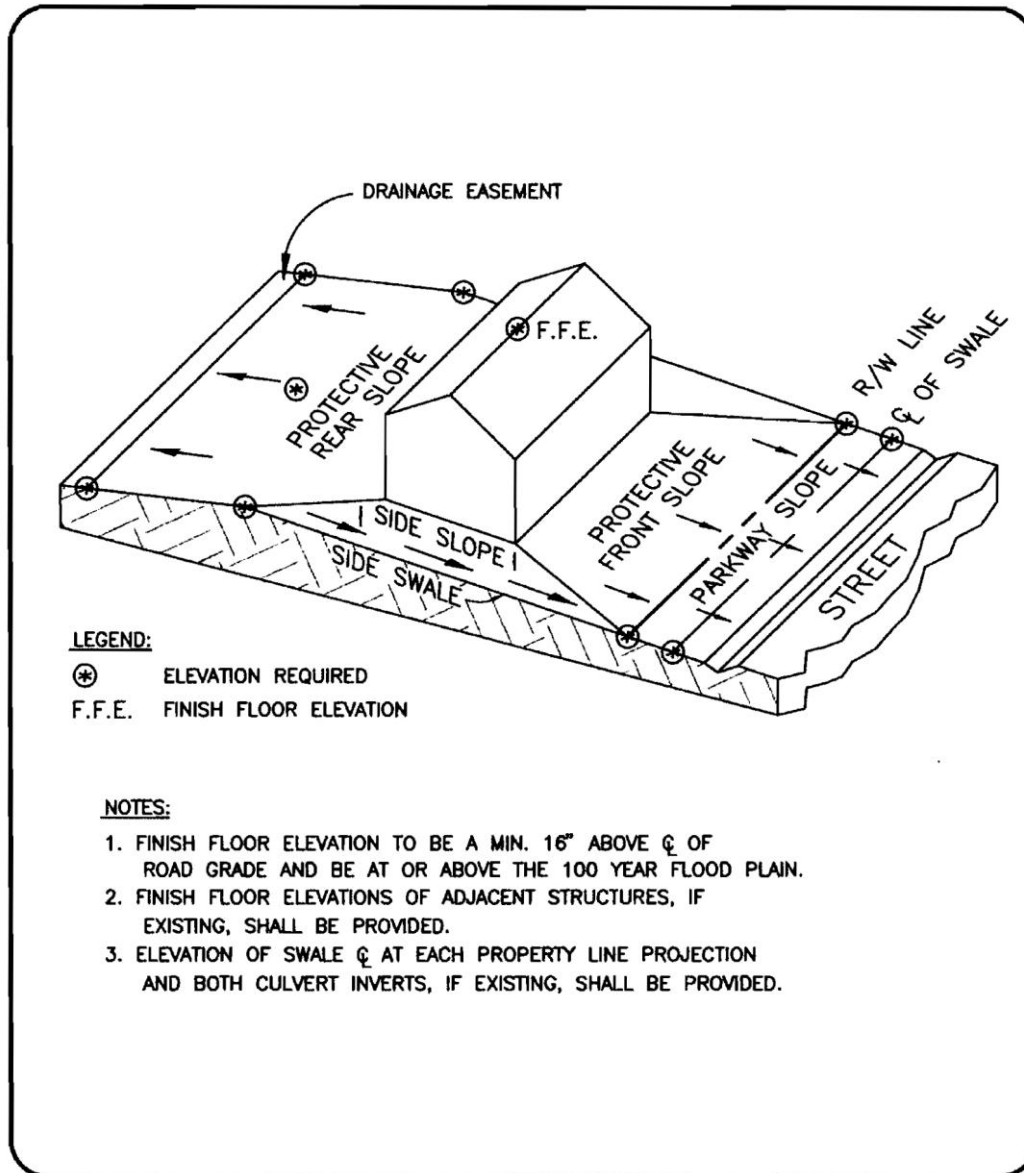
**SD
 5**

SHEET 1 OF 3

DATE: JAN 1998
 TYPE: DWG
 C: JOLLY/RFP

FIGURE 902.2.B

TYPE B TYPICAL GRADING PLAN



PASCO COUNTY
DEVELOPMENT SERVICES

STORM DRAINAGE DETAIL

**TYPICAL LOT GRADING
TYPE "B"**

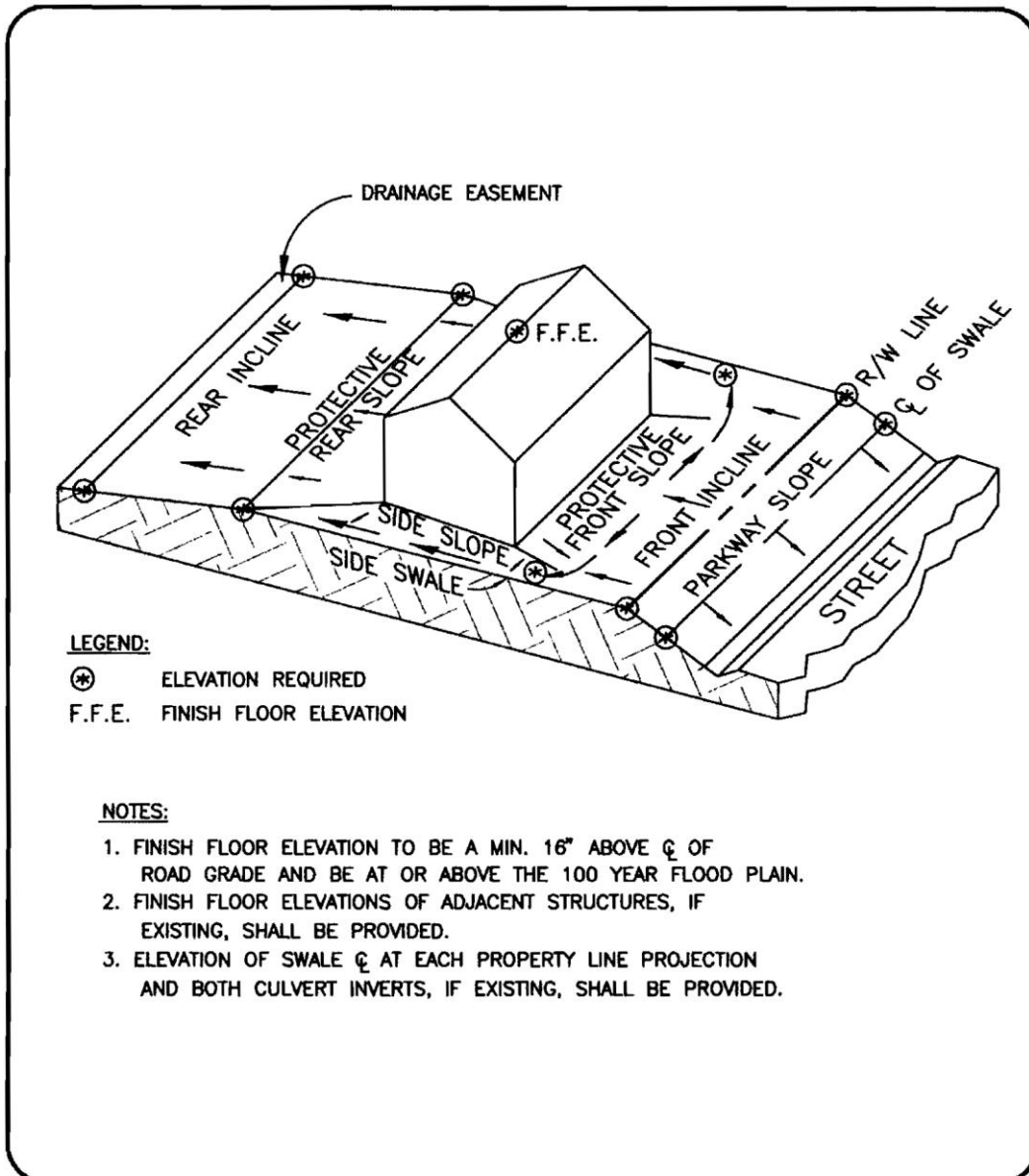
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SHEET 2 OF 3

DATE: JAN 1998
TYPE: DWG
C. JOLLY/RFP

FIGURE 902.2.C

TYPE C TYPICAL GRADING PLAN



PASCO COUNTY
DEVELOPMENT SERVICES

STORM DRAINAGE DETAIL

**TYPICAL LOT GRADING
TYPE "C"**

**SD
7**

SHEET 3 OF 3

DATE: JAN 1998
TYPE: C.DWG
C. JOLLY/RFP

2. Drainage Plan Requirements for Individual Lots

For lots one (1) acre or less in size, two (2) copies of a drainage plan shall be submitted with the Building Permit Application for review and approval. The following information shall be included in the plan, which shall be signed and sealed by a Florida registered Professional Engineer.

- a. The plan shall indicate the name of the development (if applicable), scale of plan, north arrow, and legend; parcel identification number or legal description sufficient to describe the size and location of the project site, including the plat book page and number, if platted; and the name, address, and telephone number of the builder, owner, and engineer/surveyor.
- b. The plan shall show the abutting sections of any roadway(s) and the corresponding elevations along the projection of the building lines onto the centerline of the roadway(s) and the elevations on all corners of the building pad. Lot elevation at a minimum of a 100-foot grid for lots larger than one (1) acre and a fifty (50) foot grid minimum for lots one (1) acre or less. A reference elevation may be assumed.

3. Lot Drainage Enforcement

- a. Prior to constructing a structure on one (1) acre or less, the builder shall be required to provide an engineered lot grading plan with the Building Permit Application that does not cause an adverse impact on adjacent or off-site property.
- b. As part of the Building Permit Application for any accessory structure on one (1) acre or less where impervious area is added or where a lot's contours are proposed to be altered for an area over 500 square feet, an engineered plan addressing the lot grading shall be required. These types of permits are additions, pools, slabs, etc.
- c. Prior to the release of the Certificate of Occupancy (CO), or final inspection where no CO is issued, the developer/owner/builder shall execute the Affidavit of Lot Grading and Finished Floor Elevation Compliance, provide an as-built survey prepared by a surveyor and mapper registered in the State of Florida of the lot and the driveway construction, and return same to the County Administrator or his designee. The as-built survey shall be in conformance with the approved Stormwater Management Plan and Report. Any deviations

from the approved plan must be noted and will be reviewed for compliance with this Code.

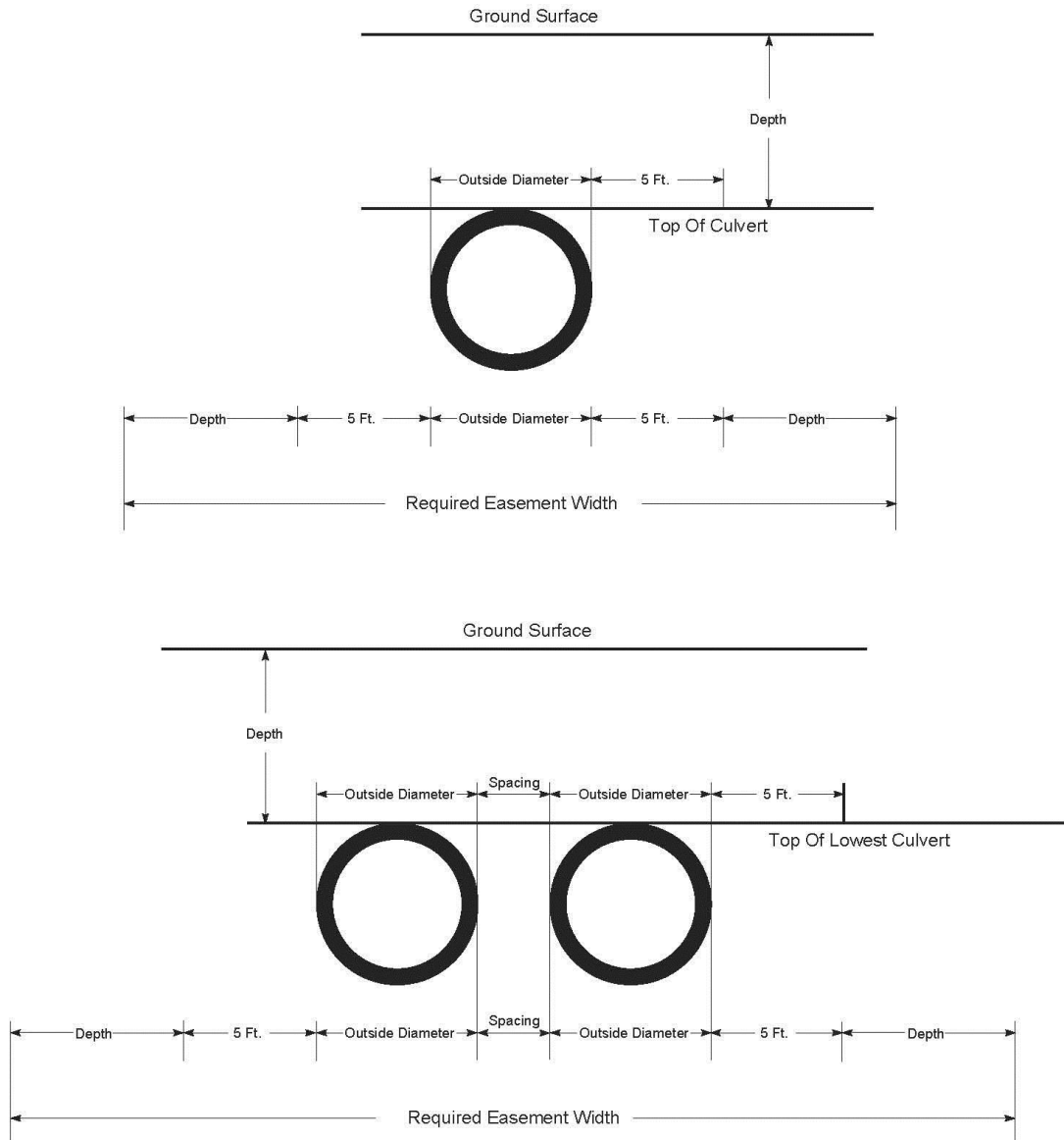
L. Swales, Culverts and Pipes

All swales, ditches, channels, and closed storm-drainage conduits within subdivisions shall be within an easement or dedicated right-of-way. Right-of-way or maintenance easements by instrument or plat dedication shall be provided for all facilities used to convey stormwater. The minimum width of said rights-of-way or easements shall conform to the widths shown in the following table:

	<u>Minimum Controlled Width</u>
Swales (except in right-of-way)	
• Rear Yard	5'
• Side Yard	10' (5' each side of swale centerline)
Pipes and Culverts	15 '(7.5' each side of pipe centerline)
See Figure	The easement required shall be the greater of fifteen (15) feet or the combination of: • the outside diameter(s) of the culvert(s), plus • all spacings between culverts, plus • five (5) feet on both sides of the culvert(s), plus • the depth of the top of the lowest culvert.

From the outer edge of any culvert, the easement must be at least five (5) feet plus the depth of the culvert.

Easements for Culverts/Pipes



A right-of-way or easement of fifteen (15) feet shall be provided for access to any stormwater detention/retention facility from a dedicated road or street. In addition, a continuous perimeter maintenance and operation easement, with a minimum width of fifteen (15) feet and slopes no steeper than 4:1 (horizontal/vertical), shall be provided landward of the control elevation water line.

M. Dedication and Maintenance

1. If a stormwater management system approved under this Code will function as an integral part of the County maintained regional system as determined by the County, the facilities may be required to be dedicated and formally accepted by the County.
2. All stormwater management systems that are not dedicated to the County shall be operated and maintained by one of the following entities:
 - a. A local governmental unit, municipality, a special district, or an active water control district created pursuant to Chapter 298, Florida Statutes; a drainage district created by special act; a Community Development District created pursuant to Chapter 190, Florida Statutes; or a Special Assessment District created pursuant to Chapter 170, Florida Statutes; or other governmental unit.
 - b. An officially franchised, licensed, or approved communication, water, sewer, electrical, or other public utility.
 - c. The property owner or developer if:
 - (1) Written proof is submitted in the appropriate form, by either letter or resolution, that a governmental entity or such other acceptable entity as set forth in this Code, Section 902.2.M.2.a or 902.2.M.2.b will accept the operation and maintenance of the stormwater management and discharge facility at a time certain in the future; and
 - (2) A bond or other assurance of continued financial capacity to operate and maintain the system is submitted.
 - d. For profit or nonprofit corporations, including homeowners' associations, property owners' associations, condominium owners' associations, or master associations if:
 - (1) The owner or developer submits documents constituting legal capacity and a binding legal obligation between the entity and the County affirmatively taking responsibility for the operation and maintenance of the stormwater management facility.

- (2) The entity has sufficient powers reflected in its organizational or operational documents to:
 - (a) Operate and maintain the stormwater management system as permitted by the County;
 - (b) Establish rules and regulations;
 - (c) Assess members;
 - (d) Contract for services; and
 - (e) Exist perpetually with the articles of incorporation providing that, if the entity is dissolved, the stormwater management system will be maintained by some other acceptable entity as described above.
- 3. The developer shall convey, at no cost to the County, a drainage easement within the project over all internal drainage features, and a drainage easement for an uninterrupted flow through the project of any offsite drainage sufficient to accommodate a 100-year/five-day, and 100-year/one-day, storm event within the limits of the easement without any increase in predevelopment upstream stages for the purpose of maintaining natural drainage and the free flow of stormwater and other surface waters. The drainage easements must also include a limited right of ingress and egress to perform maintenance activities related thereto for the County's agents and necessary equipment. The easement, encumbering SWFWMD jurisdictional wetlands, associated regulatory buffers, any channels, swales or ditches and access only, shall be dedicated prior to the final plat approval of any phase immediately adjacent to said easement. The easement dedication shall be substantially in the form approved by the Engineering Services Department except as may be modified as requested by the SWFWMD. It is expressly understood and agreed that the developer or its assigns will reserve onto itself rights of ownership of the easement premises not inconsistent with the easement rights granted in the easement to the County, including the grant of additional rights not in conflict with the rights granted in the easement; provided, however, that the developer or its assigns shall not conduct nor allow development on the easement premises. The County does not assume maintenance responsibility for these easements.
- 4. Phased Projects
 - a. If a project is to be constructed in phases, and subsequent phases will use the same stormwater management facilities as

the initial phase or phases, the operation/maintenance entity shall have the ability to accept responsibility for the operation and maintenance of the stormwater management systems of future phases of the project.

- b. In phased developments that have an integrated stormwater management system but employ independent operation/maintenance entities for different phases, the operation/maintenance entities, either separately or collectively, shall have the responsibility and authority to operate and maintain the stormwater management system for the entire project. That authority shall include cross easements for stormwater management and the authority and ability of each entity to enter and maintain all facilities should any entity fail to maintain a portion of the stormwater management system within the project.
- 5. Applicant as Acceptable Entity: The applicant shall be an acceptable entity and shall be responsible for the operation and maintenance of the stormwater management system from the time construction begins until the stormwater management system is dedicated to and accepted by another acceptable entity.
- 6. Off-Site Drainage Facilities: The County Administrator or designee may allow stormwater runoff to be discharged into drainage facilities off-site pursuant to the following:
 - a. The off-site drainage facilities and channels leading to them are designed, constructed, and maintained in accordance with the requirements of this Code and the proper easement from the owner(s) of the property to be utilized is provided; and
 - b. Adequate provision is made for the sharing of construction and operating costs of the facilities. The developer may be required to pay a portion of the cost of constructing the facilities as a condition to receiving approval of the drainage plans.

When drainage facilities which are not within a previously recorded drainage easement are utilized for off-site drainage, the owner/developer shall provide a drainage easement on the approved form with a legal description and sketch (certified by a Florida registered land surveyor) for each off-site drainage facility. The drainage easement shall be submitted to the County Administrator or his designee prior to the construction plan approval of the individual unit or phase affected.

N. Drainage Basins of Special Concern

1. Regulated Drainage Basins: The BCC may identify drainage basins or subbasins of Special Concern in order to protect the health, safety, and welfare of the public and to protect property.

Designation of Drainage Basins or subbasins of Special Concern shall include the following steps:

- a. Documentation of the fact that the basin or subbasin is prone to flooding based on records of flooding occurrence and severity. The records can include photographs and statements from the County staff or area residents.
- b. Evaluation of basin or subbasin drainage characteristics and cause of flooding based on review of relevant information, including topographic maps; drainage features and structures, such as channels and culverts; surficial soils; land use; and soil stratigraphy. If warranted, this evaluation may include modeling of stormwater runoff generation and conveyance.
- c. Determination that the flooding would be exacerbated unless the provisions of this section are put in place.

The area(s) shall be accurately depicted on maps that will be available from the County in digital and hard-copy format.

- d. Removal of the drainage Basin of Special Concern designation from any drainage Basin of Special Concern may be considered upon submittal of the following:
 - (1) A scientific analysis and a proposal to remediate or otherwise improve the conditions that supported the designation.
 - (2) Proposed funding for the implementation of the remediation plan.
 - (3) The County Administrator or designee, in consultation with the SWFWMD, will consider whether the remediation plan presents a viable solution that is permitted and funded, and shall present same to the BCC, who shall make the final determination on the proposal.
2. Exemptions: The Drainage Basins of Special Concern requirements shall not apply to development having:

- a. An approved master drainage plan or stormwater management plan, which has not expired prior to the date the BCC designated the area as a Drainage Basin of Special Concern. All subsequent stormwater management plans submitted in compliance with an approved, unexpired master drainage plan shall be exempt from this section.
 - b. A stormwater management plan for which a complete application for a stormwater management plan or drainage plan had been submitted to the County and not withdrawn prior to the date on which the applicable drainage basin is designated as one of special concern by the BCC and that is not subsequently denied or expired. The County and the applicant may agree to an earlier application date.
 - c. If required by the SWFWMD, the County shall allow deviations from the Drainage Basin of Special Concern criteria to the extent necessary to prevent adverse impacts to wetlands or other surface waters when it is demonstrated that adverse impacts cannot otherwise be practicably avoided.
- 3. Existing Designated Drainage Basins of Special Concern:
 - a. Effective July 18, 2005, Tank Lake (west of the old railroad berm) and East Zephyrhills (excluding Lake Pasadena, but including Lake Dorothea, Lost Lake, and Silver Oaks) are designated as closed Drainage Basins of Special Concern as delineated on the maps attached as Maps 902.2.A and 902.2.B.
 - b. Effective September 27, 2005, Timber Oaks is designated as a closed Drainage Basin of Special Concern as delineated on the map attached as Map 902.2.C.
- 4. Basin Specific Design Standards: The BCC may establish special design standards applicable to new development activity within a specific Drainage Basin of Special Concern. Special design standards may include, but are not limited to, the following:
 - a. Maximum allowable peak rate of discharge per acre.
 - b. Minimum required retention volume required per acre.
- 5. Standard Design Regulations for Drainage Basins of Special Concern: Unless the BCC adopts a more stringent special design standard within any Drainage Basin of Special Concern, the following standard regulations shall be applicable to Drainage Basins of Special Concern:

a. Open Drainage Basin

- (1) The maximum peak rate of stormwater runoff discharge from any development activity shall not exceed the prior existing maximum peak rate of stormwater runoff discharge for a two (2), ten (10), twenty-five (25), and 100-year return frequency storm event for a duration of twenty-four (24) hours.
- (2) There shall be no net loss of storage volume from the most restrictive of:
 - (a) FEMA established floodplain storage volume.
 - (b) Storage volume below the elevation of a recorded County observed flooding.
 - (c) Calculated ponding based upon a 100-year return frequency, twenty-four (24) hour storm event.
 - (d) A more critical event standard, including a 100-year return frequency, ten (10) day storm event, defined in a County or SWFWMD approved study for the applicable drainage basin.
- (3) The minimum habitable finished floor elevation shall be above the highest elevation established by the following criteria:
 - (a) This Code, Section 1103, Flood Damage Prevention.
 - (b) Recorded, County observed high water elevation, plus one (1) foot.
 - (c) Calculated ponding elevation based upon a 100-year return frequency, twenty-four (24) hour duration storm event, plus one (1) foot.
 - (d) A more critical event standard, including a 100-year return frequency, ten (10) day storm event, defined in a County or SWFWMD approved study for the applicable drainage basin, plus one (1) foot.

- (4) Permit applicants may present for consideration off-site mitigation plans that demonstrate that the mitigation will be viable and sustainable in perpetuity.

b. Closed Drainage Basin

- (1) The maximum peak rate of stormwater runoff discharge from any development activity shall not exceed the prior existing, maximum, peak rate of stormwater runoff discharge for a two (2), ten (10), twenty-five (25), and 100-year return frequency storm event for a duration of twenty-four (24) hours.
- (2) Runoff volume shall be limited to predevelopment conditions such that there shall be no increase in the volume of runoff resulting from development activity for a 100-year return frequency, ten (10) day duration storm event.
- (3) There shall be no net loss of storage volume from the most restrictive of:
 - (a) FEMA established floodplain storage volume.
 - (b) Storage volume below the elevation of a recorded, County observed flooding.
 - (c) Calculated ponding based upon a 100-year return frequency, ten (10) day storm event.
 - (d) A more critical event standard, including a 100-year return frequency, ten (10) day storm event, defined in a County or SWFWM approved study for the applicable drainage basin.
- (4) The minimum habitable finished floor elevation shall be above the highest elevation established by the following criteria:
 - (a) This Code, Section 1103, Flood Damage Prevention.
 - (b) Recorded, County observed flooding elevation, plus one (1) foot.
 - (c) Calculated elevation based upon a 100-year return frequency, ten (10) day duration storm event, plus one (1) foot.

- (d) A more critical event standard, including a 100-year return frequency, ten (10) day storm event, defined in a County or SWFWMD approved study for the applicable drainage basin, plus one (1) foot.
- (5) Permit applicants may present for consideration, off-site mitigation plans demonstrating that the mitigation will be viable and sustainable in perpetuity.

O. False Information

It is a violation of this Code to knowingly furnish false information or information that is not supported by scientific data to the County or any official in charge of the administration of this section on any matter relating to the administration of this section.

**APPENDIX 10.3.5
PASCO COUNTY,
NOISE ORDINANCE**

Noise

Sec. 66-91. - Definitions.

The following words, terms and phrases, when used in this division, shall have the meanings ascribed to them in this section, except where the context clearly indicates a different meaning:

Ambient noise means the all-encompassing noise associated with a given environment, being usually a composite of sound from many sources near and far.

A-weighted level (dBA) means the total broadband sound level of the noise spectrum as measured using the A-weighted network of a sound level meter. The unit of measurement is the dBA.

Continuous noise means a noise which remains essentially constant in level during the period of observation.

Decibel, dB means a division of a logarithmic scale used to express the ratio of two like quantities proportional to power or energy. The ratio is expressed in decibels by multiplying its common logarithm by 10.

Impulsive noise means a noise which is characterized by brief excursions of sound pressure which significantly exceed the ambient noise level.

Intermittent noise means a noise whose sound pressure level exceeds the ambient noise level at either regular or irregular intervals.

Noise level means the sound pressure level as measured in dBA unless otherwise specified. A measurement of noise must be at least five dB above the ambient noise level.

Sound level meter means an instrument to measure the sound pressure level of relatively continuous and broadband noises. The sound level meter used to determine compliance with this article shall meet or exceed the requirements for a type 2 sound level meter in accordance with ANSI standard S1.4.

Sound pressure level means the squared ratio, expressed in decibels, of the sound pressure under consideration to the standard reference pressure of 0.0002 dyne/cm². The ratio is squared because pressure squared, and not pressure, is proportional to energy.

(Code 1970, § 16¾-28; Ord. No. 74-10, § 3, 4-23-74)

Cross reference— *Definitions generally, § 1-2.*

Sec. 66-92. - Findings.

For the purposes of this article, it is found and declared that:

(1)

The making and creation of excessive, unnecessary or unusually loud noises within the limits of the county is a condition which has existed for some time and the amount of intensity of such noises is increasing.

(2)

The making, creation or maintenance of such excessive, unnecessary, unnatural or unusually loud noises which are prolonged, unusual and unnatural in their time, place and use affect and are a detriment to the public health, comfort, convenience, safety, welfare and prosperity of the residents of the county.

(3)

The necessity in the public interest for this article is declared as a matter of legislative determination and public policy, and it is further declared that this article is in pursuance of and for the purpose of securing and promoting the public health, comfort, safety and repose of the county and its inhabitants.

(Code 1970, § 16¾-26; Ord. No. 74-10, § 1, 4-23-74)

Sec. 66-93. - Unlawful acts.

It shall be unlawful, except as expressly permitted in this article, to make, cause or allow the making of any noise or sound within the boundaries of the county which exceed the limited set forth in this article.

(Code 1970, § 16¾-27; Ord. No. 74-10, § 2, 4-23-74)

Sec. 66-94. - Areas embraced.

All territory within the legal boundaries of the county, including all incorporated and unincorporated areas, shall be embraced by this article, unless in conflict with or specifically deleted by a municipal ordinance. Noises originating in an area not embraced by this article which emanate into an area embraced shall constitute a violation of this article if the noises are in excess of the maximum noise level limits provided in this article when measured from within the area embraced.

(Code 1970, § 16¾-34; Ord. No. 74-10, § 9, 4-23-74)

State law reference— *Application of county ordinances to incorporated areas, Fla. Const. art.*

Sec. 66-95. - Exceptions.

Under this article, the following shall be permitted:

- (1)

The operation of warning or emergency signal devices such as sirens, horns and bells when utilized for their intended purposes.
- (2)

Noises resulting from equipment or operations incidental to the emergency repair of facilities or restoration of services such as public utilities or other emergency activities in the public interest.
- (3)

Ordinary noise created by the operation of railways, shipping lanes and aircraft.
- (4)

Noises consistent with cultural, historical or traditional observances, holidays and ceremonies, provided that a permit for each event has been obtained from the county administrator in accordance with subsection 66-97(6).

(Code 1970, § 16¾-30; Ord. No. 74-10, § 5, 4-23-74)

Sec. 66-96. - Waivers.

- (a)

An application for a waiver for relief from the maximum allowable noise level limits designated in this article may be made in writing to the county administrator or his duly authorized representative. Any waiver granted by the county administrator under this section must be in writing and shall contain all conditions upon which the permit shall be effective. The county administrator or his duly authorized representative may grant the waiver as applied for under the following conditions:

 - (1)

The county administrator may prescribe any reasonable conditions or requirements he deems necessary to minimize adverse effects upon the community or the surrounding neighborhood, including but not limited to the use of mufflers, screens or other sound attenuating devices.
 - (2)

Waivers from maximum allowable noise level limits may only be granted for noises created within an industrial or commercial zone by

operations which were in existence on the effective date of the ordinance from which this article derives.

(3)

Waivers may be issued for no longer than 180 days, renewable by further application to the county administrator.

(b)

Any party feeling aggrieved by the denial of the application for waiver by the county administrator may appeal such denial to the board of county commissioners, such appeal to be filed within 30 days from the date of denial.

(Code 1970, § 16¾-31; Ord. No. 74-10, § 6, 4-23-74)

Sec. 66-97. - Specific noises prohibited.

The following specific noises are prohibited under this article:

(1)

Motor vehicle noise. The use of straight pipes, altered mufflers or gutted mufflers on a motor vehicle is specifically prohibited under this section.

(2)

Construction noise.

a.

No power-driven construction equipment shall be operated without a muffler or other noise-reduction device at least as effective as that recommended by the manufacturer or provided as original equipment.

b.

No construction activities shall be permitted between the hours of 10:00 p.m. and 7:00 a.m., Monday through Saturday, and all day Sunday that produce noise exceeding 55 dBA, measured at the nearest property line of an adjacent residential area.

c.

Construction equipment that must be operated near a residentially zoned area on a 24-hour-per-day basis (i.e., pumps, well tips, generators, etc.) shall be shielded by an acoustical barrier or enclosure during the hours of 6:00 p.m. to 7:00 a.m. daily, unless the unshielded noise level is less than 55 dBA, measured at the closest adjacent residentially zoned property line. The barrier or enclosure shall be so

constructed and maintained as to reduce the noise level to 55 dBA or less, measured at the closest adjacent residentially zoned property line.

(3)

Industrial or commercial noises.

a.

No noise shall be created in an industrial or commercial zone which exceeds those levels given on table 1 as follows, as measured on the adjacent property line.

TABLE 1

*Maximum Noise Levels Permitted in
Industrial and Commercial Zones*

District from which Noise Emanates	Adjoining Commercial District (No Time Limit)	Adjoining Residential District (7:00 a.m.—6:00 p.m., Monday through Saturday)
Industrial	72 dBA	66 dBA
Commercial	66 dBA	60 dBA

The maximum permitted noise level emanating from a commercially or industrially zoned district, measured at the closest adjacent residentially zoned property line for the hours between 6:00 p.m. and 7:00 a.m. Monday through Saturday and during all hours of Sunday shall be 55 dBA.

b.

An exception to the noise levels listed in table 1 shall be permitted by waivers granted by the county administrator under circumstances in which the activity creating the noise is of such importance to the public welfare, health or safety that

the activity cannot be shut down, even though its noise levels exceed those given in table 1, or in instances where an industry or commercial business had in prior years established its place of business in an area away from a residential district and subsequently, through the encroachment of residential development or rezoning, finds itself adjoining a residential district. In instances of this latter nature the noise restrictions pertaining to industrial-commercial boundaries shall govern, and the business shall not be required to meet those noise levels pertaining to residential boundaries.

c.

For impulsive noises, the noise levels listed in table 1 shall be increased by ten dBA, as measured on a sound level meter, during the hours of 7:00 a.m. to 6:00 p.m. Monday through Saturday, but shall not exceed the levels of table 1 during the period from 6:00 p.m. to 7:00 a.m. Monday through Saturday and all day Sunday.

(4)

Noises created within residential zones.

a.

Except for those noises otherwise specifically provided for within this section, it shall be unlawful to create or to permit to be created any noise within a residential district that exceeds 55 dBA, measured at the nearest adjacent property line during the hours of 10:00 p.m. to 7:00 a.m. daily.

b.

It shall be unlawful to operate any air conditioning, heating or ventilating unit at any time that produces a noise exceeding 60 dBA measured at the nearest adjacent property line.

c.

For multifamily dwelling units, it shall be unlawful to create or to permit to be created any noise that exceeds 40 dBA measured within a neighbor's dwelling during the hours of 10:00 p.m. to 7:00 a.m. daily.

(5)

Noises emanating from boats or barges on water adjoining residential districts.

a.

No craft operating on water areas adjoining residential areas

shall produce noise that exceeds 55 dBA measured at the nearest adjacent residential property line during the hours of 10:00 p.m. to 7:00 a.m. daily.

b.

For construction barges or dredges, a permit from the county administrator must be obtained in order to operate during the hours of 10:00 p.m. to 7:00 a.m. This permit will only be granted when the barge or dredge operator has satisfied the administrator that he has done all that is reasonably possible to minimize the noise impact on the adjacent residential community.

(6)

Noises within outdoor public recreation areas and parks.

a.

It shall be unlawful to operate any mechanical or electrical device within an outdoor public recreation area or park that produces a noise exceeding 60 dBA measured at a distance of at least ten feet from the source, except for planned community events, including but not limited to concerts, speeches, sporting events, fireworks displays, etc. When a planned community event will create noise in excess of the limit of 60 dBA, a permit must be obtained from the county administrator prior to the event.

b.

Motor vehicles such as trail bikes and all-terrain vehicles (ATVs) which are operated off the highways and road rights-of-way shall not exceed those maximum noise level limits specified by law for motorcycles between the hours of 7:00 a.m. and 10:00 p.m. daily. If such vehicles are operated between the hours of 10:00 p.m. and 7:00 a.m., the maximum permissible noise level shall be reduced to 60 dBA measured at least ten feet from the vehicle.

(7)

Noises created by radios, television sets, exterior loudspeakers, and similar devices.

a.

In the case of any radio receiving set, musical instrument, television, phonograph, drum, exterior loudspeaker, or other device for the production or reproduction of sound, it shall be unlawful to create or permit to be created any noise that

exceeds 66 dBA during the hours of 7:00 a.m. to 6:00 p.m., 60 dBA during the hours of 6:00 p.m. to 10:00 p.m., and 55 dBA during the hours of 10:00 p.m. to 7:00 a.m., measured from the property line of the noise source.

b.

It shall also be unlawful to operate or permit the use or operation of any radio receiving set, musical instrument, television, phonograph, drum, exterior loudspeaker, or other device for the production or reproduction of sound in such a manner as to cause noise disturbance so as to disturb the peace, quiet, and comfort of the neighborhood and vicinity thereof.

c.

Violations of subsection (7) shall be prosecuted as a misdemeanor in the second degree, pursuant to F.S. § 125.69(1) and section 1-6(c) of the County Code.

(Code 1970, § 16¾-29(a)(2)–(f); Ord. No. 74-10, § 4, 4-23-74; Ord. No. 97-10, § 1, 7-29-97)

APPENDIX 10.3.6
SECTION 402 OF THE
PASCO COUNTY LDC

CHAPTER 400. PERMIT TYPES AND APPLICATIONS

SECTION 402. USE PERMITS

402.4. Special Exceptions

A. Intent and Purpose

Special Exception uses may be compatible with other land uses permitted in a zoning district; but, because of their unique characteristics or potential impacts on the surrounding neighborhood, each application for a Special Exception will require an individual review of its location, design, configuration, operation, and the public need for the particular use at the particular location proposed. Each Special Exception may require the imposition of individualized conditions to ensure that the use is appropriate at a particular location.

B. Initiation

A Special Exception may only be requested in zoning districts where the use is identified as a Special Exception and is consistent with the Future Land Use classification of the subject property. Proposed Special Exception Uses may be initiated by the property owner or authorized agent.

C. Review and Decision Process

1. Decision Making Authority

The Planning Commission (PC) shall have the authority to hear and decide applications for Special Exceptions.

2. Public Hearing Required

The PC shall hold a public hearing on the proposed Special Exception use within forty-five (45) days after the application is deemed sufficient.

D. Notice

Notice of the public hearing shall be provided in accordance with this Code and the provisions of Chapter 125.66, Florida Statutes.

E. Required Standards

All proposed Special Exception uses shall meet all of the following standards:

1. The proposed use shall be consistent with the Goals, Objectives, and Policies of the adopted Comprehensive Plan elements or applicable portions thereof.

2. The proposed use will not create or excessively increase traffic or parking congestion or otherwise affect public safety.
3. The site upon which the proposed use is to be located has suitable drainage, access, ingress and egress, on-site parking, loading areas, refuse collection, and adequate utilities available to service the site.
4. The site upon which the Special Exception is to be located has, or will have, screening and buffering sufficient to prevent interference with the enjoyment of surrounding properties.
5. Proposed signs and lighting will not create any adverse glare or adversely affect traffic safety, economic value, or cause other significant problems on adjoining or surrounding properties.
6. There is adequate yard and open space to serve the property upon which the Special Exception use will be maintained.

F. Staff Recommendation

1. The County Administrator or designee, after consideration of the above standards, shall present a recommendation to the PC.
2. In consideration of the standards, the County Administrator or designee may recommend conditions necessary to ensure compliance with the required standards.

G. PC Hearing

1. Upon receipt of staff recommendation, the PC shall hold a public hearing.
2. At the conclusion of the public hearing, if the PC determines, after consideration of competent substantial evidence presented at the public hearing, that the above standards for approving a Special Exception have been met, the PC must grant the application for Special Exception. The PC shall:
 - a. Approve the application as presented.
 - b. Approve the application with modified, deleted, or added conditions as necessary to ensure compliance with review standards.
 - c. Deny the request if the PC determines, after consideration of competent substantial evidence presented at the public hearing that granting the application would have an adverse effect on the health, safety, and welfare of the public based upon the standard in Section 402.4.E., the PC shall deny the application citing reasons for the same.

H. Effect of Final Determination

1. Denial

Whenever the PC has denied an application for a Special Exception, the PC shall not thereafter:

- a. Consider any further application for the same Special Exception of any part of the same property for a period of twelve (12) months from the date of denial by the PC.
- b. Consider an application for any other kind of Special Exception use of any part of the same property for a period of six (6) months from the date of denial by the PC.

2. Approval

- a. Use Authorized. The holder of a Special Exception shall be authorized to utilize the site or location of the said use only in the manner specified in the written approval and any conditions recited therein shall be binding on the applicant and all successors in interest to the applicant. Failure to observe conditions of approval is a violation of this Code. Such use may be subject to further procedural requirements in this Code.
- b. Any substantial expansion; alteration in the manner or method of operation of the use which results in an increase in adverse effects on surrounding properties, such as noise, traffic, odor, dust, or increase in acreage; or change in the square footage or acreage utilized for the Special Exception shall require an amendment to the Special Exception, which shall be processed and reviewed in the same manner as the original Special Exception application.

An expansion, alteration, or change of a Special Exception shall also be deemed to exist where a substantial modification of any of the standards provided for in this Code results from activity associated with the Special Exception or where substantial change in circumstances or conditions arise.

I. Revocation of Special Exception and Conditional Use Approvals

1. Board of County Commissioners (BCC) Jurisdiction. The BCC hereby reserves to itself the jurisdiction and authority to review and revoke Special Exception and Conditional Use approvals.

APPENDIX 10.3.6.1
SPECIAL EXCEPTION APPROVAL
SHCCF PROJECT - DATED 1/10/2018

**BEFORE THE PLANNING COMMISSION
IN AND FOR PASCO COUNTY**

**IN RE: SPECIAL EXCEPTION APPLICATION NO. 7295
SHADY HILLS ELECTRIC COMPANY, LLC**

ORDER

THE PLANNING COMMISSION OF PASCO COUNTY, FLORIDA, on January 10, 2017, with a quorum present and voting, after due public notice, being empowered under Chapter 200, Section 204 of the Pasco County Land Development Code (LDC) to hear and decide requests for special exceptions, does hereby make the following findings, conclusions, and interpretations as applied to the above special exception request for a power generating plant for essential public services in an A-C Agricultural District:

1. A transmission and power delivery facility is a specified special exception use as set forth in the A-C Agricultural District.
2. The Planning Commission has heard and considered the presentation and evidence of the applicant and individuals in opposition to and in favor of the application.
3. The Planning Commission has reviewed the report and recommendations of County staff and the following findings of fact:

FINDS OF FACT:

- a. The subject site is a vacant portion of Shady Hills Power Company, LLC power plant tract, encompassing 10 acres of a 30 acre tract owned by Shady Hills Power Company, LLC. The applicant proposes to use the site for a new electric private utility facility (a nominal 550 megawatt (MW) combined-cycle, natural gas-fired, electric power generating plant).
- b. The applicant provided the following narrative:

Proposed Special Exception: Shady Hills Power Company LLC proposes to construct and operate a new electric private utility facility herein described as a nominal 550 megawatt (MW) combined-cycle, natural gas-fired, electric power generating plant (Project) in unincorporated

Pasco County, Florida. The proposed Project will be constructed on a 10-acre parcel of land (expansion site) situated adjacent to and east of an existing electric power generating plant that Shady Hills Power Company LLC owns and operates. The existing facility was approved by the Pasco County Planning Commission under Special Exception RA5528 dated December 8, 1999. The Site is located on Merchant Energy Way, north of Hudson Road, east of Shady Hills Wastewater Treatment Plant, and south of the Pasco County Resource Recovery facility.

The Project will consist of a single combustion turbine generator equipped with advanced emission control equipment, a heat recovery steam generator with duct burners, a single condensing Steam Turbine Generator, a deaerating surface condenser, a mechanical draft wet cooling tower, and associated ancillary equipment necessary for the generation of electric energy. A short (approximately 1.0 mile) new transmission line will be required as part of the Project that will traverse the resource recovery property and connect to a new Duke substation to be located within Duke's existing transmission lines rights-of-way.

The Project will increase electrical generation capacity that currently exists on the adjacent 20 acres by approximately 550 MWs using economical, fuel-efficient, state-of-the-art technology, while minimizing environmental impacts to the expansion site and surrounding area. The Project will be fired by natural gas only. Natural gas will be transported by Florida Gas Transmission through an existing pipeline lateral connection that terminates at the existing power plant site. The Project will utilize treated wastewater (also referred to as reclaimed water) obtained from Pasco County from and/or through the Shady Hills Wastewater Treatment Plan for process purposes, including cooling. The Project will secure the rights-of-way by easement with Pasco County and install piping in the rights-of-way to transfer reclaimed water to the County and install piping in the Rights-of-way to transfer reclaimed water to the expansion site. The plant will use zero liquid discharge technology to eliminate industrial wastewater discharge.

Potable water and sanitary sewer will be provided by Pasco County from connections at the existing adjacent power plant.

- c. The subject site is 330 feet wide and approximately 1,320 in depth.
- d. Access to the site is from Merchant Energy Way, a private, 2-lane residential paved roadway within a 24-foot wide (varies) private maintained right-of-way in very good condition. The private portion of Merchant Energy Way ties into a 2-lane county paved roadway within a 24 foot wide (varies) county maintained right-of-way in very good condition that connects to Hudson Avenue, a 2-lane residential roadway within a 24' – 26 foot wide (varies) county maintained right-of-way in good to very good condition.
- e. The subject site is located in Flood Zone "X," and development is subject to the requirements of the Land Development Code (LDC), Section 1104, Flood Damage Prevention.
- f. The surrounding area is characterized by an electric generating plant, a wastewater treatment plant, a resource recovery facility, inactive concrete batch plant, single family residential and a planned outdoor shooting range (Pasco Sheriff Office).
- g. The subject area has been designated RES-1 (Residential – 1 du/ga) under the Comprehensive Plan.
- h. The subject site is within the South Market Area and Urban Expansion Area.
- i. On December 8, 1999, the existing facility was approved by the Pasco County Planning Commission under Special Exception RZ5528.
- j. On November 17, 2017, the subject request was found to be exempt from Timing and Phasing (Section 901.12.C.1) as the highest and best use of the proposed special exception would result in less than 50 peak hour trips, a.m. or p.m. whichever is higher. Access Management Analysis and Substandard Road Review will be performed at the time of Preliminary Site Plan or Preliminary Development Plan, if applicable.

The proposed request is consistent with the LDC, Chapter 400, Permit Types and Applications; Section 402.4.E, Special Exception, Review Considerations; and the applicable provisions of

the County's Comprehensive Plan.

k. The applicant proposes to redevelop the site as a power generation facility expansion with transmission line tie-ins for essential public services in an A-C Agricultural District.

4. Upon consideration and adoption of the recommendation of staff and the evidence presented at the public hearing, the Planning Commission has determined that the standards for issuing a special exception, as set forth in the Pasco County LDC, Chapter 400, Section 402.4.F. have been met.

5. The special exception requested is consistent with the adopted Pasco County Comprehensive Plan and would not have an adverse effect on the health, safety, and welfare of the public.

Accordingly, it is hereby

ORDERED that Special Exception Application No. 7295 is hereby approved for the property described in Exhibit A attached hereto, subject to the following conditions:

CONDITIONS OF APPROVAL

1. The owner/developer shall provide a new driveway and loop road around the perimeter of the proposed plant expansion.
2. There shall be no access via Softwind Lane. All access shall be via Hudson Avenue and Merchant Energy Way.
3. The owner/applicant acknowledges that any provision of Pasco County ordinances, not specifically waived shall be in full force and effect.
4. The owner/applicant shall enter into a utility service agreement with Pasco County prior to site plan approval.
5. Prior to any development or redevelopment of the site, the owner/applicant shall submit and receive approval of a Preliminary Site Plan, per Land Development Code, Section 403.
6. Calculation of allowable density and intensity shall be in compliance with the land use category limitations set forth in the Pasco County Comprehensive Plan.
7. The owner/applicant is hereby notified that the effective date of this approval shall be the date of the final County action; however, no activity shall commence on site until such time as the acknowledgement portion of this document is completed (including notarization) and received by the Planning and Development Department.

8. This special exception shall be limited to power generating facility for essential public services use of power generating facilities (stack, heat recovery steam generator, gas turbine, inlet air filter, generator, take-off tower/circuit breaker/line disconnect switch, step-up transformer, fuel gas condition and pressure regulation station, gas metering yard, auxiliary broiler area, circulating water pumps, cooling tower (fan height 50 feet), Aqueous ammonia storage/unloading area, water treatment building (6,000 sq.ft. +/- single story max height 30 feet +/-, steam turbine, electric power distribution center (PDC) 1,500 sq.ft. +/-, surface condenser, new lines, rebuilds and maintenance needs), admin/control/warehouse building (16,000 sq.ft. +/- Single Story Max Height 30 feet), fire protection water/service water storage tank, fire pump house/raw water pumps house, parking area, plant entrance and associated and ancillary equipment for generation to occur.

9. The development of the property for utilization as a power generating facility is subject to review and approval of a Preliminary Site Plan. This review will allow the applicant to adequately identify the existing site conditions and demonstrate general conformance with the standards of the Land Development Code. These standards include, but are not limited to, public safety, environmental, site access from Hudson Avenue and Merchant Energy Way, buffering, screening, wildlife habitat including gopher tortoise, parking, proposed impervious surfaces, etc.

10. This approval is subject to the provisions of the LDC, Section 402.4.I, Revocation of Special Exception and Conditional Use Approvals. In addition, staff may initiate an enforcement for violations of the conditions of approval by any of the methods available in the LDC, Section 108, or through revocation of the Conditional Use pursuant to the provisions of the LDC, Section 402.4.I, Revocation of Special Exception and Conditional Use Approvals, or both.

11. In addition to complying with the above conditions, no activity shall commence on site until such time as the acknowledgment portion of this document is completed (including notarization) and received by the Planning and Development Department after the final action.

DONE AND ORDERED effective as of this 11th day of January, 2018.



Shannon Ezybert, DC

PAULA S. O'NEIL, Ph.D., CLERK & COMPTROLLER

PLANNING COMMISSION OF
PASCO COUNTY, FLORIDA

[Signature]

CHAIRMAN

1-10-2018

EXHIBIT A

SE-7295

A par of Ind being a por of the Inds as desc per ORB 4444, Pg 1196, of the Pub Rec of Pasco Co, FL, lying & being in the $W\frac{1}{2}$ of the $NE\frac{1}{4}$ of the $NW\frac{1}{4}$ of the $SE\frac{1}{4}$, & the $W\frac{1}{2}$ of the $SE\frac{1}{4}$ of the $NW\frac{1}{4}$ of the $SE\frac{1}{4}$, all of Sec 25, T24S, R17E, Pasco Co, FL, being more partic desc as fol:

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APPENDIX 10.4

ENVIRONMENTAL RESOURCE PERMIT DOCUMENTATION

**(AND STORMWATER MANAGEMENT SYSTEM DESIGN
AND CALCULATIONS)**



ENVIRONMENTAL RESOURCE PERMIT APPLICATION

Shady Hills Combined Cycle Facility

Pasco County, FL



February 2018

Project No. 1779520

A world of
capabilities
delivered locally



JOINT APPLICATION FOR INDIVIDUAL ENVIRONMENTAL RESOURCE PERMIT/ AUTHORIZATION TO USE STATE-OWNED SUBMERGED LANDS/ FEDERAL DREDGE AND FILL PERMIT

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION/
WATER MANAGEMENT DISTRICTS/
U.S. ARMY CORPS OF ENGINEERS

Effective October 1, 2013



INSTRUCTIONS FOR USE OF THIS FORM:

This form is designed to assist you in submitting a complete application. All applications must include Section A- General Information for All Activities. Sections B through H list typical information that is needed based on the proposed activities, and are only required as applicable. Part 1-C of Section A will guide you to the correct sections needed based on your proposed activities. Applicants are advised to consult Chapter 62-330, F.A.C., and the Environmental Resource Permit Applicant's Handbook Volumes I and II for information regarding the ERP permitting process and requirements while preparing their application. Internet addresses for Chapter 62-330, F.A.C. and the Applicant's Handbook, Agency contact information, and additional instructions for this form can be found in Attachment 1.

What Sections of the Application Must I Fill Out?

Does the project involve....	Section							
	A- General Information	B- Single Family Residential	C- Wetlands and other Surface Waters	D- Structures or Works in Surface Waters	E- Stormwater Management System	F- State-owned Submerged Lands	G- Mitigation Banks	H- Mines
Fill in wetlands or waters for a single family residence?	X	X						
Docks, shoreline stabilization, seawalls associated with a single family residence?	X	X				X, if applicable		
Wetland impacts (other than associated with an individual residence)?	X		X					
Boating facilities, a marina, jetty, reef, or dredging?	X		X	X		X if applicable		
Any work on state owned submerged land?	X		X			X		
Construction of a stormwater management system?	X		X, if applicable		X			
Constructing a mitigation bank?	X		X		X, if applicable		X	
Creating a mine?	X		X, if applicable					X

Note- if you are required to provide Section B, then you do not have to provide any other Sections, unless the activities are on state-owned submerged lands. In that case, Section F will also be required.

If you have any questions, or would like assistance completing this form, please contact the staff of the nearest office of either the Florida Department of Environmental Protection (DEP) or a Water Management District (WMD) (see Attachment 2).

Section A: General Information for All Activities

PART 1: NAME, APPLICATION TYPE, LOCATION, AND DESCRIPTION OF ACTIVITY

A. Name of project, including phase if applicable: **Shady Hills Combined Cycle Facility**

B. This is for (check all that apply):

- ☒ Construction or operation of **new** works, activities and/ or a stormwater management system
- ☐ **Conceptual Approval** of proposed works, activities and/ or a stormwater management system
- ☐ Modification or Alteration of **existing** works activities and / or a stormwater management system. Provide the existing DEP or WMD permit #, if known: ____ Note: Minor modifications do not require completion of this form, and may instead be requested by letter.
- ☐ **Maintenance or repair** of works, activities and/ or stormwater management system previously permitted by the DEP or WMD Provide existing permit #, if known: ____
- ☐ Abandonment or removal of works, activities and/ or stormwater management system Provide existing DEP or WMD permit #, if known: ____
- ☐ Operation of an **existing unpermitted** stormwater management system.
- ☐ Construction of additional phases of a permitted work, activity and/ or stormwater management system.

Provide the existing DEP or WMD permit #, if known: ____

C. **List the type of activities proposed. Check all that apply, and provide the supplemental information requested in each of the referenced application sections. Please also reference Applicant's Handbooks I and II for the type of information that may be needed.**

- ☐ Activities associated with one single-family residence, duplex, triplex, or quadruplex that do not qualify for an exemption or a General Permit: **Provide the information requested in Section B. Do not complete Section C.**
- ☐ Activities within wetlands or surface waters, or within 25 feet of a wetland or surface water, (not including the activities associated with an individual residence). *Examples include dredging, filling, outfall structures, docks, piers, over-water structures, shoreline stabilization, mitigation, reclamation, restoration/enhancement.* **Provide the information requested in Section C.**
- ☐ Activities within navigable or flowing surface waters such as a multi-slip dock or marina, dry storage facility, dredging, bridge, breakwaters, reefs, or other offshore structures: **In addition to Section C, also provide the information requested in Section D.**
- ☐ Activities that are (or may be) located within, on or over state-owned submerged lands (See Chapter 18-21, F.A.C. <https://www.flrules.org/gateway/ChapterHome.asp?Chapter=18-21>): **In addition to Section B or C, also provide the information requested in Section F**

- ☒ Construction or alteration of a stormwater management system serving residential, commercial, transportation, industrial, agricultural, or other land uses, or a solid waste facility (excluding mines that are regulated by DEP). **Provide the information requested in Section E.**
- ☐ Creation or modification of Mitigation Bank (refer to Chapter 62-342, F.A.C. <https://www.flrules.org/gateway/ChapterHome.asp?Chapter=62-342>): **Provide the information requested in Section G.**
- ☐ Mines (as defined in Section 2.0 of Applicant's Handbook Volume I) that are regulated by the DEP: **Provide the information requested in Section H.**
- ☐ Other, describe: Please contact the Agency to determine which additional sections of the application are needed. See Attachment 1 for Agency contacts.

D. Describe in general terms the proposed project, system, works, or other activities. For permit modifications, please briefly describe the changes requested to the permit:

The Shady Hills Combined Cycle Facility (SHCCF) Project involves the construction and operation of a natural gas-fired 573 megawatt (MW) (winter), combined-cycle generating facility and certain on-site and off-site associated facilities, including a 230-kV interconnection tie-line and a temporary construction parking and laydown area. The Project is proposed upon lands adjacent to the existing Shady Hills Generating Station; no wetland impacts are proposed in association with construction and operation of the Project. The 230-kV Interconnect Tie-Line will be installed and operated without any wetland impacts, in accordance with 62-330.051(14)(a), F.A.C. and 403.818(1)(a), F.S.

The SHCCF Site stormwater management system will include two dry stormwater detention ponds (Pond 1 and Pond 2), built early for management of construction related drainage. Stormwater runoff within the Site will be routed via overland flow, swales or ditches, and buried culverts that will direct flow to one of two ponds. Pond 1 is located near the northwest Site boundary and Pond 2 is located near the southwestern Site boundary. The drainage system is designed to accommodate runoff from a 100-year, 24-hour storm event without discharge. Construction stormwater will be managed following best management practice (BMP) requirements of the Generic Permit for Stormwater Discharge from Large and Small Construction Activities and the Project's stormwater management plan. The BMPs include use of silt fencing and hay wattles, which will be installed along the perimeter of the SHCCF Site, the temporary construction parking and laydown area, and the 230-kV Interconnection Tie-Line right-of-way to prevent offsite water quality impacts during construction. A soil tracking prevention device will be installed at the site entrance where construction related traffic is to enter and exit the Site. See Attachment C - Stormwater Management System Design and Calculations, Drawings 2 through 4 for details.

The stormwater management system has been designed to provide approximately 8.0 acre-feet of storage from a total contributing area of approximately 14 acres. The drainage plan has been delineated into eight drainage sub-basins, and sub-basin runoff is collected within swales, drop inlets and pipe and routed to either Pond 1 or Pond 2. Runoff from the northern portion of the Site is directed to Pond 1 and runoff from the southern portion of the Site is directed to Pond 2. Pond 1 and Pond 2 will normally be dry as peak flows and runoff volumes resulting from the 100-year, 24-hour storm event will be attenuated via percolation. Similar to design storm attenuation, these ponds have been designed to attenuate the required water quality treatment volumes via percolation.

- E. For activities in, on, or over wetlands or other surface waters, check the type of federal dredge and fill permit requested (if known): ☐ Individual ☐ Programmatic General permit #: ☐ General ☐ Nationwide permit #: ☒ Not Applicable ☐ Not sure

- F. Project/Activity Street/Road Address or other location (if applicable): **14240 Merchant Energy Way**
City: **Shady Hills** County(ies): **Pasco** Zip: **34610**

Note: For utility, road, or ditch/canal activities, provide a starting and ending point using street names and nearest house numbers or provide length of project in miles along named streets or highways.

- G. Project location map and Section, Township, and Range information (use additional sheets if needed):
Please attach a location map showing the location and boundaries of the proposed activity in relation to major intersections or other landmarks. The map should also contain a north arrow and a graphic scale; show Section(s), Township(s), and Range(s); and must be of sufficient detail to allow a person unfamiliar with the site to find it.

Section(s): **25** Township: **24 S** Range: **17 E** Land Grant name, if applicable:
Section(s): Township: Range:
Section(s): Township: Range:

See Attachment A – Site Location Information, Figure 1 – SHCCF Site Location Map

- H. Latitude (DMS) **28° 21' 58.34" N** Longitude (DMS) **82° 33' 24.94" W** (Taken from central location of the activity). Explain source for obtaining latitude and longitude (i.e. U.S.G.S. Quadrangle Map, GPS, online resource): **Google Earth**

- I. Tax Parcel Identification Number(s): **1724250000001000011, 1724250000001000010, 1724250000002000000**

[Number may be obtained from property tax bill or from the county property appraiser's office; if on multiple parcels, provide multiple Tax Parcel Identification Numbers]

- J. Directions to Site (from major roads; include distances and landmarks as applicable):

The SHCCF Certified Site is located on Merchant Energy Way, north of Hudson Avenue, east of the Pasco County's Shady Hills Wastewater Treatment Facility (SHWWTF) and south of the Pasco County Resource Recovery facility. The Site is located in Shady Hills, Florida. From State Road (SR) 589, take the exit for FL-52 and travel west for approximately 1 mile, turn right onto Hays Road and proceed for approximately 2 miles, turn right on Hudson and then left onto Merchant Energy Way.

- K. Project area or phase area: **Total of approximately 48 acres:**

SHCCF Certified Site – approximately 14.21 acres
230-kV Interconnect Tie-Line – approximately 13.7 acres
Construction Parking and Laydown Area – approximately 20.33 acres

- L. Name of waterbody(ies) (if known) in which activities will occur or into which the system will discharge:
N/A; no wetland impacts are proposed and the stormwater management system is designed to accommodate runoff from a 100-year, 24-hour storm event without discharge.

The following questions (M-O) are not applicable to activities related to a single-family residence, including private single-family residential docks, piers, seawalls or boat ramps.

- M. Is it part of a larger plan of development or sale? ☐ yes ☒ no
- N. Impervious or semi-impervious area excluding wetlands and other surface waters (if applicable):
8 acres or 348,480 square feet
- O. Volume of water the system is capable of impounding (if applicable): **8.0 acre-feet.**

PART 2: SUPPLEMENTAL INFORMATION, AND PERMIT HISTORY

- A. Is this an application to modify an existing Environmental Resource Permit, or to construct or implement part of a multi-phase project, such as a project with a Conceptual Approval permit? ☐ Yes ☒ No *If you answered "yes", please provide permit numbers below:*

AGENCY	DATE	PERMIT/APPLICATION NO.	PROJECT NAME

- B. Indicate if there have been any **pre-application meeting(s)** or other discussions about the proposed project, system or activity. If so, please provide the date(s), location(s) of the meeting, and the name(s) of Agency staff that attended the meeting(s):

AGENCY	DATE	LOCATION	MEETING ATTENDEES
FDEP Siting Office	01-24-18	Tallahassee	Michael Weiss, Cindy Mulkey, Ann Seiler, Amanda Dyer, David Read, Frank Wall, Jorge Perez
FDEP Southwest District	02-08-18	Tampa	Mark Langford, Veronica Robinson
SWFWMD	01-09-18	Tampa	James Golden, Vivian Arenas-Battles, Mario Cabana
FFWCC	01-23-18	Tallahassee	Fritz Wettstein, Jason Hight
FL DOS / DHR	01-29-18	Telephone	Deena Woodward
USFWS	02-02-18	Email and letter submittal	Tina Nguyen
Pasco County	02-12-18	Pasco County	Dan Biles, Michael Carbala, Peter Lent, Joe Richards, Kris Hughes
FDOT	01-08-18	Telephone	Kim Menchion
FDEO	01-08-18	Telephone	Scott Rogers

- C. **Attach a depiction (plan and section views), which clearly shows the works or other activities proposed to be constructed.** Use multiple sheets, if necessary, a scale sufficient to show the location and type of works, and include a north arrow and a key to any symbols used. **Specific information to be included in the plans is based on the activities proposed and is further described in Sections B-H.** However, supplemental information may be required based on the specific circumstances or location of the proposed works or other activities.

See Attachment C - Stormwater Management System Design and Calculations

- D. Processing Fee: ***Please submit the application processing fee along with this application form and supplemental information.*** Processing fees vary based on the size of the activity, the type of permit applied for, and the reviewing Agency. Please reference Attachment 3 to determine the appropriate fee.

The ERP application is being submitted as part of the SHCCF Site Certification Application

PART 3: APPLICANT AND ASSOCIATED PARTIES INFORMATION

Instructions: Permits are only issued to entities having sufficient real property interest as described in Section 4.2.3 (d) of Applicant's Handbook Volume I. Please attach evidence of sufficient real property interest over the land upon which the activities subject to the application will be conducted, including mitigation (if applicable). Refer to Section 4.2.3 (d) for acceptable ownership or real property interest documentation. For corporations, list a person who is a registered agent or officer of the corporation who has the legal authority to bind the corporation.

A. APPLICANT (ENTITY MUST HAVE SUFFICIENT REAL PROPERTY INTEREST)			
☐ THIS IS A CONTACT PERSON FOR ADDITIONAL INFORMATION			
Name: Last: Belden	First: Roy	Middle: S.	
Title: Vice President	Company: Shady Hills Energy Center, LLC		
Address: 901 Main Avenue			
City: Norwalk	State: CT	Zip: 06851	
Home Telephone:		Work Telephone: 203-357-6820	
Cell Phone: 203-204-4321		Fax:	
E-mail Address: Roy.Belden@ge.com also cc: Ankur.Mathur1@ge.com			
Correspondence will be sent via email. Check here to receive correspondence via US Mail: ☐			
B. LAND OWNER(S) (IF DIFFERENT OR IN ADDITION TO APPLICANT)			
☐ CHECK HERE IF LAND OWNER IS ALSO A CO-APPLICANT			
Name: Last: Belden	First: Roy	Middle: S.	
Title: Vice President	Company: Shady Hills Power Company, LLC		
Address: 901 Main Avenue			
City: Norwalk	State: CT	Zip: 06851	
Home Telephone:		Work Telephone: 203-357-6820	
Cell Phone: 203-204-4321		Fax:	
E-mail Address: Roy.Belden@ge.com also cc: Ankur.Mathur1@ge.com			
C. OPERATION AND MAINTENANCE ENTITY (see Applicant's Handbook I, Section 12.3)			
Entity Name: Shady Hills Energy Center, LLC	Contact: Last: Mathur	First: Ankur	Middle:
Title: Vice President	Company:		
Address: 901 Main Avenue			
City: Norwalk	State: CT	Zip: 34610	
Home Telephone:		Work Telephone:	
Cell Phone: 202-524-3486		Fax:	
E-mail Address: Ankur.Mathur1@ge.com also cc: Roy.Belden@ge.com			
D. CO-APPLICANT (IF DIFFERENT OR IN ADDITION TO APPLICANT AND OWNER)			
Name: Last:	First:	Middle:	
Title:	Company:		
Address:			

City:	State:	Zip:
Home Telephone:		Work Telephone:
Cell Phone:		Fax:
E-mail Address:		
E. ENGINEERING CONSULTANT ☒ THIS IS A CONTACT PERSON FOR ADDITIONAL INFORMATION		
Name: Last: Kelsey	First: Joel	Middle: T
Title: Senior Project Engineer	Company: Golder Associates	
Address: 5100 W. Lemon Street		
City: Tampa	State: FL	Zip: 33609
Home Telephone:		Work Telephone: 813-769-5318
Cell Phone: 916-899-1318		Fax:
E-mail Address: Joel_Kelsey@golder.com		
F. ENVIRONMENTAL CONSULTANT ☐ THIS IS A CONTACT PERSON FOR ADDITIONAL INFORMATION		
Name: Last:	First:	Middle:
Title:	Company:	
Address:		
City:	State:	Zip:
Home Telephone:		Work Telephone:
Cell Phone:		Fax:
Correspondence will be sent via email. Check here to receive correspondence via US Mail: ☐		

If necessary, please add additional pages for other contacts and property owners related to this project.

PART 4: SIGNATURES AND AUTHORIZATION TO ACCESS PROPERTY

Instructions: For multiple applicants please provide a separate Part 4 for each applicant. For corporations, the application must be signed by a person authorized to bind the corporation. A person who has sufficient real property interest (see Section 4.2.3 (d) of Applicant's Handbook Volume I) is required in (B) to authorize access to the property, except when the applicant has the power of eminent domain.

A. By signing this application form, I am applying for the permit and any proprietary authorizations identified above, according to the supporting data and other incidental information filed with this application. I am familiar with the information contained in this application and represent that such information is true, complete and accurate. I understand this is an application and not a permit, and that work prior to approval is a violation. I understand that this application and any permit issued or proprietary authorization issued pursuant thereto, does not relieve of any obligation for obtaining any other required federal, state, water management district or local permit prior to commencement of construction. I agree to operate and maintain the permitted system unless the permitting agency authorizes transfer of the permit to a different responsible operation and maintenance entity. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

Roy S. Belden	Roy S. Belden	2/16/18
Typed/Printed Name of Applicant or Applicant's Authorized Agent	Signature of Applicant or Applicant's Authorized Agent	Date

Vice President
(Corporate Title if applicable)

B. CERTIFICATION OF SUFFICIENT REAL PROPERTY INTEREST AND AUTHORIZATION FOR STAFF TO ACCESS THE PROPERTY:

I certify that:

☐ I possess sufficient real property interest in or control, as defined in Section 4.2.3 (d) of Applicant's Handbook Volume I, over the land upon which the activities described in this application are proposed and I have legal authority to grant permission to access those lands. I hereby grant permission, evidenced by my signature below, for staff of the Agency and the U.S. Army Corps of Engineers to access, inspect, and sample the lands and waters of the property as necessary for the review of the proposed works and other activities specified in this application. I authorize these agents or personnel to enter the property as many times as may be necessary to make such review, inspection, and/ or sampling. Further, I agree to provide entry to the project site for such agents or personnel to monitor and inspect permitted work if a permit is granted.

OR

☐ I represent an entity having **the power of eminent domain and condemnation authority**, and I/we shall make appropriate arrangements to enable staff of the Agency and the U.S. Army Corps of Engineers to access, inspect, and sample the property as described above.

Typed/Printed Name	Signature	Date

(Corporate Title if applicable)

C. DESIGNATION OF AUTHORIZED AGENT (IF APPLICABLE):

I hereby designate and authorize _____ to act on my behalf, or on behalf of my corporation, as the agent in the processing of this application for the permit and/or proprietary authorization indicated above; and to furnish, on request, supplemental information in support of the application. In addition, I authorize the above-listed agent to bind me, or my corporation, to perform any requirements which may be necessary to procure the permit or authorization indicated above. I understand that knowingly making any false statement or representation in this application is a violation of Section 373.430, F.S. and 18 U.S.C. Section 1001.

_____ Typed/Printed Name of Applicant	_____ Signature of Applicant	_____ Date
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(Corporate Title if applicable)

SECTION E: SUPPLEMENTAL INFORMATION REQUIRED FOR WORKS OR OTHER ACTIVITIES INVOLVING A STORMWATER MANAGEMENT SYSTEM (OTHER THAN A SINGLE-FAMILY PROJECT)

Instructions: The information listed in the checklists below represents the level of information that is usually required to evaluate an application. Information can be provided within reports, plans and documents. The level of information required for a specific project will vary depending on the nature and location of the site and the activity proposed. Conceptual approvals generally do not require the same level of detail as a construction permit. However, providing a greater level of detail will reduce the need to submit additional information at a later date. If an item does not apply to your project, proceed to the next item. The supplemental information required by this section is in addition to the information required by Section A of the ERP application.

PART 1: STORMWATER MANAGEMENT SYSTEM SUMMARY

Provide drainage calculations, signed and sealed by an appropriate registered professional, and supporting documentation demonstrating that the proposed project meets the conditions for issuance under 62-330.301(1)(a),(b),(c),(e), F.A.C. The drainage calculations should include, but not necessarily be limited to, the following:

See Attachment C - Stormwater Management System Design and Calculations

1. General Site Information:

- a. ☐ Provide pre-development and post-development drainage map(s), as appropriate, that include drainage patterns and basin boundaries with acreage served by each hydraulically separate system, showing the direction of flows, including any off-site runoff being routed through or around the system; topographic information; and connections between wetlands and other surface waters.
- b. ☐ Provide the results of any percolation tests, where appropriate, and soil borings that are representative of the actual site conditions. Identify the wet season high water table elevations, soil profiles, and hydraulic conductivity. Include dates, datum, and methods used to determine these soil parameters.
- c. ☐ Identify the onsite hydrologic soil classification (e.g. Type A, B/D, D). Reference the source, such as the USDA/NRCS Soil Survey, used in estimating the onsite hydrologic soil classification. Provide maps, as appropriate, with the project limits delineated.
See Attachment A – Site Location Information, Figure 2 - Soils
- d. ☐ Identify the seasonal high water or mean high tide elevation for receiving waters/wetlands into which runoff will be discharged. Include dates, datum, and methods used to determine these elevations.
- e. ☐ Identify the name of each receiving waterbody to which the proposed stormwater management system will discharge:
- f. ☐ Indicate the existing land use and land cover. **See Attachment A – Site Location Information, Figure 3 – Landuse. A summary table is provided below:**

FLUCFCS Code	Land Cover	Acreage
Certified Site		
190	Open Land	8.18
441	Coniferous Plantations	1.95
830	Utilities	4.08
Subtotal		14.21
230-kV Transmission Tie-line		
434	Hardwood Conifer Mixed	2.87
830	Utilities	10.83
Subtotal		13.7
Temporary Laydown Area		
111	Fixed Single Family Units	0.29
211	Improved Pasture	5.35
427	Live Oak	2.41
441	Coniferous Plantations	12.17
830	Utilities	0.10
Subtotal		20.33
TOTAL		48.24

- g. ☐ Provide the acreage, and percentages of the total project, of the following:
1. Impervious surfaces, excluding buildings, wetlands and other surface waters;
 2. Buildings;
 3. Pervious surfaces (green areas not including wetlands);
 4. Lakes, canals, retention areas, other open water areas; and
 5. Wetlands (Please refer to Section C to ensure consistency in wetland acreages).

Land Cover Type	Acreage	Percent
Certified Site		
Impervious surfaces, excluding buildings, wetlands and other surface waters	8	56.3
Buildings	1.26	8.9
Pervious Surfaces (not including wetlands)	3.69	25.9
Lakes, canals, retention area, other open water areas	1.26	8.9
Total	14.21	100
230-kV Transmission Tie-line		
Pervious Surfaces (not including wetlands)	13.7	100
Temporary Laydown Area		
Pervious Surfaces (not including wetlands)	20.33	100

- h. ☐ Provide the location and description of any nearby existing offsite features (such as wetland and other surface waters, stormwater management ponds, and building or other structures) which might be affected by or affect the proposed construction or development. **N/A**

2. Water Quality Analysis:

See Attachment C - Stormwater Management System Design and Calculations

- a. ☐ Provide a description of the proposed stormwater treatment methodology that addresses the type of treatment, pollution abatement volumes, and recovery analysis.
- b. ☐ Is the receiving waterbody known to be impaired, and/or has an established Total Maximum Daily Load (TMDL) or Basin Management Action Plan (BMAP)? If so, please provide specific descriptions of all water quality parameters for which the waterbody is known to be impaired? For more information about water quality, impaired waters, and to determine whether a TMDL has been adopted in your project area, refer to: <http://waterwebprod.dep.state.fl.us/basin411/downloads/Florida-Adopted-TMDLs.pdf>. To determine whether a BMAP exists, or is being developed in your project area, refer to: <http://www.dep.state.fl.us/water/watersheds/bmap.htm#rad>.
☐ yes ☒ no ☐ don't know
If yes, provide calculations demonstrating that the proposed project will not contribute to violations of state water quality standards in accordance with the applicable Applicant's Handbook, Vol. II.
- c. ☐ Does the project have a direct discharge to a Class I, Class II, Outstanding Florida Waters or Class III waters, which are approved, conditionally approved, restricted, or conditionally restricted for shellfish harvesting? *To determine whether your project is within, or will discharge to an OFW, or for more information about OFWs in general, refer to: <http://www.dep.state.fl.us/water/wqssp/ofw.htm>.*
☐ yes ☒ no ☐ don't know
If yes, additional treatment in accordance with the applicable Applicant's Handbook, Vol. II, may be required.
- d. ☐ Provide construction plans and calculations that address the required treatment volume and recovery, as well as stage-storage and design elevations, which demonstrate compliance with the appropriate water quality treatment criteria in the applicable Applicant's Handbook, Vol. II.

Provide a description of the engineering methodology, assumptions and references for the parameters listed above, and a copy of all such computations, engineering plans, and specifications used to analyze the system. If a computer program is used for the analysis, provide the name of the program, a description of the program, input and output data, and justification for model selection.

3. Water Quantity Analysis:

Please see Attachment C - Stormwater Management System Design and Calculations

Provide calculations and documentations demonstrating that the project, as proposed, meets the applicable design criteria as indicated in the applicable Applicant's Handbook, Vol. II. Typically, the information would include, at a minimum, but is not necessarily be limited to, the following:

- a. ☐ For projects requiring pre-development analysis, provide an analysis of the pre-development peak rate of discharge and / or volume of runoff, for all design storm events. Account for all onsite depressional storage and offsite contributing area. Please refer to the applicable Applicant's Handbook, Vol. II for the design storm event(s) that apply to your project.
- b. ☐ Provide an analysis of the post-development peak rate of discharge and / or volume of runoff for all applicable design storm events. Account for all onsite storage and offsite contributing area. Please refer to the applicable Applicant's Handbook, Vol. II for the design storm event(s) and criteria that apply to your project.

These analyses should include:

- ☐ Runoff characteristics, including area, runoff curve number or runoff coefficient, and time of concentration for each drainage basins in the pre-development and post-development condition;

- ☐ Design storms used including rainfall depth, duration, frequency, and distribution;
- ☐ Runoff hydrograph(s) for each drainage basin, for all required design storm event(s);
- ☐ Stage-storage computations for any area such as a reservoir, closed basin, detention area, or channel, used in storage routing;
- ☐ Stage-discharge computations for any storage areas at a selected control point, such as control structure or natural restriction;
- ☐ Flood routings through on-site conveyance and storage areas;
- ☐ Water surface profiles in the primary drainage system for each required design storm event(s);
- ☐ Runoff peak rates and volumes discharged from the site for each required design storm event(s);
- ☐ Design tailwater elevation(s) for each storm event at all points of discharge (include source or method of estimate); and
- ☐ Pump specifications and operating curves for range of possible operating conditions (if used in system).

Provide a description of the engineering methodology, assumptions and references for the parameters listed above, and a copy of all such computations, engineering plans, and specifications used to analyze the system. If a computer program is used for the analysis, provide the name of the program, input and output data, justification for model selection, and, if necessary, a description of the program.

4. Floodplain Analysis (where applicable).

The SHCCF Project is situated within Zone X, which is an area that is determined to be outside of the 100 and 500 year flood zones. See Attachment A – Site Location Information, Figure 4 - SHCCF FEMA Flood Zones.

The Project is within the Buckhorn Creek portion of the Bear Creek- Pithlachascotee River Watershed, an open basin, with an outfall via Beacon Woods Outfall Canal to the Gulf of Mexico. No floodplain impact will occur and no compensating storage is required.

- a. ☐ If the project is in a known floodplain of a stream or other water course, identify the appropriate floodplain boundary and approximate flooding elevations of any lake, stream or other watercourse located on or adjacent to the site.
- b. ☐ For traversing works, in accordance with the applicable Applicant's Handbook, Vol. II, provide:
 - ☐ Hydraulic calculations for all proposed traversing works; and
 - ☐ Water surface profiles showing upstream impact of traversing works.
- c. ☐ For impacts to regulated floodplains, in accordance with the applicable Applicant's Handbook, Vol. II, provide:
 - ☐ Location and volume of encroachment within regulated floodplain(s); and
 - ☐ Plans and calculations for compensating floodplain storage, if necessary, and calculations required for determining minimum building and road flood elevations.

PART 2: CONSTRUCTION PLANS

Please See Attachment C - Stormwater Management System Design and Calculations

1. Provide clear, construction level detailed plans for the system. The plans must be signed and sealed by an appropriate registered professional as required by law. These plans should include cumulative information from all applicable sections; as well as the following:
 - a. ☐ Project area boundary and total area, including distances and orientation from roads or other landmark.
 - b. ☐ Existing topography extending at least 100 feet off the project area. All topography shall include location and description of benchmarks, reference to NGVD 1929 or NAVD 1988 along with the conversion factor.
 - c. ☐ Proposed site plan with acreage, including the following:
 - ☐ plan view of proposed development, including impervious surfaces and water management areas;
 - ☐ land cover and natural communities*;
 - ☐ wetlands and other surface waters*;
 - ☐ undisturbed uplands*;
 - ☐ aquatic communities*;
 - ☐ proposed buffers*;
 - ☐ proposed impacts to wetlands and other surface waters, and any proposed connections/outfalls to other surface waters or wetlands, (if applicable); and
 - ☐ onsite wetland mitigation areas*.

*Please refer to Section C.

 - ☐ For phased projects, provide a master development plan clearing delineating the limits of each phase of construction.
 - d. ☐ Paving, Grading, and Drainage Information, which includes, but not necessarily limited to, the following:
 - ☐ Existing topography;
 - ☐ Boundaries of wetlands and other surface waters and upland buffers (see Section C);
 - ☐ Plan view of proposed development;
 - ☐ Proposed elevations and/or profiles, including:
 - ☐ roadway, parking, and pavement grades;
 - ☐ floor slabs, walkways, and other paved surfaces;
 - ☐ earthwork grades for pervious landscaped areas; and
 - ☐ perimeter site grading, tying back into existing grades.
 - ☐ Location of all water management areas, including elevations, dimensions, side slopes, and design water depths;
 - ☐ Location, size, and invert elevations of existing and proposed stormwater conveyance systems;
 - ☐ Vegetative cover plan for all on-site and off-site earth surfaces disturbed by construction; and
 - ☐ Rights-of-way and easements for the system, including all on-site and off-site areas to be reserved for water management purposes (including access), and rights-of-way and easements for the existing drainage system, if any.
 - e. ☐ Stormwater detail information, including but not necessarily limited to, the following:
 - ☐ Cross section of all stormwater management areas, including elevations, dimensions, side slopes, and proposed stabilization measures (with location of the cross section(s) shown on the corresponding plan view);

- ☐ Detail of all proposed control structures, including elevations, dimensions, and skimmer, where applicable; and
 - ☐ Details of proposed stormwater management systems, such as underdrains, exfiltration trenches, vaults, and other proposed Best Management Practices (BMPs).
- f. ☐ Location and description of any nearby existing offsite features (such as wetland and other surface waters, stormwater management ponds, and building or other structures) which might be affected by or affect the proposed construction or development.

PART 3: CONSTRUCTION SCHEDULE AND TECHNIQUES

Please See Attachment C – Stormwater Management System Design and Calculations

Provide a construction schedule, and a description of construction techniques, sequencing and equipment. This information should include, as applicable, the following.

Construction is anticipated to commence mid-2019 and be completed by December 2021.

- a. ☐ Access and staging of equipment;

Existing roadways will be used for access; the temporary construction laydown area to the west of the certified site will be used for staging of equipment as necessary.

- b. ☐ Location and details of the erosion, sediment and turbidity control measures to be implemented during each phase of construction and all permanent control measures to be implemented in post-development conditions.

Construction areas will be isolated from other surface waters through installation of staked turbidity screen and/or silt fence along the perimeter, in accordance with best management practices (BMPs).

- c. ☐ The location of disposal site(s) for any excavated material, including temporary and permanent disposal sites.

The temporary construction laydown area will be used for temporary storage of excavated materials; material that is not re-used for the Project will be disposed off-site at an appropriate solid waste facility.

- d. ☐ A demolition plan for any existing structures to be removed. **N/A**

- e. ☐ Dewatering plan details. If dewatering is required, detail the dewatering proposal including the methods that are proposed to contain the discharge, methods of isolating dewatering areas, and indicate the period dewatering structures will be in place; Note: a Consumptive Use or Water Use permit may be required for dewatering. **N/A**

- f. ☐ Methods for transporting equipment and materials to and from the work site. If barges are required for access, provide the low water depths and draft of the fully loaded barge;

Existing roadways will be used for transport.

PART 4: OPERATION AND MAINTENANCE AND LEGAL DOCUMENTATION:

- a. ☐ Describe the overall maintenance and operation schedule for the proposed system.

Shady Hills Energy Center, LLC (SHEC) will be responsible for the upkeep and maintenance of the proposed stormwater management system. SHEC will inspect and maintain the system as required to ensure proper operation.

- b. ☐ Identify the entity (or entities) that will be responsible for operating and maintaining the system (or parts of the system) to demonstrate that the entity (or entities) meet(s) the requirements of section 12.3 of the Applicant's Handbook, Vol. I.

SHEC will remain the entity responsible for operation and maintenance of the SHCCF Site system in perpetuity.

- ☐ If different from the permittee, provide a draft document enumerating the enforceable affirmative obligations on the entity to properly operate and maintain the system for its expected life, and documentation of the entity's financial responsibility for long-term maintenance.
- ☐ If the proposed operation and maintenance entity is not a property owner's association, provide proof of the existence of an entity, or the future acceptance of the system by an entity which will operate and maintain the system.
- c. ☐ Provide drafts of all proposed conservation easements, stormwater management system easements, draft property owner's association documents, and plats for the property containing the proposed system.
- d. ☐ Provide legal reservations for access to the treatment system for maintenance and operation by future maintenance entities for subdivided projects. **N/A**
- e. ☐ Provide indication of how water and wastewater service will be supplied.

The vacant and un-developed nature of the Site does not currently have water demands or activities that generate wastewater. Currently, at the adjacent Shady Hills Generating Station, potable water is provided by an onsite groundwater well and treatment /chlorination system. Sanitary wastewater is conveyed off-site by pipe for treatment and disposal by Pasco County.

Primary water uses for SHCCF will include cooling, process, service (including fire protection), irrigation, and potable water. The primary water source for cooling, process, and irrigation will be reclaimed water from the Pasco County Master Reuse System. The County will provide potable water and sewer service to the SHCCF site.

- f. ☐ Provide a copy of the boundary survey and/or legal description and acreage of the total land area of contiguous property owned/controlled the applicant.

See Attachment B – Boundary Survey.

PART 5: WATER USE

- a. ☐ Describe how irrigation will be provided to the project. Will the surface water system be used for water supply, including landscape irrigation, or recreation?

Irrigation water will be provided by the Pasco County Master Reuse System

- b. ☐ If a Consumptive Use or Water Use permit has been issued for the project, state the permit number: **N/A**

- c. ☐ If a Consumptive Use or Water Use permit has not been issued for the project, indicate if such a permit will be required. ☐ yes ☒ no ☐ don't know
If yes, please indicate when the application for a permit will be submitted:
- d. ☐ Indicate how any existing wells located within the project site will be utilized or abandoned.
N/A

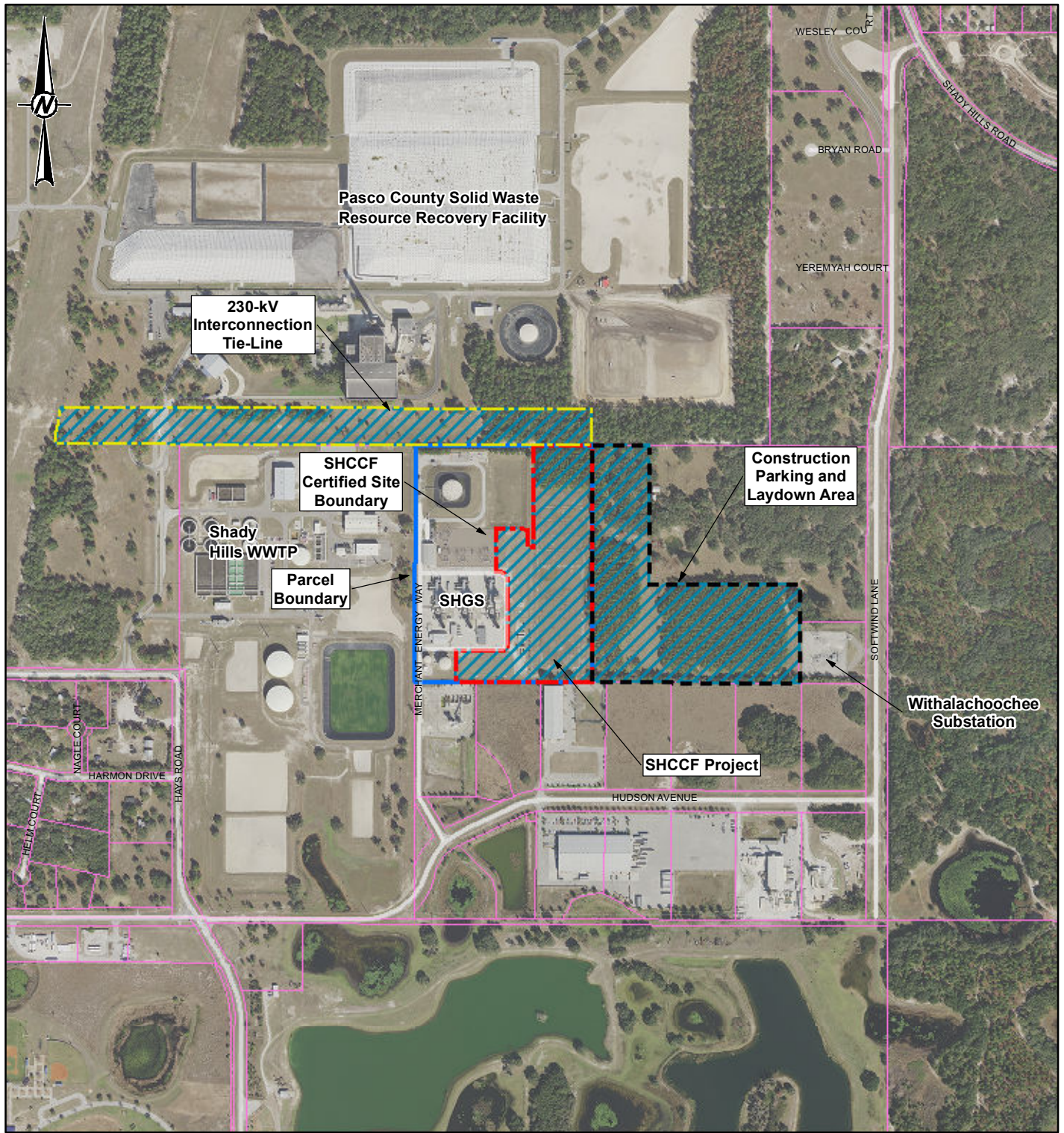
PART 6: SPECIAL BASIN INFORMATION

Is your project within a special basin as described in the applicable Applicant's Handbook, Vol. II?

☐ yes ☒ no ☐ don't know

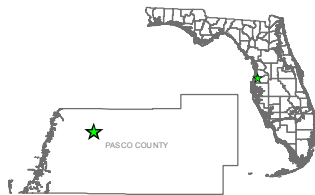
If yes, please demonstrate that the project will meet the applicable special basin criteria.

ATTACHMENT A
SITE LOCATION INFORMATION



LEGEND

- SHCCF Project
- SHCCF Certified Site Boundary
- 230-kV Interconnection Tie-Line
- Construction Parking and Laydown Area
- Parcel Boundary
- Parcels



REFERENCE(S)

SHCCF PROJECT, CERTIFIED SITE BOUNDARY, GOLDER ASSOCIATES INC., 2017
PARCELS, PASCO COUNTY, 12/15/2017

CLIENT

SHADY HILLS ENERGY CENTER, LLC

PROJECT

SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE

SHCCF SITE LOCATION MAP

CONSULTANT



YYYY-MM-DD 2018-02-12

DESIGNED NRL

PREPARED NRL

REVIEWED RAZ

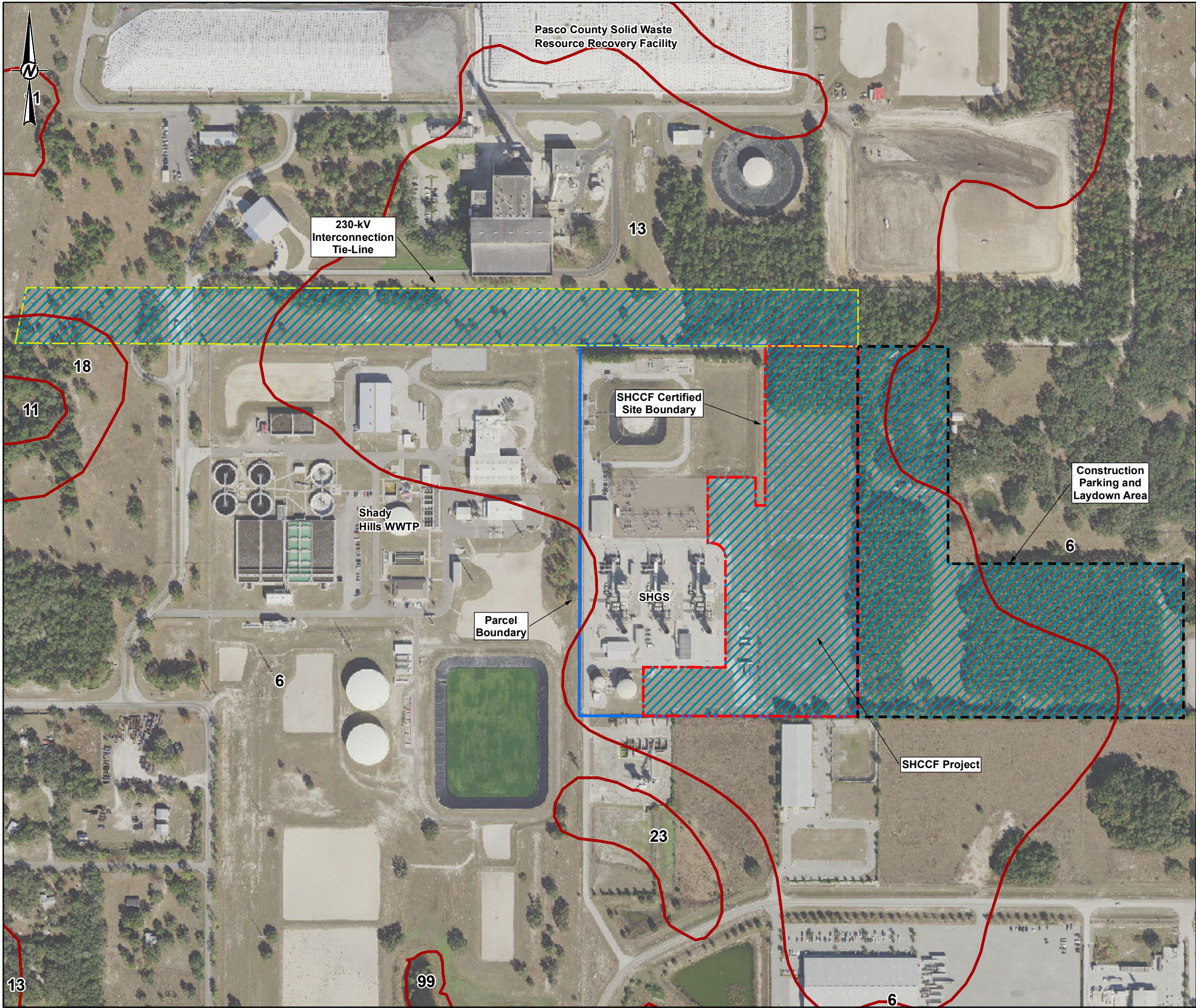
APPROVED MM

PROJECT NO.
1779520

CONTROL
K001

REV.
0

FIGURE
1



LEGEND

- SHCCF Project
- SHCCF Certified Site Boundary
- 230-kV Interconnection Tie-Line
- Construction Parking and Laydown Area
- Parcel Boundary
- Soils
 - 11 - ADAMSVILLE
 - 13 - CANDLER
 - 18 - ELECTRA VARIANT
 - 23 - BASINGER
 - 6 - TAVARES
 - 99 - WATER (FRESH)

NOTE(S)
N/A

REFERENCE(S)
SOILS, USDA NRCS SOILS DATABASE, 2015

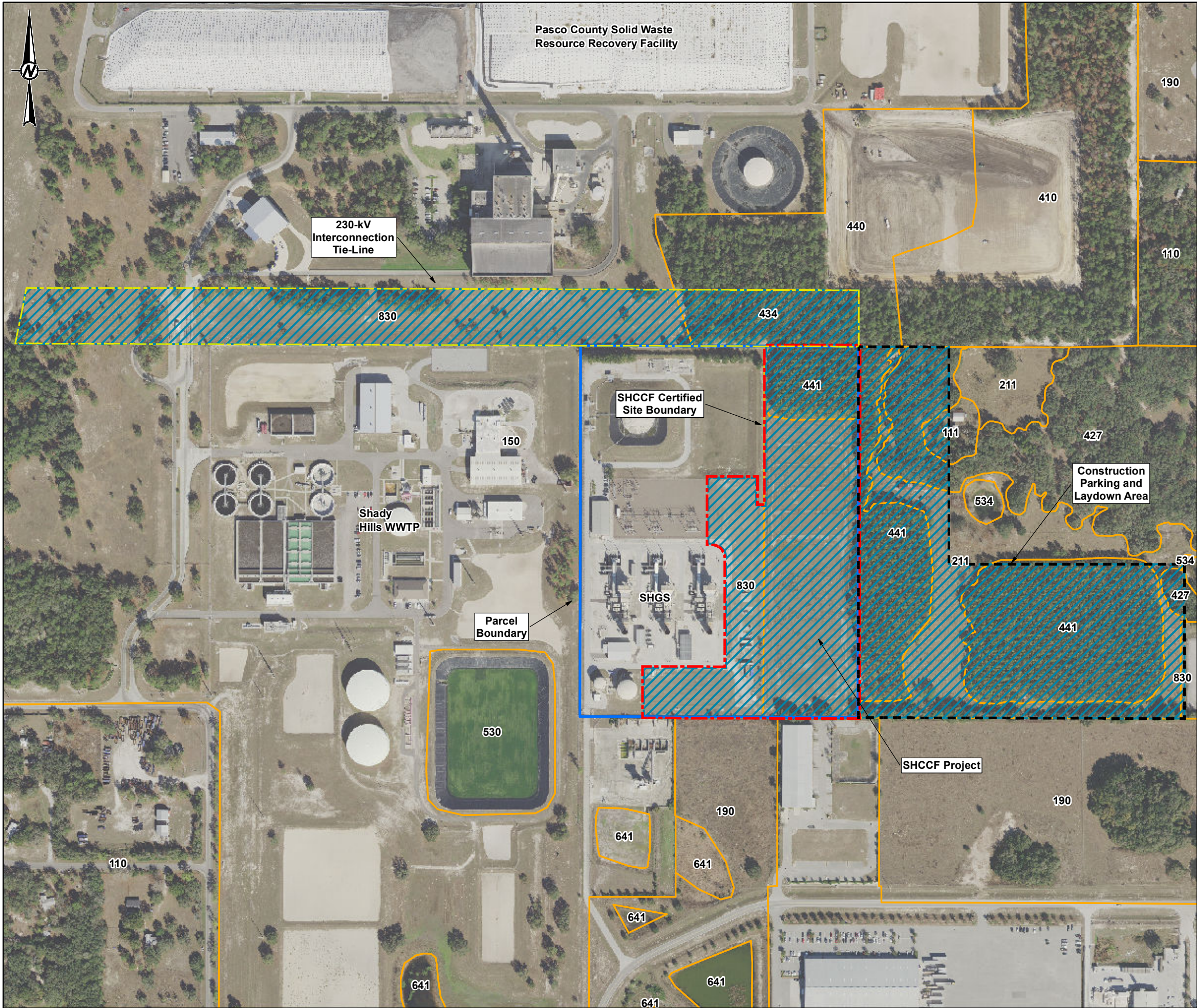
CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE
SHCCF SOILS MAP

	CONSULTANT	YYYY-MM-DD	2018-02-12
	DESIGNED	NRL	
	PREPARED	NRL	
	REVIEWED	KB	
	APPROVED	RAZ	

PROJECT NO. 1779520	CONTROL K002	REV. 0	FIGURE 2
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LEGEND

- SHCCF Project
- SHCCF Certified Site Boundary
- 230-kV Interconnection Tie-Line
- Construction Parking and Laydown Area
- Parcel Boundary
- Land Use
 - 110 - Residential Low Density < 2 Dwelling Units
 - 111 - Fixed Single Family Units
 - 150 - Industrial
 - 170 - Institutional
 - 190 - Open Land
 - 211 - Improved Pasture
 - 410 - Upland Coniferous Forest
 - 427 - Live Oak
 - 434 - Hardwood Conifer Mixed
 - 440 - Tree Plantations
 - 441 - Coniferous Plantations
 - 530 - Reservoirs
 - 534 - Reservoirs < 10 Acres
 - 641 - Freshwater Marshes
 - 643 - Wet Prairies
 - 653 - Intermittent Ponds
 - 830 - Utilities

NOTE(S)
N/A

REFERENCE(S)
LAND USE, SWFWMD, 2011 (WITH REVISIONS BY GOLDER BASED ON FIELD RECONNAISSANCE NOVEMBER, 2017)

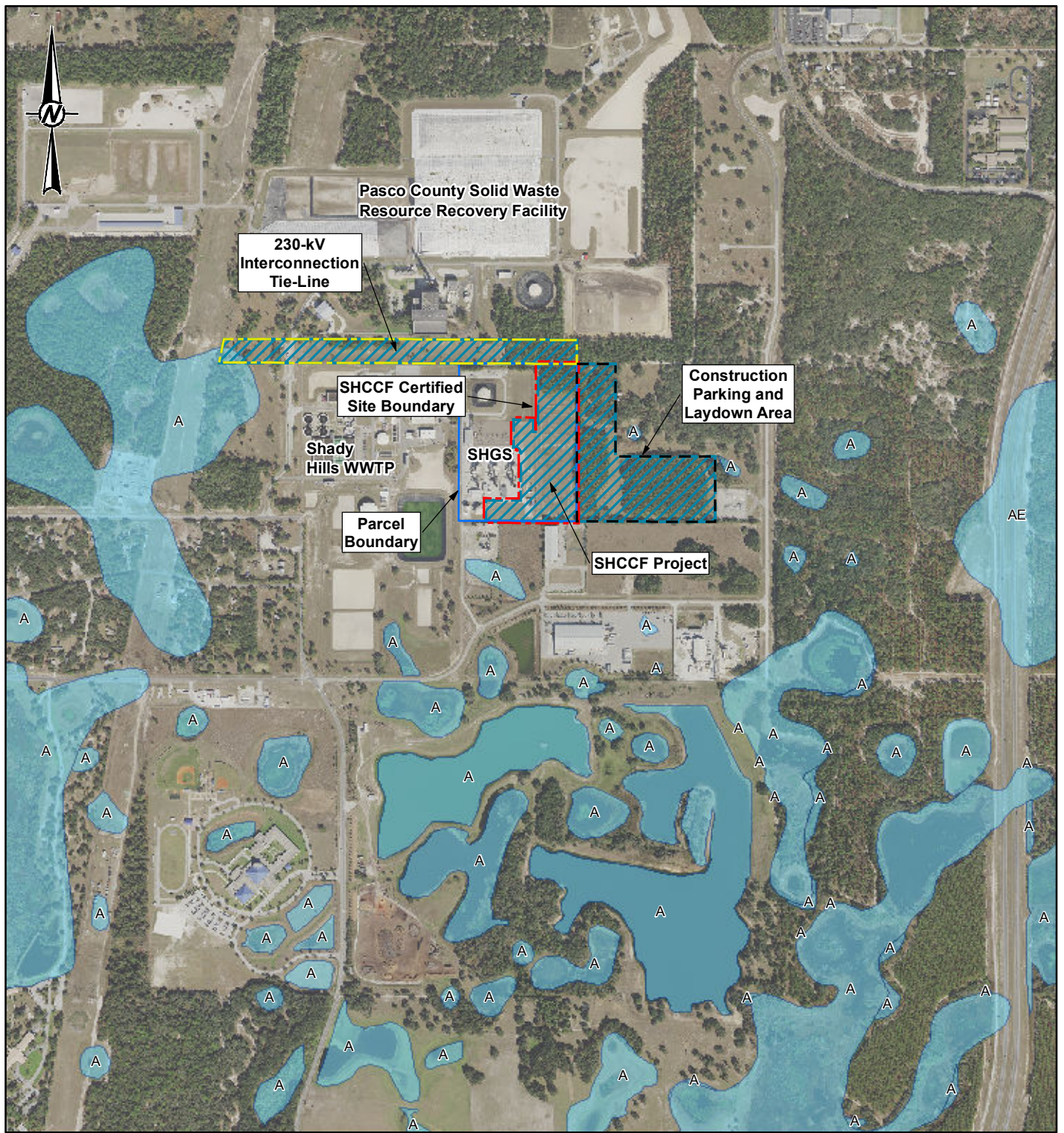
CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE
SHCCF VEGETATION / LAND USE
(FLUCCS LEVEL III)

CONSULTANT	YYYY-MM-DD	2018-02-12
	DESIGNED	NRL
	PREPARED	NRL
	REVIEWED	KB
	APPROVED	RAZ

PROJECT NO. 1779520	CONTROL K003	REV. 0	FIGURE 3
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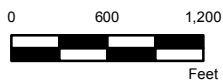
LEGEND

- SHCCF Project
- SHCCF Certified Site Boundary
- 230-kV Interconnection Tie-Line
- Construction Parking and Laydown Area
- Parcel Boundary

100-Year Flood Zone

A - Areas subject to inundation by the 1-percent-annual-chance flood event generally determined using approximate methodologies. Because detailed hydraulic analyses have not been performed, no Base Flood Elevations (BFEs) or flood depths are shown. Mandatory flood insurance purchase requirements and floodplain management standards apply.

AE - Areas subject to inundation by the 1-percent-annual-chance flood event determined by detailed methods. Base Flood Elevations (BFEs) are shown. Mandatory flood insurance purchase requirements and floodplain management standards apply.



REFERENCE(S)

SHCCF PROJECT, CERTIFIED SITE BOUNDARY, GOLDER ASSOCIATES INC., 2017
PARCEL BOUNDARY, PASCO COUNTY, 2017
FLOOD ZONES, FEMA, 2014

CLIENT

SHADY HILLS ENERGY CENTER, LLC

PROJECT

SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE

SHCCF
FEMA FLOOD ZONES

CONSULTANT



YYYY-MM-DD 2018-02-13

DESIGNED NRL

PREPARED NRL

REVIEWED RAZ

APPROVED MM

PROJECT NO.
1779520

CONTROL
K007

REV.
0

FIGURE
4

ATTACHMENT B
BOUNDARY SURVEY

Sketch & Description
Proposed Facility Limits
Shady Hills Combined Cycle Facility
Section 25, Township 24 South, Range 17 East
Pasco County, Florida

Proposed Facility Limits: As Written by SurvTech Solutions

A parcel of land lying and being in the Northwest 1/4 of the Southeast 1/4 of Section 25, Township 24 South, Range 17 East, Pasco County, Florida, being more particularly described as follows:

COMMENCE at a point marking the Southwest Corner of the Northwest 1/4 of the Southeast 1/4 of Section 25, Township 24 South, Range 17 East, Pasco County, Florida, thence coincident with the South boundary of the Northwest 1/4 of the Southeast 1/4 of said Section 25, S 89°48'05" E a distance of 227.82 feet to the POINT OF BEGINNING; thence departing said South boundary N 00°12'46" E a distance of 173.93 feet; thence S 89°47'14" E a distance of 290.79 feet; thence N 00°12'46" E a distance of 393.49 feet to a point coincident with a tangent curve concave to the Southwest, said curve having a radius of 50.00 feet, a delta angle of 90°00'00" and being subtended by a chord bearing N 44°47'14" W for a distance of 70.71 feet; thence coincident with the arc of said curve a distance of 78.54 feet; thence N 89°47'14" W a distance of 14.51 feet; thence N 00°25'38" E a distance of 233.93 feet; thence S 89°47'14" E a distance of 170.21 feet; thence S 00°12'46" W a distance of 99.68 feet; thence S 89°47'14" E a distance of 34.13 feet to a point coincident with the West boundary of the West 1/2 of the Northeast 1/4 of the Northwest 1/4 of the Southeast 1/4 of said Section 25; thence coincident with said West boundary, N 00°03'22" E a distance of 568.64 feet to a point coincident with the North boundary of the Northwest 1/4 of the Southeast 1/4 of said Section 25; thence departing said West boundary coincident with said North Boundary, S 89°47'14" E a distance of 330.17 feet to a point marking the Northeast corner of the West 1/2 of the Northeast 1/4 of the Northwest 1/4 of the Southeast 1/4 of said Section 25; thence departing said North boundary, coincident with the East boundaries of the West 1/2 of the Northeast 1/4 of the Northwest 1/4 of the Southeast 1/4 of said Section 25 and the East boundary of the West 1/2 of the Southeast 1/4 of the Northwest 1/4 of the Southeast 1/4 of said Section 25, S 00°02'10" W a distance of 1320.14 feet to a point marking the Southeast corner of the West 1/2 of the Southeast 1/4 of the Northwest 1/4 of the Southeast 1/4 of said Section 25; thence departing said East boundaries coincident with the South boundary of the Northwest 1/4 of the Southeast 1/4 of said Section 25, N 89°48'05" W a distance of 764.18 feet to the POINT OF BEGINNING.

Containing an area of 619,421.13 square feet, 14.220 acres.



Stacy L. Brown P.S.M. No. 6516
SurvTech Solutions, Inc. LB No. 7340

Project No.: 20170212
Phase: 2
Drawing Name: 20170212_2SK
Last Field Date: N/A
Field Book/Page: N/A

Drafted By: M. Rook
Date Drafted: 01/17/18
Revision Date: 02/13/18
Approved By: S. Brown
Date Approved: 01/31/18

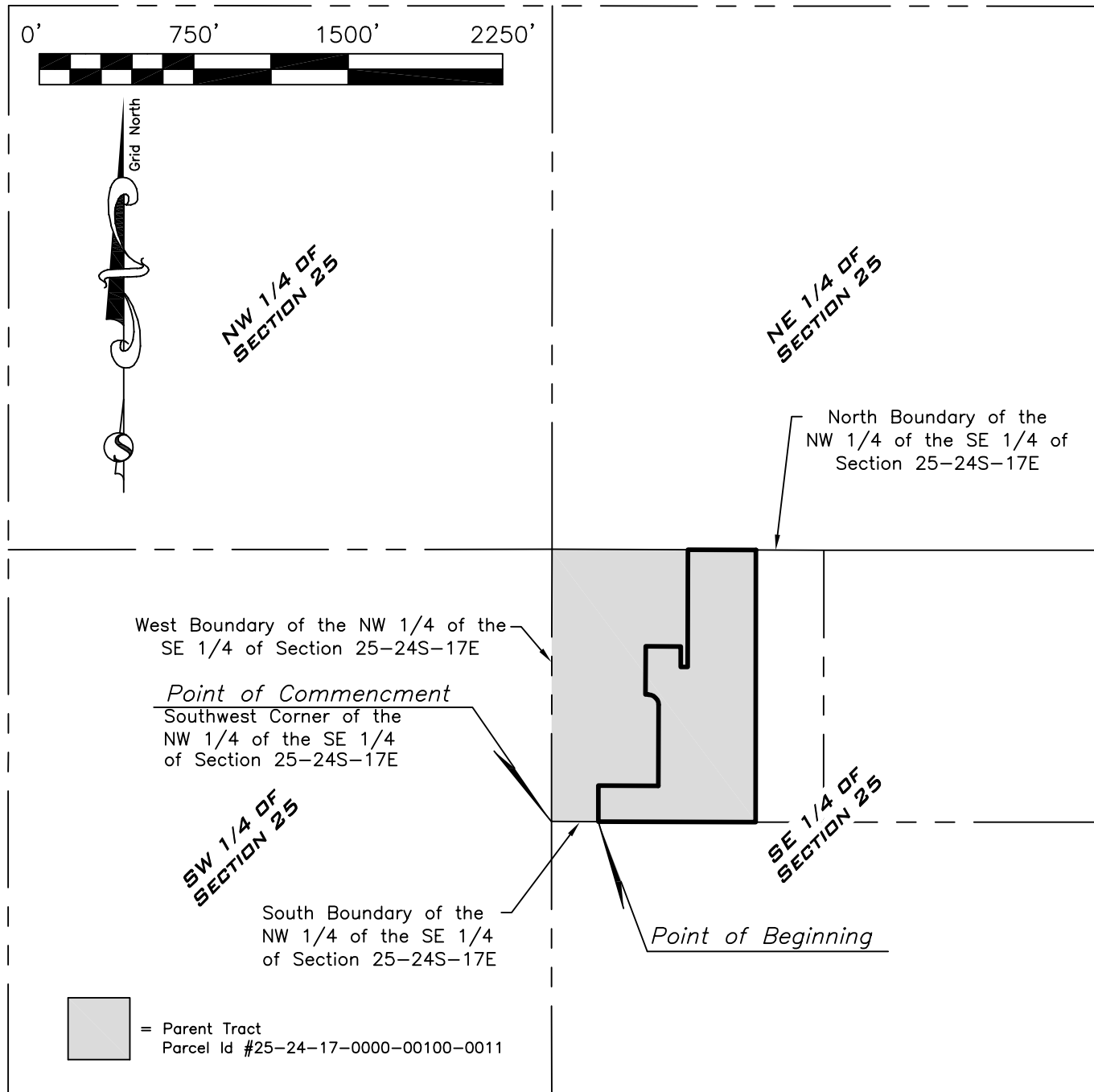
SURVTECH SOLUTIONS, INC. SURVEYORS AND MAPPERS
10220 U.S. Highway 92 East, Tampa, FL 33610
phone: (813)-621-4929, fax: (813)-621-7194, Licensed Business #7340
email: sbrown@survtechsolutions.com <http://www.survtechsolutions.com>

- 1.) Not valid without the signature and original raised seal of a Florida Licensed Surveyor and Mapper.
- 2.) The bearing structure for this survey is based on a Florida West State Plane grid bearing of S 89°47'14" E for the North Boundary of the SE ¼ of Section 25-24S-17E.
- 3.) THIS IS NOT A BOUNDARY SURVEY.

SURVEYING TODAY WITH
TOMORROW'S TECHNOLOGY



Sketch & Description
Proposed Facility Limits
Shady Hills Combined Cycle Facility
Section 25, Township 24 South, Range 17 East
Pasco County, Florida



PROJECT NO.: 20170212
 PHASE: 2
 LAST FIELD DATE: N/A



SURVTECH SOLUTIONS, INC. SURVEYORS AND MAPPERS

10220 U.S. Highway 92 East, Tampa, FL 33610
 phone: (813)-621-4929, fax: (813)-621-7194, Licensed Business #7340
 email: sbrown@survtechsolutions.com <http://www.survtechsolutions.com>

Sketch & Description
Proposed Facility Limits
Shady Hills Combined Cycle Facility
Section 25, Township 24 South, Range 17 East
Pasco County, Florida

North Boundary of the NW 1/4 of
the SE 1/4 of Section 25-24S-17E

Line Information

LINE	BEARING	DISTANCE
L1	N 00°12'46" E	173.93'
L2	S 89°47'14" E	290.79'
L3	N 00°12'46" E	393.49'
L4	N 89°47'14" W	14.51'
L5	N 00°25'38" E	233.93'
L6	S 89°47'14" E	170.21'
L7	S 00°12'46" W	99.68'
L8	S 89°47'14" E	34.13'
L9	N 00°03'22" E	568.64'
L10	S 89°47'14" E	330.17'
L11	S 89°48'05" E	227.82'

Northeast 1/4 of
the Northwest 1/4 of
the Southeast 1/4

West 1/2 of the
Northeast 1/4 of
the Northwest 1/4
of the Southeast 1/4

NOT A PART
OF THIS SURVEY

West Boundary of the
NW 1/4 of the SE 1/4
of Section 25-24S-17E

Point of Commencement

Southwest Corner of the
NW 1/4 of the SE 1/4
of Section 25-24S-17E

Total Acreage
Proposed Facility Limits
 619,421.13 Square Feet
 14.220 Acres

West 1/2 of the
Southeast 1/4 of
the Northwest 1/4
of the Southeast 1/4

Southeast 1/4 of
the Northwest 1/4 of
the Southeast 1/4

NOT A PART
OF THIS SURVEY

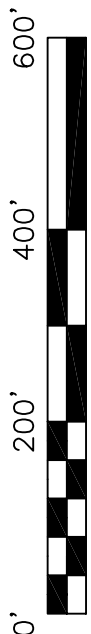
L11

N 89°48'05" W 764.18'

Point of Beginning

South Boundary of the
NW 1/4 of the SE 1/4
of Section 25-24S-17E

CURVE	RADIUS	ARC LENGTH	CHORD BEARING	CHORD LENGTH	DELTA ANGLE	TANGENT
C1	50.00'	78.54'	N 44°47'14" W	70.71'	90°00'00"	50.00'



Scale: 1" = 200'

PROJECT NO.: 20170212
 PHASE: 2
 LAST FIELD DATE: N/A



SURVTECH SOLUTIONS, INC. SURVEYORS AND MAPPERS

10220 U.S. Highway 92 East, Tampa, FL 33610
 phone: (813)-621-4929, fax: (813)-621-7194, Licensed Business #7340
 email: sbrown@survtechsolutions.com <http://www.survtechsolutions.com>

ATTACHMENT C
STORMWATER MANAGEMENT SYSTEM DESIGN AND
CALCULATIONS

Date:	February 15, 2018	Made by:	J. Kelsey
Project No.:	1779520	Checked by:	B. Holcomb
Site Name:	Shady Hills Combined Cycle Facility	Reviewed by:	A. Grasso
Subject	CONCEPTUAL - STORMWATER MANAGEMENT SYSTEM CALCULATIONS		

This document presents a summary of methods, input values, assumptions, and relevant criteria used to estimate the stormwater impacts to the Shady Hills Combined Cycle Facility (SHCCF or Site) for the design condition. Golder understands that further refinement to the site layout will likely occur once the engineering, procurement, and construction (EPC) contractor has been selected. These calculations have been performed to demonstrate that the system is capable of managing and storing the run-off for the design storm evaluated but are considered conceptual due to the likely inclusion of additional conveyance infrastructure.

1.0 PROJECT DESCRIPTION

Shady Hills Energy Center, LLC (SHEC) is proposing to construct and operate a combined-cycle generating facility in Pasco County, Florida. The SHCCF will utilize a portion of the 30-acre parcel of land owned by Shady Hills Power Company, L.L.C. for the Site. The Project will consist of on-site associated facilities including an onsite natural gas metering station and lateral, as well as an off-site, new 0.6-mile 230-kV interconnection tie-line corridor and a temporary construction parking and laydown area.

2.0 EXISTING SITE CONDITIONS

Refer to the Site Certification Application (SCA) and Appendix 10.4, Attachments A through D for illustrations of the existing Site conditions.

2.1 SHGS Site Location

The SCHHF Site is approximately 14 acres located adjacent to the existing Shady Hills Generating Station (SHGS). The Site is located within Buckhorn Creek Basin, an open basin, with an outfall via the Beacon Woods Outfall Canal to the Gulf of Mexico. However, the location of the SHCCF does not provide an obvious direct point of discharge to the nearest conveyance to connect to the Buckhorn Creek Basin; therefore, Golder evaluated the proposed drainage system as a closed basin system.

The pre-development of the SHCCF Site boundary area consists of 10 acres of vacant land, of which approximately 2 acres contain a coniferous pine plantation and approximately 4 acres which have been cleared and previously utilized as a temporary laydown and equipment storage area associated with the construction and operation of the existing SHGS.



CALCULATIONS

Page 2 of 6

Project No.:	1779520	Made by:	J. Kelsey
Site Name:	Shady Hills Combined Cycle Facility	Checked by:	B. Holcomb
Date:	2/15/18	Reviewed by:	A. Grasso

A survey performed in January 2018 indicates that the Site topography is generally flat with a gentle upward-trending slope from north to south. Elevations generally ranged from approximately 49 ft North American Vertical Datum 88 (NAVD88) near the northwest corner to 54 ft. NAVD88 near the southwest corner and 52 ft NAVD88 near the southeast corner.

According to soils data obtained from the United States Department of Agriculture National Resource Conservation Service (NRCS, 2017), the soils at the Site generally consist of Candler sands which is described as excessively drained and exhibits a very low run-off class.

2.2 Construction Laydown Area

Golder understands that SHGS is currently negotiating the use of approximately 20 acres of undeveloped property located east of the proposed SHCCF Site for a temporary construction parking and laydown area. The current identified location for the laydown areas consists of:

- Approximately 3.9 acres of improved pastures
- Approximately 16.4 acres is wooded

Design documents and supporting calculations for the temporary construction parking and laydown area are considered conceptual and will be revised with additional information once confirmation of the use of the identified location has been received.

3.0 PROPOSED DEVELOPMENT

See Permit Drawings, Site Certification Application (SCA) Appendix 10.8, for illustrations of the proposed development locations described herein.

3.1 SHCCF Site

For the proposed development, the SHCCF will consist of a combined facility constructed over a primarily gravel surface with access to facilities via asphalt-paved roads. In general, areas outside of the central power-generating and supporting structures and gravel surfaces will consist of grass-lined areas and will include a stormwater management system described below. Stormwater run-off from the proposed development will be routed via overland flow, swales or ditches, and buried culverts that will direct flow to one of two stormwater ponds. In general, road cross-slopes were modeled considering a 2 percent inward cross-slope and overland grades within the facility generally range from 0.25 to 0.50 percent.

3.2 Construction Parking and Laydown Area

The temporary construction parking and laydown area is anticipated to include areas for construction staff parking, temporary office trailers, and equipment storage and staging. Improvements to the laydown area

CALCULATIONS

Page 3 of 6

Project No.:	1779520	Made by:	J. Kelsey
Site Name:	Shady Hills Combined Cycle Facility	Checked by:	B. Holcomb
Date:	2/15/18	Reviewed by:	A. Grasso

may include clearing of trees/vegetation, placement of lime rock or similar material for vehicle access, and may include swales/ditches to convey water to discharge locations. Golder anticipates that the EPC contractor will comply with requirements set forth in the Generic Permit for Stormwater Discharge from Large and Small Construction Activities (CGP) and National Pollution Discharge Elimination System (NPDES) permit. Best Management Practices (BMPs) shown in the Permit Drawings are considered conceptual at this time.

4.0 REGULATORY REQUIREMENTS

Golder considered several stormwater permitting regulations to evaluate the criteria applicable to the conceptual stormwater management system:

- Pasco County (County) Land Development Code (LDC), Section 902
- Southwest Florida Water Management District's (SWFWMD's) Environmental Resource Permit (ERP) Applicant's Handbook, Volume II, which is incorporated by reference in 40D-4.091, Florida Administrative Code (F.A.C.)

5.0 INFILTRATION AND DEPTH TO GROUNDWATER

Field permeability tests using a Double-Ring Infiltrometer (DRI) were previously conducted in support of the development of the existing SHGS (Golder, 2000). Test results indicated measured infiltration rates between 15 to 21.5 inches per hour (in/hr) which are consistent with permeability rates for Candler sands as described in the USGS soil survey (NRCS, 2017) to rates. As a conservative measure and consistent with Golder's approach for the development of the SHGS, a reduced infiltration rate of 4 in/hr was used to model infiltration within the proposed stormwater ponds.

In 2008, Golder advanced boreholes during a geotechnical investigation within the area now proposed for the SHCCF site. Water levels were measured and the results indicated measured depths ranging between 14 to 22 ft below ground surface (bgs). In November 2017, Golder measured the depth to groundwater during a geotechnical investigation program in support of the SHCCF development. Results from the geotechnical investigation indicate that groundwater elevations were measured between 12 to 15 ft-bgs (35 ft. NAVD88 to 39 ft. NAVD88) (Golder, 2018). Based on measured water levels and current survey data, which indicates that the existing stormwater pond bottom for the SHGS is generally at 41 ft NAVD88 with some locations measuring 40 ft NAVD88, Golder selected a maximum pond bottom depth of 41 ft. NAVD88 for the stormwater ponds modeled during these calculations.

CALCULATIONS

Page 4 of 6

Project No.:	1779520	Made by:	J. Kelsey
Site Name:	Shady Hills Combined Cycle Facility	Checked by:	B. Holcomb
Date:	2/15/18	Reviewed by:	A. Grasso

6.0 DESIGN CRITERIA, METHODOLOGY, AND ASSUMPTIONS

The conceptual permit design of the SHCCF included analysis for stormwater runoff within the site considering run-off will be directed to one of two stormwater ponds (Pond 1 and Pond 2) located on the site. Surface water will be directed to the stormwater ponds using overland flow, conveyance ditches/swales, and catch basin connected to buried culverts. The following design criteria and assumptions were used by Golder in the preparation of these calculations and hydrologic modeling:

- Stormwater water runoff was modeled using the Natural Resources Conservation Service (NRCS) TR-55 method using Autodesk's Storm and Sanitary Analysis (SSA) program
- Soil types were assumed a Type A hydrologic soil group for the site, which represents well-draining sandy soils based on the Soil Conservation Service (SCS) Urban Hydrology for Small Watersheds Technical Release No. 55 (TR-55) method
- For surface water abstraction, Golder selected run-off coefficient curve number (CN) values from the TR-55 for impervious surfaces, gravel, and grass-lined areas
- The site is located in central Florida, and therefore, Golder selected an SCS Type II Florida Modified rainfall distribution
- Precipitation data for storm depths were obtained from the Southwest Florida Water Management District's (SWFWMD) Project Design Aids. For the 100-year, 24-hour storm, Golder used 12 inches. Where required for overland travel time computations, Golder used 4.25 inches for a 2-year, 24-hour duration storm
- The modeled stormwater management system was assumed to consist of dry detention ponds

6.1 Sub-Basin Delineation

Golder used topographic data provided by the 2018 survey and site layout information for the power-generating facilities provided by POWER Engineer's to delineate sub-basins. Impervious and semi-impervious surfaces within each sub-basin were tabulated to estimate an average weighted run-off coefficient CN value. Quantities of impervious and semi-impervious surfaces and CN values assigned for each surface type are presented in the SSA model output in Attachment 1.

6.2 Time of Concentration

For the conceptual design, Golder modeled water travel times for each sub-basin assuming anticipated slopes for overland and shallow concentrated flow. Travel times were estimated assuming a maximum of distance of 100 feet for overland flow before transitioning to shallow-concentrated flow. Conveyance flow travel times were calculated within the hydrology model. Time of concentration estimates are presented in the SSA model output in Attachment 1.

CALCULATIONS

Page 5 of 6

Project No.:	1779520	Made by:	J. Kelsey
Site Name:	Shady Hills Combined Cycle Facility	Checked by:	B. Holcomb
Date:	2/15/18	Reviewed by:	A. Grasso

6.3 Infiltration Operating Curves

Infiltration for each stormwater pond was estimated using the Perc Pack add-on software component within Interconnected Pond Routing (ICPR) program to model the infiltration rate based on pond stage for each pond. Model results were input into the SSA model as an output “Infiltration Operating Curve” to model the infiltration rate for 100-year, 24-hour design storm event.

6.4 Peak Discharge and Stage

Peak discharge was estimated during the modeling process for each sub-basin analyzed and to each pond. Because the proposed Site has been evaluated considering a 100-year, 24-hour storm event and stormwater run-off is not anticipated to leave the Site, Golder has not included pre-development peak discharge to provide a comparison to post-development discharge. Table 1 below summarizes the 100 year, 24-hour elevations based on model results for each stormwater pond.

Table 1: Stormwater Pond Model Elevation Results

Pond ID	Top Elevation (ft. NAVD88)	Modeled Water Level (ft. NAVD88)	Remaining Freeboard (ft)
Pond 1	49	47.62	1.38
Pond 2	51	49.47	1.53

6.5 Pond Stage-Storage

Pond surface areas for regular elevation intervals were measured using Autodesk’s Civil 3D program. Each pond was assumed to consist of 3H:1V (horizontal to vertical) side slopes with a base elevation of 41 ft. NAVD88. Pond 1 and Pond 2 have been designed assuming 49 ft. NAVD88 and 51 ft. NAVD88 top of bank elevations, respectively. Values measured were input into the hydrology modeling program to generate stage-storage plots using by the modeling program to estimate capacity within each stormwater pond. Stage-Elevation values are presented in the SSA model output in Attachment 1.

6.5.1 Treatment Volume

For treatment volume, Golder estimated the contributing area for each stormwater pond and calculated the volume based on a ½-inch of run-off. The volume was included into each stormwater pond as a starting elevation and the infiltration was modeled using ICPR to evaluate the drawdown time for each pond. Results indicate that each stormwater pond modeled, demonstrated that full treatment volume drawdown occurred within 10 hours. Attachment 2 includes the ICPR modeling input summary for each stormwater pond, and Attachment 3 includes ICPR results which show the time-dependent stage for each stormwater pond.

CALCULATIONS

Page 6 of 6

Project No.:	1779520	Made by:	J. Kelsey
Site Name:	Shady Hills Combined Cycle Facility	Checked by:	B. Holcomb
Date:	2/15/18	Reviewed by:	A. Grasso

7.0 CONCLUSIONS

Based on model inputs and included assumptions, the stormwater management system will attenuate the treatment volumes in less than 10 hours. Additionally, the stormwater management system has the capacity to store and attenuate run-off for the 100-year, 24-hour design storm event.

8.0 REFERENCES

Golder Associates Inc., 2000, Storm Water Management Plan for the Shady Hills Energy Project, Pasco County, Florida.

Golder Associates Inc., 2008, Report on Geotechnical Engineering Services for the Addition of Two General Electric Combustion Turbines at the Shady Hills Generating Station, Shady Hills, Florida.

Golder Associates Inc., 2018, Draft Report on Geotechnical Engineering Services for the Addition of a 1x1 Combined Cycle Power Plant at the Shady Hills Generating Station, Shady Hills, Florida.

NRCS, 2017, Soil Survey, for Pasco County, Florida.

<https://websoilsurvey.sc.egov.usda.gov/App/HomePage.htm>, accessed 12/2017.

ATTACHMENT 1
SSA MODEL OUTPUT

Project Description

File Name SHEC SCA R3.SPF

Project Options

Flow Units CFS
Elevation Type Elevation
Hydrology Method SCS TR-55
Time of Concentration (TOC) Method SCS TR-55
Link Routing Method Hydrodynamic
Enable Overflow Ponding at Nodes YES
Skip Steady State Analysis Time Periods ... NO

Analysis Options

Start Analysis On Jan 22, 2018 00:00:00
End Analysis On Jan 25, 2018 00:00:00
Start Reporting On Jan 22, 2018 00:00:00
Antecedent Dry Days 0 days
Runoff (Dry Weather) Time Step 0 01:00:00 days hh:mm:ss
Runoff (Wet Weather) Time Step 0 00:05:00 days hh:mm:ss
Reporting Time Step 0 00:05:00 days hh:mm:ss
Routing Time Step 2 seconds

Number of Elements

Qty
Rain Gages 1
Subbasins..... 8
Nodes..... 13
 Junctions 9
 Outfalls 2
 Flow Diversions 0
 Inlets 0
 Storage Nodes 2
Links..... 11
 Channels 0
 Pipes 9
 Pumps 0
 Orifices 0
 Weirs 0
 Outlets 2
Pollutants 0
Land Uses 0

Rainfall Details

SN	Rain Gage ID	Data Source	Data Source ID	Rainfall Type	Rain Units	State	County	Return Period (years)	Rainfall Depth (inches)	Rainfall Distribution
1		Time Series	TS-100	Cumulative	inches	Florida	Pasco	100	12.00	SCS Type II FL 24-hr

Subbasin Summary

SN	Subbasin ID	Area	Weighted Curve Number	Total Rainfall	Total Runoff	Total Runoff Volume	Peak Runoff	Time of Concentration
		(ac)		(in)	(in)	(ac-in)	(cfs)	(days hh:mm:ss)
1	Sub-01	1.70	55.85	12.00	5.92	10.06	4.93	0 00:41:15
2	Sub-02	1.55	85.15	12.00	10.13	15.68	9.58	0 00:10:00
3	Sub-03	1.00	89.09	12.00	10.65	10.66	6.36	0 00:10:00
4	Sub-04	1.02	82.62	12.00	9.80	10.03	6.19	0 00:10:00
5	Sub-05	0.52	88.97	12.00	10.63	5.49	3.30	0 00:10:00
6	Sub-06	2.83	85.39	12.00	10.17	28.73	17.53	0 00:10:00
7	Sub-07	2.23	57.20	12.00	6.13	13.66	6.58	0 00:44:02
8	Sub-08	2.76	61.14	12.00	6.74	18.61	11.86	0 00:10:00

Node Summary

SN	Element ID	Element Type	Invert Elevation	Ground/Rim (Max) Elevation	Initial Water Elevation	Surcharge Elevation	Ponded Area	Peak Inflow	Max HGL Elevation Attained	Max Surcharge Depth Attained	Min Freeboard Attained	Time of Peak Flooding Occurrence	Total Flooded Volume	Total Time Flooded
			(ft)	(ft)	(ft)	(ft)	(ft²)	(cfs)	(ft)	(ft)	(ft)	(days hh:mm)	(ac-in)	(min)
1	Jun-2A	Junction	44.00	49.00	44.00	1000.00	100.00	9.54	47.62	0.00	1.38	0 00:00	0.00	0.00
2	Jun-3A	Junction	43.90	49.00	43.90	1000.00	100.00	15.79	47.62	0.00	1.38	0 00:00	0.00	0.00
3	Jun-4A	Junction	46.00	51.10	46.00	1000.00	100.00	6.17	49.47	0.00	1.63	0 00:00	0.00	0.00
4	Jun-4B	Junction	45.00	51.10	45.00	1000.00	100.00	6.17	49.47	0.00	1.63	0 00:00	0.00	0.00
5	Jun-5A	Junction	44.80	51.10	44.80	1000.00	100.00	9.42	49.47	0.00	1.63	0 00:00	0.00	0.00
6	Jun-6A	Junction	46.00	51.10	46.00	1000.00	100.00	17.47	49.57	0.00	1.53	0 00:00	0.00	0.00
7	Jun-6B	Junction	45.00	51.10	45.00	1000.00	100.00	17.46	49.48	0.00	1.62	0 00:00	0.00	0.00
8	Jun-7A	Junction	46.00	51.50	46.00	1000.00	100.00	6.56	49.48	0.00	2.02	0 00:00	0.00	0.00
9	Jun-8A	Junction	44.00	51.10	44.00	1000.00	100.00	20.75	49.48	0.00	1.62	0 00:00	0.00	0.00
10	Out-03	Outfall	0.00					1.64	0.00					
11	Out-04	Outfall	0.00					2.90	0.00					
12	Pond 01	Storage Node	41.00	49.00	41.00		0.00	18.22	47.62				0.00	0.00
13	Pond 02	Storage Node	41.00	51.00	41.00		0.00	41.70	49.47				0.00	0.00

Link Summary

SN	Element ID	Element Type	From (Inlet) Node	To (Outlet) Node	Length	Inlet Invert Elevation	Outlet Invert Elevation	Average Slope	Diameter or Height	Manning's Roughness	Peak Flow	Design Flow Capacity	Peak Flow/ Design Flow Ratio	Peak Flow Velocity	Peak Flow Depth	Peak Flow Depth/ Total Depth Ratio	Total Time Reported	Surcharged Condition
					(ft)	(ft)	(ft)	(%)	(in)		(cfs)	(cfs)		(ft/sec)	(ft)		(min)	
1	Link-2A-3A	Pipe	Jun-2A	Jun-3A	96.42	44.00	43.00	1.0400	24.000	0.0150	9.47	6.31	1.50	5.34	2.00	1.00	869.00	SURCHARGED
2	Link-3A-P1	Pipe	Jun-3A	Pond 01	53.80	43.00	41.00	3.7200	24.000	0.0150	15.55	91.04	0.17	3.63	2.00	1.00	914.00	SURCHARGED
3	Link-4A-4B	Pipe	Jun-4A	Jun-4B	121.56	46.00	45.00	0.8200	24.000	0.0150	6.17	17.78	0.35	2.65	2.00	1.00	796.00	SURCHARGED
4	Link-4B-5A	Pipe	Jun-4B	Jun-5A	89.46	45.00	44.80	0.2200	24.000	0.0150	6.16	9.27	0.66	2.45	2.00	1.00	1251.00	SURCHARGED
5	Link-5A-P2	Pipe	Jun-5A	Pond 02	110.00	44.80	41.00	3.4500	30.000	0.0150	9.42	66.07	0.14	2.24	2.50	1.00	1084.00	SURCHARGED
6	Link-6A-6B	Pipe	Jun-6A	Jun-6B	148.08	46.00	45.00	0.6800	24.000	0.0150	17.46	16.11	1.08	5.56	2.00	1.00	835.00	SURCHARGED
7	Link-6B-8A	Pipe	Jun-6B	Jun-8A	56.26	45.00	44.00	1.7800	24.000	0.0150	17.45	26.14	0.67	5.56	2.00	1.00	1273.00	SURCHARGED
8	Link-7A-8A	Pipe	Jun-7A	Jun-8A	131.94	47.00	45.00	1.5200	24.000	0.0150	6.50	24.14	0.27	2.27	2.00	1.00	473.00	SURCHARGED
9	Link-8A-P2	Pipe	Jun-8A	Pond 02	40.00	44.00	43.00	2.5000	24.000	0.0150	22.35	31.00	0.72	7.11	2.00	1.00	2036.00	SURCHARGED
10	Infil_01	Outlet	Pond 01	Out-03		41.00	0.00				1.64							
11	Infil_02	Outlet	Pond 02	Out-04		41.00	0.00				2.90							

Subbasin Hydrology

Subbasin : Sub-01

Input Data

Area (ac) 1.70
Weighted Curve Number 55.85
Rain Gage ID Rain Gage

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
50 - 75% grass cover, Fair	0.81	A	49.00
Gravel	0.43	A	76.00
Pond	0.46	A	49.00
Composite Area & Weighted CN	1.70		55.85

Time of Concentration

TOC Method : SCS TR-55

Sheet Flow Equation :

$$T_c = (0.007 * ((n * L_f)^{0.8})) / ((P^{0.5}) * (S_f^{0.4}))$$

Where :

T_c = Time of Concentration (hr)
n = Manning's roughness
L_f = Flow Length (ft)
P = 2 yr, 24 hr Rainfall (inches)
S_f = Slope (ft/ft)

Shallow Concentrated Flow Equation :

V = 16.1345 * (S_f^{0.5}) (unpaved surface)
V = 20.3282 * (S_f^{0.5}) (paved surface)
V = 15.0 * (S_f^{0.5}) (grassed waterway surface)
V = 10.0 * (S_f^{0.5}) (nearly bare & untilled surface)
V = 9.0 * (S_f^{0.5}) (cultivated straight rows surface)
V = 7.0 * (S_f^{0.5}) (short grass pasture surface)
V = 5.0 * (S_f^{0.5}) (woodland surface)
V = 2.5 * (S_f^{0.5}) (forest w/heavy litter surface)
T_c = (L_f / V) / (3600 sec/hr)

Where:

T_c = Time of Concentration (hr)
L_f = Flow Length (ft)
V = Velocity (ft/sec)
S_f = Slope (ft/ft)

Channel Flow Equation :

$$V = (1.49 * (R^{2/3}) * (S_f^{0.5})) / n$$

$$R = A_q / W_p$$

$$T_c = (L_f / V) / (3600 \text{ sec/hr})$$

Where :

T_c = Time of Concentration (hr)
L_f = Flow Length (ft)
R = Hydraulic Radius (ft)
A_q = Flow Area (ft²)
W_p = Wetted Perimeter (ft)
V = Velocity (ft/sec)
S_f = Slope (ft/ft)
n = Manning's roughness

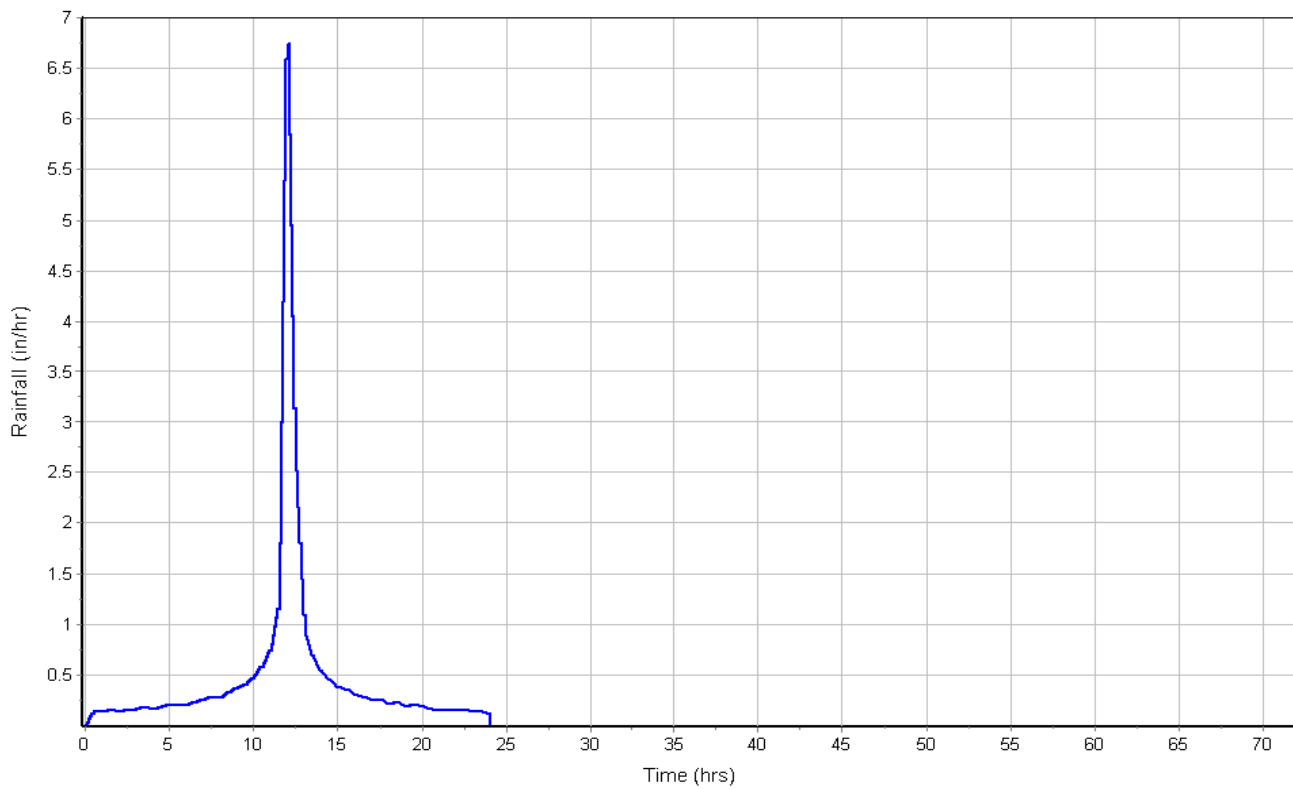
	Subarea	Subarea	Subarea
	A	B	C
Sheet Flow Computations			
Manning's Roughness :	.35	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.25	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.04	0.00	0.00
Computed Flow Time (min) :	38.47	0.00	0.00
	Subarea	Subarea	Subarea
	A	B	C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	135	0.00	0.00
Slope (%) :	.25	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	0.81	0.00	0.00
Computed Flow Time (min) :	2.78	0.00	0.00
Total TOC (min)	41.25		

Subbasin Runoff Results

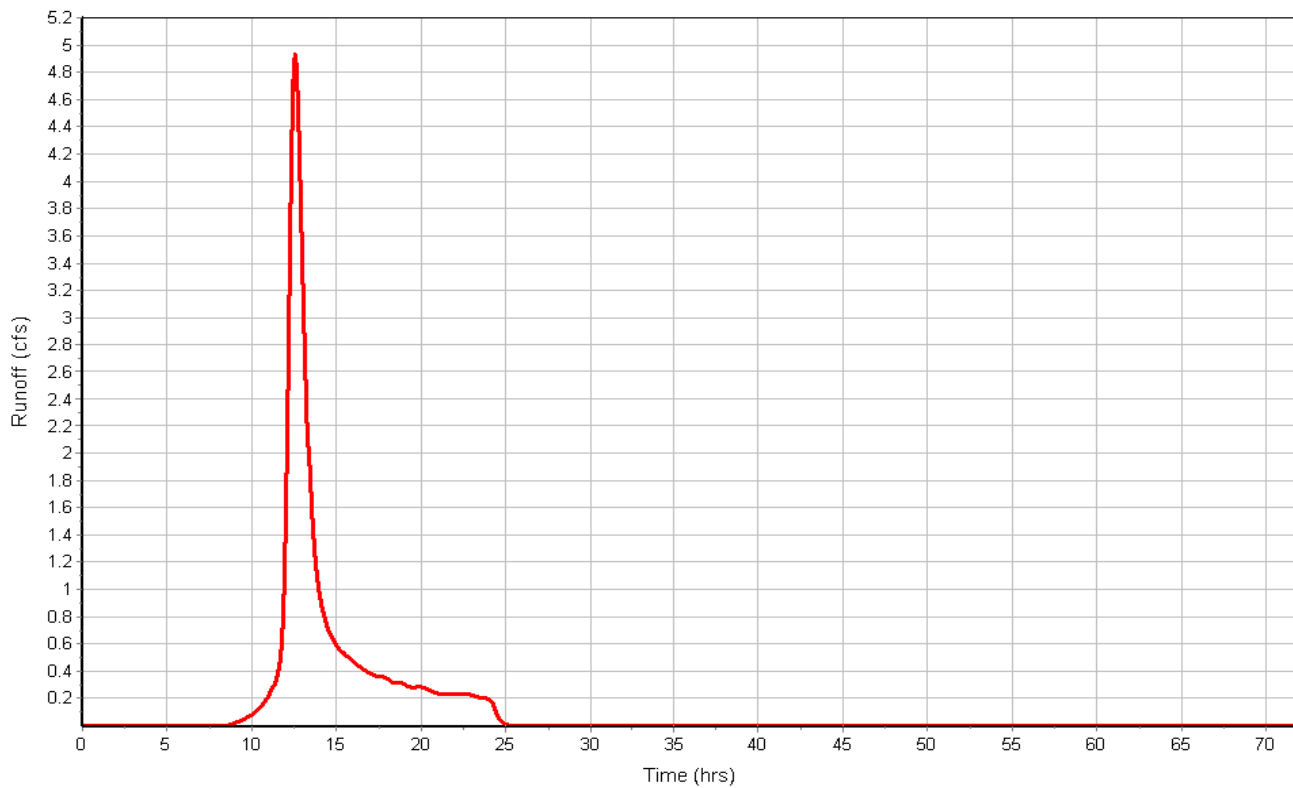
Total Rainfall (in)	12.00
Total Runoff (in)	5.92
Peak Runoff (cfs)	4.93
Weighted Curve Number	55.85
Time of Concentration (days hh:mm:ss)	0 00:41:15

Subbasin : Sub-01

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-02

Input Data

Area (ac) 1.55
Weighted Curve Number 85.15
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.24	A	98.00
Buildings/Structures	0.10	A	98.00
Concrete	0.30	A	98.00
Gravel	0.90	A	76.00
Composite Area & Weighted CN	1.54		85.15

Time of Concentration

	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.01	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.5	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.98	0.00	0.00
Computed Flow Time (min) :	1.70	0.00	0.00

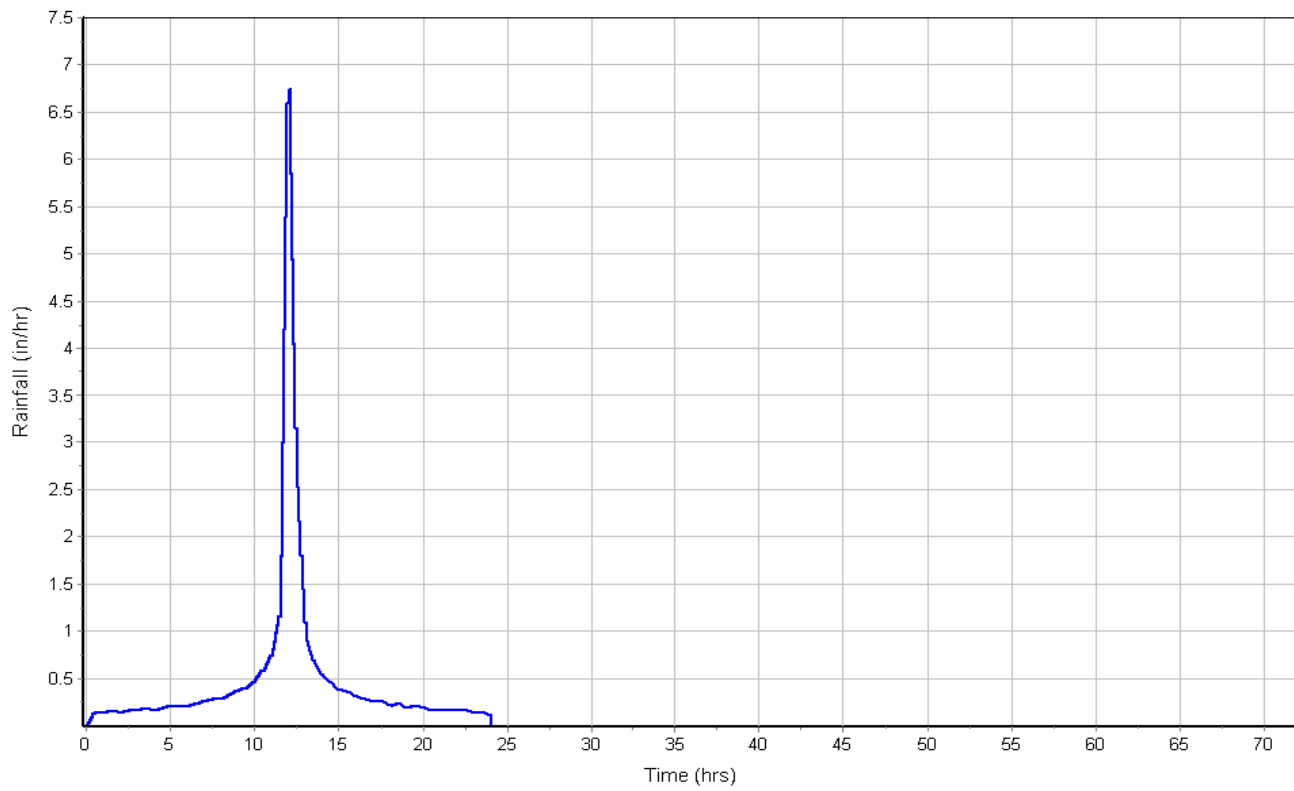
	Subarea A	Subarea B	Subarea C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	200	0.00	0.00
Slope (%) :	.5	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	1.14	0.00	0.00
Computed Flow Time (min) :	2.92	0.00	0.00
Total TOC (min)	4.62		

Subbasin Runoff Results

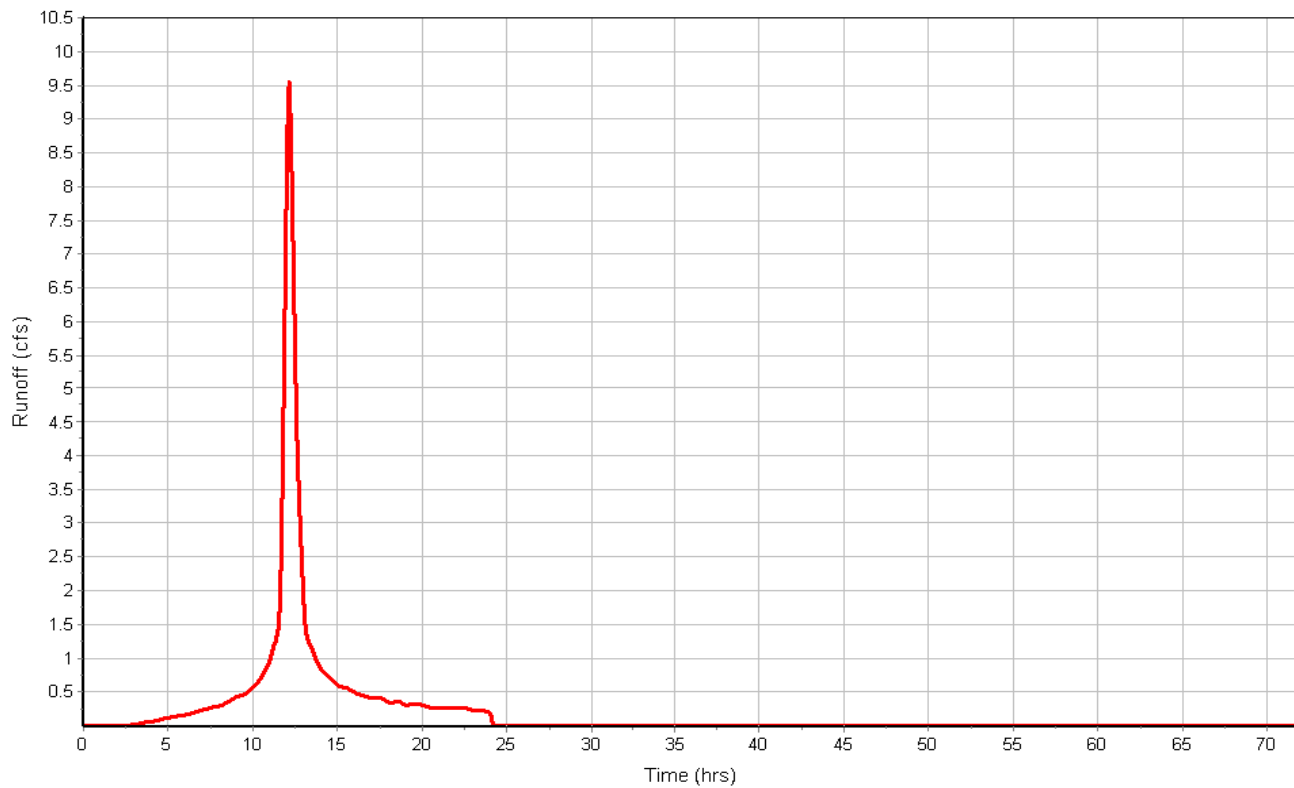
Total Rainfall (in) 12.00
Total Runoff (in) 10.13
Peak Runoff (cfs) 9.58
Weighted Curve Number 85.15
Time of Concentration (days hh:mm:ss) 0 00:04:37

Subbasin : Sub-02

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-03

Input Data

Area (ac) 1.00
Weighted Curve Number 89.09
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.37	A	98.00
Buildings/Structures	0.22	A	98.00
Gravel	0.41	A	76.00
Composite Area & Weighted CN	1.00		89.09

Time of Concentration

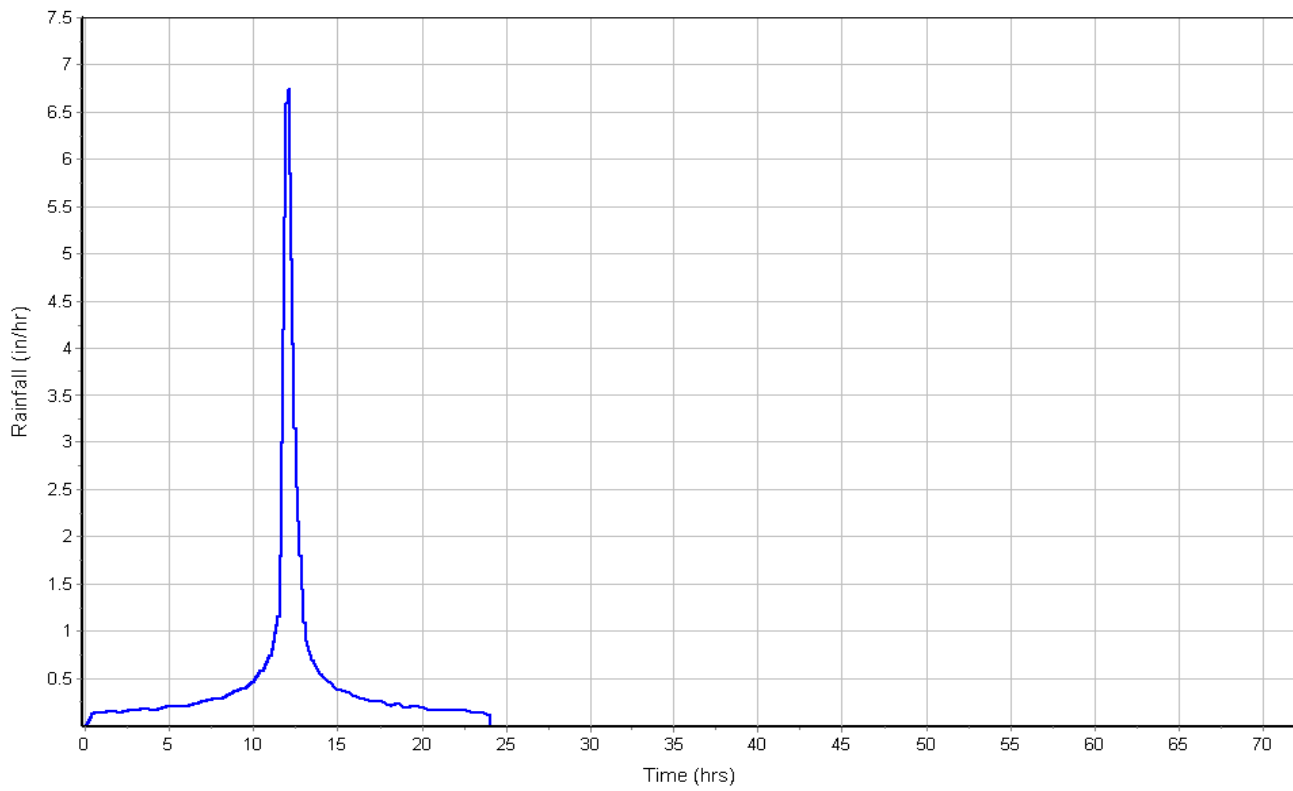
	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.01	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.5	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.98	0.00	0.00
Computed Flow Time (min) :	1.70	0.00	0.00
Shallow Concentrated Flow Computations			
Flow Length (ft) :	230	0.00	0.00
Slope (%) :	.5	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	1.14	0.00	0.00
Computed Flow Time (min) :	3.36	0.00	0.00
Total TOC (min)	5.06		

Subbasin Runoff Results

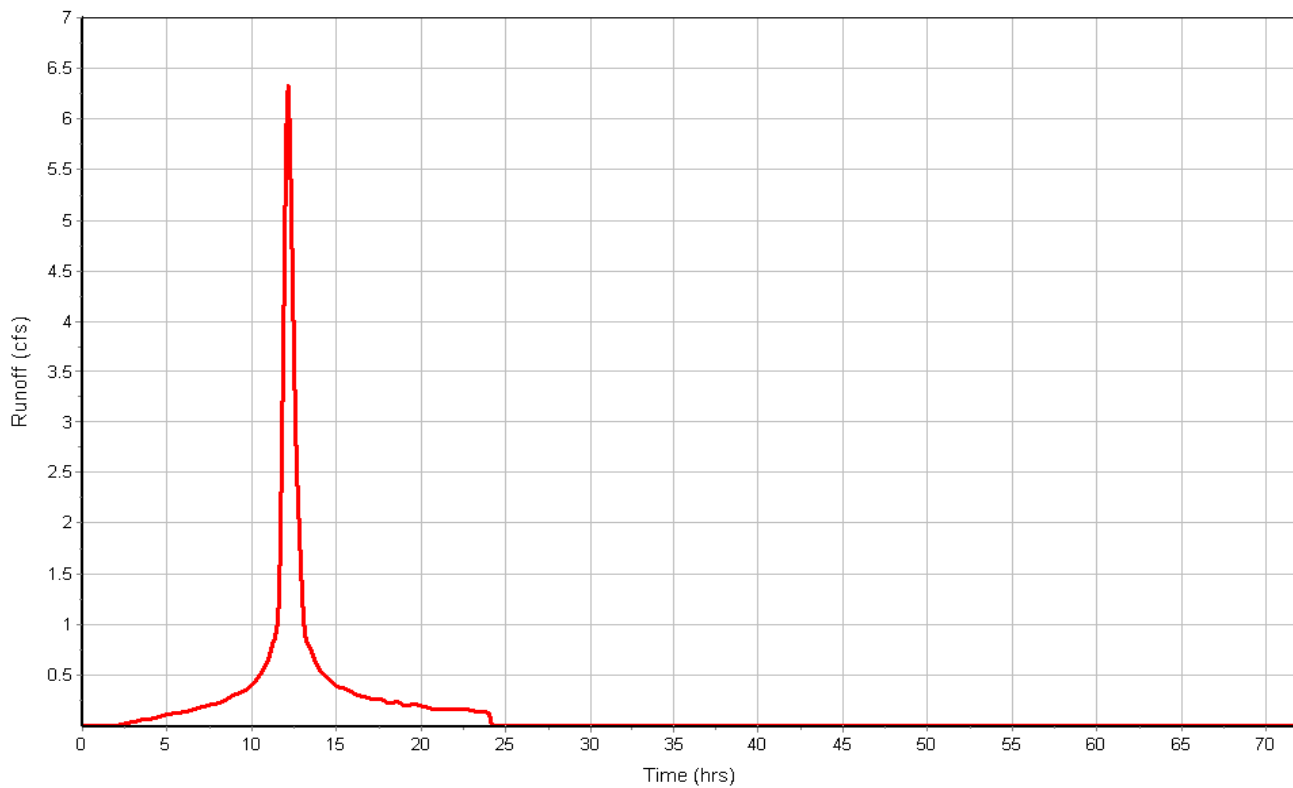
Total Rainfall (in) 12.00
Total Runoff (in) 10.65
Peak Runoff (cfs) 6.36
Weighted Curve Number 89.09
Time of Concentration (days hh:mm:ss) 0 00:05:04

Subbasin : Sub-03

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-04

Input Data

Area (ac) 1.02
Weighted Curve Number 82.62
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.24	A	98.00
Buildings/Structures	0.03	A	98.00
Concrete	0.10	A	98.00
Grass	0.05	A	49.00
Gravel	0.61	A	76.00
Composite Area & Weighted CN	1.03		82.62

Time of Concentration

	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.01	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.5	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.98	0.00	0.00
Computed Flow Time (min) :	1.70	0.00	0.00

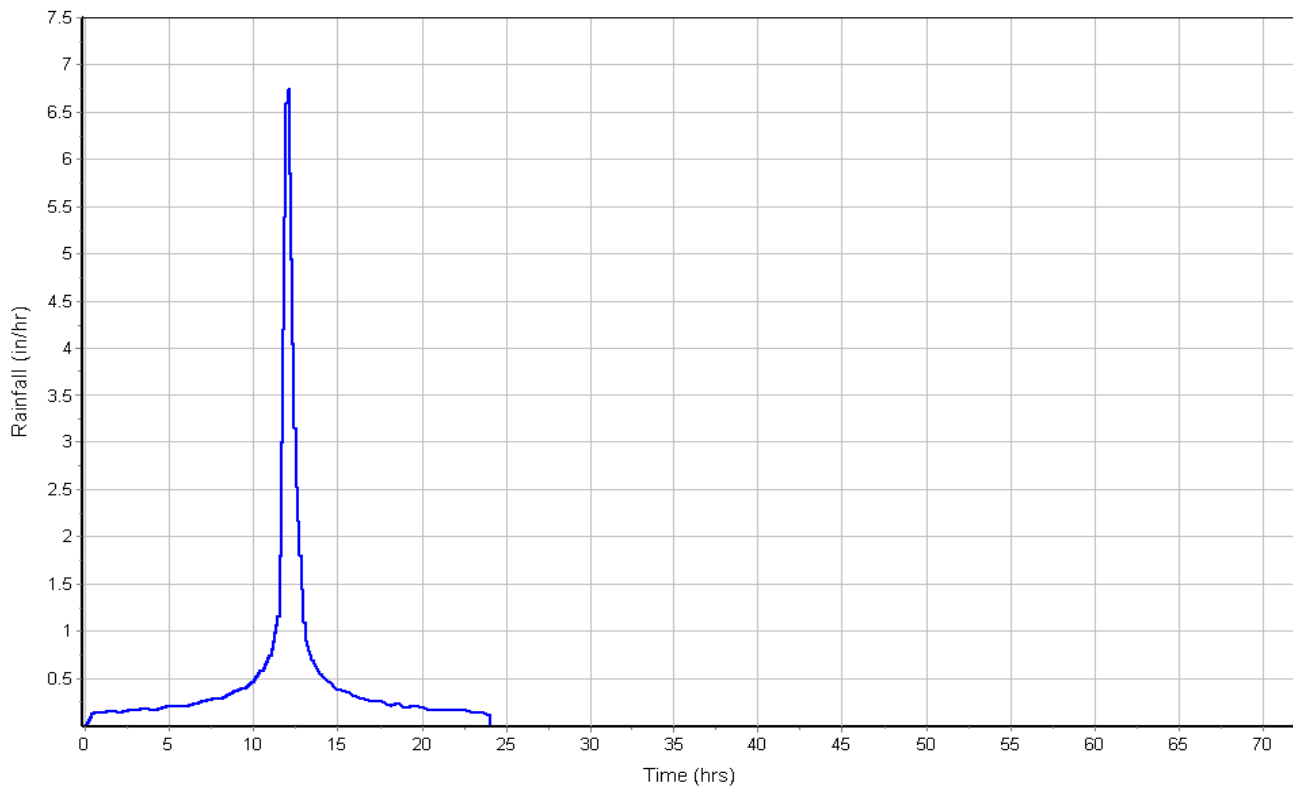
	Subarea A	Subarea B	Subarea C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	60	0.00	0.00
Slope (%) :	.5	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	1.14	0.00	0.00
Computed Flow Time (min) :	0.88	0.00	0.00
Total TOC (min)2.57			

Subbasin Runoff Results

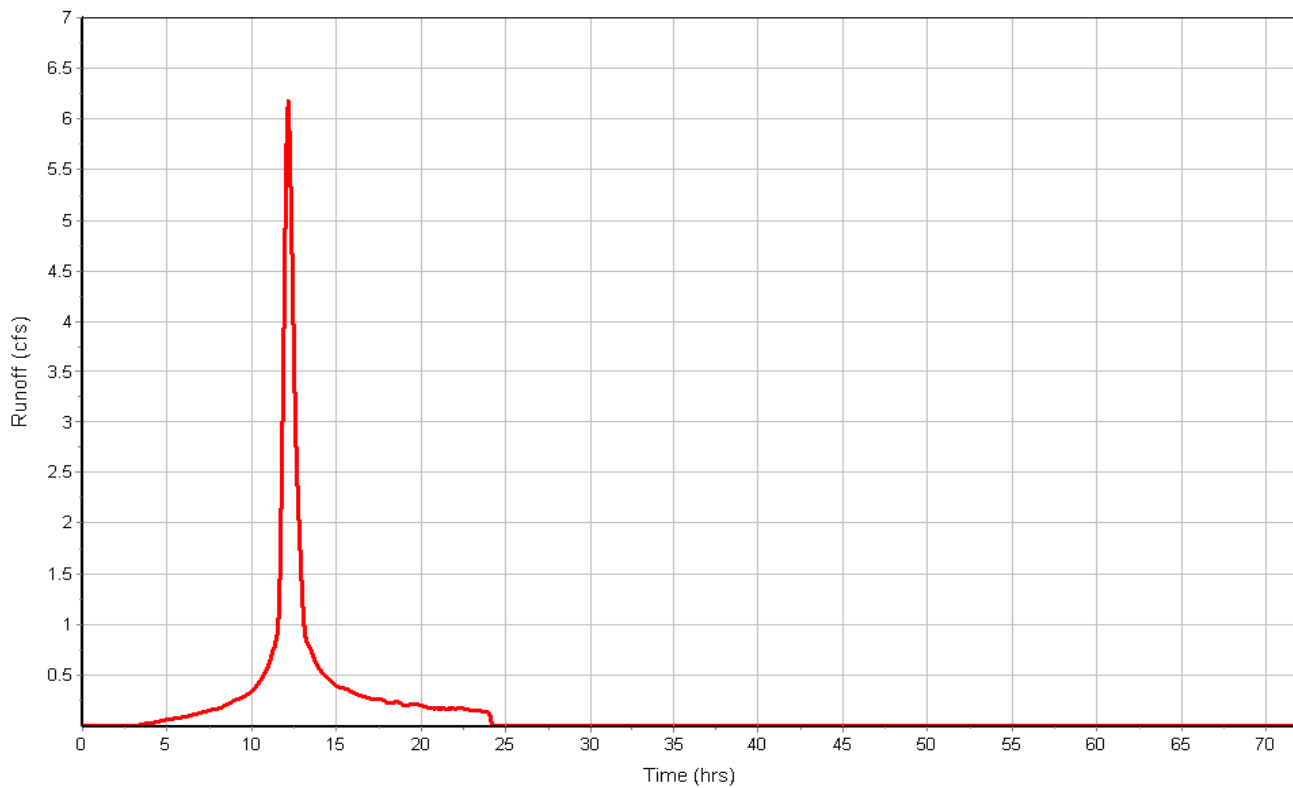
Total Rainfall (in) 12.00
Total Runoff (in) 9.80
Peak Runoff (cfs) 6.19
Weighted Curve Number 82.62
Time of Concentration (days hh:mm:ss) 0 00:02:34

Subbasin : Sub-04

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-05

Input Data

Area (ac) 0.52
Weighted Curve Number 88.97
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.30	A	98.00
Gravel	0.21	A	76.00
Composite Area & Weighted CN	0.51		88.97

Time of Concentration

	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.01	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.5	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.98	0.00	0.00
Computed Flow Time (min) :	1.70	0.00	0.00

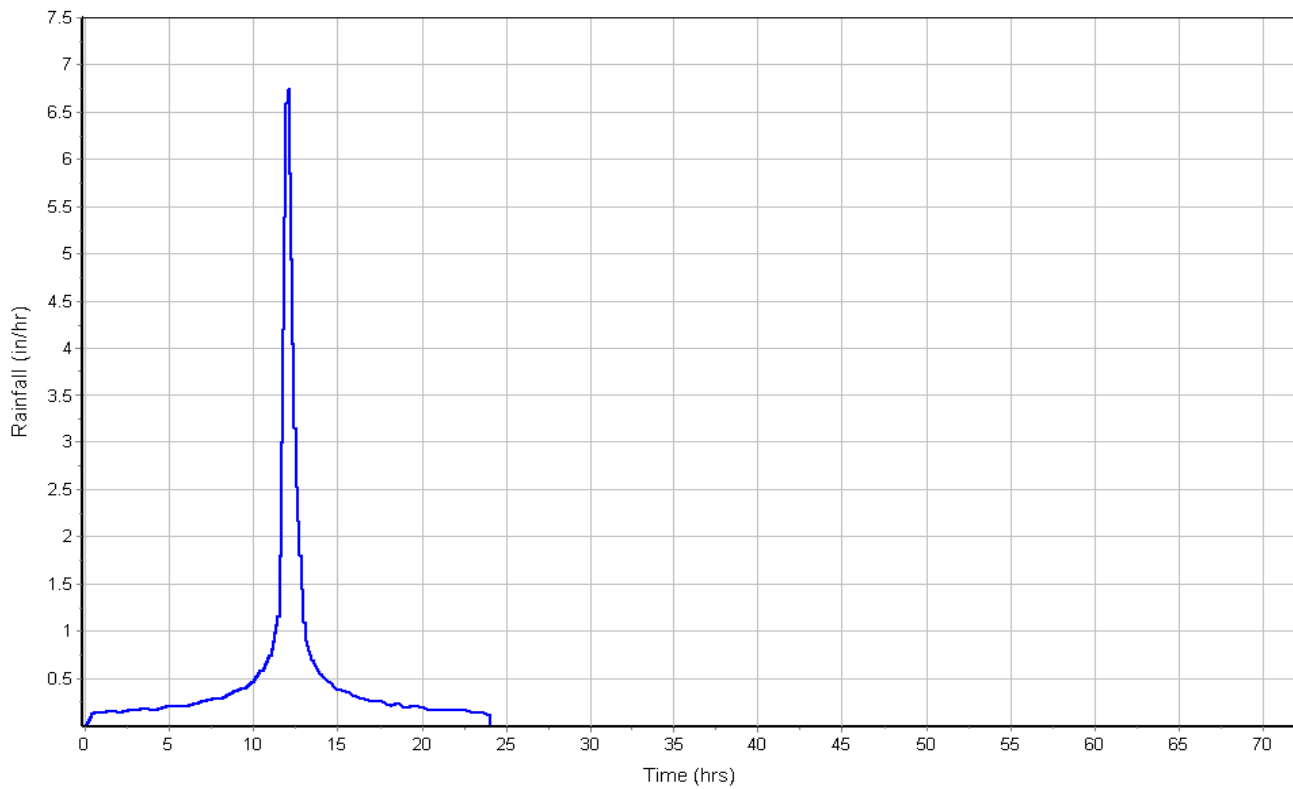
	Subarea A	Subarea B	Subarea C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	20	0.00	0.00
Slope (%) :	.5	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	1.14	0.00	0.00
Computed Flow Time (min) :	0.29	0.00	0.00
Total TOC (min)1.99			

Subbasin Runoff Results

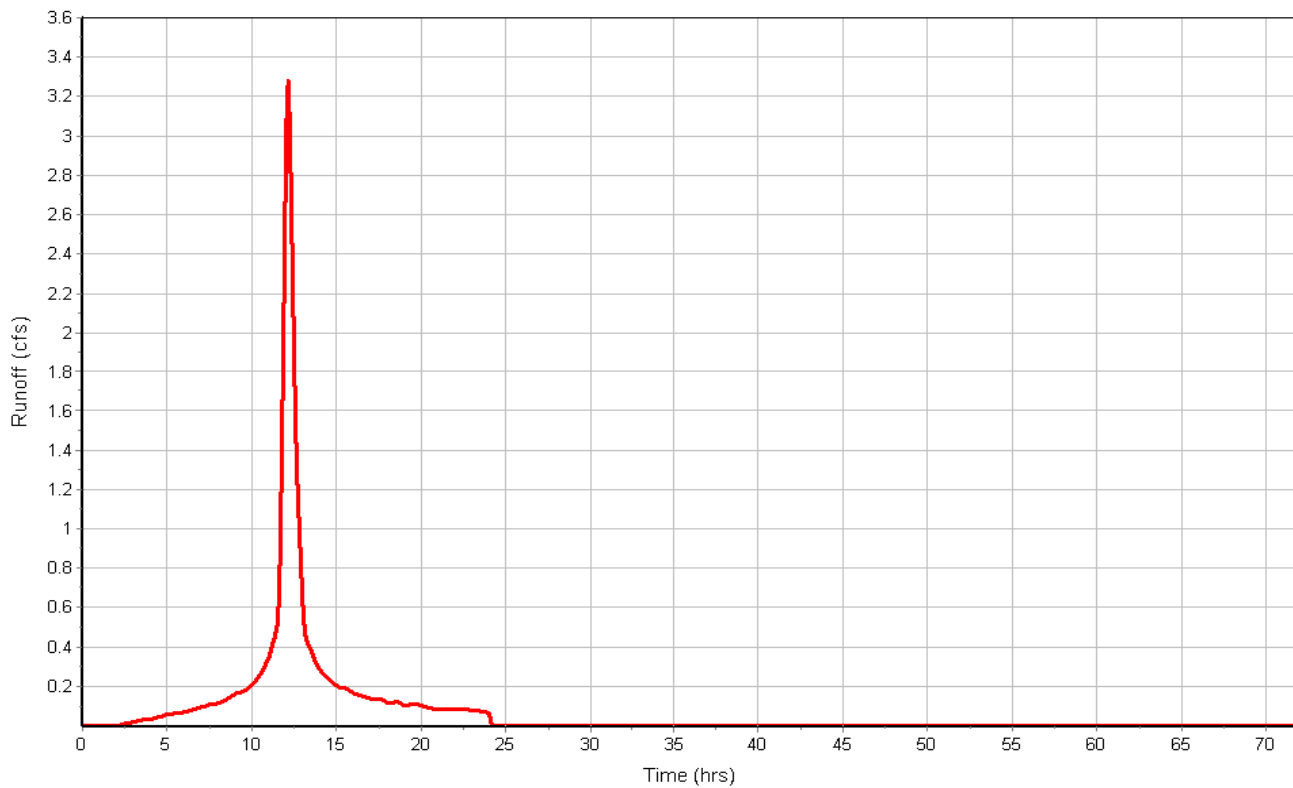
Total Rainfall (in) 12.00
Total Runoff (in) 10.63
Peak Runoff (cfs) 3.30
Weighted Curve Number 88.97
Time of Concentration (days hh:mm:ss) 0 00:01:59

Subbasin : Sub-05

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-06

Input Data

Area (ac) 2.83
Weighted Curve Number 85.39
Rain Gage ID Rain Gage

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.67	A	98.00
Buildings/Structures	0.54	A	98.00
Gravel	1.62	A	76.00
Composite Area & Weighted CN	2.83		85.39

Time of Concentration

	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.02	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.25	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.43	0.00	0.00
Computed Flow Time (min) :	3.90	0.00	0.00

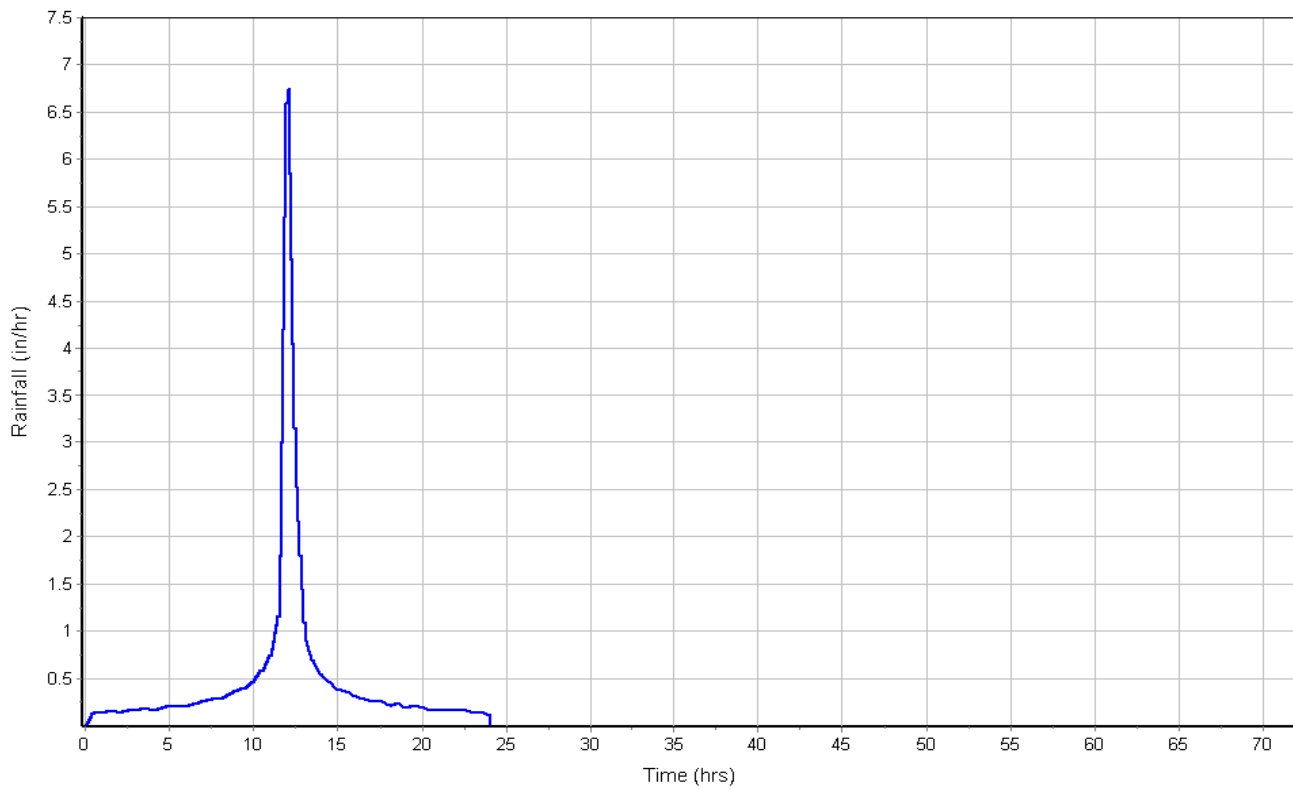
	Subarea A	Subarea B	Subarea C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	200	0.00	0.00
Slope (%) :	.25	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	0.81	0.00	0.00
Computed Flow Time (min) :	4.12	0.00	0.00
Total TOC (min)8.01			

Subbasin Runoff Results

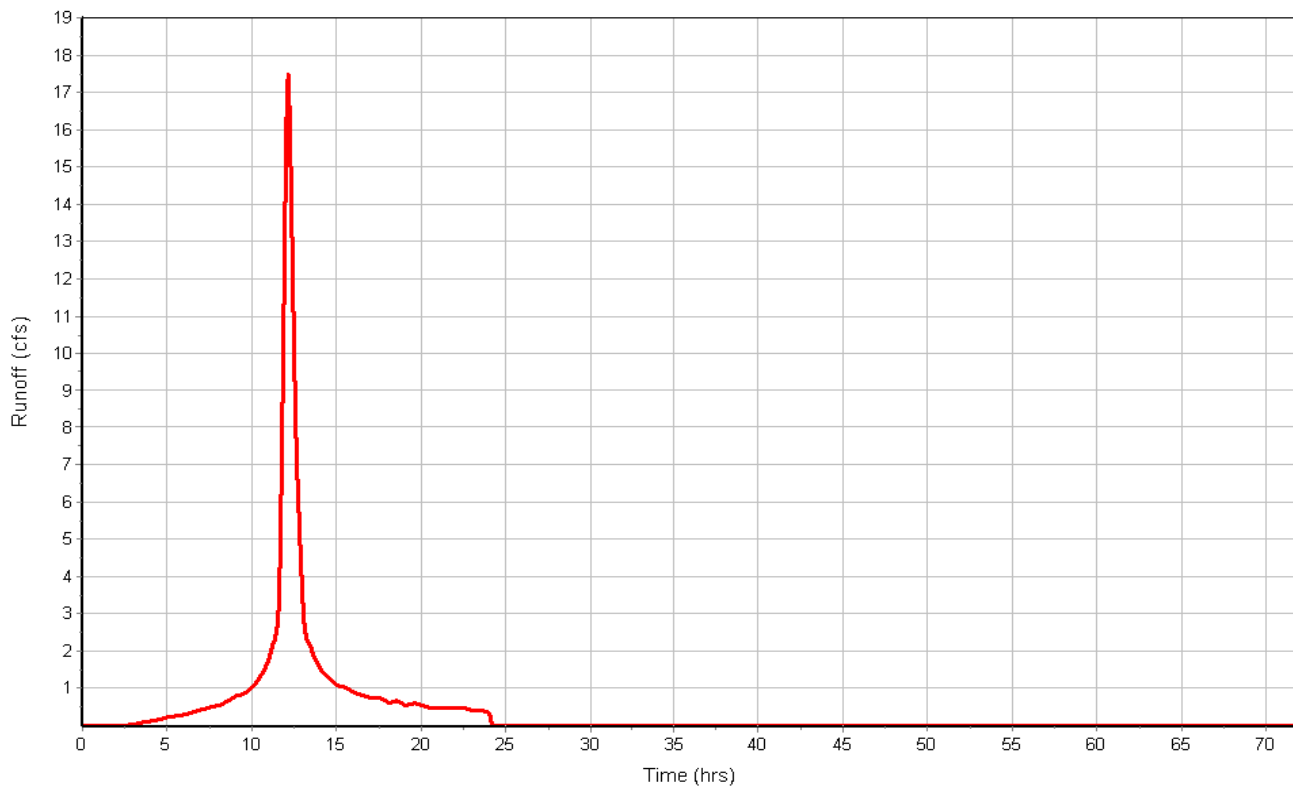
Total Rainfall (in) 12.00
Total Runoff (in) 10.17
Peak Runoff (cfs) 17.53
Weighted Curve Number 85.39
Time of Concentration (days hh:mm:ss) 0 00:08:01

Subbasin : Sub-06

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-07

Input Data

Area (ac) 2.23
Weighted Curve Number 57.20
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Building	0.37	A	98.00
Grass	1.85	A	49.00
Composite Area & Weighted CN	2.22		57.20

Time of Concentration

	Subarea A	Subarea B	Subarea C
Sheet Flow Computations			
Manning's Roughness :	.4	0.00	0.00
Flow Length (ft) :	100	0.00	0.00
Slope (%) :	.25	0.00	0.00
2 yr, 24 hr Rainfall (in) :	4.25	0.00	0.00
Velocity (ft/sec) :	0.04	0.00	0.00
Computed Flow Time (min) :	42.81	0.00	0.00

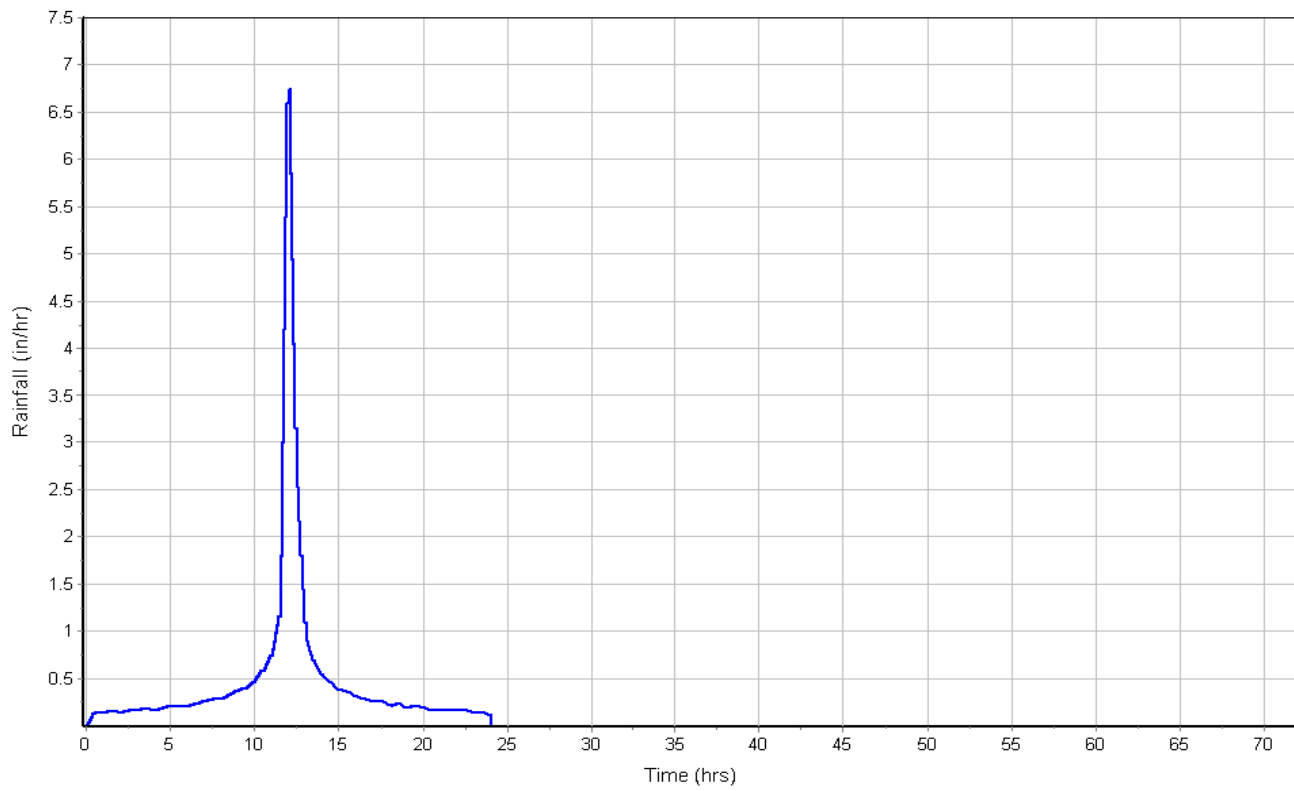
	Subarea A	Subarea B	Subarea C
Shallow Concentrated Flow Computations			
Flow Length (ft) :	60	0.00	0.00
Slope (%) :	.25	0.00	0.00
Surface Type :	Unpaved	Unpaved	Unpaved
Velocity (ft/sec) :	0.81	0.00	0.00
Computed Flow Time (min) :	1.23	0.00	0.00
Total TOC (min)	44.04		

Subbasin Runoff Results

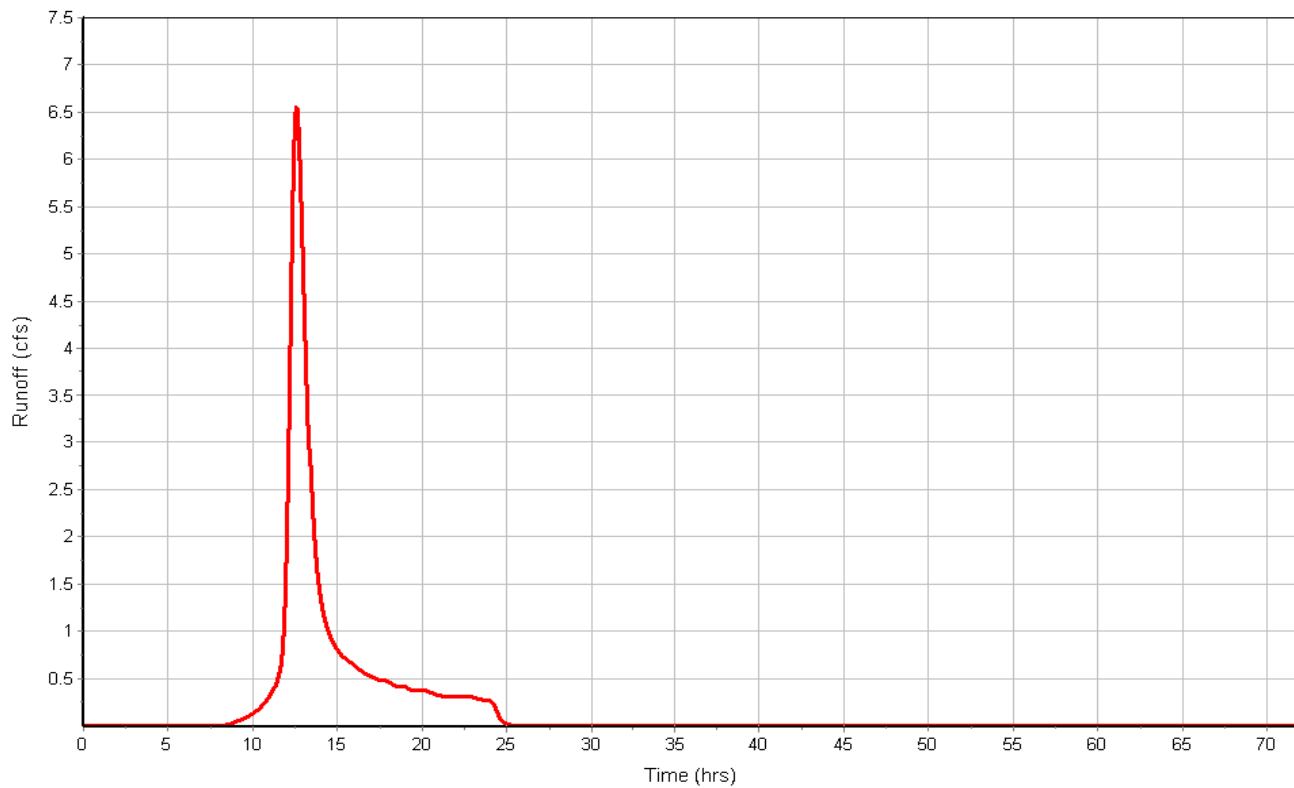
Total Rainfall (in) 12.00
Total Runoff (in) 6.13
Peak Runoff (cfs) 6.58
Weighted Curve Number 57.20
Time of Concentration (days hh:mm:ss) 0 00:44:02

Subbasin : Sub-07

Rainfall Intensity Graph



Runoff Hydrograph



Subbasin : Sub-08

Input Data

Area (ac) 2.76
Weighted Curve Number 61.14
Rain Gage ID

Composite Curve Number

Soil/Surface Description	Area (acres)	Soil Group	Curve Number
Asphalt	0.32	A	98.00
Grass	0.98	A	49.00
Gravel	0.67	A	76.00
Pond	0.80	A	49.00
Composite Area & Weighted CN	2.77		61.14

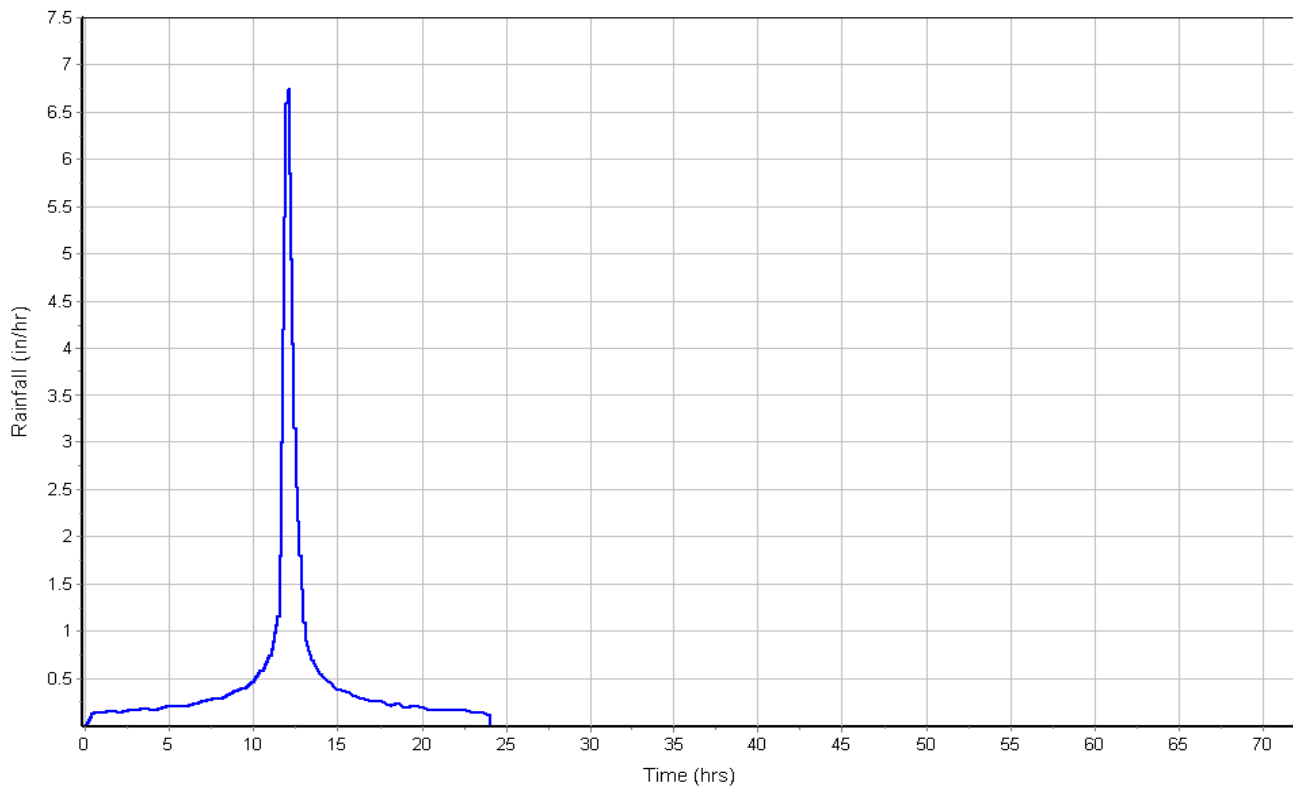
Time of Concentration

Subbasin Runoff Results

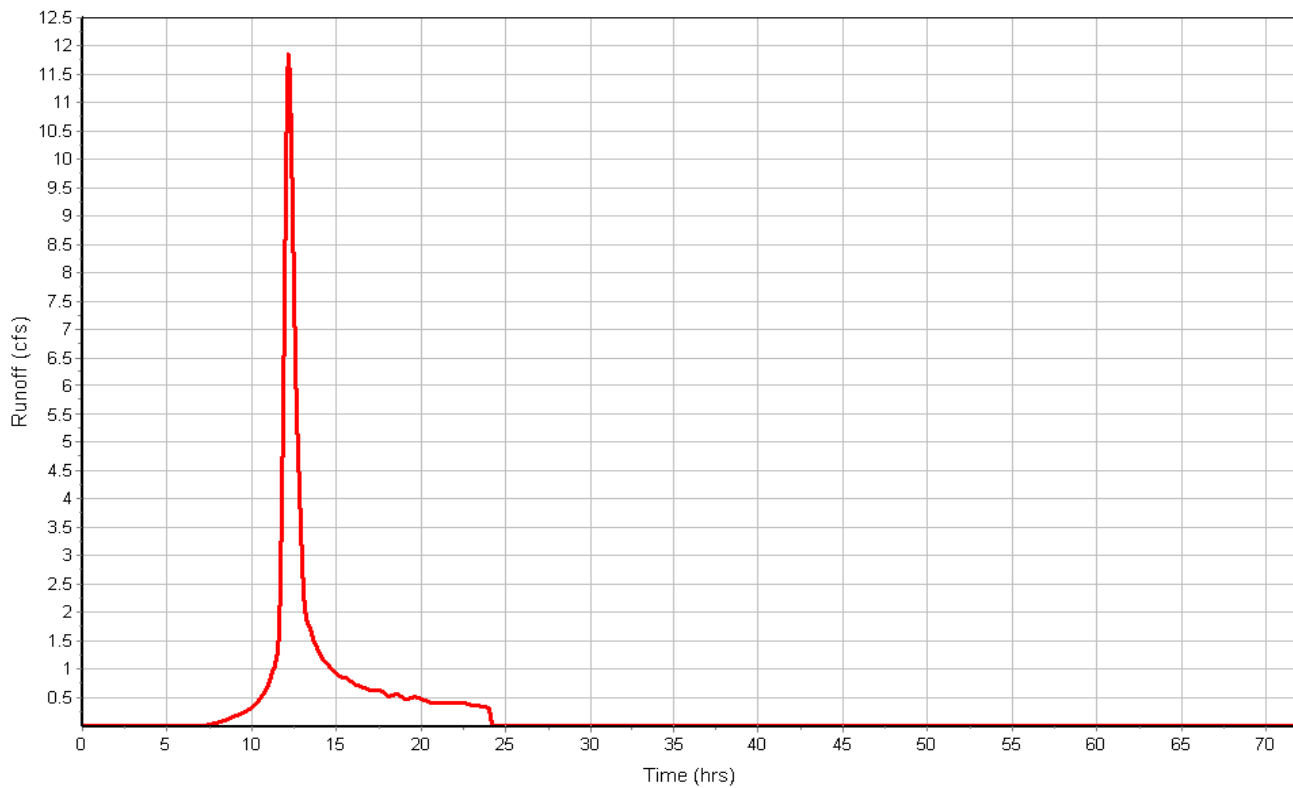
Total Rainfall (in) 12.00
Total Runoff (in) 6.74
Peak Runoff (cfs) 11.86
Weighted Curve Number 61.14
Time of Concentration (days hh:mm:ss) 0 00:00:00

Subbasin : Sub-08

Rainfall Intensity Graph



Runoff Hydrograph



Junction Input

SN	Element ID	Invert Elevation	Ground/Rim (Max) Elevation	Ground/Rim (Max) Offset	Initial Water Elevation	Initial Water Depth	Surcharge Elevation	Surcharge Depth	Ponded Area	Minimum Pipe Cover
		(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(ft²)	(in)
1	Jun-2A	44.00	49.00	5.00	44.00	0.00	1000.00	951.00	100.00	36.00
2	Jun-3A	43.90	49.00	5.10	43.90	0.00	1000.00	951.00	100.00	48.00
3	Jun-4A	46.00	51.10	5.10	46.00	0.00	1000.00	948.90	100.00	37.20
4	Jun-4B	45.00	51.10	6.10	45.00	0.00	1000.00	948.90	100.00	49.20
5	Jun-5A	44.80	51.10	6.30	44.80	0.00	1000.00	948.90	100.00	45.60
6	Jun-6A	46.00	51.10	5.10	46.00	0.00	1000.00	948.90	100.00	37.20
7	Jun-6B	45.00	51.10	6.10	45.00	0.00	1000.00	948.90	100.00	49.20
8	Jun-7A	46.00	51.50	5.50	46.00	0.00	1000.00	948.50	100.00	30.00
9	Jun-8A	44.00	51.10	7.10	44.00	0.00	1000.00	948.90	100.00	49.20

Junction Results

SN	Element ID	Peak Inflow	Peak Lateral Inflow	Max HGL Elevation Attained	Max HGL Depth Attained	Max Surcharge Depth Attained	Min Freeboard Attained	Average HGL Elevation Attained	Average HGL Depth Attained	Time of Max HGL Occurrence	Time of Peak Flooding Occurrence	Total Flooded Volume	Total Time Flooded
		(cfs)	(cfs)	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(days hh:mm)	(days hh:mm)	(ac-in)	(min)
1	Jun-2A	9.54	9.54	47.62	3.62	0.00	1.38	44.96	0.96	0 15:02	0 00:00	0.00	0.00
2	Jun-3A	15.79	6.33	47.62	3.72	0.00	1.38	44.88	0.98	0 15:03	0 00:00	0.00	0.00
3	Jun-4A	6.17	6.17	49.47	3.47	0.00	1.63	46.82	0.82	0 15:56	0 00:00	0.00	0.00
4	Jun-4B	6.17	0.00	49.47	4.47	0.00	1.63	46.41	1.41	0 15:56	0 00:00	0.00	0.00
5	Jun-5A	9.42	3.28	49.47	4.67	0.00	1.63	46.37	1.57	0 15:56	0 00:00	0.00	0.00
6	Jun-6A	17.47	17.47	49.57	3.57	0.00	1.53	46.86	0.86	0 12:19	0 00:00	0.00	0.00
7	Jun-6B	17.46	0.00	49.48	4.48	0.00	1.62	46.45	1.45	0 15:53	0 00:00	0.00	0.00
8	Jun-7A	6.56	6.56	49.48	3.48	0.00	2.02	47.32	1.32	0 15:53	0 00:00	0.00	0.00
9	Jun-8A	20.75	0.00	49.48	5.48	0.00	1.62	46.26	2.26	0 15:54	0 00:00	0.00	0.00

Pipe Input

SN	Element ID	Length (ft)	Inlet Invert Elevation (ft)	Inlet Invert Offset (ft)	Outlet Invert Elevation (ft)	Outlet Invert Offset (ft)	Total Drop (ft)	Average Slope (%)	Pipe Shape	Pipe Diameter or Height (in)	Pipe Width (in)	Manning's Roughness	Entrance Losses	Exit/Bend Losses	Additional Losses	Initial Flap Flow Gate	No. of Barrels
																(cfs)	
1	Link-2A-3A	96.42	44.00	0.00	43.00	-0.90	1.00	1.0400	CIRCULAR	24.000	24.000	0.0150	0.5000	0.8000	0.0000	0.00 No	1
2	Link-3A-P1	53.80	43.00	-0.90	41.00	0.00	2.00	3.7200	CIRCULAR	24.000	24.000	0.0150	0.5000	0.0000	0.0000	0.00 No	2
3	Link-4A-4B	121.56	46.00	0.00	45.00	0.00	1.00	0.8200	CIRCULAR	24.000	24.000	0.0150	0.5000	0.5000	0.0000	0.00 No	1
4	Link-4B-5A	89.46	45.00	0.00	44.80	0.00	0.20	0.2200	CIRCULAR	24.000	24.000	0.0150	0.5000	0.6000	0.0000	0.00 No	1
5	Link-5A-P2	110.00	44.80	0.00	41.00	0.00	3.80	3.4500	CIRCULAR	30.000	30.000	0.0150	0.5000	0.0000	0.0000	0.00 No	1
6	Link-6A-6B	148.08	46.00	0.00	45.00	0.00	1.00	0.6800	CIRCULAR	24.000	24.000	0.0150	0.5000	0.5000	0.0000	0.00 No	1
7	Link-6B-8A	56.26	45.00	0.00	44.00	0.00	1.00	1.7800	CIRCULAR	24.000	24.000	0.0150	0.5000	0.5000	0.0000	0.00 No	1
8	Link-7A-8A	131.94	47.00	1.00	45.00	1.00	2.00	1.5200	CIRCULAR	24.000	24.000	0.0150	0.5000	0.8000	0.0000	0.00 No	1
9	Link-8A-P2	40.00	44.00	0.00	43.00	2.00	1.00	2.5000	CIRCULAR	24.000	24.000	0.0150	0.5000	0.5000	0.0000	0.00 No	1

Pipe Results

SN Element ID	Peak Flow	Time of Peak Flow Occurrence	Design Flow Capacity	Peak Flow/ Design Flow Ratio	Peak Flow Velocity	Travel Time	Peak Flow Depth	Peak Flow Depth/ Total Depth Ratio	Total Time Surcharged	Froude Number	Reported Condition
	(cfs)	(days hh:mm)	(cfs)		(ft/sec)	(min)	(ft)		(min)		
1 Link-2A-3A	9.47	0 12:15	6.31	1.50	5.34	0.30	2.00	1.00	869.00		SURCHARGED
2 Link-3A-P1	15.55	0 12:15	91.04	0.17	3.63	0.25	2.00	1.00	914.00		SURCHARGED
3 Link-4A-4B	6.17	0 12:15	17.78	0.35	2.65	0.76	2.00	1.00	796.00		SURCHARGED
4 Link-4B-5A	6.16	0 12:15	9.27	0.66	2.45	0.61	2.00	1.00	1251.00		SURCHARGED
5 Link-5A-P2	9.42	0 12:15	66.07	0.14	2.24	0.82	2.50	1.00	1084.00		SURCHARGED
6 Link-6A-6B	17.46	0 12:15	16.11	1.08	5.56	0.44	2.00	1.00	835.00		SURCHARGED
7 Link-6B-8A	17.45	0 12:15	26.14	0.67	5.56	0.17	2.00	1.00	1273.00		SURCHARGED
8 Link-7A-8A	6.50	0 12:40	24.14	0.27	2.27	0.97	2.00	1.00	473.00		SURCHARGED
9 Link-8A-P2	22.35	0 12:08	31.00	0.72	7.11	0.09	2.00	1.00	2036.00		SURCHARGED

Storage Nodes

Storage Node : Pond 01

Input Data

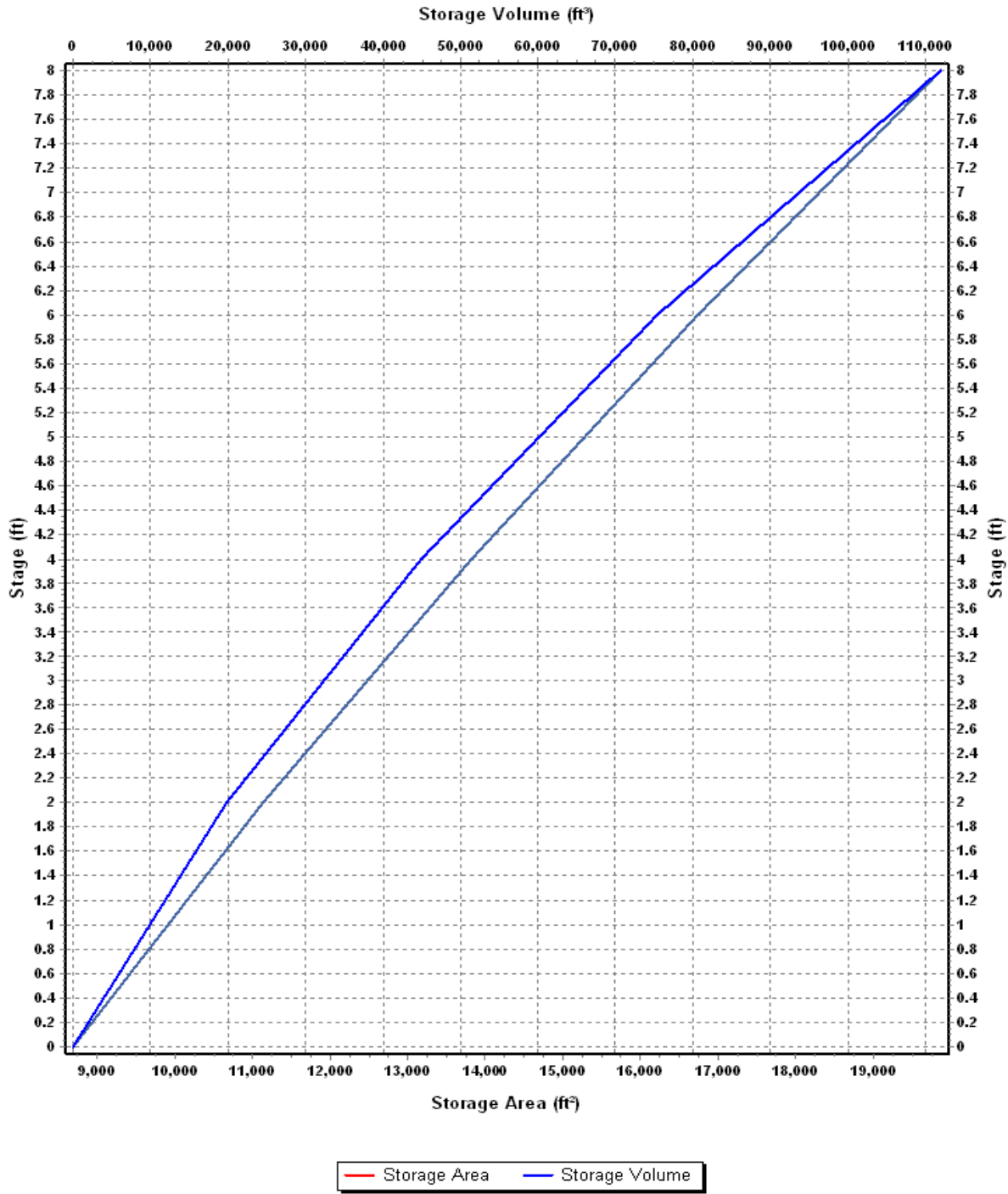
Invert Elevation (ft)	41.00
Max (Rim) Elevation (ft)	49.00
Max (Rim) Offset (ft)	8.00
Initial Water Elevation (ft)	41.00
Initial Water Depth (ft)	0.00
Ponded Area (ft²)	0.00
Evaporation Loss	0.00

Storage Area Volume Curves

Storage Curve : Storage-01

Stage	Storage Area	Storage Volume
(ft)	(ft²)	(ft³)
0	8693.61	0.000
2	11147.09	19840.70
4	13826.76	44814.55
6	16732.62	75373.93
8	19864.68	111971.23

Storage Area Volume Curves



Storage Node : Pond 01 (continued)

Output Summary Results

Peak Inflow (cfs)	18.22
Peak Lateral Inflow (cfs)	4.93
Peak Outflow (cfs)	1.64
Peak Exfiltration Flow Rate (cfm)	0.00
Max HGL Elevation Attained (ft)	47.62
Max HGL Depth Attained (ft)	6.62
Average HGL Elevation Attained (ft)	44.37
Average HGL Depth Attained (ft)	3.37
Time of Max HGL Occurrence (days hh:mm)	0 15:03
Total Exfiltration Volume (1000-ft ³)	0.000
Total Flooded Volume (ac-in)	0
Total Time Flooded (min)	0
Total Retention Time (sec)	0.00

Storage Node : Pond 02

Input Data

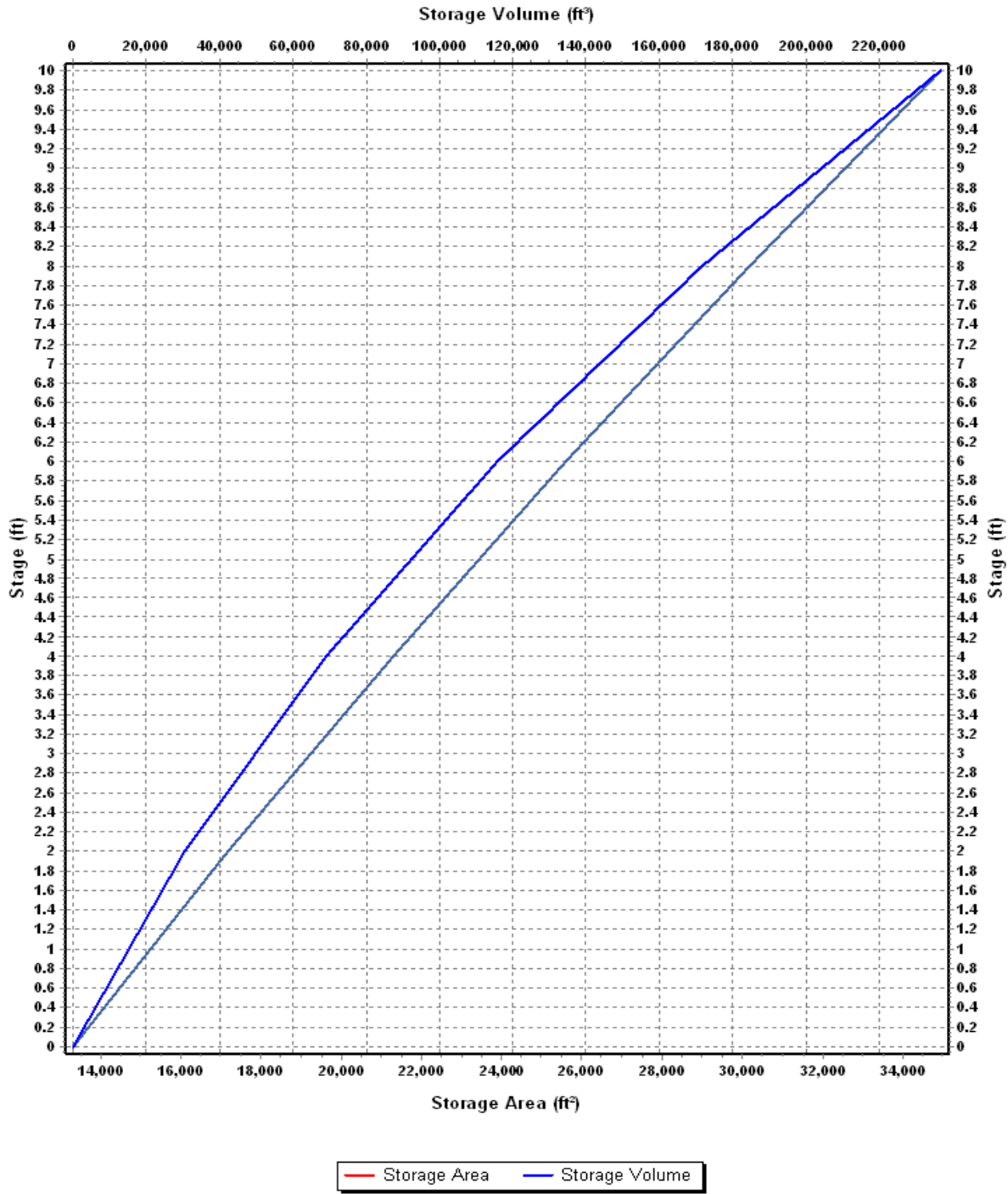
Invert Elevation (ft)	41.00
Max (Rim) Elevation (ft)	51.00
Max (Rim) Offset (ft)	10.00
Initial Water Elevation (ft)	41.00
Initial Water Depth (ft)	0.00
Ponded Area (ft ²)	0.00
Evaporation Loss	0.00

Storage Area Volume Curves

Storage Curve : Storage-02

Stage	Storage Area	Storage Volume
(ft)	(ft ²)	(ft ³)
0	13318.22	0.000
2	17192.32	30510.54
4	21290.04	68992.90
6	25613.95	115896.89
8	30164.06	171674.90
10	34940.36	236779.32

Storage Area Volume Curves



Storage Node : Pond 02 (continued)

Output Summary Results

Peak Inflow (cfs)	41.70
Peak Lateral Inflow (cfs)	11.85
Peak Outflow (cfs)	2.90
Peak Exfiltration Flow Rate (cfm)	0.00
Max HGL Elevation Attained (ft)	49.47
Max HGL Depth Attained (ft)	8.47
Average HGL Elevation Attained (ft)	45.78
Average HGL Depth Attained (ft)	4.78
Time of Max HGL Occurrence (days hh:mm)	0 15:56
Total Exfiltration Volume (1000-ft ³)	0.000
Total Flooded Volume (ac-in)	0
Total Time Flooded (min)	0
Total Retention Time (sec)	0.00

**ATTACHMENT 2
ICPR MODEL INPUT**

```

=====
==== Nodes =====
=====

Name: GW_Sink_1      Base Flow(cfs): 0.000      Init Stage(ft): 38.000
Group: BASE          Warn Stage(ft): 38.000
Type: Time/Stage

Time(hrs)      Stage(ft)
-----
0.00           38.000
999.00         38.000

-----
Name: GW_Sink_2      Base Flow(cfs): 0.000      Init Stage(ft): 38.000
Group: BASE          Warn Stage(ft): 38.000
Type: Time/Stage

Time(hrs)      Stage(ft)
-----
0.00           38.000
999.00         38.000

-----
Name: Pond_1         Base Flow(cfs): 0.000      Init Stage(ft): 41.800
Group: BASE          Warn Stage(ft): 49.100
Type: Stage/Area

Stage(ft)      Area(ac)
-----
41.000         0.1996
43.000         0.2559
45.000         0.3174
47.000         0.3841
49.000         0.4560

-----
Name: Pond_2         Base Flow(cfs): 0.000      Init Stage(ft): 42.150
Group: BASE          Warn Stage(ft): 51.100
Type: Stage/Area

Stage(ft)      Area(ac)
-----
41.000         0.3057
43.000         0.3947
45.000         0.4888
47.000         0.5880
49.000         0.6925
51.000         0.8021

=====
==== Percolation Links =====
=====

Name: Perc_1         From Node: Pond_1      Flow: Both
Group: BASE          To Node: GW_Sink_1    Count: 1

Surface Area Option: Vary based on Stage/Area Table
Vertical Flow Termination: Horizontal Flow Algorithm
Aquifer Base Elev(ft): 31.000      Perimeter 1(ft): 390.100
Water Table Elev(ft): 38.000      Perimeter 2(ft): 700.100
Ann Recharge Rate(in/year): 0.000  Perimeter 3(ft): 3831.700
Horiz Conductivity(ft/day): 40.000 Distance 1 to 2(ft): 50.000
Vert Conductivity(ft/day): 8.000   Distance 2 to 3(ft): 450.000
Effective Porosity(dec): 0.329     Num Cells 1 to 2: 10
Suction Head(in): 4.170           Num Cells 2 to 3: 80
Layer Thickness(ft): 3.000

-----
Name: Perc_2         From Node: Pond_2      Flow: Both
Group: BASE          To Node: GW_Sink_2    Count: 1

Surface Area Option: Vary based on Stage/Area Table
Vertical Flow Termination: Horizontal Flow Algorithm
Aquifer Base Elev(ft): 31.000      Perimeter 1(ft): 623.829
Water Table Elev(ft): 38.000      Perimeter 2(ft): 937.988
Ann Recharge Rate(in/year): 0.000  Perimeter 3(ft): 3765.422

```

Horiz Conductivity(ft/day): 40.000	Distance 1 to 2(ft): 50.000
Vert Conductivity(ft/day): 8.000	Distance 2 to 3(ft): 450.000
Effective Porosity(dec): 0.329	Num Cells 1 to 2: 10
Suction Head(in): 4.170	Num Cells 2 to 3: 80
Layer Thickness(ft): 3.000	

=====
Hydrology Simulations
=====

Name:
Filename:

Override Defaults: Yes
Storm Duration(hrs): 0.00
Rainfall File:
Rainfall Amount(in): 0.00

Time(hrs)	Print Inc(min)
-----	-----
30.000	5.00

=====
Routing Simulations
=====

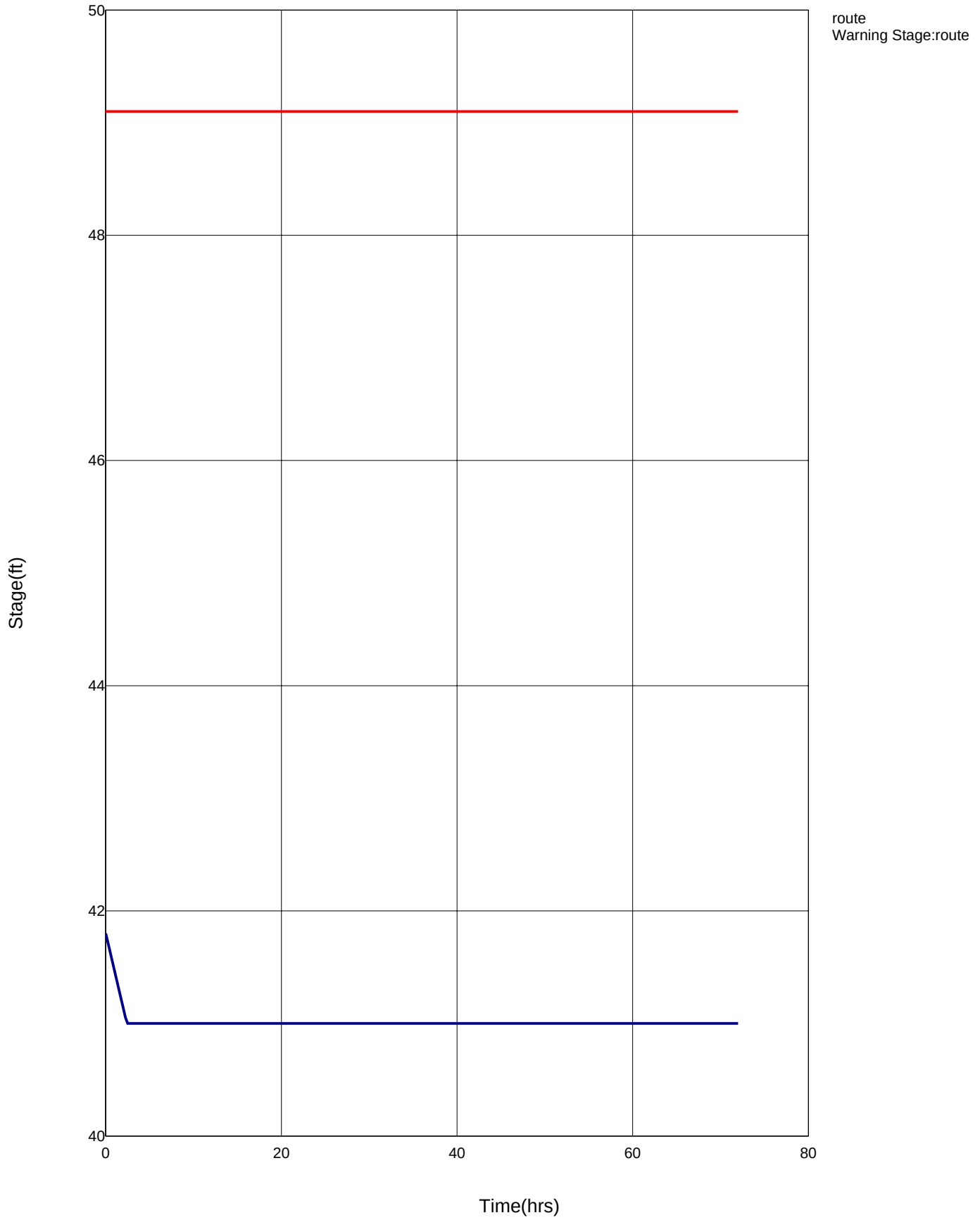
Name: route	Hydrology Sim:
Filename: C:\Users\jkelsey\Desktop_shady Hills\SCA\ERP\Hydrology\Treatment_route.I32	
Execute: Yes	Restart: No
Alternative: No	Patch: No
Max Delta Z(ft): 1.00	Delta Z Factor: 0.00500
Time Step Optimizer: 10.000	
Start Time(hrs): 0.000	End Time(hrs): 72.00
Min Calc Time(sec): 0.5000	Max Calc Time(sec): 60.0000
Boundary Stages:	Boundary Flows:

Time(hrs)	Print Inc(min)
-----	-----
999.000	15.000

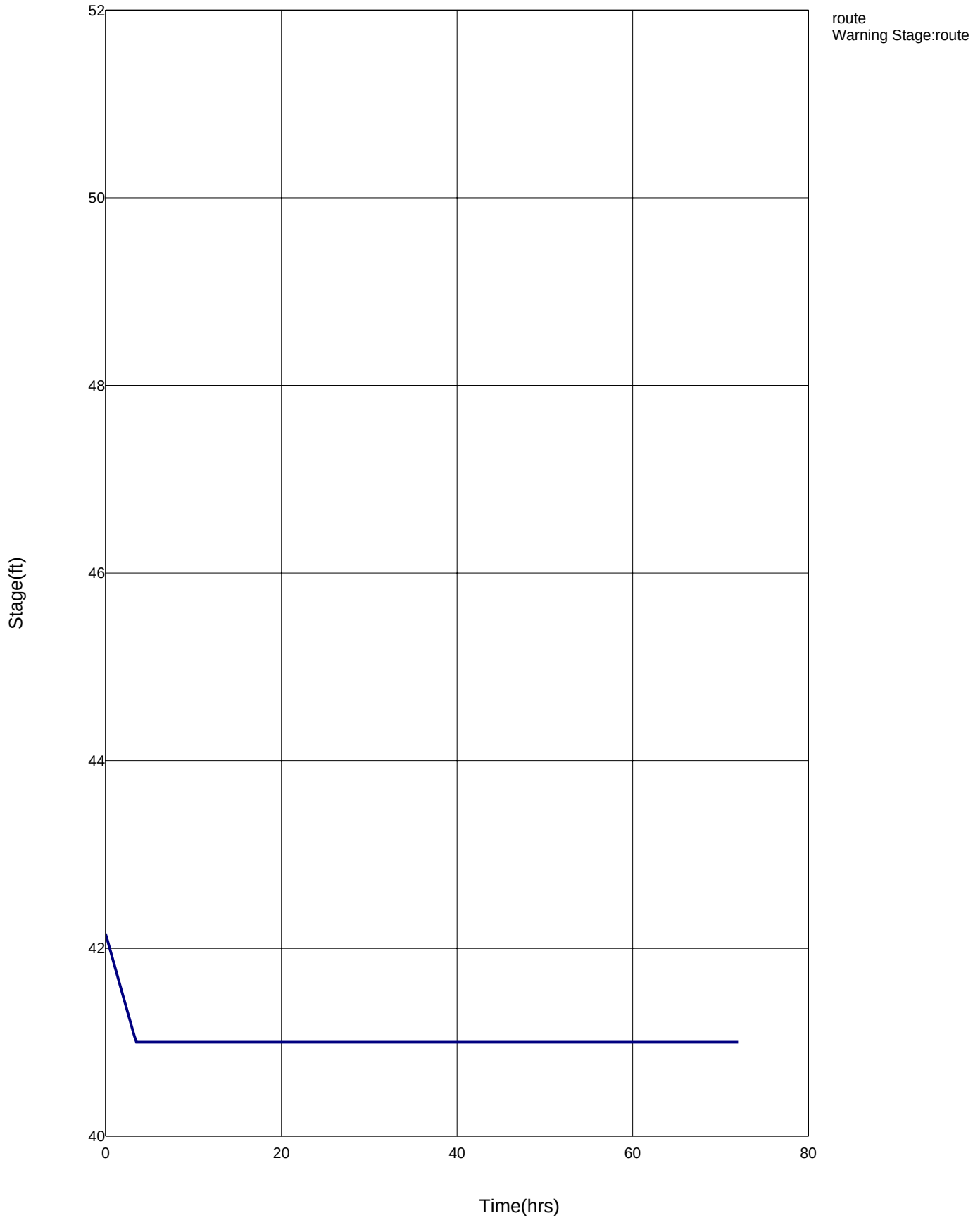
Group	Run
-----	-----
BASE	Yes

ATTACHMENT 3
ICPR MODEL RESULTS

Node Pond_1



Node Pond_2



Interconnected Channel and Pond Routing Model (ICPR) ©2002 Streamline Technologies, Inc. Page 1 of 7

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Interconnected Channel and Pond Routing Model (ICPR) ©2002 Streamline Technologies, Inc. Page 3 of 7

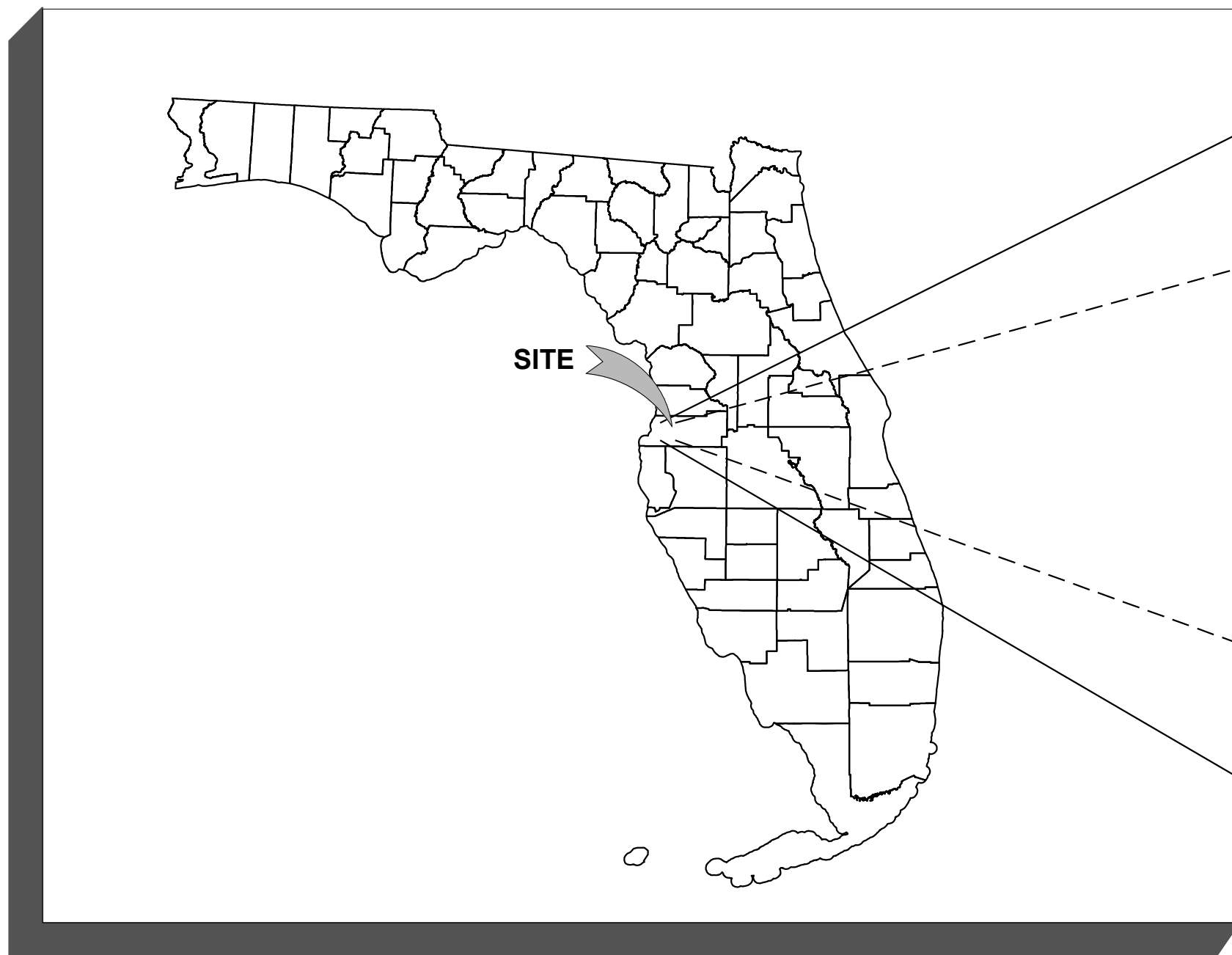
Simulation	Node	Group	Time hrs	Stage ft	Warning Stage ft	Surface Area ft2	Total Inflow cfs	Total Outflow cfs	Total Vol In af	Total Vol Out af
route	Pond_1	BASE	64.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	64.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	65.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	65.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	65.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	65.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	66.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	66.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	66.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	66.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	67.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	67.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	67.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	67.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	68.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	68.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	68.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	68.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	69.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	69.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	69.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	69.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	70.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	70.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	70.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	70.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	71.01	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	71.26	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	71.51	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	71.76	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_1	BASE	72.00	41.00	49.10	8694	0.00	0.00	0.0	0.2
route	Pond_2	BASE	0.00	42.15	51.10	15546	0.00	0.00	0.0	0.0
route	Pond_2	BASE	0.25	42.07	51.10	15386	0.00	1.42	0.0	0.0
route	Pond_2	BASE	0.50	41.98	51.10	15223	0.00	1.41	0.0	0.0
route	Pond_2	BASE	0.76	41.90	51.10	15060	0.00	1.39	0.0	0.1
route	Pond_2	BASE	1.01	41.82	51.10	14897	0.00	1.38	0.0	0.1
route	Pond_2	BASE	1.25	41.73	51.10	14740	0.00	1.36	0.0	0.1
route	Pond_2	BASE	1.50	41.65	51.10	14577	0.00	1.35	0.0	0.2
route	Pond_2	BASE	1.76	41.57	51.10	14414	0.00	1.33	0.0	0.2
route	Pond_2	BASE	2.01	41.48	51.10	14252	0.00	1.32	0.0	0.2
route	Pond_2	BASE	2.25	41.40	51.10	14094	0.00	1.31	0.0	0.2
route	Pond_2	BASE	2.50	41.32	51.10	13932	0.00	1.29	0.0	0.3
route	Pond_2	BASE	2.76	41.23	51.10	13769	0.00	1.27	0.0	0.3
route	Pond_2	BASE	3.01	41.15	51.10	13606	0.00	1.26	0.0	0.3
route	Pond_2	BASE	3.25	41.07	51.10	13449	0.00	1.25	0.0	0.3
route	Pond_2	BASE	3.50	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	3.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	4.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	4.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	4.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	4.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	5.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	5.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	5.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	5.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	6.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	6.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	6.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	6.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	7.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	7.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	7.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	7.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	8.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	8.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	8.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	8.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	9.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	9.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	9.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	9.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	10.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	10.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	10.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	10.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	11.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	11.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	11.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	11.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	12.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	12.26	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	12.51	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	12.76	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	13.01	41.00	51.10	13318	0.00	0.00	0.0	0.4
route	Pond_2	BASE	13.26	41.00	51.10	13318	0.00	0.00	0.0	0.4

Interconnected Channel and Pond Routing Model (ICPR) ©2002 Streamline Technologies, Inc. Page 5 of 7

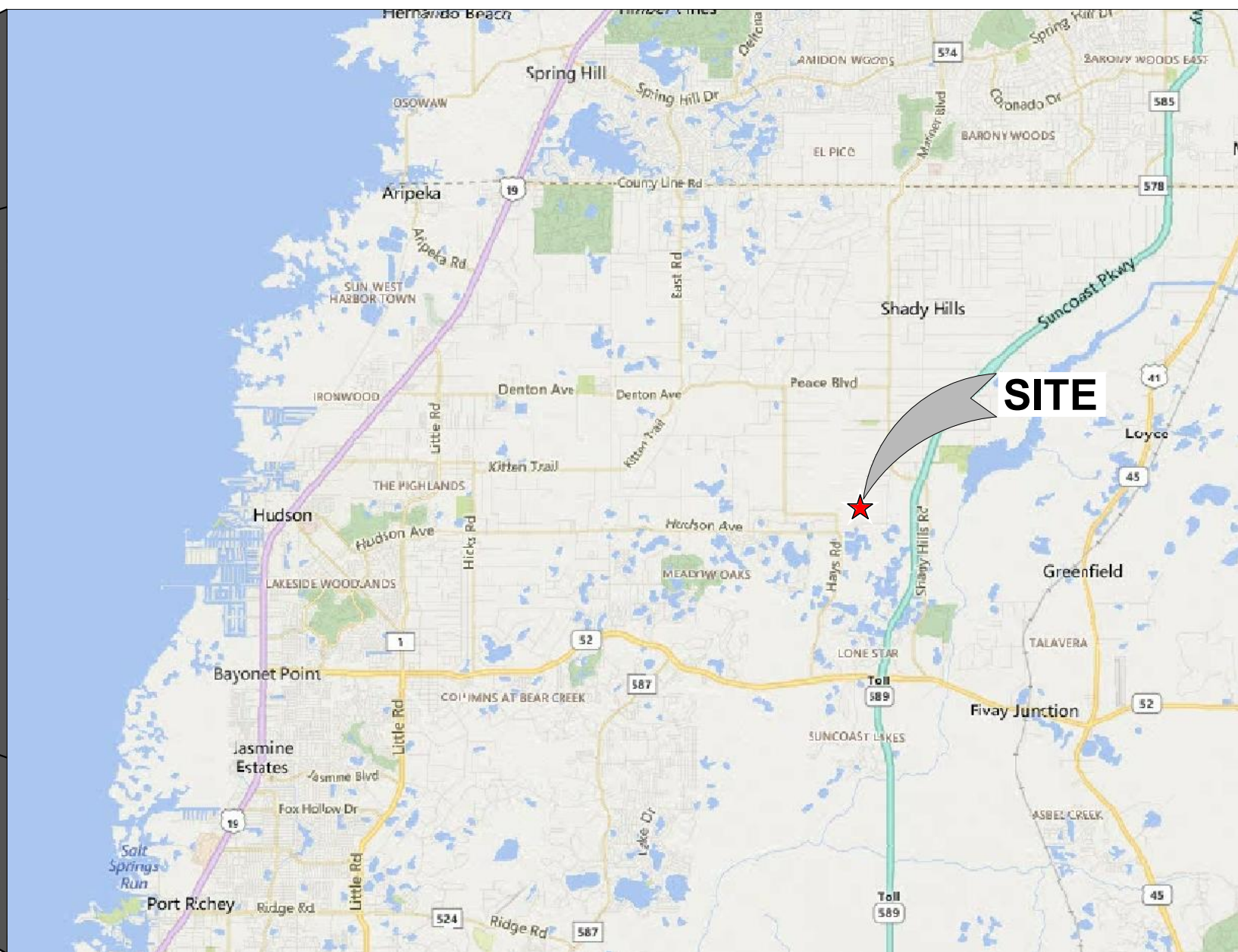
Interconnected Channel and Pond Routing Model (ICPR) ©2002 Streamline Technologies, Inc. Page 6 of 7

Attachment E
Drawings

SHADY HILLS ENERGY CENTER, LLC
SITE CERTIFICATION APPLICATION
SHADY HILLS COMBINED CYCLE FACILITY
PASCO COUNTY, FLORIDA



VICINITY MAP
NOT TO SCALE



LOCATION MAP
NOT TO SCALE

DRAWING SCHEDULE		
DRAWING NO.	SHEET TITLE	REVISION
001	TITLE SHEET	A
002	EXISTING CONDITIONS	A
003	SITE CLEARING AND DEMOLITION	A
004	STORMWATER MANAGEMENT SYSTEM PLAN	A
005	SECTIONS AND DETAILS	A
006	STORMWATER POLLUTION PREVENTION PLAN	A
007	STORMWATER POLLUTION PREVENTION PLAN DETAILS	A
008	STORMWATER POLLUTION PREVENTION PLAN NOTES	A

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CALL TOLL FREE
811 or
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SUNSHINE STATE UNDERGROUND
UTILITIES NOTIFICATION CENTER

PERMIT DRAWINGS

A	2018-02-08	PRELIMINARY	JTK	JTK	MM	MM
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED	APPROVED

SEAL

CLIENT
SHADY HILLS ENERGY CENTER, LLC

CONSULTANT

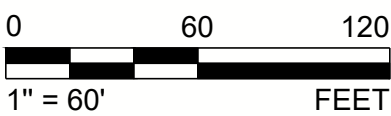


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PASCO COUNTY, FLORIDA

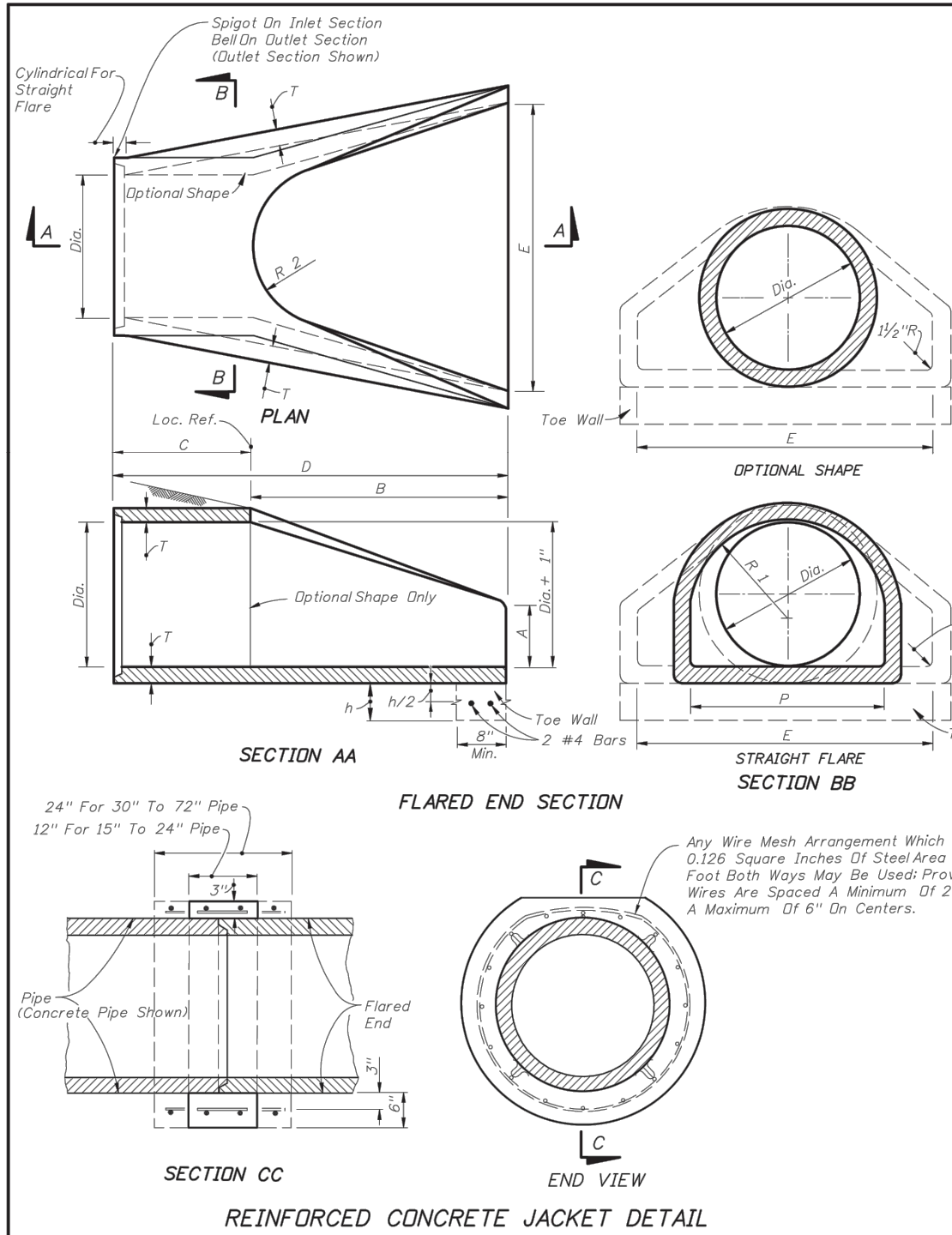
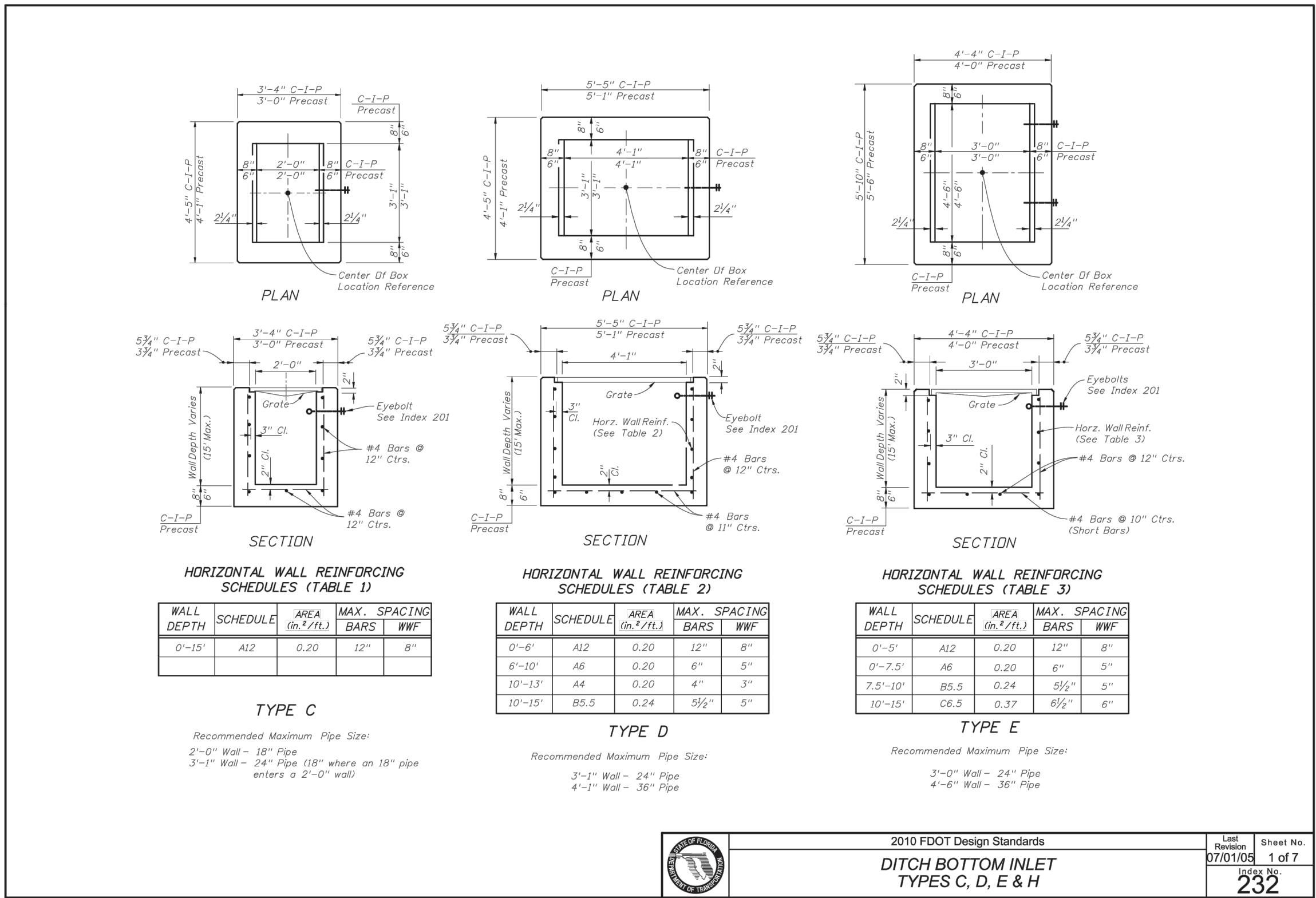
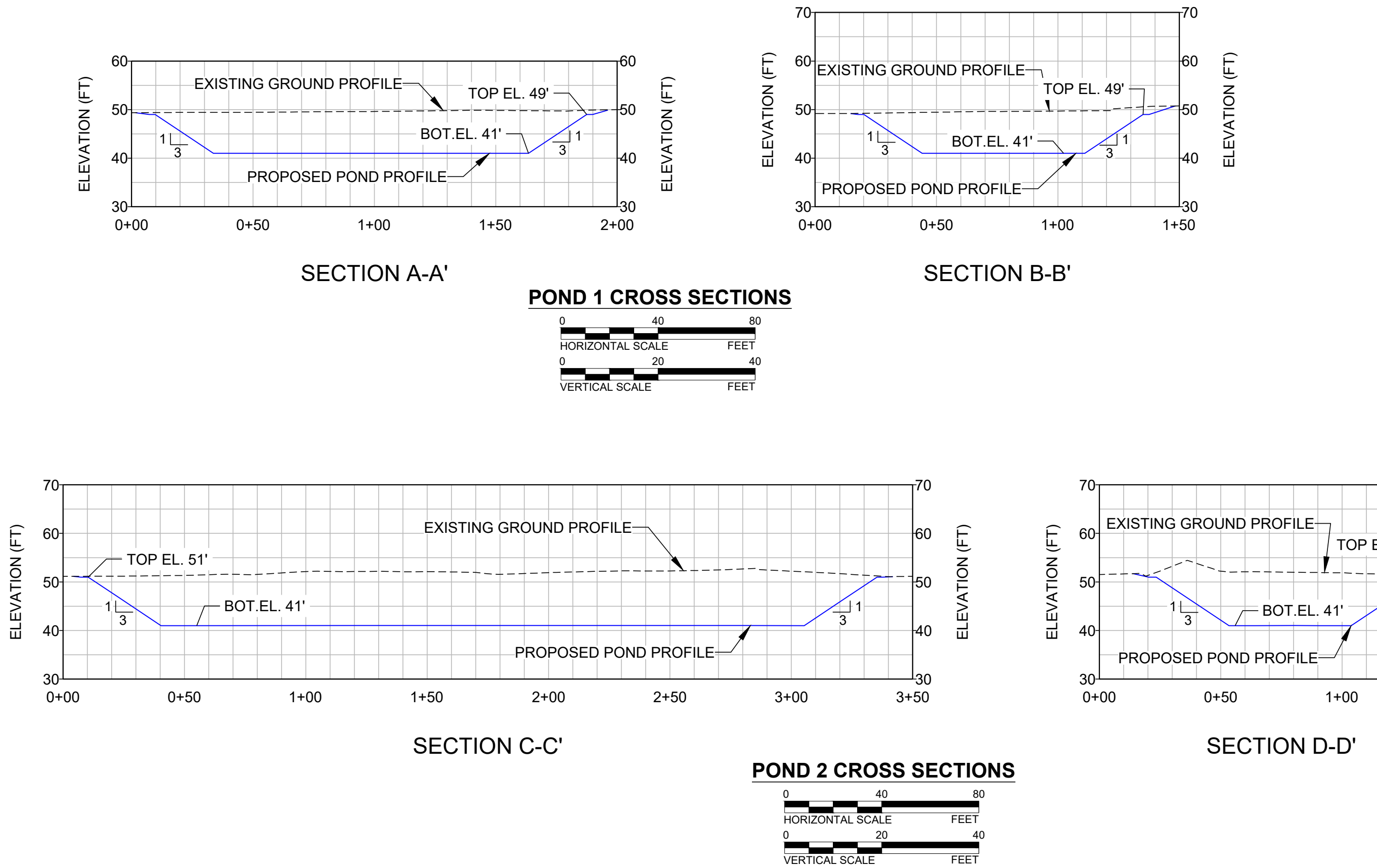
TITLE
TITLE SHEET

PROJECT NO. 17-79520 Control No. REV. 001 of 008 DWG 001



004

A	YYYY-MM-DD	DESCRIPTION	XXX	XXX	XXX	XXX
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED	APPROVED



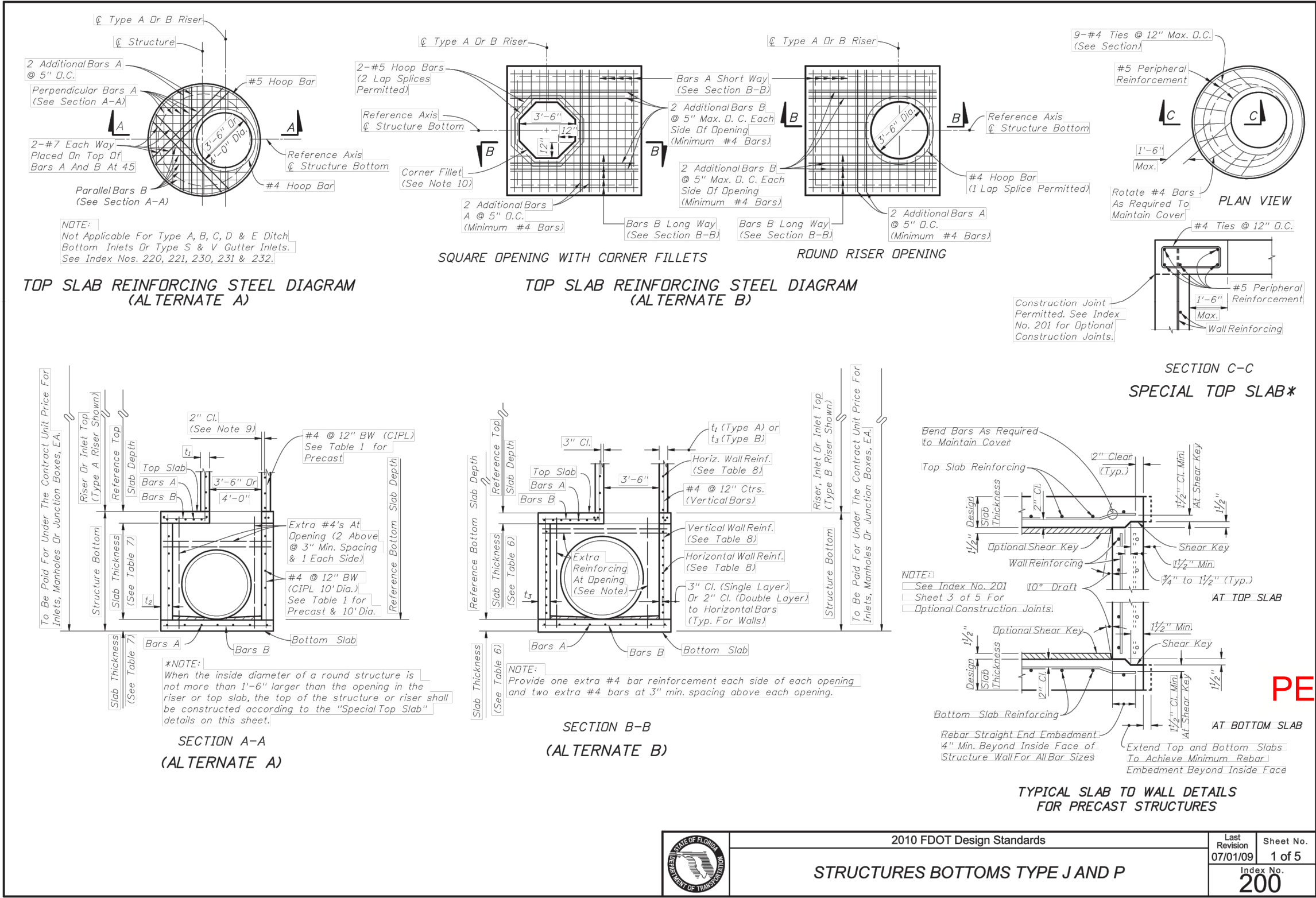
DIA	T	REINFORCING	BELL	A	B	C	D	E	P	R	I	R	2	FLAT	WEIGHT	TYPE	WALL
12"	2"	0.07	2"	4"	2"-0"	4"-0"	8"-0"	2"-0"	19 1/2"	10 1/2"	5"	3 1/2"	330	12"	.08	5"	CLASS I CONC
15"	2 1/4"	0.07	2 1/4"	6"	2"-3"	3"-10"	6"-1"	2"-6"	24 3/4"	12 1/4"	11"	3 1/2"	740	12"	.07	5"	CLASS I CONC
18"	2 1/4"	0.07	2 1/4"	9"	2"-3"	3"-10"	6"-1"	3"-0"	29"	15 1/2"	12"	4"	990	15"	.11	5"	CLASS I CONC
21"	2 1/4"	0.07	2 1/4"	9"	2"-11"	3"-2"	6"-1"	3"-6"	35 1/2"	16 1/2"	13"	4"	1280	15"	.12	5"	CLASS I CONC
24"	3"	0.07	2 1/4"	9 1/2"	3"-7 1/2"	2"-6"	6"-1 1/2"	4"-0"	33 3/4"	16 1/2"	14"	4 1/2"	1520	18"	.17	5"	CLASS I CONC
27"	3 1/4"	0.148	2 1/4"	10 1/2"	4"-0"	2"-1 1/2"	6"-1 1/2"	4"-6"	36"	18 1/2"	14 1/2"	4 1/2"	1830	18"	.19	5"	CLASS I CONC
30"	3 1/2"	0.148	2 1/4"	11"	1"-0"	4"-6"	11"-1 1/2"	6"-0"	37"	18 1/2"	15"	5"	2190	21"	.24	5"	CLASS I CONC
36"	4"	0.148	3 1/4"	11-3"	5"-3"	2"-10 1/4"	6"-1 1/2"	6"-0"	47 1/2"	24 3/4"	20"	5 1/2"	4100	21"	.29	5"	CLASS I CONC
42"	4 1/2"	0.148	3 1/4"	11-9"	5"-3"	2"-11"	8"-2"	6"-6"	53 1/2"	27 1/2"	22"	5 1/2"	5380	24"	.36	5"	CLASS I CONC
48"	5"	0.148	4 1/4"	12"-0"	6"-0"	2"-2"	8"-2"	7"-0"	56 1/2"	28 1/2"	22"	5 1/2"	5550	24"	.39	5"	CLASS I CONC
54"	5 1/2"	0.174	4 1/4"	12"-3"	5"-5"	2"-11"	8"-4"	7"-6"	65 1/2"	33 1/2"	24"	6"	8040	24"	.42	5"	CLASS I CONC
60"	6"	0.174	5"	12"-6"	5"-0"	3"-3"	8"-3"	8"-0"	72 1/2"	36 1/2"	24"	6 1/2"	8750	24"	.44	5"	CLASS I CONC
66"	6 1/2"	0.174	5"	12"-6"	6"-6"	1"-9"	8"-3"	6"	72"	36 1/2"	24"	7 1/2"	10630	24"	.47	5"	CLASS I CONC
72"	7"	0.174	6"	12"-9"	6"-6"	1"-9"	8"-3"	9"-0"	77 1/2"	38 1/2"	24"	7 1/2"	12520	24"	.50	5"	CLASS I CONC

GENERAL NOTES

- Flared end sections shall conform to the requirements of ASTM C76 with the exception that dimensions and reinforcement shall be as prescribed in the table above. Circumferential reinforcement may consist of either one cage or two cages of steel. Compressive strength of concrete shall be 4000 psi. Shop drawings for flared end sections having dimensions other than those shown must be submitted for approval to the State Drainage Engineer.
- Connections between the flared end section and the pipe culvert may be any of the following types unless otherwise shown on the plans.
 - Joints meeting the requirements of Section 449 of the Standard Specifications (D-Ring Gasket). Flared end section joint dimensions and tolerances shall be identical or compatible to those used in the pipe culvert joint. When pipe culvert and flared end section manufacturers are different, the compatibility of joint designs shall be certified to by the manufacturer of the flared end sections.
 - Joints sealed with preformed plastic gaskets. The gaskets shall meet the requirements of Section 942-2 of the Standard Specifications and the minimum sizes for gaskets shall be as that specified for equivalent sizes of elliptical pipe.
 - Reinforced concrete jackets, as detailed on this drawing. Cost of the reinforced concrete jacket to be included in the contract unit price for the flared end section. When non-coated corrugated metal pipe is called for in the plans, the pipe shall be blumious coated in the jacketed area as specified on Index No. 280. Blumious coating to be included in the contract unit price for the pipe culvert. Concrete jacket shall be as specified on Index No. 280. Cost of concrete and reinforcement shall be included in the contract unit price for the pipe culvert.
- Toe walls shall be constructed when shown on the plans or at locations designated by the Engineer. Toe walls are to be cast-in-place with Class I Concrete and paid for under the contract unit price for Flared End Section (Concrete). EA Reinforcing steel shall also be included in the cost of the Flared End Section (Concrete). EA
- On skewed pipe culverts the flared end sections shall be placed in line with the pipe culvert. Side slopes shall be warped as required to fit the flared end sections.
- Flared End Section to be paid for under the contract unit price for Flared End Section (Concrete). EA Soding shall be in accordance with Index No. 281, and paid for under the contract unit price for Performance Turt. SY.

DESIGN NOTES

- Flared end sections are intended for use outside the clear zone on median drain and cross drain installation, except that flared end sections for pipe sizes 12" and 15" are permitted within the clear zone. When the slope intersection permits, 12" and 15" flared end sections may be located with the culvert opening as close as 8' beyond the outside edge of the shoulder. Flared end sections are not intended for side drain installations.
- Reinforced concrete jackets shall be used at all locations where high velocities and/or highly erosive soils may cause disjoints. These locations are to be shown on the plans.
- Toe walls shall be used whenever the anticipated velocity of discharge and soil type are such that erosive action would occur. Toe walls are not required where ditch pavement is provided, except when disjoints would occur if the ditch pavement should fail.



- NOTE(S)**
- VERTICAL DATUM REFERENCE: Feet-NAVD88.
 - CROSS SECTION LOCATIONS SHOWN ON DWG 004.

PERMIT DRAWINGS

A	2018-02-13	DESCRIPTION	BTH	BCL	MM	MM
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED	APPROVED

CLIENT
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CONSULTANT



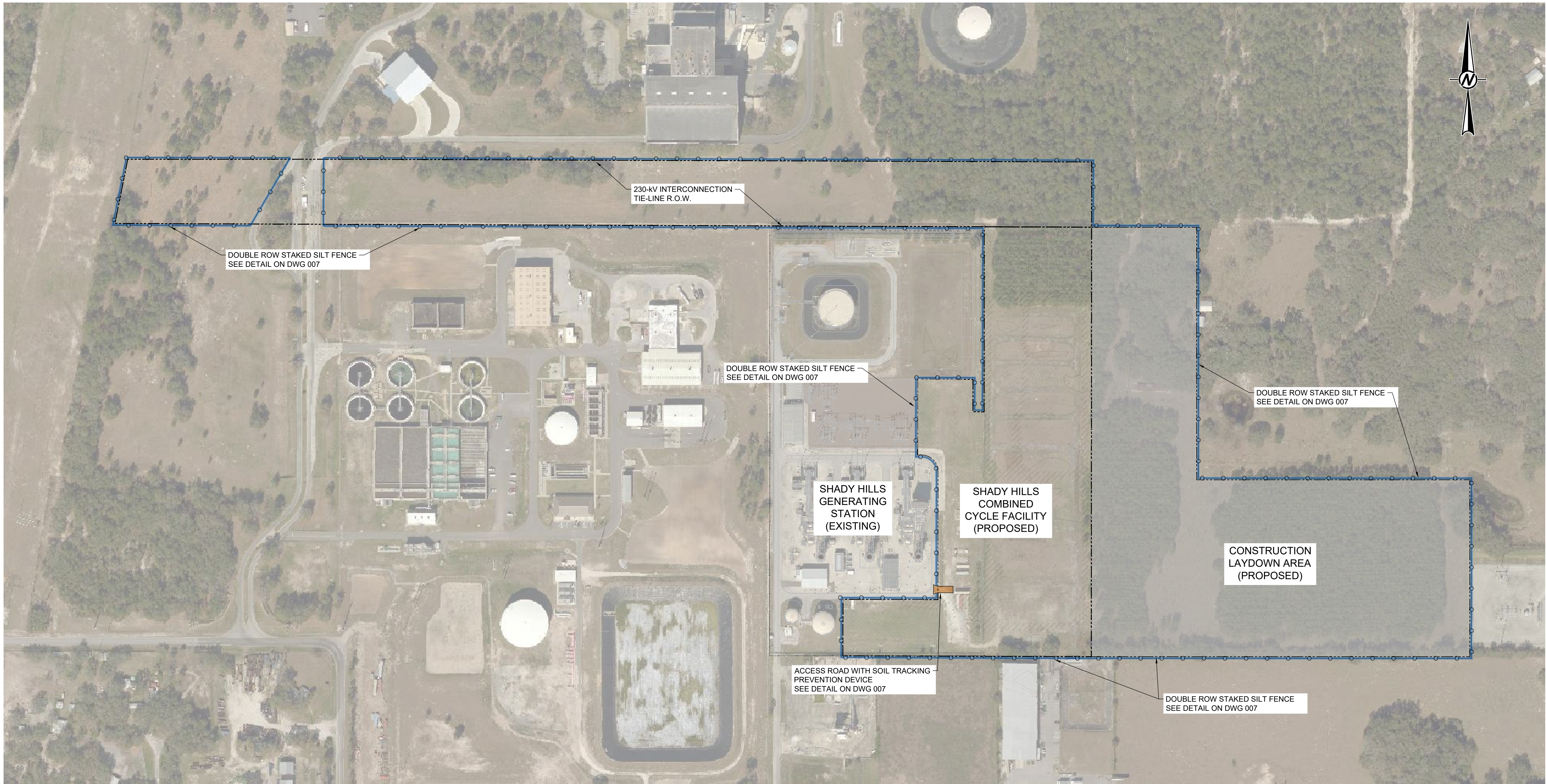
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SITE CERTIFICATION APPLICATION
SHADY HILLS COMBINED CYCLE FACILITY
PASCO COUNTY, FLORIDA

TITLE
SECTIONS AND DETAILS

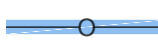
PROJECT NO. 17-79520
CONTROL
REV. 005 of 008
DWG 005

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NOTE(S)

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SHADY HILLS COMBINED CYCLE FACILITY
PASCO COUNTY, FLORIDA

TITLE
STORMWATER POLLUTION PREVENTION PLAN

PROJECT NO.
17-790520

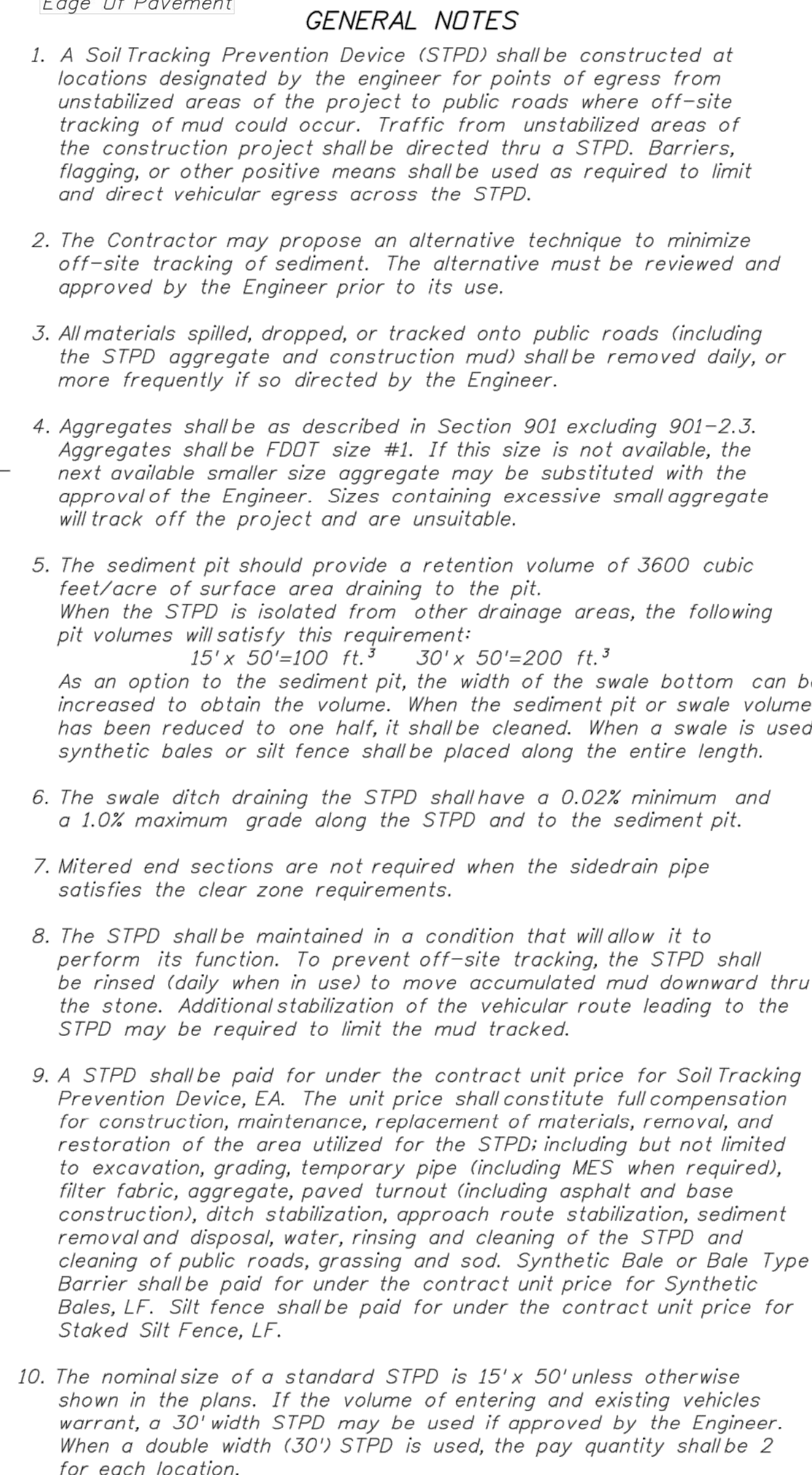
CONTROL

REV. 006 of 008
A

DWG
006

A	YYYY-MM-DD	DESCRIPTION	XXX	XXX	XXX	XXX
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED	APPROVED

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM A3/D



A	YYYY-MM-DD	DESCRIPTION	XXX	XXX	XXX	XXX
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED	APPROVED

PROJECT NO.	CONTROL	REV.	007 of 008	DWG
17-790520		A		007

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NOTE(S)

GENERAL NOTES:

- SEDIMENT BARRIERS SHALL BE PLACED PRIOR TO ANY WORK ON SITE. SEDIMENT BARRIER SHALL BE ALIGNED AS SHOWN ON THE STORMWATER POLLUTION PREVENTION PLAN DRAWINGS.
- SEDIMENT BARRIERS SHALL BE INSPECTED AFTER EACH RAINFALL AND AT LEAST DAILY DURING PROLONGED RAINFALL.
- DAMAGED BALES/FABRIC, UNDERCUTTING OF BARRIER AND/OR EROSION SHALL BE REPAIRED PROMPTLY AND BEFORE ANY SUBSEQUENT RAINFALL.
- BARRIERS SHALL REMAIN IN PLACE THROUGHOUT CONSTRUCTION AND SHALL BE REMOVED ONLY AFTER CONTRIBUTING UPLAND AREAS HAVE BEEN STABILIZED.
- CONTRACTOR SHALL COMPLY WITH ALL TERMS AND CONDITIONS OF THE U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA), NATIONAL DISCHARGE ELIMINATION SYSTEM (NPDES) PERMIT, IN PARTICULAR, SEDIMENT AND EROSION CONTROLS AND STORM WATER MANAGEMENT MEASURES SHALL BE STRICTLY FOLLOWED.
- THE CONTRACTOR SHALL BE RESPONSIBLE FOR THIS PLAN FOR THE DURATION OF THE PROJECT. ONCE THE PROJECT HAS BEEN COMPLETED, THE CONTRACTOR SHALL REMOVE ALL TEMPORARY STORM WATER MANAGEMENT MEASURES AND SHALL DISPOSE THEM ACCORDING TO CODE.

EROSION AND SEDIMENT CONTROLS:

- CONTRACTOR SHALL INSTALL A SILT FENCE (SEDIMENT BARRIER) AT LOCATIONS SHOWN ON THE ADJACENT PLAN PRIOR TO ANY CLEARING, DEMOLITION, FILLING OR GRADING OF ANY PORTIONS OF THE SITE.
- ALL PROPOSED INLET/OUTFALLS, ONCE INSTALLED, SHALL BE PROTECTED FROM EROSION AND SEDIMENT RUNOFF PER FDOT INDEX NO. 102.
- GRAVEL ACCESS ROAD (STPD) SHALL BE CONSTRUCTED AT THE ENTRANCE TO THE PROJECT SITE PER FDOT INDEX NO. 106 TO MINIMIZE THE EFFECTS OF TRUCK TRAFFIC AND SEDIMENTATION TRACKING BOTH ON AND OFF OF THE SITE.
- DISTURBED PORTIONS OF THE SITE WHERE CONSTRUCTION ACTIVITY TEMPORARILY CEASES FOR AT LEAST 21 DAYS SHALL BE STABILIZED WITH SOD NO LATER THAN 14 DAYS FROM THE LAST CONSTRUCTION ACTIVITY IN THAT AREA.
- DISTURBED PORTIONS OF THE SITE WHERE CONSTRUCTION ACTIVITIES PERMANENTLY CEASE SHALL BE STABILIZED WITH SOD NO LATER THAN 14 DAYS AFTER THE LAST CONSTRUCTION ACTIVITY.

OTHER CONTROLS:

- CONTRACTOR SHALL COMPLY WITH SPILL PREVENTION, CONTROL AND COUNTER MEASURES (SPCC) REQUIREMENTS PURSUANT TO EPA RULES AND REGULATIONS.
- ALL CONSTRUCTION WASTE MATERIALS SHALL BE COLLECTED AND STORED IN A SECURED METAL DUMPSTER RENTED FROM A LOCAL WASTE MANAGEMENT COMPANY. THE DUMPSTER WILL MEET ALL LOCAL AND STATE SOLID WASTE MANAGEMENT REGULATIONS. ALL PERSONNEL SHALL BE INSTRUCTED REGARDING THE CORRECT PROCEDURE FOR WASTE DISPOSAL. NOTICES STATING THAT THESE PRACTICES SHALL BE POSTED IN THE OFFICE TRAILER AND THE CONTRACTOR SHALL BE RESPONSIBLE FOR SEEING THAT THESE PROCEDURES ARE FOLLOWED.
- ALL SANITARY WASTE SHALL BE COLLECTED FROM PORTABLE UNITS A MINIMUM OF ONCE PER WEEK BY A LICENSED SANITARY WASTE MANAGEMENT CONTRACTOR, AS REQUIRED BY LOCAL REGULATIONS.
- DUMP TRUCKS IMPORTING FILL MATERIALS TO THE SITE SHALL COVER THEIR LOADS WITH A TARPAULIN TO AVOID UNNECESSARY GENERATION OF DUST.
- ALL HAZARDOUS WASTE MATERIALS SHALL BE DISPOSED OF AS PER LOCAL AND/OR STATE REGULATIONS OR AS RECOMMENDED BY THE MANUFACTURER. SITE PERSONNEL SHALL BE INSTRUCTED IN THESE PRACTICES AND THE CONTRACTOR SHALL BE RESPONSIBLE FOR SEEING THAT THESE PROCEDURES ARE FOLLOWED.
- THE EXISTING DRIVEWAY SHALL SERVE AS THE CONSTRUCTION ENTRANCE AND A SOIL TRACKING PREVENTION DEVICE PER FDOT INDEX NO. 106 SHALL BE PROVIDED TO HELP REDUCE VEHICLE TRACKING OF THESE SEDIMENTS. THE PAVED STREET ADJACENT TO THE SITE ENTRANCE SHALL BE SWEEPED DAILY TO REMOVE ANY EXCESS OF MUD, DIRT, OR ROCK TRACKED FROM SITE.

MAINTENANCE AND INSPECTION PROCEDURES:

- THE GENERAL CONTRACTOR'S SITE SUPERINTENDENT SHALL SELECT THREE INDIVIDUALS WHO WILL BE

RESPONSIBLE FOR THE INSPECTIONS, MAINTENANCE AND REPAIR ACTIVITIES, AND FILLING OUT THE INSPECTION MAINTENANCE REPORT. PERSONNEL SELECTED FOR THE INSPECTION AND MAINTENANCE RESPONSIBILITIES SHALL RECEIVE PROPER TRAINING IN ALL THE INSPECTION AND MAINTENANCE PRACTICES NECESSARY FOR KEEPING EROSION AND SEDIMENT CONTROLS USED ON SITE IN GOOD WORKING ORDER.

- ALL EROSION AND SEDIMENTATION CONTROLS SHALL BE INSPECTED 7 DAYS OR WITHIN 24 HOURS OF A STORM OF 0.5 INCH OR MORE IN DEPTH. ALL CONTROLS MUST BE IN GOOD OPERATING CONDITION UNTIL THE AREA THEY PROTECT HAS BEEN COMPLETELY STABILIZED AND THE CONSTRUCTION IS COMPLETE.
- BUILT UP SEDIMENT WILL BE REMOVED FROM THE SILT FENCE WHEN IT HAS REACHED ONE THIRD OF THE HEIGHT OF THE FENCE.
- SILT FENCE SHALL BE INSPECTED FOR DEPTH OF SEDIMENT, TEARS, IF FABRIC IS SECURELY ATTACHED TO THE FENCE POSTS, AND IF FENCE POSTS ARE FIRMLY IN THE GROUND.
- SODDED AREAS SHALL BE INSPECTED FOR BARE SPOTS, WASHOUTS, AND HEALTHY GROWTH.
- THE INSPECTOR SHALL RECORD ANY DAMAGES OR DEFICIENCIES IN THE CONTROL MEASURES ON AN INSPECTION REPORT FORM PROVIDED FOR THIS PURPOSE. THESE REPORTS SHALL DOCUMENT THE INSPECTION OF ALL POLLUTION PREVENTION MEASURES AND SHALL ALSO BE USED TO REQUEST MAINTENANCE AND REPAIR. THE CONTRACTOR SHALL CORRECT DAMAGE OR PROVIDE MAINTENANCE AS RECOMMENDED BY REPORT AS SOON AS PRACTICAL BUT IN NO CASE LATER THAN 7 DAYS AFTER THE INSPECTION. FAILURE TO DO SO SHALL BE REPORTED TO THE FDEP.

GENERAL SEQUENCE OF MAJOR ACTIVITIES:

- INSTALL SILT FENCE AT LOCATIONS SHOWN ON ADJACENT PLAN.
- COMMENCE SITE CONSTRUCTION ACTIVITIES.
- AS PROPOSED INLETS ARE CONSTRUCTED, INSTALL SILT FENCE AROUND EACH.
- INSTALL SOD IN AREAS WHERE CONSTRUCTION TEMPORARILY CEASES FOR AT LEAST 21 DAYS, NO LATER THAN 14 DAYS AFTER THE LAST CONSTRUCTION ACTIVITIES IN THAT AREA.
- INSTALL SOD IN AREAS WHERE CONSTRUCTION ACTIVITIES HAVE BEEN COMPLETED NO LATER THAN 4 DAYS AFTER THE LAST CONSTRUCTION ACTIVITIES.
- REMOVED ACCUMULATED SEDIMENT.
- REMOVE TEMPORARY POLLUTION PREVENTION MEASURES AFTER ALL CONSTRUCTION ON SITE HAS BEEN COMPLETED AND DISPOSE MATERIALS ACCORDING TO APPLICABLE F.D.E.P. REGULATIONS AND/OR LOCAL GOVERNMENTAL CODES, ETC.

CONTRACTOR'S CERTIFICATION:

I CERTIFY UNDER PENALTY OF LAW THAT I UNDERSTAND, AND SHALL COMPLY WITH THE TERMS AND CONDITIONS OF THE STATE OF FLORIDA GENERIC PERMIT FOR STORM WATER DISCHARGE FROM LARGE AND SMALL CONSTRUCTION ACTIVITIES AND THIS STORM WATER POLLUTION PREVENTION PLAN PREPARED THEREUNDER

NAME, TITLE, COMPANY NAME, ADDRESS, PHONE NUMBER, AND DATE

PREPARER'S CERTIFICATION:

I CERTIFY UNDER PENALTY OF LAW THAT THIS DOCUMENT AND ALL ATTACHMENTS WERE PREPARED UNDER MY DIRECTION OR SUPERVISION IN ACCORDANCE WITH A SYSTEM DESIGNED TO ASSURE THAT QUALIFIED PERSONNEL PROPERLY GATHERED AND EVALUATED THE INFORMATION SUBMITTED. BASED ON MY INQUIRY OF THE PERSON OR PERSONS WHO MANAGE THE SYSTEM, OR THOSE PERSONS DIRECTLY RESPONSIBLE FOR GATHERING THE INFORMATION, THE INFORMATION SUBMITTED IS TO THE BEST OF MY KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE INFORMATION, INCLUDING THE POSSIBILITY OF FINE AND IMPRISONMENT FOR KNOWING VIOLATIONS.

NAME (OPERATOR AND/OR RESPONSIBLE AUTHORITY)

PERMIT DRAWINGS

		SEAL			
A	YYYY-MM-DD	DESCRIPTION	XXX	XXX	XXX
REV.	YYYY-MM-DD	DESCRIPTION	DESIGNED	PREPARED	REVIEWED
			APPROVED		



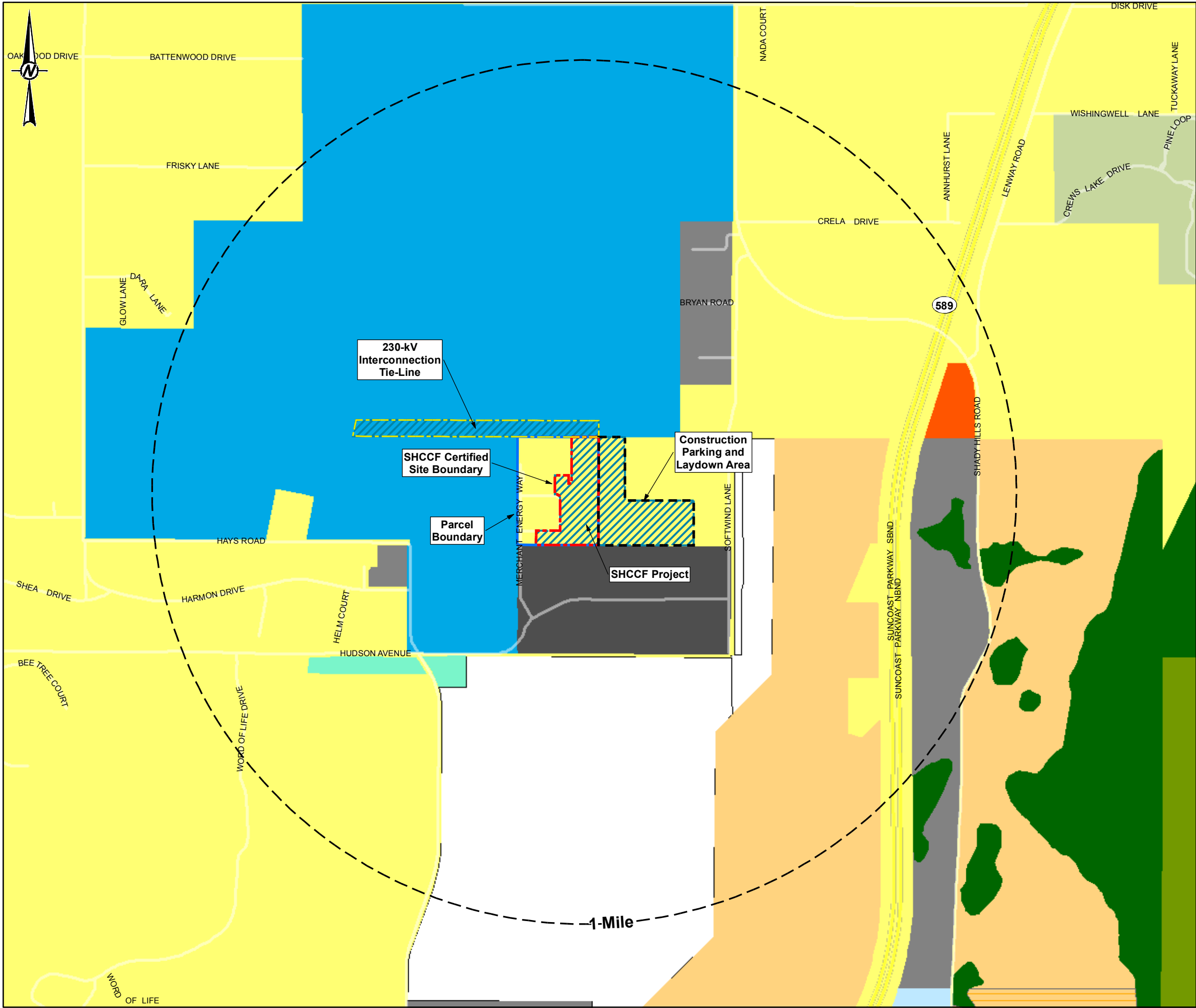
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TAMPA, FL 33609
USA
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PROJECT		TITLE	
SITE CERTIFICATION APPLICATION		STORMWATER POLLUTION PREVENTION PLAN NOTES	
SHADY HILLS COMBINED CYCLE FACILITY			
PASCO COUNTY, FLORIDA			
PROJECT NO.	CONTROL	REV.	DWG
17-790520		A	008

1 in IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM A3 AND D

APPENDIX 10.5
LAND USE PLAN DESCRIPTIONS

APPENDIX 10.5.1
FUTURE LAND USE MAP



LEGEND

- SHCCF Project
- SHCCF Certified Site Boundary
- 230-kV Interconnection Tie-Line
- Construction Parking and Laydown Area
- Parcel Boundary

Future Land Use - Pasco County

- AG/R - AGRICULTURAL/RURAL-.2 du/ga*
- COM - COMMERCIAL
- CON - CONSERVATION LANDS
- EC - EMPLOYMENT CENTER
- IH - INDUSTRIAL-HEAVY
- IL - INDUSTRIAL-LIGHT
- OFF - OFFICE
- P/SP - MAJOR PUBLIC/SEMI-PUBLIC
- R/OS - MAJOR RECREATION/OPEN SPACE
- RES-1 - RESIDENTIAL-1 du/ga*
- RES-12 - RESIDENTIAL-12 du/ga*
- RES-3 - RESIDENTIAL-3 du/ga*
- ROR - RETAIL/OFFICE/RESIDENTIAL

NOTE(S)
* du / ga = DWELLING UNITS PER GROSS ACRE

REFERENCE(S)
FUTURE LAND USE, PASCO COUNTY, 2017

CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE
FUTURE LAND USE
WITHIN THE VICINITY OF SHCCF

CONSULTANT	YYYY-MM-DD	2018-02-13
	DESIGNED	NRL
	PREPARED	NRL
	REVIEWED	KB
	APPROVED	RAZ

PROJECT NO. 1779520	CONTROL H039	REV. 0	FIGURE 10.5-1
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APPENDIX 10.5.2
PASCO COUNTY
2025 COMPREHENSIVE PLAN
FUTURE LAND USE ELEMENT

2025 COMPREHENSIVE PLAN PASCO COUNTY, FLORIDA

OBJECTIVE FLU 1.4: PROTECTION OF RESIDENTIAL NEIGHBORHOODS

To ensure the long-term viability of residential neighborhoods by regulating future development and redevelopment to create compatibility with surrounding land uses.

POLICY FLU 1.4.1: SUBDIVISION STANDARDS

Pasco County shall maintain the viability of established and future residential neighborhoods by continuing to enforce Land Development Code provisions relating to:

- a. Development within flood-prone areas;
- b. Building setbacks and heights;
- c. Roadway buffers;
- d. Landscaping;
- e. Tree preservation;
- f. Signage;
- g. On-site traffic circulation and parking;
- h. Drainage and stormwater management;
- i. Fences, walls, and entrance features;
- j. Maintenance and use of common open-space areas and neighborhood parks through homeowners' associations or Community Development Districts, if approved by the Board of County Commissioners. This requirement does not apply to conservation subdivision open space, which can be held in private ownership;
- k. Arterial and collector, design and spacing standards;
- l. Traffic impact studies and mitigation;
- m. Access management;
- n. Concurrency; and
- o. Corridor Preservation.

2025 COMPREHENSIVE PLAN PASCO COUNTY, FLORIDA

POLICY FLU 1.4.2: RESIDENTIAL COMPATIBILITY: STANDARDS FOR REVIEW OF REZONING REQUESTS

Pasco County shall amend the Land Development Code by December 2008 to include specific review criteria for rezoning actions to address residential compatibility. These criteria shall specifically include a method for 1) determining compatibility between residential zoning classifications and 2) additional buffer or transition requirements that are necessary to develop or achieve compatibility where necessary. The purpose of such criteria is to provide standard and predictable measures for establishing and creating compatibility through landscapes, buffers, natural areas, or transitional development practices in an effort to lessen impacts and integrate development along the edges of properties where different zoning districts are present, screen undesirable views, preserve tree canopy and vegetation, and facilitate the safe movement of traffic and pedestrians in vehicle-use areas.

POLICY FLU 1.4.3: TRANSITIONAL LAND USES

Pasco County shall evaluate Comprehensive Plan amendments to ensure that transitional land uses are provided as a buffer between residential and nonresidential land use designations, between varying densities of residential land use designations, and in managing redevelopment of areas no longer appropriate as viable residential areas. Exhibit 2-2, Appropriate Transitional Land Uses, is to be used as a guideline in evaluating appropriate transitional uses, except for properties located within the Northeast Pasco County Rural Area Plan or the Rural Transition Area.

POLICY FLU 1.4.4: RESIDENTIAL COMPATIBILITY: BUFFER STANDARDS BETWEEN RESIDENTIAL AND NONRESIDENTIAL LAND USES

The County shall protect residential uses from the sensory intrusions of adjacent uses and shall amend the Land Development Code by December 2008 to include methods of protecting neighborhoods from the sensory intrusions of adjacent nonresidential uses that may affect the long-term viability of those neighborhoods. Sensory intrusions include unwanted light, noise, physical access, odor, and other sources of disruptions. These criteria shall include provisions that:

- Prevent uses that generate obnoxious, sensory intrusion from being developed or expanded in certain areas;
- Eliminate or reduce the sensory intrusions of proposed development or redevelopment; and
- Intercept or prevent the sensory intrusion from affecting the adjacent use.

POLICY FLU 1.4.5: ROADWAY COMPATIBILITY

Pasco County shall encourage the viability of future residential neighborhoods adjacent to collector and arterial roadways by:

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- a. Continuing to require additional setbacks and buffers for residential development and redevelopment adjacent to future major collector and arterial roadways to minimize the impacts of future roadway improvements;
- b. Enforcing existing Land Development Code provisions or creating, when necessary, additional standards providing when and where pedestrian, bicycle, and vehicular linkages between abutting residential areas are required to provide convenient access to recreation, schools, libraries, and shopping.

POLICY FLU 1.4.6: UTILITY COMPATIBILITY

Protect the integrity of existing neighborhoods from the effects, if any, of bulk, electric-transmission corridors; natural-gas pipeline easements; and similar facilities by prohibiting, to the maximum extent of the County's jurisdictional authority, their location through or immediately adjacent to existing neighborhoods.

POLICY FLU 1.4.7: LIMITS ON INDUSTRIAL USES ADJACENT TO RESIDENTIAL AREAS

Pasco County shall ensure that future Comprehensive Plan amendments to industrial uses adjacent to residential land use categories and/or residentially zoned properties shall be light industrial uses only to protect residences from the adverse impacts of smoke, fumes, vibrations, light, glare, odors, and noise. Access which is limited only to local residential roadways shall be considered unacceptable for heavy industrial uses, notwithstanding applicable access management requirements.

POLICY FLU 1.4.8: PERSONAL WIRELESS SERVICE FACILITIES

To the extent allowed by law, Pasco County shall continue to enforce Land Development Code regulations regarding the location, siting, and design of personal wireless service facilities to promote the said facilities' compatibility with surrounding land uses and protect the attractiveness, health, safety, general welfare, and property values of the community.

POLICY FLU 1.4.9: COMMUNICATION TOWERS

To the extent allowed by law, Pasco County shall consider regulating the location, siting, and design of communication towers other than personal wireless service facilities and may adopt land development regulations to promote the said communication towers' compatibility with surrounding land uses and protect the attractiveness, health, safety, general welfare, and property values of the community.

2025 COMPREHENSIVE PLAN PASCO COUNTY, FLORIDA

OBJECTIVE FLU 3.1: COORDINATION OF DEVELOPMENT ACTIVITIES

Continue to coordinate with the cities and other agencies to facilitate consistent facility and land use plans, provide cost-effective services, maintain compatible land uses, and ensure coordination of resource planning and management plans. The County shall coordinate with responsible local, regional, and State authorities and private utility companies, as appropriate, in the establishment of Level of Service standards for public facilities. Upon adoption of the County and adjacent governments' Comprehensive Plans, the County shall initiate further coordination efforts, if necessary, to ensure consistency with adopted Level of Service standards.

POLICY FLU 3.1.1: INTERLOCAL AGREEMENT WITH DADE CITY

Pasco County shall continue to implement the Interlocal Agreement between Pasco County and the City of Dade City adopted by the Board of County Commissioners on May 10, 2005, and as may be amended from time to time.

POLICY FLU 3.1.2: JOINT PLANNING AGREEMENTS

Pasco County shall pursue Joint Planning Agreements with each of the cities in Pasco County to address, at a minimum, future annexations, provision of services and facilities, and land use compatibility.

POLICY FLU 3.1.3: REGIONAL COORDINATION

Pasco County shall continue to coordinate with the Florida Department of Environmental Protection, the Southwest Florida Water Management District, the Tampa Bay Water Authority, and the Tampa Bay Regional Planning Council in the development and implementation of resource-management plans through the following:

- a. Forwarding development proposals to State agencies and the Tampa Bay Water Authority for review and comment on projects located adjacent to land owned by the State or by the Tampa Bay Water Authority prior to final action; and
- b. Continuing to coordinate with the Southwest Florida Water Management District in identifying high-priority acquisition areas.

OBJECTIVE FLU 3.2: COORDINATION OF UTILITY SERVICES

To ensure the availability of suitable land for utility facilities to support new development.

POLICY FLU 3.2.1: COUNTY UTILITIES

Pasco County Utilities; i.e., water, sewer, and solid waste, needed to support growth in the unincorporated area should, when possible, be protected from encroachment of incompatible uses through one (1) or more of the following actions:

2025 COMPREHENSIVE PLAN PASCO COUNTY, FLORIDA

- a. County purchase of adjacent property for buffer purposes;
- b. Adequate buffers on development plans; or
- c. Amendment of adjacent land uses to a compatible Future Land Use designation.

POLICY FLU 3.2.2: PRIVATE UTILITIES

Private electric public utilities needed to support growth may be permitted in all land use designations subject to the following:

- a. All electrical service to new subdivisions shall be installed underground;
- b. All feeder service shall be installed underground where the County has designated this requirement in the Land Development Code. The County shall evaluate and revise, if necessary, the County's Right-of-Way Utilization Permit form and Land Development Code provisions relating to utility-permitting activities and consider the viability and possibility of receiving compensation for the use of County right-of-way by utility companies; and
- c. All new power plants and transmission lines shall be subject to applicable State and Federal siting regulations and shall be consistent with the Goals, Objectives, and Policies of this Comprehensive Plan:
 - a. The County shall encourage electrical transmission lines and related facility sitings to be located outside sensitive-lands areas and areas of special concern.
 - b. The County shall encourage service providers to use existing corridors for expansions whenever possible and otherwise consistent with the provisions of this Comprehensive Plan.
 - c. The County shall encourage repowering (increasing voltage) of existing transmission lines whenever possible to reduce the need for securing additional right-of-way corridors and the resulting impacts to the public relating thereto.
- d. All new substations installed after the adoption of these amendments adjacent to single-family neighborhoods or visible from a public roadway shall be reviewed by the County and required to provide landscaping and buffering to minimize visual and noise impacts.

POLICY FLU 3.2.3: WATER SUPPLY FACILITIES PLAN

Pasco County shall coordinate Future Land Use planning efforts with the 10-Year Water Supply Facilities Work Plan, accounting for the following:

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- (b) Site design elements and guidelines - general building placement, orientation, and character.
 - (c) Establishment of appropriate intensities and densities for the specific areas of the classification after consideration of compatibility of surrounding and planned uses, adequacy of existing and programmed concurrency facilities, and consistency with the Comprehensive Plan.
 - (d) Public realm category, street types, building lot types, and park and open space types.
 - (e) General assignment of land uses to lots, blocks, or block groups.
 - (f) Consideration of an integrated and consistent development pattern for the twenty (20)-acre area surrounded by, but not included in, the New Port Corners FLU Classification, located east of Little Road and south of DeCubellis Road.
 - (g) Identification of infrastructure needs and an implementation plan for the provision of that infrastructure.
 - (h) Preservation of transportation capacity for the office and industrial entitlements consistent with Policy FLU 1.8.10.
 - (i) Urban landscape standards.
 - (j) A general parking plan.
 - (k) Demonstration of consistency with the guiding principles contained within the FLU Classification.
- (5) Any parcel of land within New Port Corners seeking to increase entitlements shall be consistent with the New Port Corners Development District Overlay and/or the Conceptual Master Plan.

P/SP (PUBLIC/SEMIPUBLIC)

Intent: To recognize major existing and programmed public/semipublic facilities, primarily those facilities associated with public or private utilities and those associated with frequent or regular use by the residents of the community; e.g., educational and health care facilities. Also, to recognize major public facilities which are also not permitted within the residential land use classifications of this Comprehensive Plan. Additional uses under this classification may be recognized by amendments to the Future Land Use Map, if appropriate.

Where used to designate easements for electrical transmission lines and any other utility easements, the P/SP (Public/Semipublic) Classification functions as an overlay classification.

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General Range of Potential Uses:

Sanitary landfills; permanent water and wastewater treatment/storage/facilities; solid waste management facilities including, but not limited to, major maintenance facilities, solid waste transfer stations, major utility-transmission corridors.

Universities, colleges, or groupings of other major educational facilities, hospitals, and complementary or accessory health-care uses not designated under other Future Land Use classifications; community centers.

Major public/semipublic facilities not permitted in other Future Land Use classifications must be located in the P/SP (Public/Semipublic) classification.

Density Restrictions: Dwelling Units/Developable Residential Acre

N/A

Maximum Nonresidential Intensity: Floor Area Ratio

3.0

For uses where Floor Area Ratio is not an appropriate measure of intensity, a minimum of twenty (20) percent of the land area must be kept as open space.

AT (MAJOR ATTRACTORS)

Note: This Future Land Use Classification is INACTIVE. Existing properties assigned AT (Major Attractors) as of the effective date of this Comprehensive Plan may continue to rely upon this definition for future development proposals. No new Future Land Use Map amendment requests may be considered for or granted as an AT (Major Attractors) Future Land Use Classification.

Intent: To recognize major existing and programmed facilities, both public and private, which by virtue of their highly specialized function; e.g., theme or amusement parks, or their infrequent (but significant) impact on public facilities, are inconsistent with the intent and definition of other Future Land Use classifications.

General Range of Potential Uses:

Mass-seating facilities, civic centers, convention facilities, and other major attractors.

Density Restrictions: Dwelling Units/Gross Acre

N/A

Maximum Nonresidential Intensity: Floor Area Ratio

N/A

APPENDIX 10.6

EXISTING STATE PERMITS

**Southwest Florida Water Management District
Water Use Permit No. 20-012052.005**

**SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT
WATER USE
GENERAL
PERMIT NO. 20 012052.005**

EXPIRATION DATE: September 09, 2020

PERMIT ISSUE DATE: October 01, 2010

The Permittee is responsible for submitting an application to renew this permit no sooner than one year prior to the expiration date, and no later than the end of the last business day before the expiration date, whether or not the Permittee receives prior notification by mail. Failure to submit a renewal application prior to the expiration date and continuing to withdraw water after the expiration date is a violation of Chapter 373, Florida Statutes, and Chapter 40D-2, Florida Administrative Code, and may result in a monetary penalty and/or loss of the right to use the water. Issuance of a renewal of this permit is contingent upon District approval.

TYPE OF APPLICATION: Letter Modification

GRANTED TO: SHADY HILLS POWER COMPANY, LLC
14240 MERCHANT ENERGY WAY
SPRING HILL, FL 34610

PROJECT NAME: Shady Hills Power Company, LLC

WATER USE CAUTION AREA: Northern Tampa Bay

COUNTY: Pasco

TOTAL QUANTITIES AUTHORIZED UNDER THIS PERMIT (in gpd)

ANNUAL AVERAGE	153,870 gpd
PEAK MONTH ¹	476,000 gpd

¹ Peak Month: Average daily use during the highest water use month.

This is a renewal with modification of an existing industrial/commercial water use permit for back-up electrical generation when demand is high. The Average Annual quantity decreases slightly from 164,000 gallons per day (gpd) to 153,870 gpd and the Peak Month quantity decreases slightly from 479,000 gpd to 476,000 gpd. The decrease in quantities is due to a more accurate assessment of demand. Quantities are based on information submitted by the applicant. Special Conditions include those that require the Permittee to continue to record and report monthly meter readings from the major withdrawal points; install a flow meter on a reclaimed water; and modify the permit to reflect incorporation of any new alternative sources of water. Impacts will be minor since the quantities are not high and the power plant will only be used occasionally.

WATER USE TABLE (in gallons per day)

<u>USE</u>	<u>ANNUAL AVERAGE</u>	<u>PEAK MONTH</u>
INDUSTRIAL AND COMMERCIAL	153,870	476,000

IRRIGATION ALLOCATION RATE TABLE

<u>CROP/USE TYPE</u>	<u>IRRIGATED ACRES</u>	<u>IRRIGATION METHOD</u>	<u>STANDARD IRRIGATION RATE</u>
Lawn & Landscape Irrigation	4.00	Low Volume Spray	2.90"/yr.
Cleaning And Maintenance			
Emission Control			
Evaporative Cooling			
Fire Protection/Testing			
Personal Sanitary Use			

WITHDRAWAL POINT QUANTITY TABLE

Water use from these withdrawal points are restricted to the quantities given below:

<u>I.D. NO. PERMITTEE/ DISTRICT</u>	<u>DIAM (IN.)</u>	<u>DEPTH TTL./CSD.FT. (feet bls)</u>	<u>USE</u>	<u>AVERAGE (gpd)</u>	<u>PEAK MONTH (gpd)</u>
SH-1 / 1	16	600 / 230	I	153,210	475,310
SH-2 / 2	16	600 / 230	I	152,300	466,300
Standby					
SH-3 / 3	5	250 / 140	PS	660	690
reclaim meter / 5	2	N/A / N/A	IR	8,100	24,000

I = Industrial-Commercial

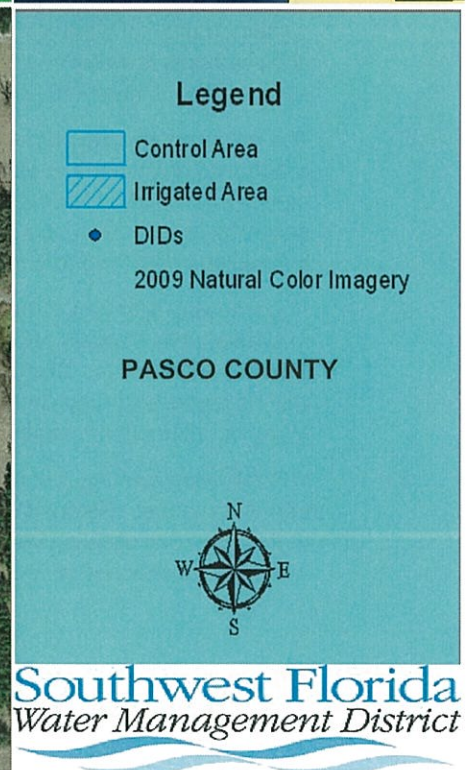
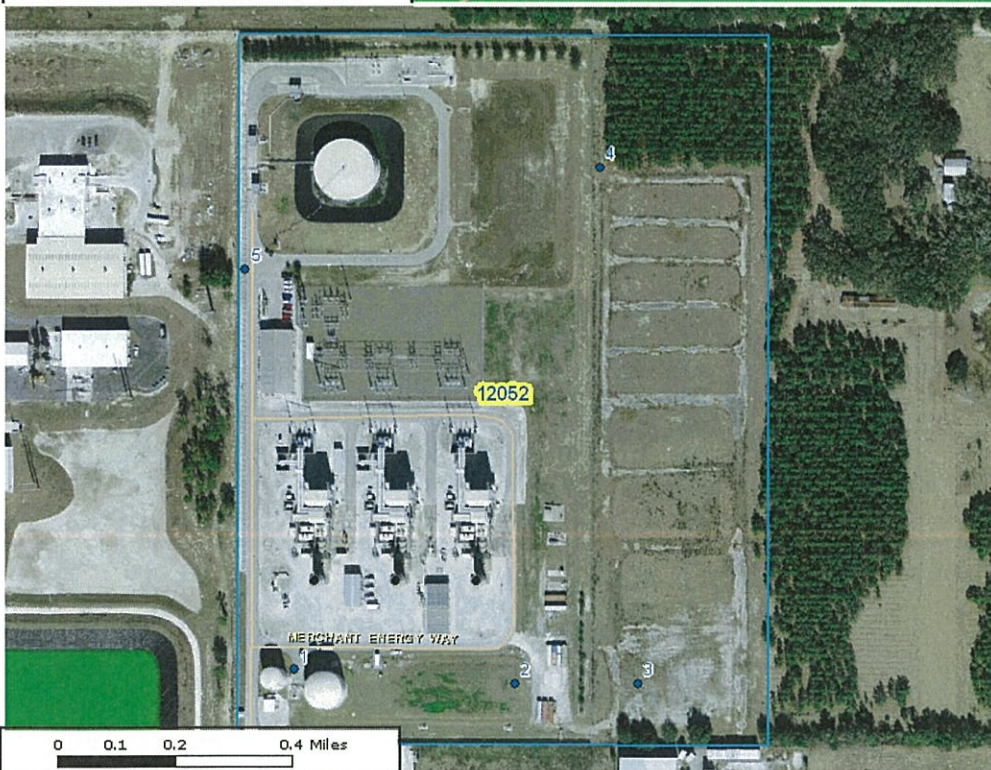
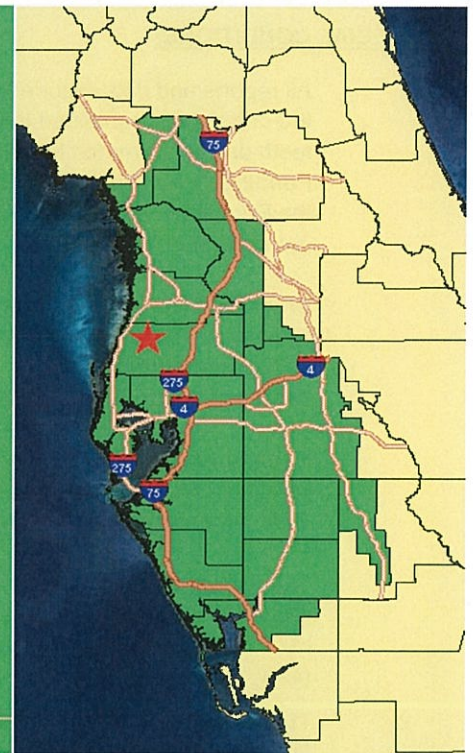
IR = Irrigation

PS = Personal Sanitary

WITHDRAWAL POINT LOCATION TABLE

<u>DISTRICT I.D. NO</u>	<u>LATITUDE/LONGITUDE</u>
1	28° 21' 54.01"/82° 33' 32.54"
2	28° 21' 53.76"/82° 33' 27.90"
3	28° 21' 53.76"/82° 33' 25.33"
5	28° 22' 01.35"/82° 33' 33.59"

Location Map
SHADY HILLS POWER COMPANY, LLC
WUP No. 20 012052.005



STANDARD CONDITIONS:

The Permittee shall comply with the Standard Conditions attached hereto, incorporated herein by reference as Exhibit A and made a part hereof.

SPECIAL CONDITIONS:

1. All reports and data required by condition(s) of the permit shall be submitted to the District according to the due date(s) contained in the specific condition. If the report or data is received on or before the tenth day of the month following data collection, it shall be deemed as a timely submittal. The Permittee may use the District's website to submit data, plans or reports online. To set up an account, the Permittee can address the request to permitdata@watermatters.org. All mailed reports and data are to be sent to:

Brooksville Regulation Department
Southwest Florida Water Management District
2379 Broad Street
Brooksville, Florida 34604-6899

Submission of plans and reports: Unless submitted online or otherwise indicated in the special condition, the original and two copies of each plan and report, such as conservation plans, environmental analyses, aquifer test results, per capita annual reports, etc. are required.

Submission of data: Unless otherwise indicated in the special condition, an original (no copies) is required for data submittals such as crop report forms, meter readings and/or pumpage, rainfall, water level evapotranspiration, or water quality data.
(499)

2. The Permittee shall immediately implement the District-approved water conservation plan dated April 1, 2010 that was submitted in support of the application for this permit. Annual progress reports on the implementation of water conservation practices indicated as proposed in the plan as well as achievements in water savings that have been realized from each water conservation practice shall be submitted by January 10 of each year. (449)
3. The following existing standby withdrawal facilities (those that provide back-up water for another withdrawal point in the event the other withdrawal point becomes unusable) shall continue to be metered: District ID No(s). 2, Permittee ID No(s). SH-2. Meter reading and reporting, as well as meter accuracy checks every five years shall be in accordance with instructions in Exhibit B, Metering Instructions, attached to and made part of this permit.(722)
4. The following withdrawal facilities shall continue to be maintained and operated with existing, non-resettable, totalizing flow meter(s) or other measuring device(s) as approved by the Regulation Department Director: District ID No(s). 1, Permittee ID No(s). SH-1. Meter reading and reporting, as well as meter accuracy checks every five years shall be in accordance with instructions in Exhibit B, Metering Instructions, attached to and made part of this permit.(719)
5. The following existing, but previously un-metered reclaimed water inflow lines shall be metered upon permit issuance: District ID No(s). 5, Permittee ID No(s) 5. Meter reading and reporting, as well as meter accuracy checks every five years shall be in accordance with instructions in Exhibit B, Metering Instructions, attached to and made part of this permit.(702)

40D-2
Exhibit A

WATER USE PERMIT STANDARD CONDITIONS

1. The Permittee shall provide access to an authorized District representative to enter the property at any reasonable time to inspect the facility and make environmental or hydrologic assessments. The Permittee shall either accompany District staff onto the property or make provision for access onto the property.
2. When necessary to analyze impacts to the water resource or existing users, the District shall require the Permittee to install flow metering or other measuring devices to record withdrawal quantities and submit the data to the District.
3. The District shall collect water samples from any withdrawal point listed in the permit or shall require the permittee to submit water samples when the District determines there is a potential for adverse impacts to water quality.
4. A District identification tag shall be prominently displayed at each withdrawal point that is required by the District to be metered or for which withdrawal quantities are required to be reported to the District, by permanently affixing the tag to the withdrawal facility.
5. The Permittee shall mitigate to the satisfaction of the District any adverse impact to environmental features or off-site land uses as a result of withdrawals. When adverse impacts occur or are imminent, the District shall require the Permittee to mitigate the impacts. Adverse impacts include the following:
 - A. Significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams or other watercourses; or
 - B. Sinkholes or subsidence caused by reduction in water levels;
 - C. Damage to crops and other vegetation causing financial harm to the owner; and
 - D. Damage to the habitat of endangered or threatened species.
6. The Permittee shall mitigate, to the satisfaction of the District, any adverse impact to existing legal uses caused by withdrawals. When adverse impacts occur or are imminent, the District shall require the Permittee to mitigate the impacts. Adverse impacts include the following:
 - A. A reduction in water levels which impairs the ability of a well to produce water;
 - B. Significant reduction in levels or flows in water bodies such as lakes, impoundments, wetlands, springs, streams or other watercourses; or
 - C. Significant inducement of natural or manmade contaminants into a water supply or into a usable portion of an aquifer or water body.
7. Notwithstanding the provisions of Rule 40D-1.6105, F.A.C., persons who wish to continue the water use permitted herein and who have acquired ownership or legal control of permitted water withdrawal facilities or the land on which the facilities are located must apply to transfer the permit to themselves within 45 days of acquiring ownership or legal control of the water withdrawal facilities or the land.
8. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if the Permittee fails to comply with all of the provisions of Chapter 373, Florida Statutes (F.S.), Chapter 40D, Florida Administrative Code (F.A.C.), or the conditions set forth herein, the Governing Board shall revoke this permit in accordance with Rule 40D-2.341, F.A.C., following notice and hearing.
9. Issuance of this permit does not exempt the Permittee from any other District permitting requirements.
10. The Permittee shall cease or reduce surface water withdrawal as directed by the District if water levels in lakes fall below the applicable minimum water level established in Chapter 40D-8, F.A.C., or rates of flow in streams fall below the minimum levels established in Chapter 40D-8, F.A.C.
11. The Permittee shall cease or reduce withdrawal as directed by the District if water levels in aquifers fall below the minimum levels established by the Governing Board.

12. The Permittee shall not deviate from any of the terms or conditions of this permit without written approval by the District.
13. The Permittee shall practice water conservation to increase the efficiency of transport, application, and use, as well as to decrease waste and to minimize runoff from the property. At such time as the Governing Board adopts specific conservation requirements for the Permittee's water use classification, this permit shall be subject to those requirements upon notice and after a reasonable period for compliance.
14. The District may establish special regulations for Water-Use Caution Areas. At such time as the Governing Board adopts such provisions, this permit shall be subject to them upon notice and after a reasonable period for compliance.
15. In the event the District declares that a Water Shortage exists pursuant to Chapter 40D-21, F.A.C., the District shall alter, modify, or declare inactive all or parts of this permit as necessary to address the water shortage.
16. This permit is issued based on information provided by the Permittee demonstrating that the use of water is reasonable and beneficial, consistent with the public interest, and will not interfere with any existing legal use of water. If, during the term of the permit, it is determined by the District that the use is not reasonable and beneficial, in the public interest, or does impact an existing legal use of water, the Governing Board shall modify this permit or shall revoke this permit following notice and hearing.
17. All permits issued pursuant to these Rules are contingent upon continued ownership or legal control of all property on which pumps, wells, diversions or other water withdrawal facilities are located.

APPENDIX 10.7
MONITORING PROGRAMS

APPENDIX 10.7.1
CULTURAL RESOURCES

Golder Associates Inc.

5405 West Cypress Street, Suite 215
Tampa, FL 33607
Telephone (813) 287-1717
Fax (813) 287-1716



March 23, 2000

Ms. Laura Kammerer
Historic Preservation Supervisor
Florida Department of State
Division of Historical Resources
R.A. Gray Building
500 South Bronough Street
Tallahassee, FL 32399-0250

Re: Request for Review of Historical or Archaeological Sites
Shady Hills Project Site (Section 25, Township 24 South, Range 17 East)
Pasco County

Dear Ms. Kammerer:

Golder Associates, Inc. has been retained to assist in the environmental permitting of a proposed power plant project in west Pasco County. The project is located in unincorporated Pasco County in Section 25, Township 24 South, Range 17 East. A project location map is attached.

Would you please provide, at your earliest convenience, the following information concerning this property:

- The location of any known cultural resources within, or immediately adjacent to, the delineated site boundary,
- The location of any areas within the site or site vicinity that are likely to contain cultural resources, and
- A determination as to whether a pedestrian survey with subsurface testing is required.

Should you need additional information or have any questions, please call me or Betty Robinson at (813) 287-1717.

Sincerely,

GOLDER ASSOCIATES INC.

A handwritten signature in dark ink, appearing to read "Richard A. Zwolak", is written over the printed name.

Richard A. Zwolak, AICP
Associate, Director of Environmental Planning

Attachment

cc: Betty Robinson, Golder Associates

993-9525/ips shady hills/shpo review request letter.doc

DIVISIONS OF FLORIDA DEPARTMENT OF STATE

Office of the Secretary
Office of International Relations
Division of Elections
Division of Corporations
Division of Cultural Affairs
Division of Historical Resources
Division of Library and Information Services
Division of Licensing
Division of Administrative Services



FLORIDA DEPARTMENT OF STATE

Katherine Harris

Secretary of State

DIVISION OF HISTORICAL RESOURCES

MEMBER OF THE FLORIDA CABINET

State Board of Education
Trustees of the Internal Improvement Trust Fund
Administration Commission
Florida Land and Water Adjudicatory Commission
Siting Board
Division of Bond Finance
Department of Revenue
Department of Law Enforcement
Department of Highway Safety and Motor Vehicles
Department of Veterans' Affairs

Mr. Richard A. Zwolak
Golder Associates Inc.
5405 West Cypress Street, Suite 215
Tampa, FL 33607

May 2, 2000

RE: DHR Project File No. 2000-02289
Cultural Resource Assessment Request
IPS/EL Pasco Energy, Shady Hills Proposed Power Plant Project
Pasco County, Florida

Dear Mr. Zwolak:

In accordance with the procedures contained in 36 C.F.R., Part 800 ("Protection of Historic Properties"), we have reviewed the referenced project(s) for possible impact to historic properties listed, or eligible for listing, in the *National Register of Historic Places*.

A review of the Florida Site File indicates that no significant archaeological or historical sites are recorded for or likely to be present within the project area of potential effects. Furthermore, because of the project location and/or nature it is unlikely that historic properties will be affected.

If you have any questions concerning our comments, please contact Ms. Robin Jackson, Historic Sites Specialist at (850) 487-7278. Your interest in protecting Florida's historic properties is appreciated.

Sincerely,

Janet Snyder Matthews, Ph.D., Director
Division of Historical Resources
State Historic Preservation Officer

JSM/Trj

R.A. Gray Building • 500 South Bronough Street • Tallahassee, Florida 32399-0250 • <http://www.flheritage.com>

☐ Director's Office (850) 488-1480 • FAX: 488-3355	☐ Archaeological Research (850) 487-2299 • FAX: 414-2207	☐ Historic Preservation (850) 487-2333 • FAX: 922-0496	☐ Historical Museums (850) 488-1484 • FAX: 921-2503
☐ Historic Pensacola Preservation Board (850) 595-5985 • FAX: 595-5989	☐ Palm Beach Regional Office (561) 279-1475 • FAX: 279-1476	☐ St. Augustine Regional Office (904) 825-5045 • FAX: 825-5044	☐ Tampa Regional Office (813) 272-3843 • FAX: 272-2340



FLORIDA DEPARTMENT of STATE

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

Mr. Davis Larocca
Golder Associates Inc.
5100 W. Lemon Street, Suite 208
Tampa, Florida 33609

September 20, 2012

RE: DHR Project File No.: 2012-4217 / Received by DHR: August 20, 2012
U. S. Environmental Protection Agency
Shady Hills Generating Station
Expansion Project – Addition of Generators and Switchyard
14240 Merchant Energy Way, Shady Hills, Pasco County

Dear Mr. Larocca:

Our office reviewed the referenced project for possible impact to historic properties listed, or eligible for listing, in the National Register of Historic Places. The review was conducted in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended and 36 CFR Part 800: Protection of Historic Properties.

A review of the Florida Master Site File data indicated that no significant archaeological or historical resources are recorded within the project area. However, due to environmental conditions consistent with those found at other archaeological sites in Pasco County and lack of professional archaeological or historical investigation, there is some potential for undiscovered archaeological sites to occur. Therefore, it is the opinion of this agency that, in addition to the standard permitting condition, this permit, if issued, should include the following special condition regarding unexpected discoveries during ground disturbing activities on the property:

If prehistoric or historic artifacts, such as pottery or ceramics, stone tools or metal implements, or any other physical remains that could be associated with Native American cultures, or early colonial or American settlement are encountered at any time within the project site area, the permitted project should cease all activities involving subsurface disturbance in the immediate vicinity of such discoveries. The permittee, or other designee, should contact the Florida Department of State, Division of Historical Resources, Review and Compliance Section at 850.245.6333 or 800.847.7278, as well as the appropriate permitting agency office. Project activities should not resume without verbal and/or written authorization from the Division of Historical Resources. In the event that unmarked human remains are encountered during permitted activities, all work shall stop immediately and the proper authorities notified in accordance with Section 872.05, *Florida Statutes*.

DIVISION OF HISTORICAL RESOURCES
R. A. Gray Building • 500 South Bronough Street • Tallahassee, Florida 32399-0250
Telephone: 850.245.6300 • www.flheritage.com
Commemorating 500 years of Florida history www.fla500.com



Mr. Larocca
DHR Project File No.: 2012-4217
September 20, 2012
Page 2

For any questions concerning our comments, please contact Robin Jackson, Historic Sites Specialist, by phone at 850.245.6333, or by electronic mail at robin.jackson@dos.myflorida.com. We appreciate your continued interest in protecting Florida's historic properties.

Sincerely,

A handwritten signature in blue ink, appearing to read "RFB", with a stylized flourish to the right.

Robert F. Bendus, Director
Division of Historical Resources
and State Historic Preservation Officer



February 8, 2018

1779520

Mr. Timothy A. Parsons, Ph.D., RPA
Division Director, State Historical Preservation Officer
Florida Division of Historical Resources &
State Historic Preservation Office
R.A. Gray Building
500 South Bronough Street
Tallahassee, FL 32399-0250

**RE: CULTURAL RESOURCES DESKTOP ANALYSIS FOR SHADY HILLS, COMBINED CYCLE
FACILITY PROJECT – 230-KV INTERCONNECTION TIE-LINE, SHADY HILLS, PASCO
COUNTY, FLORIDA**

Dear Dr. Parsons:

On behalf of Shady Hills Energy Center, LLC, Golder Associates Inc. (Golder) is submitting to the Florida Division of Historical Resources (FDHR) the following cultural resources desktop analysis. Golder respectfully requests FDHR's review of the provided information and concurrence that no additional cultural resources investigation is required to demonstrate compliance with Section 106 of the National Historic Preservation Act (NHPA).

INTRODUCTION

Shady Hills Energy Center, LLC, owns and operates the Shady Hills Generating Station located at 14240 Merchant Energy Way, Shady Hills, Pasco County, Florida, within Section 25, Township 24S, and Range 17E. The property is approximately 30 acres (Figures 1 and 2). Shady Hills is proposing to expand the Shady Hills Generating Station (Project). The Project will be located adjacent to the existing generators. The Project will require a new 230-kV interconnection tie-line, less than 1 mile in length, extending from the project location, westward, to connect to the existing Duke Energy high voltage transmission grid.

The area where the additional generators and switchyard will be located was previously used as a construction laydown area during the construction of the existing Shady Hills Generating Station. This area was previously reviewed by FDHR with a concurrence letter (DHR Project File No.: 2012-4217) received September 20, 2012. At this time, we are requesting review for concurrence involving the 230-kV interconnection tie-line, which is located on Figure 2.

PREVIOUSLY CONDUCTED SURVEYS AND PREVIOUSLY RECORDED CULTURAL RESOURCES WITHIN THE PROJECT AREA

This interconnection tie-line area is owned by Pasco County and had been previously evaluated for cultural resources and archaeological significance (letter dated July 30, 1986) during the planning and construction of the Pasco County's Shady Hills Wastewater Treatment Facility, located to the west, and the Pasco County Solid Waste Resource Recovery Facility, located to the north, of the project location. According to the desktop analysis that has been conducted, there were no significant archaeological and/or historical sites recorded or considered likely to be present within this area.

Based on the characteristics of the Project and the previous disturbances by the utility improvements performed by Pasco County, Golder anticipates the interconnection tie-line will have no impacts on cultural

1779520 shady hills_cultural resources ltr.docx

Golder Associates Inc.
5100 W. Lemon Street, Suite 208
Tampa, FL 33609 USA
Tel: (813) 287-1717 Fax: (813) 287-1716 www.golder.com

Golder Associates: Operations in Africa, Asia, Australasia, Europe, North America and South America

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resources, and therefore recommends that the FDHR confirms in writing that no further investigation of cultural resources is required for the proposed Project.

If you have any questions, please feel free to contact the undersigned at (813) 287-1717.

Sincerely,

GOLDER ASSOCIATES INC.

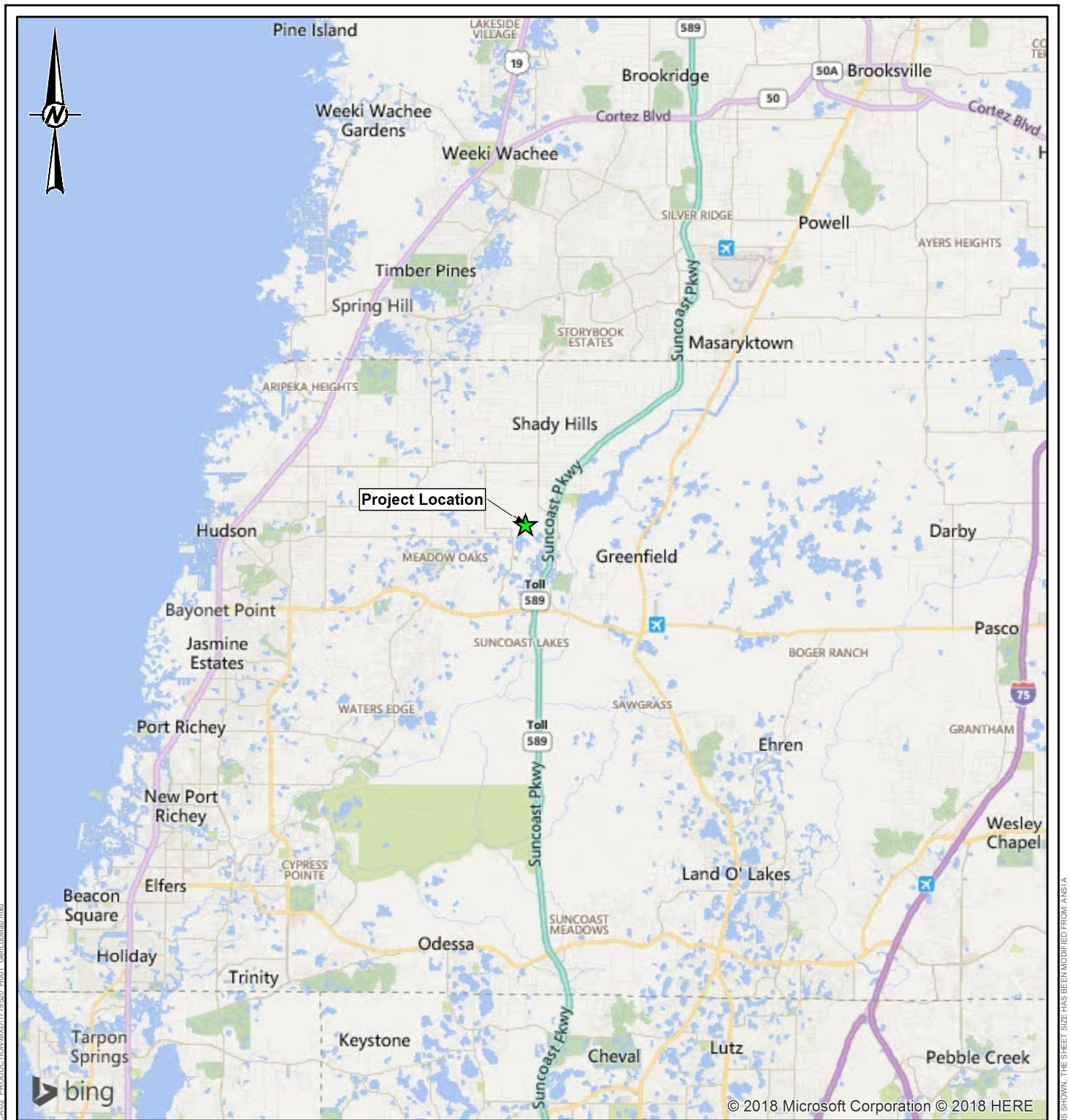


Kerri J. Burns
Senior Environmental/Land Use Planner



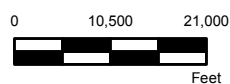
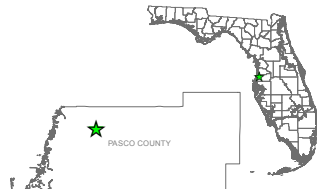
Manitia Moultrie
Project Manager/ Principal

Attachments: Figure 1 – General Location Map
Figure 2 – Project Overview



LEGEND

Project Location



REFERENCE(S)
PROJECT LOCATION, GOLDER ASSOCIATES INC., 2017

CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE
GENERAL LOCATION MAP

CONSULTANT



YYYY-MM-DD	2018-02-01
DESIGNED	NRL
PREPARED	NRL
REVIEWED	RAZ
APPROVED	MM

PROJECT NO.
1779520

CONTROL
H001

REV.
0

FIGURE
1

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

G:\PROJECTS\GE_Energy_Systems\Shady_Hills\03_Permits\Support\HIL_SCAN02_PRODUCTION\MXD\1779520_14003_SitePlan.mxd



- LEGEND
- SHCCF Certified Site Boundary
 - Interconnection tie-line
 - Parcel Boundary



REFERENCE(S)
INTERCONNECTION TIE-LINE, GOLDER ASSOCIATES INC., 2017
SHCCF CERTIFIED SITE BOUNDARY, POWER ENGINEERS, 2018
PARCEL BOUNDARY, PASCO COUNTY, 2017

CLIENT
SHADY HILLS ENERGY CENTER, LLC

PROJECT
SHADY HILLS COMBINED CYCLE FACILITY (SHCCF)

TITLE
SHCCF PROJECT OVERVIEW

CONSULTANT	YYYY-MM-DD	2018-02-08
	DESIGNED	NRL
	PREPARED	NRL
	REVIEWED	RAZ
	APPROVED	MM

PROJECT NO.
1779520

CONTROL
H037

REV.
0

FIGURE
2

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

1 in

Appendix 10.7.2

TRAFFIC INFORMATION

TECHNICAL MEMORANDUM

DATE February 15, 2018

Project No. 1779520

TO Manitia Moulrie
Golder Associates Inc.

CC Richard Zwolak

FROM Kerri J Burns

EMAIL kburns@golder.com

SHADY HILLS COMBINED CYCLE FACILITY, PASCO COUNTY, TRANSPORTATION REVIEW MEMO

Introduction

The Shady Hills Combined Cycle Facility (SHCCF) Project involves the construction and operation of a new, state-of-the-art natural gas-fired 573 megawatt (MW) (winter), combined-cycle generating facility and associated facilities to be constructed, owned and operated by Shady Hills Energy Center, LLC (SHEC). The SHCCF Site is proposed for approximately 14 acres on portions of the 30-acre parcel of land owned by Shady Hills Power Company, L.L.C. for power generation in Shady Hills, Pasco County, Florida.

Land Use and Access

The existing area is currently vacant and undeveloped and was previously used as temporary laydown and equipment storage for the Shady Hills Generating Station (SHGS). The SHCCF Site is located east of the Pasco County's Shady Hills Wastewater Treatment Facility (SHWWTF) and south of the Pasco County Solid Waste Resource Recovery Facility. The SHCCF Site is accessible from Merchant Energy Way, which is located off of Hudson Avenue and Hays Road, north of State Road (SR) 52.

SHGS has been in operation since 2002 and currently contains three combustion turbines in simple-cycle configuration that are permitted and capable of producing a total of 510 MW (nominal). The existing SHGS operates 24/7 and has 11 employees and receives between 1 and 3 truck deliveries daily.

Roadway System

Federal and State roadways providing access to the area include Interstate 75, SR589 (Suncoast Parkway), and SR52. Primary access to the SHCCF Site will SR52, Hays Road, Hudson Avenue, and Merchant Energy Way.

The section of SR52 where it intersects with Hays Road is a paved six-lane divided arterials roadway (three lanes in each direction) with dedicated turn lanes. SR52 (between SR589 and Hays Road) has an Annual Average Daily

Trips volume of 29,000 vehicles. With a Level-Of-Service (LOS) Standard of D, SR52 roadway functions at LOS B. SR52 is also a designated truck route that services local industrial plants, warehouses, and material suppliers in the area. The posted speed limit is 50 miles per hour.

Hays Road is a paved two-lane collector roadway, operated and maintained by Pasco County. Hays Road has an Annual Average Daily Trips volume of 6,900 vehicles. With a LOS Standard of D, Hays Road functions at an existing LOS B. The posted speed limit is 45 miles per hour. Truck traffic makes up approximately 11% percent of the total traffic on SR52 and Hays Road.

Hudson Avenue is a paved two-lane collector roadway, operated and maintained by Pasco County. Hudson Avenue has an Annual Average Daily Trips of 3,542 vehicles. With a LOS Standard of D, Hudson Avenue functions at an existing LOS B. The posted speed limit is 35 miles per hour.

At the SR52/Hays Road intersection there is a traffic light with dedicated turn lanes. On SR52 there are dedicated turn lanes for SR52 westbound traffic making right-turns north onto Hays Road and for eastbound traffic making left-turns onto Hays Road. On Hays Road, there is a dedicated turn lane for southbound traffic turning both eastbound and westbound onto SR52. At the intersection of Hudson Avenue and Hays Road there are dedicated turn lanes from Hays Road onto Hudson Avenue north-bound and south-bound.

The identified traffic counts were obtained from the Florida Department of Transportation (FDOT), for SR52, and from Pasco County for Hays Road and Hudson Avenue. The traffic counts are also contained in the attached Appendix.

Trip Generation

Proposed Operation

The operations workforce for SHCCF is anticipated to be 25, a slight increase from the current operating staff of 11 employees, with truck deliveries remaining between 1 - 3 daily to the existing SHGS and the proposed SHCCF. All employees will utilize the existing secured access point to enter into the secured area. Extensions to the internal driveways will provide access to SHCCF parking and site infrastructure.

The projected operation workforce and delivery requirements will be less than 50 daily trips, which is below the Pasco County Land Development Code identified threshold and therefore could qualify for exemption from transportation analysis requirements (Section 901.12(c)).

Proposed Construction

Construction on the SHCCF Project is anticipated to commence in mid-2019, with peak construction anticipated in late-2020. The construction workforce is expected to average approximately 230 workers per day during the period between 2019 and 2021. At peak construction (during 4th quarter 2020), approximately 370 workers per day are anticipated. For purposes of this review, the worst-case scenario was evaluated, which is 370 inbound vehicles during the AM peak hour and 370 peak hour exiting vehicles during the PM peak hour. During construction an estimate 13 trucks will arrive daily with supplies to the SHCCF Site, this is an increase from the existing 1-3 truck delivers daily for the existing plant operations.

The anticipated trip distribution for the SHCCF Project has been based on the existing traffic patterns and review of the surrounding road system located in the immediate vicinity. Changes to the existing roadway system is not required to meet SHCCF Project needs.

Primary construction access will be from the SR52, which is identified as a major truck route. In addition, the following access options onto the SHCCF Site are being considered:

- Directly to the SHCCF Site from Hays Road (north of SR52), to Hudson Avenue, to Merchant Energy Way;
- Directly to land located within the North Suncoast Industrial Park and then internal activity between the parcels;
- From Hudson Avenue to Softwind Lane, then accessing the SHCCF Site through the existing Seminole parcel; or
- From Hudson Avenue, establish a new driveway adjacent to and north of the Withlacoochee Electric Cooperative parcel.

Inside the SHEC property, the existing driveways are both paved and unpaved. In the areas that are unpaved, these areas will be reinforced with gravel and dust suppression measures that will be in place for the duration of the construction period. Fugitive dust generation from traffic and/or excavation/construction activities on-site or in the laydown area will be minimized through paving, seeding or placing of sod in areas not utilized for construction, water sprinkling, or other dust-suppressant techniques.

Summary

The existing roadway system anticipated for use by both construction and operation traffic (SR52, Hays Road, and Hudson Avenue) are currently perform at a LOS B, with available carrying capacity that exceeds the construction-related traffic associated with the SHCCF Project. With these roadways performing above their design standard and maintaining available carrying capacity the additional operation traffic is not anticipated to degrade the roadway

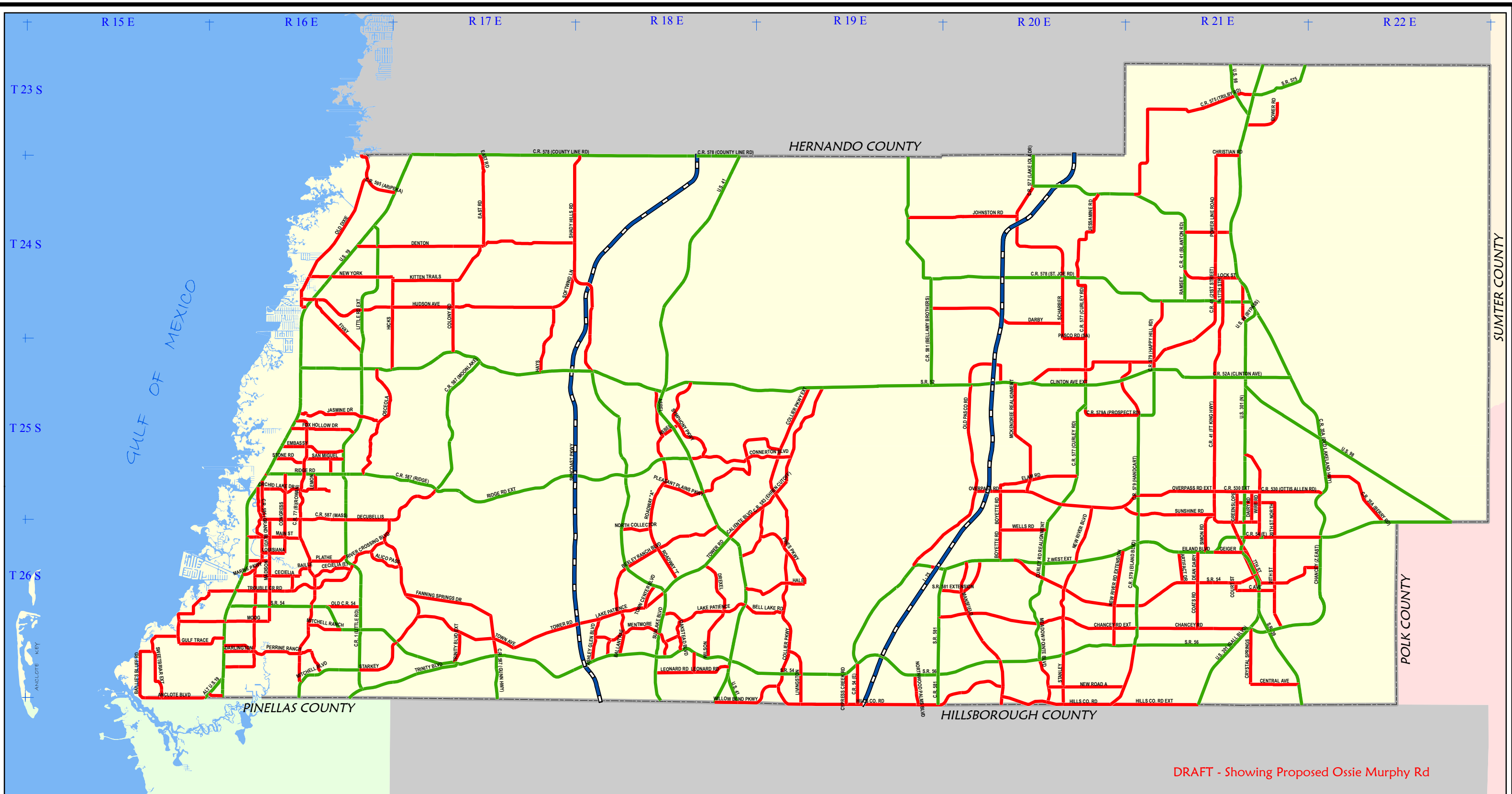
conditions from the existing LOS B. The additional traffic, associated with construction-related activities, will be temporary and will not degrade or result in a long-term impact on the existing roadways.

Traffic management practices will be implemented during the peak AM and PM hours to facility ingress and egress. The contractor for the SHCCF Project will develop a traffic management plan to include the appropriate traffic management, as necessary, to maintain acceptable level of service for access.

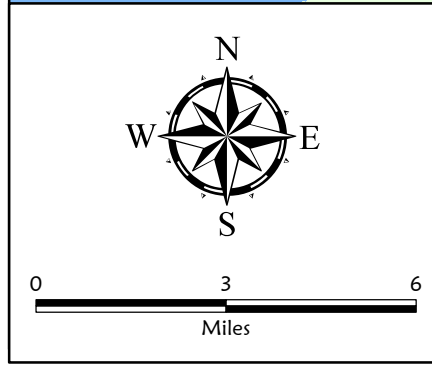
KJB / RAZ / MM

1779520 shady hills_traffic memo.docx

ATTACHMENT 1
TRAFFIC COUNT INFORMATION



DRAFT - Showing Proposed Ossie Murphy Rd



FUNCTIONAL CLASSIFICATION

- COLLECTOR
- ARTERIAL
- INTERSTATE

REVISIONS :			
DATE	ORDINANCE #	DATE	ORDINANCE #
11/25/08	// 08-49		

THE COMPREHENSIVE PLAN
OF UNINCORPORATED
PASCO COUNTY



MAP 7 - 24
FUTURE ROADWAY FUNCTIONAL
CLASSIFICATION (2035)
Pasco GIS | 02.28.13 | JMH

Traffic Counts displayed in Latest Available Annual Average Daily Traffic (AADT) Volumes
March 17, 2015

DataID	ROADWAY	LOCATION	FDOT/County Count	YEAR	AADT
920.3	DENTON AVE	WEST OF EAST RD.	County	2013	4,224
920.1	DENTON AVE (SEE 920)*****	LITTLE RD EXT TO COYOTE	County	2013	3,829
149065	DENTON AVENUE	E OF US 19	FDOT	2013	3,300
940.0	EAST RD	SOUTH OF COUNTY LINE RD	County	2011	1,914
149066	EAST RD	N OF DENTON AVE	FDOT	2013	2,000
149067	EAST RD	S OF COUNTY LINE ROAD/CR 578	FDOT	2013	2,200
146044	EAST RD SOUTH OF COUNTY LINE RD (HPMS)		FDOT	2010	2,100
146030	EHREN CUTOFF SOUTH OF SR 52 (HPMS)	SOUTH OF SR 52 (HPMS)	FDOT	2013	2,050
146018	EILAND BLVD EAST OF CR 579 HANDCART RD (HPMS)	EAST OF CR 579/HANDCART RD (HPMS)	FDOT	2013	13,600
960.0	EMBASSY BLVD	WEST OF HAVERFORD LN	County	2007	10,234
950.1	EMBASSY BLVD	WEST OF LIDO LN	County	2010	11,022
149034	EMBASSY BLVD	E OF US 19	FDOT	2013	11,200
950.0	EMBASSY BLVD (SEE 950.1)*****	US 19 TO SHOPPERS WAY	County	2010	9,023
970.1	FIVAY RD	SOUTH OF LIBRARY RD	County	2011	7,457
149013	FIVAY RD	W OF LITTLE RD/CR1	FDOT	2013	10,000
970.0	FIVAY RD (SEE 970.1)*****	LITTLE RD TO CLAYTON AVE	County	2010	7,653
149072	FORT KING RD	S OF US 301	FDOT	2013	5,600
149073	FORT KING RD	N OF CR 52A/CLINTON AVE	FDOT	2013	6,300
146052	FORT KING RD NORTH OF BOZEMAN RD (HPMS)	NORTH OF BOZEMAN RD (HPMS)	FDOT	2013	3,400
146051	FORT KING RD NORTH OF EILAND BLVD (CR 54) (HPMS)		FDOT	2013	9,400
140019	FORT KING ROAD	NORTH OF CR 41	FDOT	2013	25,000
146045	FORT KING ROAD WEST OF FORT KING RD (HPMS)	WEST OF FORT KING RD (HPMS)	FDOT	2013	6,700
149035	FOX HOLLOW DRIVE	W OF US 19	FDOT	2013	2,000
980.0	FRAZEE HILL RD*****	WEST OF 21ST ST	County	2011	938
149036	GALEN WILSON BLVD	N OF RIDGE RD	FDOT	2013	4,100
995.0	GALEN WILSON BLVD	NORTH OF RIDGE RD	County	2013	3,842
990.0	GEIGER RD	WEST OF MASSEY RD	County	2010	4,142
149032	GEIGER RD	W OF US 301	FDOT	2013	6,500
146013	GEIGER RD EAST OF EILAND BLVD (HPMS)	EAST OF EILAND BLVD (HPMS)	FDOT	2013	3,100
149094	GRAND BLVD	S OF SR 54	FDOT	2013	12,500
149095	GRAND BLVD	N OF MASSACHUSETTS	FDOT	2013	2,500
146031	GRAND BLVD NORTH OF MAIN ST (HPMS)	NORTH OF MAIN ST (HPMS)	FDOT	2013	1,500
146032	GRAND BLVD SOUTH OF MAIN STREET (HPMS)	SOUTH OF MAIN STREET (HPMS)	FDOT	2013	6,600
3160.1	GREENSLOPE*****	CITY LIMITS TO CR 530 EXT	County	2009	7,017
3160.0	GREENSLOPE*****	S OF PRETTY POND	County	2012	4,379
2110.0	GULF DR	WEST OF ASPEN ST	County	2009	5,374
2120.0	GULF DR	EAST OF MAPLE ST	County	2009	3,252
149037	GULF DR	E OF US 19	FDOT	2013	6,000
110.0	GULF TRACE BLVD (CABBAGE)	WEST OF US 19	County	2013	2,716
1000.0	HALE RD	EAST OF DEERHOUND DR	County	2009	5,219
149038	HALE RD	E OF US 41	FDOT	2013	4,300
149070	HALE RD	E OF COLLIER PKWY	FDOT	2013	3,500
1035.0	HAYS RD	SOUTH OF HUDSON AVE	County	2011	5,305
1035.1	HAYS RD (SEE 1035)*****	MABLE RIDGE E/W TO HUDSON AVE	County	2011	1,468
149039	HAYS ROAD	N OF SR 52	FDOT	2013	6,900
1040.0	HICKS RD	NORTH OF SR 52	County	2009	6,158

County Road Information

Road Number: 003821.02 **Road Name:** HAYS RD
Section: 1 **Township:** 25 **Range:** 17

Road Description:

HUDSON AREA FROM .91 MILES -N- OF SR 52 -N- FOR .40
MILES

Class:	Collector	Road Width:	24
Maintenance:	Pasco	Miles Paved:	0.40
Comm. District:	5	Miles UnPaved:	0.00
Right of Way:	60	Total Miles:	0.40
Lanes:	2	Speed Limit:	0
Roadway Condition:	Very Good	Shoulder Condition:	Poor

Information current as of: 02/03/2015

[Previous Road \(HAYS RD\)](#)

[Next Road \(HAYS RD\)](#)

Close Window

County Road Information

Road Number: 003821.04 **Road Name:** HAYS RD
Section: 25 **Township:** 24 **Range:** 17

Road Description:

HUDSON AREA HUDSON AV -N & W- FOR .50
MILES

Class:	Residential	Road Width:	24
Maintenance:	Pasco	Miles Paved:	0.50
Comm. District:	5	Miles UnPaved:	0.00
Right of Way:	50	Total Miles:	0.50
Lanes:	2	Speed Limit:	30
Roadway Condition:	Good	Shoulder Condition:	Good

Information current as of: 10/26/2010

[Previous Road \(HAYS RD\)](#)

[Next Road \(HAYS RD\)](#)

Close Window

County Road Information

Road Number: 003821.03 **Road Name:** HAYS RD
Section: 36 **Township:** 24 **Range:** 17

Road Description:

HUDSON AREA
MILES

HUDSON AV -S- FOR 1.02



Class:	Collector	Road Width:	24
Maintenance:	Pasco	Miles Paved:	1.02
Comm. District:	5	Miles UnPaved:	0.00
Right of Way:	50	Total Miles:	1.02
Lanes:	2	Speed Limit:	45
Roadway Condition:	Good	Shoulder Condition:	Poor

Information current as of: 02/03/2015

[Previous Road \(HAYS RD\)](#)

[Next Road \(HAYS RD\)](#)

Close Window

**Generalized Annual Average Daily Volumes for Florida's
Urbanized Areas**

TABLE 1

12/18/12

INTERRUPTED FLOW FACILITIES						UNINTERRUPTED FLOW FACILITIES					
STATE SIGNALIZED ARTERIALS						FREEWAYS					
Class I (40 mph or higher posted speed limit)						Core Urbanized					
Lanes	Median	B	C	D	E	Lanes	B	C	D	E	
2	Undivided	*	16,800	17,700	**	4	47,400	64,000	77,900	84,600	
4	Divided	*	37,900	39,800	**	6	69,900	95,200	116,600	130,600	
6	Divided	*	58,400	59,900	**	8	92,500	126,400	154,300	176,600	
8	Divided	*	78,800	80,100	**	10	115,100	159,700	194,500	222,700	
						12	162,400	216,700	256,600	268,900	
Class II (35 mph or slower posted speed limit)						Urbanized					
Lanes	Median	B	C	D	E	Lanes	B	C	D	E	
2	Undivided	*	7,300	14,800	15,600	4	45,800	61,500	74,400	79,900	
4	Divided	*	14,500	32,400	33,800	6	68,100	93,000	111,800	123,300	
6	Divided	*	23,300	50,000	50,900	8	91,500	123,500	148,700	166,800	
8	Divided	*	32,000	67,300	68,100	10	114,800	156,000	187,100	210,300	
Non-State Signalized Roadway Adjustments						Freeway Adjustments					
(Alter corresponding state volumes by the indicated percent.)						Auxiliary Lanes					
Non-State Signalized Roadways						Present in Both Directions					
						+ 20,000					
Non-State Signalized Roadways						Ramp Metering					
						+ 5%					
Median & Turn Lane Adjustments						UNINTERRUPTED FLOW HIGHWAYS					
Lanes	Median	Exclusive Left Lanes	Exclusive Right Lanes	Adjustment Factors		Lanes	Median	B	C	D	E
2	Divided	Yes	No	+5%		2	Undivided	8,600	17,000	24,200	33,300
2	Undivided	No	No	-20%		4	Divided	36,700	51,800	65,600	72,600
Multi	Undivided	Yes	No	-5%		6	Divided	55,000	77,700	98,300	108,800
Multi	Undivided	No	No	-25%							
—	—	—	Yes	+ 5%							
One-Way Facility Adjustment						Uninterrupted Flow Highway Adjustments					
Multiply the corresponding two-directional volumes in this table by 0.6						Lanes	Median	Exclusive left lanes	Adjustment factors		
						2	Divided	Yes	+5%		
						Multi	Undivided	Yes	-5%		
						Multi	Undivided	No	-25%		
BICYCLE MODE ²						¹ Values shown are presented as two-way annual average daily volumes for levels of service and are for the automobile/truck modes unless specifically stated. This table does not constitute a standard and should be used only for general planning applications. The computer models from which this table is derived should be used for more specific planning applications. The table and deriving computer models should not be used for corridor or intersection design, where more refined techniques exist. Calculations are based on planning applications of the Highway Capacity Manual and the Transit Capacity and Quality of Service Manual. ² Level of service for the bicycle and pedestrian modes in this table is based on number of motorized vehicles, not number of bicyclists or pedestrians using the facility. ³ Buses per hour shown are only for the peak hour in the single direction of the higher traffic flow. * Cannot be achieved using table input value defaults. ** Not applicable for that level of service letter grade. For the automobile mode, volumes greater than level of service D become F because intersection capacities have been reached. For the bicycle mode, the level of service letter grade (including F) is not achievable because there is no maximum vehicle volume threshold using table input value defaults.					
(Multiply motorized vehicle volumes shown below by number of directional roadway lanes to determine two-way maximum service volumes.)											
Paved Shoulder/Bicycle											
Lane Coverage	B	C	D	E							
0-49%	*	2,900	7,600	19,700							
50-84%	2,100	6,700	19,700	>19,700							
85-100%	9,300	19,700	>19,700	**							
PEDESTRIAN MODE ²						¹ Values shown are presented as two-way annual average daily volumes for levels of service and are for the automobile/truck modes unless specifically stated. This table does not constitute a standard and should be used only for general planning applications. The computer models from which this table is derived should be used for more specific planning applications. The table and deriving computer models should not be used for corridor or intersection design, where more refined techniques exist. Calculations are based on planning applications of the Highway Capacity Manual and the Transit Capacity and Quality of Service Manual. ² Level of service for the bicycle and pedestrian modes in this table is based on number of motorized vehicles, not number of bicyclists or pedestrians using the facility. ³ Buses per hour shown are only for the peak hour in the single direction of the higher traffic flow. * Cannot be achieved using table input value defaults. ** Not applicable for that level of service letter grade. For the automobile mode, volumes greater than level of service D become F because intersection capacities have been reached. For the bicycle mode, the level of service letter grade (including F) is not achievable because there is no maximum vehicle volume threshold using table input value defaults.					
(Multiply motorized vehicle volumes shown below by number of directional roadway lanes to determine two-way maximum service volumes.)											
Sidewalk Coverage											
B	C	D	E								
0-49%	*	*	2,800	9,500							
50-84%	*	1,600	8,700	15,800							
85-100%	3,800	10,700	17,400	>19,700							
BUS MODE (Scheduled Fixed Route) ³						¹ Values shown are presented as two-way annual average daily volumes for levels of service and are for the automobile/truck modes unless specifically stated. This table does not constitute a standard and should be used only for general planning applications. The computer models from which this table is derived should be used for more specific planning applications. The table and deriving computer models should not be used for corridor or intersection design, where more refined techniques exist. Calculations are based on planning applications of the Highway Capacity Manual and the Transit Capacity and Quality of Service Manual. ² Level of service for the bicycle and pedestrian modes in this table is based on number of motorized vehicles, not number of bicyclists or pedestrians using the facility. ³ Buses per hour shown are only for the peak hour in the single direction of the higher traffic flow. * Cannot be achieved using table input value defaults. ** Not applicable for that level of service letter grade. For the automobile mode, volumes greater than level of service D become F because intersection capacities have been reached. For the bicycle mode, the level of service letter grade (including F) is not achievable because there is no maximum vehicle volume threshold using table input value defaults.					
(Buses in peak hour in peak direction)											
Sidewalk Coverage											
B	C	D	E								
0-84%	> 5	≥ 4	≥ 3	≥ 2							
85-100%	> 4	≥ 3	≥ 2	≥ 1							

Source:
Florida Department of Transportation
Systems Planning Office
www.dot.state.fl.us/planning/systems/sm/los/default.shtm

TABLE 1
(continued)

Generalized Annual Average Daily Volumes for Florida's Urbanized Areas

12/18/12

INPUT VALUE ASSUMPTIONS	Uninterrupted Flow Facilities				Interrupted Flow Facilities					
					State Arterials				Class I	
	Freeways	Core Freeways	Highways		Class I		Class II		Bicycle	Pedestrian
ROADWAY CHARACTERISTICS										
Area type (u,lu)	lu	lu	u	u	u	u	u	u	u	u
Number of through lanes (both dir.)	4-10	4-12	2	4-6	2	4-8	2	4-8	4	4
Posted speed (mph)	70	65	50	50	45	50	30	30	45	45
Free flow speed (mph)	75	70	55	55	50	55	35	35	50	50
Auxiliary Lanes (n,y)	n	n								
Median (n, nr, r)			n	r	n	r	n	r	r	r
Terrain (l,r)	l	l	l	l	l	l	l	l	l	l
% no passing zone			80							
Exclusive left turn lane impact (n, y)			[n]	y	y	y	y	y	y	y
Exclusive right turn lanes (n, y)					n	n	n	n	n	n
Facility length (mi)	4	4	5	5	2	2	1.9	1.8	2	2
Number of basic segments	4	4								
TRAFFIC CHARACTERISTICS										
Planning analysis hour factor (K)	0.090	0.085	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Directional distribution factor (D)	0.547	0.547	0.550	0.550	0.550	0.560	0.565	0.560	0.565	0.565
Peak hour factor (PHF)	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Base saturation flow rate (pcphpl)			1,700	2,100	1,950	1,950	1,950	1,950	1,950	1,950
Heavy vehicle percent	4.0	4.0	2.0	2.0	1.0	1.0	1.0	1.0	2.5	2.0
Local adjustment factor	0.91	0.91	0.97	0.98						
% left turns					12	12	12	12	12	12
% right turns					12	12	12	12	12	12
CONTROL CHARACTERISTICS										
Number of signals					4	4	10	10	4	6
Arrival type (1-6)					3	3	4	4	4	4
Signal type (a, c, p)					c	c	c	c	c	c
Cycle length (C)					120	150	120	120	120	120
Effective green ratio (g/C)					0.44	0.45	0.44	0.44	0.44	0.44
MULTIMODAL CHARACTERISTICS										
Paved shoulder/bicycle lane (n, y)									n, 50%, y	n
Outside lane width (n, t, w)									t	t
Pavement condition (d, t, u)									t	
On-street parking (n, y)										
Sidewalk (n, y)										n, 50%, y
Sidewalk/roadway separation(a, t, w)										t
Sidewalk protective barrier (n, y)										n
LEVEL OF SERVICE THRESHOLDS										
Level of Service	Freeways	Highways		Arterials			Bicycle	Ped	Bus	
	Density	Two-Lane	Multilane	Class I		Class II	Score	Score	Buses/hr.	
		%ffs	Density	ats		ats				
B	≤ 17	> 83.3	≤ 17	> 31 mph		> 22 mph	≤ 2.75	≤ 2.75	≤ 6	
C	≤ 24	> 75.0	≤ 24	> 23 mph		> 17 mph	≤ 3.50	≤ 3.50	≤ 4	
D	≤ 31	> 66.7	≤ 31	> 18 mph		> 13 mph	≤ 4.25	≤ 4.25	< 3	
E	≤ 39	> 58.3	≤ 35	> 15 mph		> 10 mph	≤ 5.00	≤ 5.00	< 2	

% ffs = Percent free flow speed ats = Average travel speed

CHAPTER 900. DEVELOPMENT STANDARDS

SECTION 901. INFRASTRUCTURE STANDARDS

901.5. Transportation Impact Study

A. Intent and Purpose

The intent and purpose of the Traffic Impact Study (TIS) is to identify the potential traffic impacts of new development on the transportation system and to develop mitigation strategies to address said impacts.

B. Applicability

This section applies whenever a Traffic Impact Study (TIS) is required by this Code.

C. General

The TIS is to be signed and sealed by a Florida Registered Professional Engineer.

For Development of Regional Impact (DRI) developments and Florida Quality Developments, completing a traffic study in accordance with Chapter 380, Florida Statutes, the methodological procedures and interpretation of the Level of Service (LOS) standards provided in the definitions, as they relate to the Committed Network, Background Traffic Growth/Future Traffic, and LOS Standards sections herein shall be followed. DRIs and Florida Quality Developments shall also comply with the requirement to estimate when facilities are expected to fail, pursuant to the procedures identified in Section 901.12, Transportation Analysis, and the requirements of Section 901.4, Substandard Roadway Analysis. (Note: opt-out projects shall be subject to the LOS standards as provided in the Comprehensive Plan and shall have the ability to pay proportionate share in accordance with State law.)

To demonstrate concurrency de minimis status, the following subsections shall be applicable, in addition to other information as required by the County:

- Methodology Statement
- Definitions
- General Analysis Requirements and Software
- Impacted Roadways/Intersections
- Trip Generation
- Distribution/Assignment

- Internal Capture
- Passerby Capture
- Traffic Counts
- Background Traffic Growth

The network on which de minimis determinations are based may include the Committed Network as defined herein.

D. Methodology Statement

Prior to conducting any study, a methodology statement shall be prepared by the applicant and submitted for review and approval by the County Administrator or designee. The purpose of the methodology statement is to establish agreed-upon methodologies and assumptions prior to the start of the study and, if appropriate, to provide substantiation that the development's impacts are de minimis and further traffic study and review is not required. The following elements of the methodology, as listed below, should be specifically addressed at a minimum:

- Description of land uses, site location, build-out schedule, and phasing, including any interim uses generating traffic.
- Preliminary Site Plan
- Trip Generation
- Internal Capture
- Background Traffic Growth Procedure
- Distribution and Assignment
- De Minimis Assertion, if applicable.
- Committed Network

Unless otherwise agreed to in the methodology process, the procedures of this subsection shall be followed.

A methodology statement shall be prepared using the guidelines provided in the following paragraphs. The methodology statement shall be first reviewed by a County representative, if necessary, through a methodology meeting with the applicant's consultant. The applicant's consultant will then revise the statement based upon agreed upon methodologies. The applicant shall ensure the consultant does not prepare a traffic study without an approved methodology statement signed by the County Administrator or designee.

In some subsections, these TIS Guidelines identify optional ways to undertake elements of the analysis, and the methods to actually be applied should be agreed upon in the methodology process.

Methodology Agreements shall be valid to govern submittal of the TIS for a period of six (6) months from the date of approval. If Methodology Agreements have been reached under earlier editions of these procedures, those agreements will remain valid for a period of six (6) months after approval of the methodology. Expired Methodology Agreements must be updated to reflect the current version of the TIS Guidelines, as well as changes in the Committed Network, Background Traffic Growth/Future Traffic, and the Non-De Minimis Roadway List.

E. Impacted Roadways/Intersections

Impacted roadways and intersections that must be studied in the TIS shall include the following:

1. If a development generating less than 1,200 gross external (driveway) daily trips is determined to require a traffic study; e.g., is not de minimis under concurrency, then the study network for that development shall include the road facilities on the Non-De Minimis Roadway List causing that determination as well as any others required under the below sections. In the case that the roadway causing the requirement to undertake the traffic study is a Near-Critical Road and if development traffic consumes less than one (1) percent of the service volume, then no further analysis of that facility is required.
2. Any Major Road Network Facilities to which development traffic makes its first connection to the Major Road Network, provided the development traffic consumes one (1) percent or more of the facility service volume on any one (1) road segment of the facility. If the first connection to the Major Road Network is to a Critical Road, then the facility shall be studied even if development traffic is below one (1) percent of the service volume.
3. Major Road Facilities on which the two (2) way peak-hour project traffic consumes five (5) percent or more of the existing or committed two (2) way peak-hour-service flow rate on any included road segment.
4. The site driveway connections to public roads are considered impacted. In addition, intersections of the local/nonmajor roads with the Major Road Network segments identified in this Code, Section 901.5.D.2, that provide access between the site to the Major Road Network.
5. Major Intersections that are part of the impacted roadways.

Lanes	Road Type	Area	Service Volume	
			LOS C	LOS D
2	Collector	Urbanized	870	1,390
4	Collector	Urbanized	2,030	2,950
2	Arterial	Urbanized	1,310	1,560
4	Arterial	Urbanized	3,300	3,390
6	Arterial	Urbanized	4,950	5,080
8	Arterial	Urbanized	6,280	6,440
4	Freeway	Urbanized	5,350	6,510
6	Freeway	Urbanized	8,270	10,050
8	Freeway	Urbanized	11,180	13,600
2	Collector	Transitioning	670	1,300
4	Collector	Transitioning	1,570	2,810
2	Arterial	Transitioning	1,260	1,490
4	Arterial	Transitioning	3,150	3,290
6	Arterial	Transitioning	4,730	4,930
4	Freeway	Transitioning	5,250	6,220
6	Freeway	Transitioning	8,110	9,600
8	Freeway	Transitioning	10,960	12,980
2	Arterial	Rural Undeveloped	740	1,190
4	Arterial	Rural Undeveloped	4,000	5,140
6	Arterial	Rural Undeveloped	6,000	7,710
4	Freeway	Rural Undeveloped	4,980	5,890
6	Freeway	Rural Undeveloped	7,690	9,090
2	Collector	Rural Developed	1,070	1,350
2	Arterial	Rural Developed	1,100	1,500
4	Arterial	Rural Developed	4,060	5,250
6	Arterial	Rural Developed	6,080	7,870
4	Freeway	Rural Developed	4,980	5,890
6	Freeway	Rural Developed	7,690	9,090

Mainline segments of toll roads may be excluded from the analysis, but analysis of ramp-merge and diverge sections, toll booths, and ramp connections of expressways to the nonexpressway road network shall be included to ensure toll road operations do not adversely affect other public road operations.

For purposes of determining if peak-hour-development traffic consumes one (1) percent or five (5) percent or more of the existing service capacity of a road, the generalized roadway service volumes from the Generalized Service Volumes tables of the Florida Department of Transportation (FDOT) current *Quality/LOS Handbook* (the 2002 values are reproduced in Table 1 for convenience) shall be used. Roadway functional classification shall be based on the Vision Plan Map of the Comprehensive Plan.

F. Analysis Scenarios (see Section 901.12)

G. General Analysis Requirements and Software

LOS and turn-lane-length analysis shall be undertaken for all impacted roadways and intersections in accordance with the procedures below.

1. For the facility on the Major Road Network to which the development has direct access:
 - a. If the future year total volume is seventy (70) percent or less of the Major Road, generalized service volume using the latest version of FDOT generalized tables, detailed capacity and turn-lane-length analyses shall be undertaken for site driveway connections to that facility, and/or of the local street providing site traffic access to that major road facility. Turn-lane-length analysis shall be undertaken in accordance with Section 901.3, Access Management.
 - b. If the future year total volume is more than seventy (70) percent of the generalized service volume using the latest version of FDOT generalized tables, a detailed capacity analysis shall be undertaken for that facility that evaluates LOS and the adequacy of turn-lane lengths. Turn-lane-length analysis shall only be required for signalized and major unsignalized intersections within the directly accessed facility that are within one mile of the driveway or local street intersection providing access to the site from the Major Road. Turn-lane-length analysis shall be undertaken in accordance with Section 901.3, Access Management.
2. For analysis of roadways outside of the area as described in Paragraph 901.5.G.1.b above, the use of the latest version of FDOT's generalized tables is permitted as an initial screening tool. If failure is estimated, then a more detailed analysis is required using the procedures described below.
3. Road Facility limits shall be as defined in the County's Annual Concurrency monitoring LOS report. Adjustments, if appropriate, shall be proposed in the methodology statement, and be developed based on acceptable engineering and planning practices as set forth in the *Highway Capacity Manual* (HCM).
4. All analysis shall be undertaken for conditions during the 100th highest hour of the year. Other time periods or a.m. analysis may be required if requested during the methodology meeting or during the first sufficiency review.
5. Use of analysis software is allowed in accordance with the following:

- a. For unsignalized intersections, the latest version of *Highway Capacity Software* is the preferred software for analyzing delay and LOS.
- b. For signalized intersections, the latest version of *Synchro* software using the percentile delay methodology is required.
- c. For interrupted flow road segment analysis, the preferred software is the latest version of *Synchro*.
- d. For uninterrupted flow roads (those with more than two [2] mile signal spacing) the latest version of the FDOT's *Highplan* software is acceptable.
- e. The electronic copy of the analysis files shall be provided. The hard copy of the summary sheets shall be provided unless otherwise requested by the County Administrator or designee.
- f. Other analysis software may be required by the County to address situations not addressed by the above provisions or if requested by the applicant and approved by the County Administrator or designee during the methodology step.
- g. If any analysis software is used as an alternative to the FDOT's generalized tables, detailed LOS analysis of all major intersections within the facility is required.
- h. The input data to the software shall be field verified and provided in the report including, but not limited to:
 - (1) Geometry, including lane widths and turn-lane lengths.
 - (2) Heavy vehicle factor.
 - (3) Directional factor, (D Factor, not to be less than 0.52 for the future conditions analysis).
 - (4) Peak-hour factor, not to exceed 0.95 for the future conditions analysis.
 - (5) Values of the above parameters should be estimated in the future conditions analysis to reflect unconstrained, demand conditions.
 - (6) Existing signal timing and phasing can be obtained from the County Administrator or designee. The existing signal timing, including its maximum and minimum settings, shall be used for the initial analysis of future conditions. Any timing change outside of the existing minimum and maximum setting may be

presented for County approval as part of the mitigation strategy.

- (7) Segment lengths.
- i. If the FDOT's generalized, roadway service-volume tables are used, the following information shall be provided in a separate table:
 - (1) Class of roadway (interrupted or uninterrupted).
 - (2) County or State maintained.
 - (3) Area type.
 - (4) Signal density.
 - (5) LOS standard.
- j. Other parameters that govern the roadway/intersection capacity analysis shall be based on the parameters described in the latest version of the HCM.
- k. The County may require the inclusion of proposed or anticipated traffic signals in the future year condition that may not exist in the "existing condition," including signals at development entrances.
- 6. Where driveway movements are restricted, the associated necessary U-turns and added flow at the upstream and downstream median openings or intersections should be identified and analyzed as development traffic.
- 7. Procedure to determine detailed facility service volume for purposes of establishing Critical and Near-Critical Roads:
 - a. Undertake *Synchro* intersection capacity analysis using current 100th highest-hour volume estimates.
 - b. Check turn movements to be sure the volume/capacity (v/c) ratio is less than or equal to one (1.0) on all turning movements.
 - c. Check turn-lane length to accommodate 95th percentile queue, if inadequate, increase green to shorten the queue.
 - d. Allocate remaining green time to through movements to minimize delay subject to the v/c ratio <1.0.
 - e. Apply the through movement v/c ratios determined in this way to an *ArtPlan* analysis to solve for facility service volume.

- f. Divide the weighted average volume for the facility (weighted by segment length) by the facility service volume determined by *ArtPlan*.

H. Trip Generation

The trips from/to the site shall be estimated using the latest *Institute of Transportation Engineers (ITE) Trip Generation Handbook* (ITE Manual), including separate trip-generation estimates for interim traffic-generating uses. An interim use would be land excavation, as defined in this Code, Chapter 1300, and removal of more than 30,000 cubic yards even as an interim use, is presumed to be a separate and distinct land use requiring separate trip-generation estimates. Such land use is also presumed to generate more than ten (10) percent heavy vehicles. Other rates may be required by the County, or may be used if requested by the applicant and approved by the County. Use of other rates must be requested during the methodology step.

Heavy vehicles adversely affect traffic because they occupy more roadway space and have poorer operating capabilities than passenger cars, particularly with regard to acceleration, deceleration, and the ability to maintain speed on upgrades. Accordingly, for trip-generation purposes, if heavy vehicles are ten (10) percent or more of the trips generated by the proposed land use, the total estimated trips for heavy vehicles shall be multiplied by two (2) unless ITE heavy vehicle data or other County-approved heavy vehicle, trip-generation data for the land use support a different multiplier; however, in no event shall the multiplier be less than one (1). The multiplier shall not be used for purposes of study area determination. The multiplier shall not be used in addition to the multiplier used in the analysis software to determine LOS.

For estimating daily trip generation for purposes of establishing de minimis status, the daily trip-generation rates of Section 1302.2, Mobility Fees, shall be acceptable.

To encourage redevelopment of previously developed sites, a credit against any previously existing land uses shall be given for the replacement of any traffic generating building or structure that existed on or after January 1, 1985. If the petitioner can provide evidence of such a prior use on the site, the TIS shall analyze the net increase in trips associated with the proposed land use as development traffic. If the site was dormant during the collection of the traffic-count data the analysis is based upon, then the prior-vested portion of the development traffic must be added as "background" traffic. For purposes of access-management analysis, the total trips (prior vested plus additional, new trips) should be analyzed at site access and connection points to the Major Road Network.

I. Internal Capture

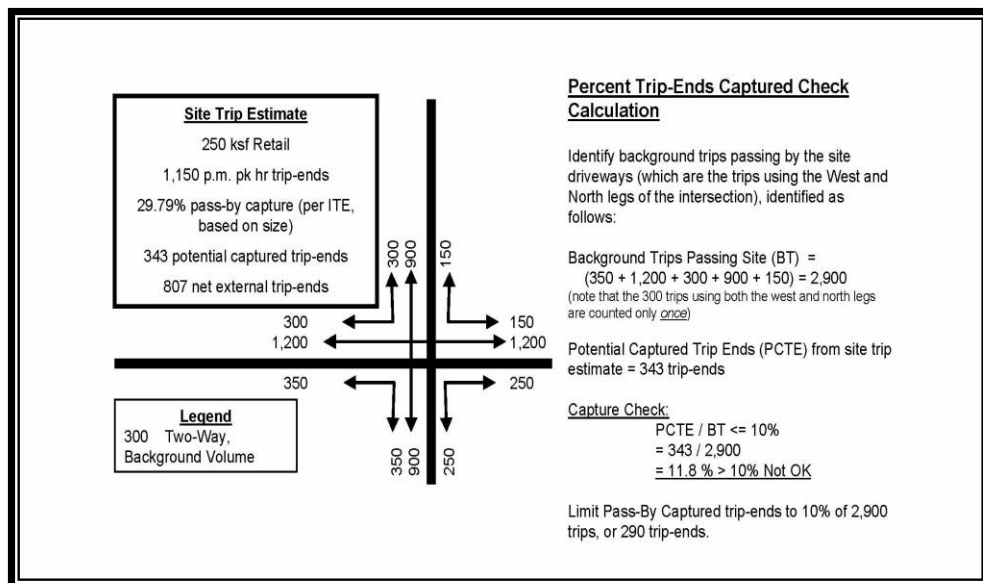
Internal capture estimates shall be based on ITE acceptable methodologies and, where the ITE data is not applicable, professional judgment. However, in no case will an internal capture of more than twenty (20) percent be acceptable unless the County accepts a higher internal capture percentage based on verifiable documentation; e.g., field studies of comparable sites.

J. Passerby Capture

The total, gross, external trips of the project traffic may be reduced by a passerby factor to account for the project traffic that is already traveling on the adjacent roadway. Passerby capture shall not exceed twenty (20) percent of site-generated traffic unless data supporting higher rates are included in the current version of the ITE Manual or are otherwise approved by the County Administrator or designee. In no event shall the total passerby trips entering and exiting a site exceed ten (10) percent of the total, background traffic on the adjacent roadway. In analysis of the site-access intersections with major roads, the passerby trips shall be included and separately identified.

In cases where median controls limit left-in/left-out access to the site, traffic on the "far side" of the road can be considered in assessing the upper limit on captured trips; however, the effects of that traffic in the associated necessary U-turns and added flow at the upstream and downstream median openings or intersections should be identified as development traffic at those locations.

The passerby-capture percentage shall be computed as the number of trips entering, plus exiting the site land uses claimed as captured, divided by the number of background trips passing by the site on major roads directly abutting or passing through the site. An example of this computation is provided below:



K. Distribution/Assignment

The latest, adopted, Tampa Bay Regional Planning Model (TBRPM) is acceptable in determining the trip-distribution percentages and trip assignments. The results of the model will be reviewed by the County Administrator or designee for reasonableness to ensure the existing and future travel patterns are correctly simulated. Manual trip distribution and assignment may also be acceptable as long as it is reviewed and accepted by the County Administrator or designee and logically replicates the existing and future travel patterns.

L. Traffic Counts

All counts shall be conducted based on acceptable engineering standards. Raw turning-movement counts and daily tube counts (minimum forty-eight [48] hours) shall be provided for all the intersections and road segments that are being analyzed. The raw counts shall be converted to the 100th highest hour of the year based on the FDOT's peak season adjustment factors and minimum K100 factors. Prior to approval of the methodology statement, other peak season adjustment factors or adjustment methodologies that may result in different peak season adjustment factors may be requested at the discretion of the County.

For saturated intersections, the FDOT's methodology shall be followed to estimate the turning-movement counts by multiplying the average annual daily traffic (AADT) tube count at appropriate locations by field verified "D" and minimum K100 factors, and by applying the percentage turns obtained from the field turning-movement counts. In no event, however, shall the estimated, turning-movement counts be less than the existing field counts.

Tube counts at appropriate locations shall be provided for segment analysis using the FDOT procedures. The segment tube counts at mid-block locations shall be checked against turning-movement counts at near intersections. In general, the mid-block counts and turning-movement counts shall not be significantly different unless the difference can logically be explained.

Approved FDOT- or County-maintained counts may be used if they are less than one (1) year old. However, new counts may be requested if there are recent improvements to the transportation system that cause significant changes in traffic patterns. Counts more than one (1) year old will not be acceptable unless otherwise approved by the County Administrator or designee. Machine counts should start no earlier than 9:00 a.m. on Mondays and end no later than 3:00 p.m. on Fridays.

M. Background Traffic Growth/Future Traffic

The existing traffic counts shall be increased by a growth factor up to the project's build-out date, which shall be reasonably specified to account for increases in existing traffic due to other approved and pending developments, as determined by the County Administrator or designee.

In the case of pending or approved developments having a build-out period longer than the development under review, the County Administrator or designee may allow the incorporation of a reasonable fraction of the approved or pending development in the background traffic estimate. The County Administrator or designee may maintain a database of traffic growth rates for this purpose.

Any development for which the applicant demonstrates that the project is not built or the project is not pending need not be considered in background traffic.

Background traffic growth rates and background traffic volume estimates shall be based on any combination of the following techniques, which must be proposed and agreed upon in the methodology process:

1. Historical growth rates (minimum of the past three [3] years) may be used in areas where the expected growth is representative of the past growth.
2. Consideration of traffic from approved and pending developments may be required in areas where the historical trend is judged by the County to be inappropriate. This may be accomplished through application of the latest adopted TBRPM, the Metropolitan Planning Organization's (MPO) Urban Area Transportation System Planning Model.
3. The growth/future traffic on roads that do not currently exist shall be based on the TBRPM (the latest, adopted model).
4. If the TBRPM is used, the background-traffic growth for existing roads shall be determined as follows: (a) identify the validated year-model volume and build-out year (future) model volume, (b) interpolate these values to identify a model-based volume for existing conditions (year to be consistent with the date of "current" count data), (c) identify the growth rate between the interpolated existing conditions model-based volume and the build-out year (future) model volume, and (d) apply this growth rate to the existing conditions traffic counts. The build-out year (future) model volume is determined by applying the project's build-out year socioeconomic data to the committed and/or improved network. The build-out year socioeconomic data may be obtained by interpolating between the MPO's or County's adopted, validated year and the adopted, interim, or future year, socioeconomic data, then adjusting to reflect the pending and approved developments.
5. The socioeconomic data of the model shall reasonably represent, if appropriate, the approved and pending developments in the vicinity of the project as approved by the County Administrator or designee during the methodology process.
6. Minimum, annual growth rates in all cases shall be two (2) percent, unless otherwise approved by the County Administrator or designee.

7. The assumed growth rate for each impacted roadway segment shall be presented in a table.
8. The background traffic growth estimates of the model will be reviewed by the County Administrator or designee to ensure growth reasonably reflects recent and expected growth trends.
9. The connections of surrounding traffic analysis zones in the model should be reviewed to reflect other approved and pending developments and to ensure appropriate network loading.

For purposes of de minimis determinations under Section 1301.6.D.3.e, 100th highest hour-traffic volume data shall be factored to account for vested and de minimis trips to the calendar year of the list of non-de minimis roads that is current at the time the petition for de minimis determination is submitted.

N. Level of Service Standards

1. The LOS standards for all major road segments (facilities) shall be consistent with the letter standards per the County's latest adopted Comprehensive Plan.
2. The overall intersection LOS standard is the same as the segment (facility) standard. Where different LOS standards apply to different legs of an intersection, the overall intersection LOS standard will be "D."
3. The delay for individual-turning movements and through movements may exceed the segment standard by one (1) letter grade (maximum of 100 seconds of delay for the "F" condition) provided that the v/c ratio for the subject movement remains less than or equal to one (1). Average delays up to 100 seconds are acceptable for individual turning movements where the v/c ratio is less than 0.8.
4. For site-access driveways and local street connections serving site-access traffic, delays up to 100 seconds will be considered acceptable.

O. Inventory of Existing and Future Conditions

At minimum, the following additional information shall be provided:

1. Build-out date of the project must be a reasonable date based on the size of the project.
2. The geometry, speed limit, and the LOS standard of all the existing roadways, intersections and committed intersections, and roadway improvement projects within and in close proximity of the study area.

3. Existing vehicle counts and data supporting heavy vehicle factor for capacity and substandard road analysis.
4. Graphic presentation of the project's proposed access locations, types, and internal roads with connections to the County's vision/build-out or long-range plan of roadways. The graphic shall also cover the area beyond the boundary of the project to include all the external, major roadways and existing or future, access points and types of developments surrounding the project.
5. Pavement-marking plans/concept plans of roadways that provide direct access to the project and have completed or are undergoing design or route study phase, if available.
6. Graphic presentation of project, traffic percent distribution and total background and project traffic assignments.
7. Inventory of existing or committed, traffic-control devices.

P. Mitigation of Impacts

1. General Guidance

- a. This subsection provides discussion on how the adequacy of mitigation will be technically reviewed and determined by the County Administrator or designee. The mitigation options discussed below are set forth in Section 1301, Concurrency.
- b. Improvements for mitigation of impacts at an individual location must work effectively relative to upstream and downstream roadway conditions. As examples:
 - (1) A proposed improvement that relies upon dual lefts, three (3) through lanes, and a right-turn lane to provide adequate capacity to serve the traffic demand at an intersection approach where only one (1) lane feeds traffic might not be considered an effective improvement, because for example, one (1) lane can only feed traffic at a rate of 1,850 vehicles per hour, but the intersection capacity analysis relies upon approach-lane capacity in excess of the 1,850 vehicles per hour.
 - (2) A proposed improvement that cannot achieve effective lane utilization due to downstream conditions would not be considered an effective improvement. For example, provision of a second through lane with a receiving lane on the far side of an intersection of only 300 feet in length.

- (3) Analyses of improvements to closely spaced intersections should include evaluations of the traffic flow interaction and signal timings of the two (2) intersections to ensure the proposed improvements will achieve the intended result.

2. Mitigation Options

- a. Restore to adopted standard: Identify an improvement at an impacted location that restores LOS to the adopted standard for the "future year with development traffic" condition, as defined in Section 901.12.G.
- b. Proportionate-Share Mitigation: The proportionate-share payment shall be calculated in accordance with State law.

- (1) Cost values for proportionate-share calculations shall include route study costs, design, right-of-way, construction, construction engineering/inspection costs, and contingency costs.

- (a) For improvements to County roads, the following general rules shall apply to estimate improvement costs. The County Administrator or designee reserves the right to make use of more detailed information when available prior to the issuance of a Certificate of Capacity requiring a proportionate-share or cost calculation. The latest available cost estimates will be used only after the needed improvements for the proposed development are identified to the satisfaction of the County:

- (i) The route study cost should be \$40,000.00 per mile.

- (ii) The construction cost should be based on 85 percent of the costs in the latest available FDOT, District Seven, Cost Reports column presently titled Subtotal. This cost column represents Long-Range Estimate (LRE) costs, plus Maintenance of Traffic, plus Mobilization.

- (iii) The design cost should be five (5) percent of the total construction cost from Step (ii).

- (iv) The Construction Engineering Inspection (CEI) cost should be three (3) percent of the cost from Step (ii).
- (v) Contingency cost shall be ten (10) percent of the construction cost from Step (ii).
- (vi) Right-of-way costs from a location specific study should be used when available. Right-of-way costs of at least 23.5 percent of the cost from Step (ii) are generally expected.

For intersections, site-specific conditions should be reviewed in every case.

The County Administrator or designee will be the agency responsible for review and approval of the County road improvement cost estimates.

- (b) For FDOT-maintained roads, the following general rules shall apply to estimate improvement costs. If more detailed studies have been undertaken that provide better estimates, they may be submitted for consideration. The FDOT shall have the right to change these general rules no later than two (2) weeks prior to the issuance of a Certificate of Capacity requiring a proportionate-share or cost calculation.
 - (i) The construction cost, including Design and CEI for improvements, should be based on latest available general cost estimates produced by FDOT, District Seven.
 - (ii) The right-of-way cost estimate should be 120 percent of the estimated construction cost (LRE column).
 - (iii) The Project Development and Environment Study cost should be five (5) percent of the construction cost.

The latest available costs estimates will be used after the list of needed improvements are finalized to the satisfaction of the County.

- (2) Where an improvement to an alternate road which draws background traffic away from an existing road estimated to fail is identified as a solution to congestion, and development traffic is assigned to both the existing road as well as the alternate road, then the proportionate-share computation will include the total, development traffic on the existing road and the new road.

EXHIBIT 901.5.A

PASCO COUNTY TIS GUIDELINES SIZE OF DEVELOPMENT THAT GENERATES 600 DAILY DRIVEWAY TRIPS

Land Use	Trip Rate (1)	Size of Dev.	Unit
RESIDENTIAL:			
Single-Family (Detached)	7.59	80	DU
Multifamily (Apartments)	6.30	96	DU
Mobile Home Park	4.67	129	DU
Age-Restricted Single-Family	3.71	162	DU
Congregate-Care Facility (Attached)	2.25	267	DU
Low-Rise Condominium (1 to 2 stories)/Townhouse	5.20	116	DU
High-Rise Condominium (3 or more stories)	4.18	114	DU
LODGING:			
Hotel	8.30	73	Room
Motel	5.63	107	Room
Resort Hotel	5.10	118	Room
Recreational Vehicle Park	3.70	163	RV Space
RECREATION:			
Marina	2.96	203	Berth
Golf Course	35.74	17	Hole
Miniature Golf Course	3.30	182	Hole
Movie Theaters	106.63	6	Screen
General Recreation	2.28	264	Acres
Racquet Club/Health Club/Spa/Dance Studio	14.03	43	1,000 SF
Bowling Alley	33.33	19	1,000 SF
Community Center	22.88	27	1,000 SF
INSTITUTIONAL:			
Hospital	17.57	35	1,000 SF
Nursing Home	2.48	242	Bed
Elementary School	1.29	466	Student
Middle School	1.62	371	Student
High School	1.71	351	Student
Junior/Community College	1.20	501	Student
University	2.38	253	Student
Church	9.11	66	1,000 SF
Day Care	3.03	199	Student
Cemetery	4.73	127	Acres
OFFICE:			
General Office - 50,000 SF or less	15.65	39	1,000 SF
General Office - 50,001 to 100,000 SF	14.25	All	1,000 SF
General Office - 100,001 to 200,000 SF	12.15	All	1,000 SF
General Office - 200,001 to 400,000 SF	10.36	All	1,000 SF
OFFICE (cont.):			
General Office - Greater than 400,000 SF	8.83	All	1,000 SF
Medical Office	35.95	17	1,000 SF
Office Park	11.70	52	1,000 SF
Veterinarian Clinic	32.80	19	1,000 SF
RETAIL:			
Specialty Retail	49.99	13	1,000 SF
Shopping Center - Under 50,000 GSF	86.56	7	1,000 SF
Shopping Center - 50,000 to 200,000 GSF	62.81	All	1,000 SF
Shopping Center - 200,001 to 400,000 GSF	46.23	All	1,000 SF
Shopping Center - 400,001 to 600,000 GSF	38.66	All	1,000 SF
Shopping Center - 600,001 to 800,000 GSF	34.37	All	1,000 SF
Shopping Center - Greater than 800,000 GSF	30.33	All	1,000 SF
Pharmacy/Drug Store with Drive-Through	95.21	7	1,000 SF
Home Improvement Superstore	29.80	21	1,000 SF
Hardware/Paint	51.29	12	1,000 SF
Quality Restaurant	91.10	7	1,000 SF
High-Turnover Restaurant	126.50	5	1,000 SF
Fast Food Restaurant with Drive-Through	522.62	2	1,000 SF
Gasoline Station	168.56	4	Fuel POS
Quick-Lube	40.00	16	Bays
Auto Repair or Body Shop	30.09	20	1,000 SF
Self-Service Car Wash	108.00	6	Bay
Tire Store	24.87	25	1,000 SF
New/Used Auto Sales	32.93	19	1,000 SF
Supermarket	103.38	6	1,000 SF
Convenience Store with Gas Pumps	803.24	1	1,000 SF
Furniture Store	5.06	119	1,000 SF
Bank/Savings Drive-In	281.55	3	1,000 SF
Convenience/Gasoline/Fast-Food Store	984.59	1	1,000 SF
INDUSTRY:			
General Light Industrial	6.97	87	1,000 SF
General Heavy Industrial	1.50	401	1,000 SF
Industrial Park	6.96	87	1,000 SF
Manufacturing	3.82	158	1,000 SF
Warehouse	4.96	121	1,000 SF
Miniwarehouse	2.50	241	1,000 SF
High-Cube Warehouse	1.20	501	1,000 SF
Airport Hangar	4.96	121	1,000 SF

NOTES: For land uses not listed herein, either the *ITE Trip Generation Handbook*, latest edition, or other trip-generation studies as approved by the County shall be used.

To estimate total daily driveway trips for land uses listed herein with heavy vehicles that are 10 percent or more of the total daily driveway trips, the total estimated daily driveway trips for heavy vehicles shall be multiplied by 2, unless ITE heavy vehicle data or other County-approved heavy vehicle trip generation data for the land use support a different multiplier; however, in no event shall the multiplier be less than 1. The size of the development thresholds listed herein may be reduced based on additional heavy vehicles trips.

Source: Pasco County 2006 Transportation Impact Fee Update Study Summary Report.

EXHIBIT 901.5.B

PASCO COUNTY TIS GUIDELINES SIZE OF DEVELOPMENT THAT GENERATES 1,200 DAILY DRIVEWAY TRIPS

Land Use	Trip Rate (1)	Size of Dev.	Unit
RESIDENTIAL:			
Single-Family (Detached)	7.59	159	DU
Multifamily (Apartments)	6.30	191	DU
Mobile Home Park	4.67	257	DU
Age-Restricted Single-Family	3.71	324	DU
Congregate-Care Facility (Attached)	2.25	534	DU
Low-Rise Condominium (1 to 2 stories)/Townhouse	5.20	231	DU
High-Rise Condominium (3 or more stories)	4.18	288	DU
RECREATION:			
Hotel	8.30	145	Room
Motel	5.63	214	Room
Resort Hotel	5.10	236	Room
Recreational Vehicle Park	3.70	325	RV Space
INSTITUTIONAL:			
Marina	2.96	406	Berth
Golf Course	35.74	34	Hole
Miniature Golf Course	3.30	364	Hole
Movie Theaters	106.63	12	Screen
General Recreation	2.28	527	Acres
Racquet Club/Health Club/Spa/Dance Studio	14.03	86	1,000 SF
Bowling Alley	33.33	37	1,000 SF
Community Center	22.88	53	1,000 SF
INSTITUTIONAL:			
Hospital	17.57	69	1,000 SF
Nursing Home	2.48	484	Bed
Elementary School	1.29	931	Student
Middle School	1.62	741	Student
High School	1.71	702	Student
Junior/Community College	1.20	1,001	Student
University	2.38	505	Student
Church	9.11	132	1,000 SF
Day Care	3.03	397	Student
Cemetery	4.73	254	Acres
OFFICE:			
General Office - 50,000 SF or less	15.65	None	1,000 SF
General Office - 50,001 to 100,000 SF	14.25	85	1,000 SF
General Office - 100,001 to 200,000 SF	12.15	All	1,000 SF
General Office - 200,001 to 400,000 SF	10.36	All	1,000 SF
OFFICE (cont.):			
General Office - Greater than 400,000 SF	8.83	All	1,000 SF
Medical Office	35.95	34	1,000 SF
Office Park	11.70	103	1,000 SF
Veterinarian Clinic	32.80	37	1,000 SF
RETAIL:			
Specialty Retail	49.99	25	1,000 SF
Shopping Center - Under 50,000 GSF	86.56	14	1,000 SF
Shopping Center - 50,000 to 200,000 GSF	62.81	All	1,000 SF
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Shopping Center - 600,001 to 800,000 GSF	34.37	All	1,000 SF
Shopping Center - Greater than 800,000 GSF	30.33	All	1,000 SF
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Home Improvement Superstore	29.80	41	1,000 SF
Hardware/Paint	51.29	24	1,000 SF
Quality Restaurant	91.10	14	1,000 SF
High-Turnover Restaurant	126.50	10	1,000 SF
Fast Food Restaurant with Drive-Through	522.62	3	1,000 SF
Gasoline Station	168.56	8	Fuel POS
Quick-Lube	40.00	31	Bays
Auto Repair or Body Shop	30.09	40	1,000 SF
Self-Service Car Wash	108.00	12	Bay
Tire Store	24.87	49	1,000 SF
New/Used Auto Sales	32.93	37	1,000 SF
Supermarket	103.38	12	1,000 SF
Convenience Store with Gas Pumps	803.24	2	1,000 SF
Furniture Store	5.06	238	1,000 SF
Bank/Savings Drive-In	281.55	5	1,000 SF
Convenience/Gasoline/Fast-Food Store	984.59	2	1,000 SF
INDUSTRY:			
General Light Industrial	6.97	173	1,000 SF
General Heavy Industrial	1.50	801	1,000 SF
Industrial Park	6.96	173	1,000 SF
Manufacturing	3.82	315	1,000 SF
Warehouse	4.96	242	1,000 SF
Miniwarehouse	2.50	481	1,000 SF
High-Cube Warehouse	1.20	1,001	1,000 SF
Airport Hangar	4.96	242	1,000 SF

NOTES: For land uses not listed herein, either the *ITE Trip Generation Handbook*, latest edition, or other trip-generation studies as approved by the County shall be used.

To estimate total daily driveway trips for land uses listed herein with heavy vehicles that are 10 percent or more of the total daily driveway trips, the total estimated daily driveway trips for heavy vehicles shall be multiplied by 2, unless ITE heavy vehicle data or other County-approved heavy vehicle trip generation data for the land use support a different multiplier; however, in no event shall the multiplier be less than 1. The size of the development thresholds listed herein may be reduced based on additional heavy vehicles trips.

Source: Pasco County 2006 Transportation Impact Fee Update Study Summary Report.

CHAPTER 900. DEVELOPMENT STANDARDS

SECTION 901. TRANSPORTATION

901.12. Transportation Analysis

A. Intent and Purpose

The intent and purpose of this section is to identify potential transportation impacts of discretionary development approvals on the transportation system consistent with the mobility fee regulations, access management regulations, transportation corridor spacing requirements, and the Comprehensive Plan Transportation Level of Service (LOS) standards. The transportation analysis will be used by the County to determine whether the discretionary development approval request should be approved, denied, or conditioned, where applicable, to ensure consistency with the adopted Comprehensive Plan and this Code.

B. Applicability

Except as exempted below, transportation analysis shall be required for all Future Land Use (FLU) Map amendments, rezonings, and amendments to Developments of Regional Impact (DRI) and MPUD Master Planned Unit Developments.

Except in the case of conflict zoning where a property has zoning which permits more trips than provided for under the FLU Map, amendments to the FLU Map shall undergo transportation needs assessment. Rezonings, amendments to DRIs and MPUDs, and FLU Map amendments associated with conflict zonings shall undergo timing and phasing analysis.

Additionally, the County may use the standards herein to evaluate other discretionary developments such as conditional uses and special exceptions for the purposes of evaluating transportation system impacts, if it exceeds the thresholds in C-1, or where the increase in gross trips is less than 50 peak hour trips.

C. Exemptions

1. Applications where the increase in gross trips is less than 50 peak hour trips, AM or PM, whichever is higher, provided the access is not on a roadway with a known LOS deficiency (see Table 901.12-2).
2. FLU Map amendments to the following land use classifications:
 - a. OF (Office)
 - b. EC (Employment Center)
 - c. IL (Industrial - Light)

- d. IH (Industrial - Heavy)
 - e. PD (Planned Development): The portion of the planned development with government buildings, office, hotel, industrial, corporate business park, and/or transit-oriented development (TOD), as defined in the mobility fee definitions and regulations.
3. Rezoning to the following zoning districts:
- a. EC-MPUD Employment Center Master Planned Unit Development
 - b. MPUD Master Planned Unit Development: The portion of the MPUD which is government buildings, office, corporate business park, hotel, industrial, and TOD.
 - c. MPUDs within the following land use classifications: OF, EC, IL, and IH.
 - d. PO-1 Professional Office
 - e. I-1 Light Industrial Park
 - f. I-2 General Industrial Park
4. Applications where the increased number of trips is from the Transfer of Development Rights (TDRs) which are purchased or received in compliance with the TDR provisions of the Comprehensive Plan and this Code.
5. Unexpired DRIs and MPUDs which do not propose to eliminate or delay the timing of their existing road construction obligations or increase gross AM or PM peak hour trips, whichever is higher, beyond the threshold permitted by Section 901.12.C.1.
6. Requests to eliminate or delay site-access improvements or substandard road improvements; however, such requests may be subject to additional review pursuant to Section 901.3 or 901.4.
7. Requests to utilize statutorily-authorized extensions.
8. Government buildings as defined in this Code, under the Mobility Fee definitions in Appendix A.
9. Existing entitlements.

D. Methodology Meeting

Upon submission of a Timing and Phasing Application or Comprehensive Plan Amendment Application requiring transportation analysis, staff will contact the applicant to:

1. Determine whether the County or applicant will conduct the study.
2. Set up a methodology meeting with the applicant or applicant's representative.

The date of the methodology meeting will be determined within one (1) week of distribution of the application to County staff. If the County is performing the analysis, the County will prepare and submit a methodology statement for the applicant's review no later than two (2) weeks after the methodology meeting. The purpose of the methodology statement is to establish agreed upon methodologies and assumptions prior to the start of the study and, if appropriate, to provide substantiation that the development's impacts are exempt (no net peak hour traffic impact) and further traffic study and review is not required. If the applicant chooses to perform the study, a County-approved methodology statement shall be required prior to submission of any transportation analysis. At a minimum, the following elements of the methodology, as listed below, will be specifically addressed:

3. Exemption assertions.
4. Collection of traffic counts.
5. Description of land uses, site location, build-out schedule, and phasing, including any interim uses generating traffic.
6. Study area.
7. Access locations.
8. Trip generation.
9. Internal capture/passerby.
10. Background growth procedure.
11. Distribution and assignment.

If the County conducts the study, unless otherwise agreed to by the County, the applicant shall be required to obtain the traffic count data. If the County agrees to obtain the traffic counts, the time to complete these counts may delay the commencement of development review time frames in this Code, Table 303.1. In addition, if the County acquires the traffic counts, the applicant remains responsible for paying for the associated costs. Consistent with the standards set forth in this Code, Section 901.12.E.4, the County may

use currently available counts. If new counts are needed, the County may choose to perform the counts in-house or through a third-party consultant.

To maintain the review schedule, if the County is performing the study, the applicant will be required to respond to the draft methodology statement within four (4) business days. The applicant may request additional time for review, which will trigger an automatic extension of the review schedule. If the County is performing the study, the timeframe the County estimates to complete the analysis will be provided to the applicant in the methodology statement. Furthermore, if the applicant chooses not to have the County complete the analysis, the hearing timeframes provided in Section 303 shall be extended to permit completion of the analysis and review and comment by the County.

E. Standards for Transportation Analysis

1. Trip Generation

- a. Institute of Transportation Engineers (ITE) *Trip Generation Manual* (ITE Manual). The latest version of the ITE Manual will be used to estimate project traffic and exempted trips traveling to and from the site and trips associated with existing entitlements. Other rates may be used by the County or may be used if requested by the applicant and approved by the County. Unless the applicant has requested a conditioned approval identifying use density/intensity, rates associated with the highest trip generating use permitted by the existing/proposed zoning will be applied.
- b. Interim uses. Separate trip generation estimates for interim traffic-generating uses¹ shall also be considered.
- c. Reasonable yield. Unless the applicant has requested a conditioned approval identifying use density/intensity, a twenty-five (25) percent reduction factor will be applied to the maximum allowable density/intensity to determine a reasonable assumption of trip yield from the site for both existing and proposed density/intensity. For example, a site with a proposed RES-6 (Residential - 6 du/ga) FLU Classification will be evaluated presuming a yield of 4.5 dwelling units per acre.
- d. Heavy vehicles. If heavy vehicles are ten (10) percent or more of the trips generated by the proposed land use, the total estimated trips for heavy vehicles shall be multiplied by two (2) unless ITE heavy vehicle data or other County-approved heavy vehicle trip generation data for the land use supports a

¹ Land Excavation and Mining (as defined in this Code, Sections 404.2 and 404.3) even as an interim use, is presumed to be a separate and distinct land use requiring separate trip generation estimates. Such land use is also presumed to generate more than ten (10) percent heavy vehicles.

different multiplier. In no event shall the multiplier be less than one (1). The multiplier will not be used in addition to the heavy vehicle adjustment factor used in the analysis software to determine the LOS.

2. Internal Capture

Internal capture estimates shall be based on ITE acceptable methodologies, and where the ITE data is not applicable, professional judgment. However, in no case will an overall internal capture of more than twenty (20) percent be used unless a higher internal capture percentage based on verifiable documentation; e.g., field studies of comparable sites, is available. Internal capture shall include the trips associated with existing entitlements. Exempted uses are allowed in calculation of internal trip capture.

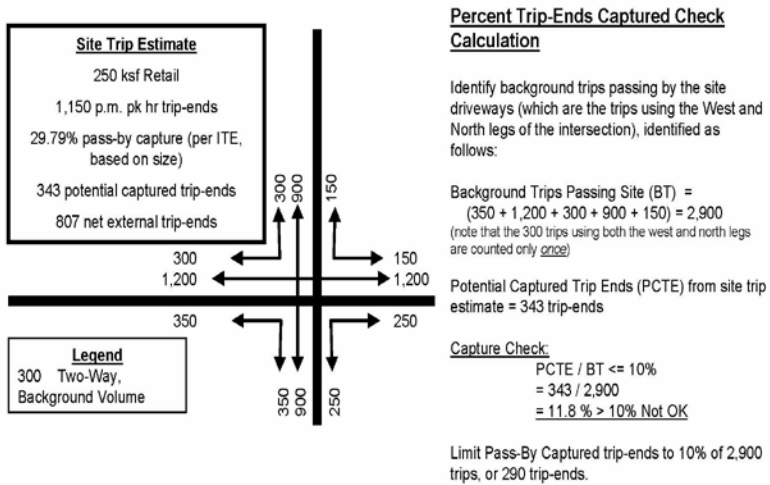
3. Passerby Capture

The total gross external trips of the project traffic may be reduced by a passerby factor to account for the project traffic that is already traveling on the adjacent roadway. Passerby capture will not exceed twenty (20) percent of site generated traffic, unless data supporting higher rates are included in the current version of the ITE Manual reference, latest mobility fee study, or are otherwise approved by the County. In no event shall the total passerby trips entering and exiting a site exceed ten (10) percent of the total background (existing plus future) traffic on the adjacent roadway.

In cases where median controls limit left-in/left-out access to the site, traffic on the "far side" of the road can be considered in assessing the upper limit on captured trips; however, the effects of that traffic in the associated necessary U-turns and added flow at the study area/impacted transportation system, the upstream and downstream median openings or intersections, should be identified as development traffic at those locations.

The passerby capture percentage shall be computed as the number of trips entering, plus exiting the site land uses claimed as captured, divided by the number of background trips passing by the site on Major County Roads directly abutting or passing through the site. An example of this computation is provided on Exhibit 901.12-1.

EXHIBIT 901.12-1



The passerby trips shall include trips associated with the existing entitlements.

4. Trip Counts

- a. General. All counts shall be conducted based on acceptable engineering standards. Raw turning movement counts shall be conducted during the a.m. and/or p.m. peak hours, consistent with the analysis parameters. Daily tube counts shall be conducted for a minimum of forty-eight (48) hours at all intersections and road segments that are being analyzed in accordance with these provisions. The raw counts shall be converted to the 100th highest hour of the year based on the Florida Department of Transportation's (FDOT) peak season adjustment factors and minimum K100 factors. Other peak-season adjustment factors or adjustment methodologies that may result in different peak-season adjustment factors may be used at the discretion of the County.
- b. Saturated intersections. To estimate turning movement counts for saturated intersections, the FDOT's methodology shall be followed by multiplying the average annual daily traffic tube count at appropriate locations by "the directional factor" and minimum K100 factors and by applying the percentage of turns obtained from the field-turning movement counts. The field-turning movement percentages may also be adjusted based on anticipated future development patterns in the area.
- c. Tube counts at approximate locations should be provided for segment analysis using the FDOT procedure. The segment tube counts at mid-block locations should be checked against

turning movements at nearby intersections. In general, the mid-block counts and turning-movement counts should not be significantly different, unless the difference can be logically explained.

- d. Age of counts. Approved FDOT or County-maintained counts may be used if they are less than one (1) year old. However, new counts shall be performed if there are recent improvements to the transportation system causing significant changes in traffic patterns. Counts more than one (1) year old shall not be used unless the latest counts are representative of present conditions where little or no growth has occurred.

5. Background Traffic Growth/Future Traffic

The existing traffic counts shall be increased by a growth factor to the project's build-out date, which shall be reasonably determined.

The growth rate shall also include all trips from exempt uses associated with the development under review. The final growth rates using the techniques in a and b below will be assumed to have contained the trips for exempt uses except for the access management portion of the analysis at the access intersections.

- a. Timing and phasing background traffic. Background traffic growth rates and background traffic volume estimates for timing and phasing shall be based on a combination of the following techniques:
 - (1) Historical growth rates (minimum of the past three [3] years) shall be used in areas where the expected growth is representative of the past growth.
 - (2) Consideration of traffic from other developments shall be used in areas where the historical trend is judged by the County to be inappropriate. This may be accomplished through application of the latest adopted Tampa Bay Regional Planning Model (TBRPM), the Metropolitan Planning Organization's (MPO) Urban Area Transportation System Planning Model, or by estimating the anticipated trips using the latest edition of the ITE Manual.
 - (3) The growth/future traffic on roads that do not currently exist shall be based on the TBRPM, the latest adopted model, or other acceptable planning/engineering techniques or tools.

(4) If the TBRPM is used, the background traffic growth for existing roads shall be determined as follows:

- (a) Identify the validated year model volume and build-out year (future) model volume.
- (b) Interpolate these values to identify a model-based volume for existing conditions (year to be consistent with the date of "current" count data).
- (c) Identify the growth rate between the interpolated existing conditions model-based volume and the build-out year (future) model volume.
- (d) Apply this growth rate to the existing conditions traffic counts.

The build-out year (future) model volume is determined by applying the project's build-out year socioeconomic data to the committed and/or improved network. The build-out year socioeconomic data may be obtained by interpolating between MPO's or the County's adopted validated year and the adopted interim or future year, socioeconomic data, then adjusting to reflect the pending and approved developments.

The socioeconomic data of the model should reasonably represent, if appropriate, other developments in the vicinity of the development under review.

Minimum annual growth rates in all cases shall be two (2) percent, unless other reasonable rates are deemed to be more appropriate by the County.

The connections of surrounding traffic analysis zones in the model shall be reviewed to reflect other approved and pending developments and to ensure appropriate network loading.

b. Transportation Needs Assessment

The following techniques or combination thereof shall be used to estimate background traffic growth used for transportation needs assessment. The build-out of the project is assumed to

match the horizon year of the Long-Range Transportation Plan (LRTP):

- (1) Historical growth rates (minimum of the past three [3] years) shall be used in areas where the expected growth is representative of the past growth.
- (2) The volumes produced by the TBRPM as part of the latest LRTP development process documented in the LRTP Technical Appendix may be used. The traffic generated by existing entitlements is assumed to be included in the LRTP volumes.

Minimum annual growth rates in all cases should be two (2) percent, unless other reasonable rates are deemed to be more appropriate by the County.

6. LOS Standards

The following LOS standards shall be used:

- a. The LOS standards for through movements on all major County road segments (facilities) shall be consistent with the standards in the County's latest adopted Comprehensive Plan.
- b. The volume over capacity (v/c) ratio of turning movements on Major County Roads cannot exceed 1.2 for TRP or 1.0 for other nonexempt uses, with a maximum delay of 120 seconds. Delays of up to 150 seconds are acceptable for turning movements with a v/c ratio less than 0.8.
- c. For all access driveways and local street connections to Major County Roads approach delays of up to 150 seconds will be acceptable.
- d. For developments in urban areas with v/c ratio standards, at the intersection of a collector and an arterial roadway, the collector standard shall not exceed the v/c ratio of the arterial road standard.
- e. The LOS standard for the freeway (I-75) is only applicable to the main line.
- f. The LOS or v/c standards applicable to collector or arterial roadways are also applicable to all freeway interchanges, including the intersections of on/off ramps with Major County Roads.
- g. If a roadway forms a boundary between different area types, urban, suburban, or rural as defined in the Comprehensive Plan and mobility fee regulations, the less stringent standards

will be applied. In addition, if a roadway facility under review crosses boundary lines, the less stringent standard will be applied to the first road segment/intersection.

- h. Any requirement set forth above relating to intersection LOS is only applicable to timing and phasing analysis.

7. Study Area/Impacted Transportation System

At a minimum, the following roadway segments and intersections will be assumed to be within the study area and will be analyzed.

- a. All Major County Road segments (and associated signalized intersections including interchanges) that are directly or indirectly accessed by the proposed development.
- b. As a general rule, road segments outside of the minimum study area will not be considered impacted if the net external peak-hour project traffic (only from nonexempt uses) consumes less than or equal to five (5) percent of the road segments' service-flow rate. The following two (2) way peak-hour service flow rates will be used to determine the five (5) percent impact. The study area maybe less than the five (5) percent impact area, based on the methodology agreed to at the methodology meeting and in the methodology statement.

TABLE 901.12-1

Type of Roadway	Lanes	Two-Way, Peak-Hour Flow Rate
Freeway	4	6,460
	6+	9,710
Other	2	1,370
	4	3,110
	6+	4,710

- c. Proximity to existing or proposed interchanges or major intersections may increase the size of the study area and impacted roads regardless of the five (5) percent rule.

F. General Analysis Requirements and Software

LOS analysis shall be undertaken in accordance with the procedures below:

- 1. The main focus of transportation analysis is the identification of improvements to through movements. If there are any known turn-lane deficiencies at study intersections, the County may adjust the analysis parameters to account for the deficiency.

2. Road facility limits shall be based on acceptable engineering and planning practices as set forth in the *Highway Capacity Manual*(HCM).
3. All analysis shall be undertaken for conditions during the 100th highest hour of the year. Other analysis periods, including the a.m. peak hour, may also be conducted, if appropriate.
4. As part of the timing and phasing analysis and for uninterrupted road facilities (intersection spacing of more than two [2] miles), the capacity of upstream and downstream intersections may be analyzed, which may restrict the amount of traffic that can be allowed on the uninterrupted portion of the facility.
5. For purposes of analysis in *ArtPlan*, at major T-intersections, the dominant-turning movement will be assumed to be the through movement.
6. For timing and phasing analysis, use of analysis software will be in accordance with the following:
 - a. For unsignalized intersections, the latest version of *Highway Capacity Software* (HCS) is the preferred software.
 - b. For signalized intersections and interrupted road segments, the latest version of *ArtPlan* is the preferred software, except as necessary to identify alternate solutions to through movement improvements, for which *Synchro* is the preferred software.
 - c. For uninterrupted flow roads (those with more than two [2] mile signal spacing), the latest version of the FDOT's Highplan is the preferred software.
 - d. Other analysis software acceptable to the County may be used to address situations not addressed by the above provisions.
 - e. Existing signal timing will be obtained from the County Traffic Operations Division. The existing signal timings, including minimum and maximum settings, will be used for the initial analysis of future conditions. Timing changes outside of the existing minimum and maximum settings may be used or timing splits may be modified, but the existing cycle length will generally remain the same.
 - f. Proposed or anticipated traffic signals may be considered in the future year condition, such as signals at development entrances.

- g. Other parameters that govern the roadway/intersection capacity analysis should be based on the parameters described in the latest version of the HCM.
- 7. For long-term transportation assessment, the latest FDOT generalized service flow-rate tables will be used to assess the capacity of the road network.

G. Analysis Scenarios

- 1. For timing and phasing, the following standards will be used in analysis.
 - a. The analysis scenarios listed below shall be applied in the following order, as necessary:
 - (1) Impact determination compares the existing and proposed net-peak-hour, external trips to determine the degree of impact to the road network. If the net-peak-hour, external trips of the existing entitlements are greater than or equal to the nonexempt net-peak-hour, external trips from proposed entitlements, no additional analysis is necessary.
 - (2) If there is a net increase in peak-hour, external trips, the future scenario will be evaluated. The future scenario is defined as the analysis of existing traffic, plus reasonable background traffic and project traffic at build-out on the committed network. If no failure occurs, the analysis stops.
 - (3) In circumstances where there is a failure, the future scenario will be evaluated including any improvements where construction is fully funded in the FDOT's Five-Year Transportation Improvement Plan and the County's Five-Year Capital Improvement Plan. If no failure occurs, the analysis stops.
 - (4) Where there is a failure, the analysis will continue with inclusion of any cost-affordable improvements from the MPO's adopted LRTP and the Comprehensive Plan.
 - b. For all locations which are estimated to fail, the analysis shall identify when each failure is expected as a fraction of development trips associated with nonexempt on-site land use quantities and the estimated year of the failure. If possible, the analysis shall identify improvements that are necessary to accommodate trips for the additional nonexempt entitlements being sought. These improvements may include new interchanges, overpasses, and/or roadways identified in the

Comprehensive Plan or as required by this Code, Section 901.1.

2. Transportation Needs Assessment

For transportation needs assessment, the analysis scenarios listed below shall be applied in the following order as necessary:

- a. Impact determination compares the existing and proposed net-peak-hour, external trips to determine the degree of impact to the road network. If the net peak hour external trips of the project traffic are less than or equal to the nonexempt net-peak-hour, external trips from existing entitlements, the analysis stops.
 - b. Otherwise, the future scenario shall be analyzed with the MPO's adopted LRTP and the County's Comprehensive Plan.
 - c. If failures occur, (1) appropriate improvements to accommodate future project traffic will be identified, and/or (2) appropriate reductions in proposed density/intensity increases in terms of net-peak-hour trips will be identified.
3. Regardless of which analysis type or scenario is performed, the needed transportation corridors to satisfy this Code, Section 901.1, shall be assessed and identified.

H. Analysis Timelines and Recommendations

1. Time to Complete Study

The estimated time to complete a study, including the methodology statement, is generally between one (1) to four (4) months, depending on the size of the project, associated complexities, and promptness in the applicant's responses to questions from the County.

If the County performs the analysis, applicants will have four (4) business days to comment on the methodology statement and seven (7) business days to comment on the draft analysis report. The applicant may request additional time for review which will trigger an automatic extension of the review schedule.

The County will address the applicant's comments and concerns in an efficient manner in order to complete the study within the one (1) to four (4) month period. If the applicant elects to conduct the study, the County will have 30 days from each submittal to review and respond with comments.

If there are any remaining unresolved issues with the methodology or analysis after the final study is forwarded to the applicant and the applicant chooses not to request a continuance to resolve the issues,

the applicant will need to address the unresolved issues directly to the Development Review Committee (DRC), Planning Commission (PC), and/or the Board of County Commissioners (BCC) at the appropriate public hearing.

a. MPUD/DRI/Conflict Rezoning

- (1) If the applicant elects to conduct the analysis, the review times provided for in Section 303 shall be extended to provide time for the County to review and comment on the analysis.
- (2) When the County is conducting the analysis, the draft analysis report will be forwarded to the applicant no less than four (4) weeks prior to the first public hearing and the final study will be forwarded to the applicant two (2) weeks prior to the first public hearing.
- (3) The review time/analysis period of 120 days for MPUDs may be extended up to an additional 60 days for those projects that have outstanding issues as a result of the timing and phasing analysis.

b. Euclidean Rezoning

To maintain the review times provided in Section 303, the timing and phasing analysis shall be completed prior to submitting a Euclidean rezoning application.

2. Results and Recommendation

The results of the analysis will be used to provide a recommendation to the DRC, PC, and BCC. The report presented from the analysis will identify when failures are estimated to occur and to what degree the failure is as a result of the request for increased entitlements.

In circumstances where a failure is identified, recommendations shall be presented to the DRC, PC, and BCC, as appropriate. The recommendations shall be based on an evaluation of the proposed project and the total impact on the transportation network. The recommendation may be to:

- a. Approve the project.
- b. Approve the project with limitations on the phasing of the project.
- c. Approve the project subject to the timing of improvements.
- d. Approve the project subject to advance payment of mobility fees.

- e. Approve the project subject to the conversion of requested entitlements to exempt uses.
 - f. Approve the project with other mitigation requirements including but not limited to transit, bicycle and pedestrian connectivity, changing the land use mix or incorporating MUTRM (MixedUse TripReduction Measures).
 - g. Deny the project.
3. Deficiencies and/or Backlogs. Mitigation assessed pursuant to this section shall not assess for the additional cost of reducing or eliminating existing deficiencies or backlogs.

I. Waiver of the Requirements of this Section

The County Administrator or designee may waive any of the requirements of this section if it is determined that the requirement is not necessary to:

- a. Ensure consistency with the Comprehensive Plan LOS Standards.
- b. Ensure compliance with Section 901.1.
- c. Ensure the safety of the traveling public.

J. Establishment of Uniform Approaches to Specific Segments

- 1. Common Understanding. When there is a common understanding of the capacity impacts to particular portions of the transportation system, to eliminate unnecessary time and expenditures to study the known condition, the BCC may adopt by resolution an approach to mitigation of transportation capacity issues on specific road segments.
- 2. Local Planning Agency Recommendation Required. Prior to adopting such a resolution, the LPA shall review the proposal and make a recommendation to the BCC.
- 3. Resolution Requirements. Such resolution shall be required to identify:
 - a. The transportation capacity issues.
 - b. Approved mitigation measures.
 - c. Applicability of the resolution.
 - d. The extent to which the resolution modifies the transportation analysis requirements for projects.
- 4. Access Management. Access management analysis will continue to be required at the same stage in the review process.

TABLE 901.12-2

Transportation Analysis

50-Peak Hour Trip Threshold

Land Use	AM Trip Rate	PM Trip Rate	Approx. Size of Development (Using Highest Peak Hour Rate)	Unit
RESIDENTIAL:				
Single-Family (Detached)	0.75	1	50	DU
Multiple-Family (Apartments)	0.51	0.62	81	DU
Mobile Home Park	0.44	0.59	85	DU
Senior Adult Housing (Detached)	0.22	0.27	185	DU
Congregate Care Facility	0.06	0.17	294	DU
Low-Rise Condominium (1 to 2 Stories)/Townhouse	0.67	0.78	64	DU
High-Rise Condominium (3 or More Stories)	0.34	0.38	132	DU
LODGING:				
Hotel	0.53	0.6	83	Room
Motel	0.45	0.47	106	Room
Resort Hotel	0.31	0.42	119	Room
RECREATION:				
Marina	0.08	0.19	263	Berth
Golf Course	2.06	2.92	17	Hole
Miniature Golf Course	N/A	0.33	152	Hole
Multiplex Movie Theater	N/A	13.64	4	Screen
Multipurpose Recreational Facility	0.17	3.58	14	1,000 SF
Health/Fitness Club	1.41	3.53	22	1,000 SF
Bowling Alley	1.71	1.71	29	1,000 SF
Recreational Community Center	2.05	2.74	18	1,000 SF

INSTITUTIONAL:				
Hospital	0.95	0.93	53	1,000 SF
Nursing Home	0.17	0.22	227	Bed
Elementary School	0.45	0.15	111	Student
Middle School	0.54	0.16	93	Student
High School	0.43	0.13	116	Student

INSTITUTIONAL:				
Junior/ Community College	0.12	0.12	417	Student
University	0.17	0.17	294	Student
Church	0.56	0.55	89	1,000 SF
Day Care	0.8	0.81	62	Student

OFFICE:				
General Office - 50,000 SF or Less	2.52	4.24	12	1,000 SF
General Office - 50,001-100,000 SF	2.03	2.16	23	1,000 SF
General Office - 100,001-200,000 SF	1.77	1.64	28	1,000 SF
General Office - 200,001-400,000 SF	1.54	1.38	32	1,000 SF
General Office - Greater than 400,000 SF	1.21	1.2	41	1,000 SF
Medical/Dental Office	2.39	3.57	14	1,000 SF
Office Park	1.71	1.48	29	1,000 SF
Corporate Headquarters	1.52	1.41	33	1,000 SF

RETAIL:				
Specialty Retail	-	2.71	18	1,000 SF
Shopping Center - Under 50,000 GSF	2.68	9.48	5.3	1,000 SF
Shopping Center - 50,000-200,000 GSF	1.43	5.57	9	1,000 SF
Shopping Center - 200,001-400,000 GSF	1.02	4.17	12	1,000 SF
Shopping Center - 400,001-600,000 GSF	0.83	3.52	14	1,000 SF
Shopping Center - 600,001-800,000 GSF	0.73	3.15	16	1,000 SF
Shopping Center - Greater than 800,000 GSF	0.59	2.64	19	1,000 SF
Pharmacy/Drug Store with Drive-Thru	3.45	9.91	5	1,000 SF
Home Improvement Superstore	1.49	2.33	21	1,000 SF
Hardware/Paint	1.08	4.84	10	1,000 SF
Quality Restaurant	0.81	7.49	6.7	1,000 SF
High-Turnover (Sit Down) Restaurant	10.81	9.85	4.6	1,000 SF
Fast Food Restaurant with Drive-Thru	45.42	32.65	1.1	1,000 SF
Gasoline Station	12.16	13.87	3.6	Fuel Pos
Quick Lube	3	5.19	10	Bays
Automobile Repair or Body Shop	2.25	3.11	16	1,000 SF
Self-Service Car Wash	-	5.54	9	Bay
Tire Store	2.89	4.15	12	1,000 SF
Automobile Sales	1.92	2.62	19	1,000 SF
Supermarket	3.4	9.48	5.3	1,000 SF
Convenience Store with Gas Pumps	40.92	50.92	All	1,000 SF
Furniture Store	0.17	0.45	111	1,000 SF
Drive-Thru Bank	12.08	24.3	2.1	1,000 SF
Gasoline/Service Station w/Conv Market	82.13	97.47	All	1,000 SF

INDUSTRY:				
General Light Industrial	0.92	0.97	52	1,000 SF
General Heavy Industrial	0.51	0.68	74	1,000 SF
Industrial Park	0.82	0.85	59	1,000 SF
Manufacturing	0.73	0.73	68	1,000 SF
Warehouse	0.3	0.32	156	1,000 SF
Miniwarehouse	0.14	0.26	192	1,000 SF
High Cube Warehouse	0.11	0.12	417	1,000 SF

FLORIDA DEPARTMENT OF TRANSPORTATION
2016 ANNUAL AVERAGE DAILY TRAFFIC REPORT - REPORT TYPE: ALL

COUNTY: 14 PASCO

SITE =====	SITE TYPE =====	DESCRIPTION =====	DIRECTION 1 =====		DIRECTION 2 =====		AADT TWO-WAY =====	"K" FCTR =====	"D" FCTR =====	"T" FCTR =====
0092		SR 52, EAST OF CR 577	E	6600	W	6600	13200 C	9.0	57.9F	10.6A
0093		SR 93/I-75, NORTH OF SR 52	N	E	S	E	40000 E	9.0	58.0F	17.5F
0094		SR 93/I-75, NORTH OF CR41 & SOUTH OF HERNANDO CO	N	22000	S	21500	43500 C	9.0	58.0F	17.5F
0106		SR 52, WEST OF SR 45/US 41	E	12000	W	11500	23500 C	9.0	57.9F	10.7A
0107		SR 52, EAST OF CR 1/LITTLE RD	E	19000	W	19500	38500 C	9.0	57.9F	4.8A
0108		SR 52, WEST OF MOON LAKE RD.	E	14500	W	14500	29000 C	9.0	57.9F	6.0A
0110		SR 55/US 19 NORTH OF CR 1, HUDSON BLVD	N	18500E	S	20000E	38500 S	9.0	57.9F	3.9P
0111		SR 35/SR 700/US 98/US 301, N OF LOCK STREET	N	11500	S	10500	22000 C	9.0	57.9F	10.4A
0156		SR 93/I-75, SOUTH OF SR 56 (NB FRONTAGE RD EXCLU	N	37500	S	62500	100000 C	9.0	57.9F	17.5F
0190	T	SR-93/I-75, 1.0 MI N OF SR-56,PASCO CO.	N	45283	S	44005	89288 C	9.0	58.0A	12.6A
0199	T	SR-55/US-19,1.4 MI N SR-54,NEWPORT RICHEY,PASCO	N	27084	S	27259	54343 C	9.0	55.3A	4.3A
2701		RP, CR54 TO SB SR93/I-75	S	E	E	12500 E	9.0	99.9W	17.5F	
2702		RP, SB SR93/I-75 TO CR54	S	E	E	2900 E	9.0	99.9W	17.5F	
2703		RP, NB SR93/I-75 TO CR54	N	E	E	12000 E	9.0	99.9W	17.5F	
2704		RP, CR54 TO NB SR93/I-75	N	3200	0	3200 C	9.0	99.9W	17.5F	
2705		RP, SR52 TO SB SR93/I-75		0E	0E	8500 T	9.0	99.9W	17.5F	

SITE TYPE : BLANK= PORTABLE; T= TELEMETERED

"K" FACTOR : DEPARTMENT ADOPTED STANDARD K FACTOR BEGINING WITH COUNT YEAR 2011

AADT FLAGS : C= COMPUTED; E= MANUAL EST; F= FIRST YEAR EST; S= SECOND YEAR EST; T= THIRD YEAR EST; R= FOURTH YEAR EST;
V= FIFTH YEAR EST; 6= SIXTH YEAR EST; X= UNKNOWN

"D/T" FLAGS : A= ACTUAL; F= FACTOR CATG; D= DIST FUNCL; P= PRIOR YEAR; S= STATEWIDE DEFAULT; W= ONE-WAY ROAD; X= CROSS REF

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