PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT B IGCC PROJECT

Prepared for:

OUC
The *Reliable* One℠
Orlando, Florida

and

SOUTHERN COMPANY
Energy to Serve Your World℠
Southern Power Company-
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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Orlando Utilities Commission (OUC) and Southern Power Company-Orlando Gasification LLC (SPC-OG) plan to construct, own, and operate a new integrated gasification combined-cycle (IGCC) power generation facility at the existing Stanton Energy Center located southeast of Orlando in Orange County, Florida. The new IGCC facility, which will be called Unit B, will gasify sub-bituminous coal and supply syngas fuel for the generation of a nominal 285 megawatts (MW) from a combined-cycle power plant. The Unit B IGCC project will support OUC's generation expansion plan and the company's obligation to provide reliable and economical electrical power to its existing and future customers.

Unit B will employ air-blown gasification technology to produce syngas from sub-bituminous coal. Unit B will be the first application of this gasification technology for power generation and is a demonstration project under the U.S. Department of Energy's (DOE) Clean Coal Power Initiative (CCPI). Since Stanton Energy Center is a certified site, the Unit B project is being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

The Stanton Unit B IGCC project can be divided into two major process groups: (a) coal gasification and (b) combined-cycle power generation. The coal gasification process converts pulverized coal into syngas and also includes processes that remove particulates, mercury, nitrogenous-compounds, and sulfur. The clean (or *sweet*) syngas resulting from the gasification process is used as fuel for the Unit B combustion turbine (CT). The CT is a part of the combined-cycle power process, which provides electricity to the electrical grid. Unit B will also include one fired heat recovery steam generator (HRSG) and one steam turbine (ST).

The Unit B CT will be primarily fired with coal-derived syngas. It will also have the capability of continuously firing natural gas. The Unit B HRSG will include DBs (DBs)

that will be fired exclusively with natural gas. The primary source of emissions from the Unit B IGCC process is combustion of syngas (or natural gas) in the CT.

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

Unit B will be located in an attainment area and will have potential nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), particulate matter less than or equal to 10 micrometers (PM_{10}), sulfur dioxide (SO_2), and sulfuric acid (H_2SO_4) mist emission that exceed the prevention of significant Deterioration (PSD) significant emission rate thresholds for *major* modifications. Consequently, Unit B qualifies as a major modification to an existing major facility and is subject to the PSD New Source Review (NSR) NSR requirements of Rule 62-212.400, F.A.C., for NO_x, CO, VOC, PM, PM_{10}, SO_2, and H_2SO_4 mist. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes the NSR requirements and discusses applicability of these requirements to the proposed project.
- Section 4.0 describes the applicable state and federal emission standards.
- Section 5.0 provides an analysis of best available control technology (BACT).

- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on the Chassahowitzka National Wildlife Refuge (NWR) Class I area.

Appendices A and B provide emission rate calculations and the FDEP Application for Air Permit—Long Form, respectively. All dispersion modeling input and output files for the ambient impact analyses are provided in Appendix C.

1.2 SUMMARY

The Unit B project will consist of coal gasification and combined-cycle power generation equipment. Emission units associated with the coal gasification process will include coal receiving, transfer, crushing, and storage, a flare that will be used during gasifier startups and process upsets, and a gasifier startup stack that will also be used during gasifier startups (i.e., during the gasifier preheat period). The primary Unit B emission source will be the combined-cycle power generation equipment. Ancillary emission sources include one, six-cell mechanical draft cooling tower.

The planned construction start date for Unit B is late 2007. Initial operation of the combined-cycle unit with natural gas-firing is planned for late 2009. Initial operation of the gasification portion of the project and syngas-firing of the combined-cycle unit is planned to occur during the first half of 2010.

Based on an evaluation of anticipated worst-case annual operating scenarios, Unit B will have the potential to emit 611.4 tons per year (tpy) of NO_x (Phase II), 653.5 tpy of CO, ~~174.0~~179.2 tpy of PM_{10}, 161.5 tpy of SO_2, and 128.9 tpy of VOCs. Regarding noncriteria pollutants, Unit B will potentially emit 24.0 tpy of H_2SO_4 mist and trace amounts of heavy metals and organic compounds associated with syngas and natural gas combustion. Based

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on these annual emission rate potentials, NO_x, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist emissions are subject to PSD review.

As presented herein, the analyses required for this permit application have resulted in the following conclusions. Since the primary Unit B emission source is the combined-cycle equipment, these conclusions primarily address this emission unit.

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. Unit B will be fired with low-sulfur, low-ash syngas and pipeline natural gas, and will use efficient combustion efficiency to minimize PM/PM_{10} emission rates. Water suppression, enclosure, and fabric filter technology will be used to control PM/PM_{10} emission from the coal and gasification ash material handling activities.
- Use of oxidation catalyst technology to control CO and VOC emissions from the IGCC unit is not technically feasible since this technology has not been demonstrated on any coal-fired IGCCs. In addition, oxidation catalysts are susceptible to deactivation due to a variety of impurities. Due to the lack of operating experience and potential catalyst deactivation, the performance and reliability of oxidation catalyst controls applied to syngas fired CT/HRSGs are unknown.
- OUC/SPC-OG will evaluate the viability of a selective catalytic reduction (SCR) control system to control NO_x emissions from an IGCC unit. The SCR control system, the first one to be installed on a coal-fired IGCC unit anywhere in the world, will be evaluated during the 4-year DOE demonstration period. Use of oxidation catalyst would also significantly exacerbate the formation of ammonium bisulfate by substantially increasing sulfur trioxide (SO_3)—up to 90 percent of SO_2 would be oxidized to SO_3 by an oxidation catalyst system. During syngas firing, this would significantly increase the formation of ammonium bisulfate.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as CO BACT for Unit B. At baseload operation during syngas and pipeline natural gas firing, Unit B CO exhaust con-

centrations without HRSG DB firing are projected to be 17 and 25 parts per million by dry volume dry (ppmvd) corrected to 15 percent oxygen (O_2) (ppmvd at 15 percent O_2), respectively. The corresponding syngas and natural gas CO exhaust concentrations with HRSG DB firing are 21 and 28 ppmvd at 15 percent O_2, respectively. These concentrations are consistent with prior FDEP CO BACT determinations for combined-cycle units.

- Advanced burner design and good operating practices to minimize incomplete combustion are also proposed as VOC BACT for Unit B. At baseload operation during syngas and pipeline natural gas firing, Unit B VOC exhaust concentrations without HRSG DB firing are projected to be 5.0 and 7.7 ppmvd at 15 percent O_2, respectively. The corresponding syngas and natural gas VOC exhaust concentrations with HRSG DB firing are 7.8 and 10.1 ppmvd at 15 percent O_2, respectively. These concentrations are consistent with prior FDEP VOC BACT determinations for combined-cycle units.
- Use of SCR technology to control NO_x emissions from the combined-cycle unit is not technically feasible since SCR has not been demonstrated on any operating coal-derived IGCC. Nor has it been installed on any coal-derived IGCC. The performance and reliability of SCR applied to coal-derived syngas fired CT/HRSGs are unknown.
- Unit B will employ air-blown gasification technology to produce syngas from sub-bituminous coal. Unit B will be the first application of this gasification technology for power generation. Actual performance of the Unit B gasification process, including the syngas clean-up components, will not be known with any certainty until the 4-year DOE demonstration period is completed. These uncertainties prevent SCR control technology from being considered applicable to Unit B when operating on syngas.
- Although the application of SCR is not considered technically feasible for Unit B while firing syngas, a major objective of the Unit B DOE demonstration project is to evaluate the viability of SCR control technology to syngas-fired CT/HRSG units. To achieve this objective, a two-phase NO_x reduction program during Unit B syngas-firing is proposed. For the first phase, a com-

bination of SCR operation and combustion tuning will achieve a NO_x concentration of 20 ppmvd at 15 percent O_2. This Phase I NO_x limit would be applicable during the 4-year DOE demonstration period. In Phase II, a SCR outlet NO_x concentration of 12 ppmvd at 15 percent O_2 is proposed as the limit that will become effective following completion of the 4-year DOE demonstration period. This limit will become effective unless the Phase I technical report demonstrates that Unit B cannot technically achieve this level of NO_x control. If the Phase II limit is shown to be unachievable, the final Unit B CT/HRSG NO_x emission limit would be set at the lowest level demonstrated to be achievable and no higher than the Phase I limit.

- For the Unit B CT/HRSG during natural gas-firing, use of the SCR control technology installed for syngas evaluation purposes is proposed as BACT. Consistent with recent FDEP BACT determinations for natural gas-fired combined cycle units, SCR control technology achieving 80 percent NO_x reduction (i.e., 5.0 ppmvd NO_x at 15 percent O_2) with 5 ppmvd ammonia slip is proposed as NO_x BACT for Unit B during natural gas-firing.
- BACT for SO_2 and H_2SO_4 mist will be achieved through the exclusive use of low-sulfur syngas and pipeline natural gas.
- Unit B is projected to emit NO_x, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the Unit B project qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(260), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class I and II increment consumption was not required.

- Based on refined dispersion modeling, Unit B will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Chassahowitzka National Wildlife Refuge) is located approximately 144 kilometers (km) northwest of the project site. Air quality related value and visibility impacts at this Class I area will be negligible.

2.0 PROJECT DESCRIPTION

2.1 PROJECT LOCATION, AREA MAP, AND PLOT PLAN

The Stanton Unit B IGCC facility will be constructed on a portion of the approximately 3,280-acre site of OUC's existing Stanton Energy Center located southeast of Orlando in Orange County, Florida. Figure 2-1 shows the general location of the Stanton Energy Center within the state of Florida. Figure 2-2 shows the Stanton site relative to Orlando, including nearby major roadways.

Approximately 1,100 acres of the 3,280-acre site have been licensed by the state of Florida for an ultimate site capacity of up to 2,000 MW of power generation and supporting facilities. Stanton Unit B will be constructed within this licensed 1,100 acres. Most of the remaining 2,180 acres of the Stanton Energy Center site has been left in its preexisting condition and provides buffer between the main generating units and the surrounding area. Figure 2-3 provides a recent aerial photograph of the plant site and immediate surroundings.

The major equipment associated with Stanton Unit B will be located south of Stanton Unit A and north of the existing Stanton Energy Center coal-fired units. Figure 2-4 shows the major process equipment and structures associated with Unit B.

2.2 PROJECT DESCRIPTION AND FLOW DIAGRAM

The Stanton Unit B IGCC project can be divided into two major process groups: coal gasification and combined-cycle power generation. The coal gasification process converts pulverized coal into syngas and also includes processes that remove particulates, mercury, nitrogenous compounds, and sulfur. The clean *sweet* syngas resulting from the gasification process is used as fuel for the Unit B CT. The CT is a part of the combined-cycle power process, which provides electricity to the electrical grid. Figure 2-5 provides an overall block flow schematic diagram of the proposed project outlining the gasification and combined-cycle islands.

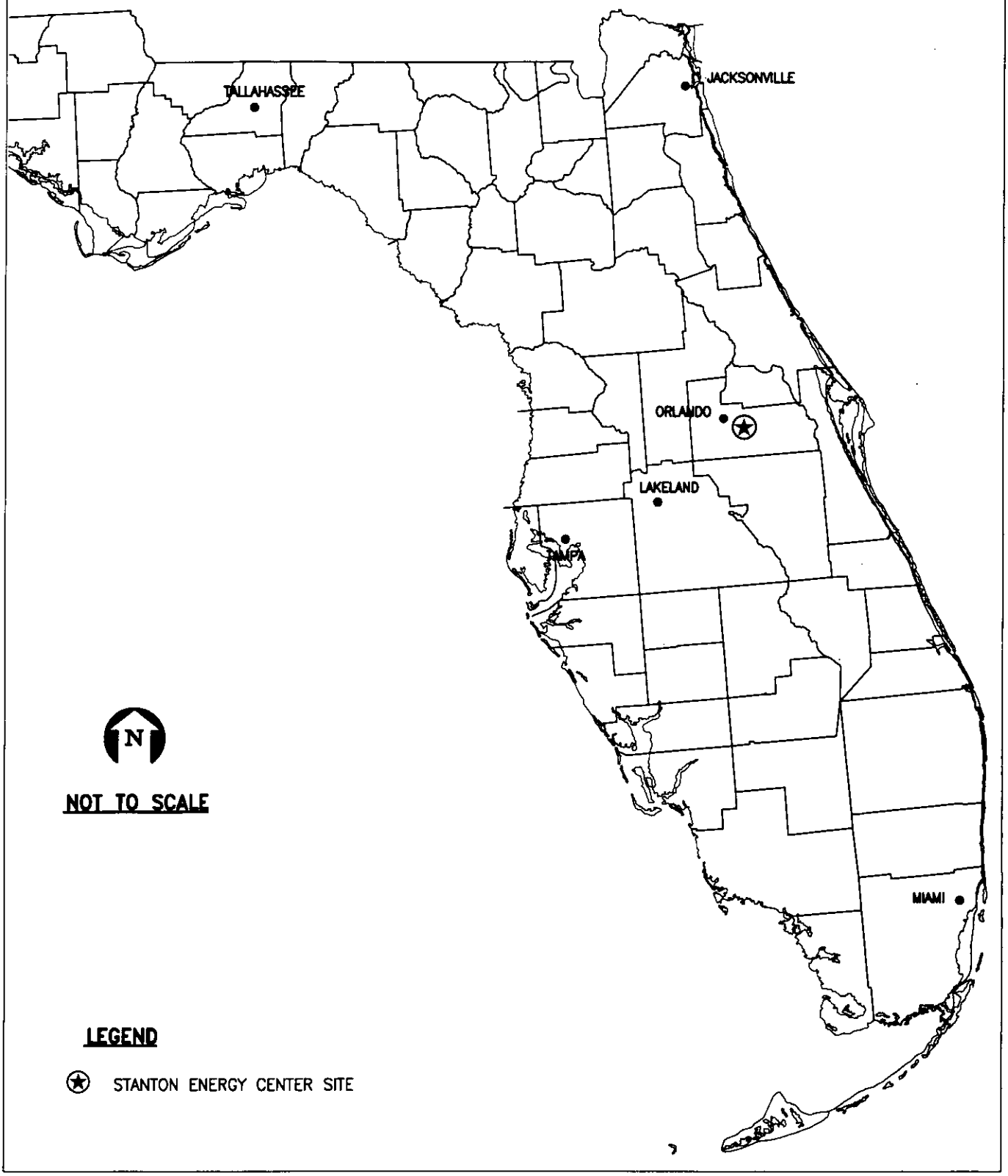

FIGURE 2-1.

LOCATION OF THE STANTON SITE WITHIN THE STATE OF FLORIDA

Source: ECT, 2005.

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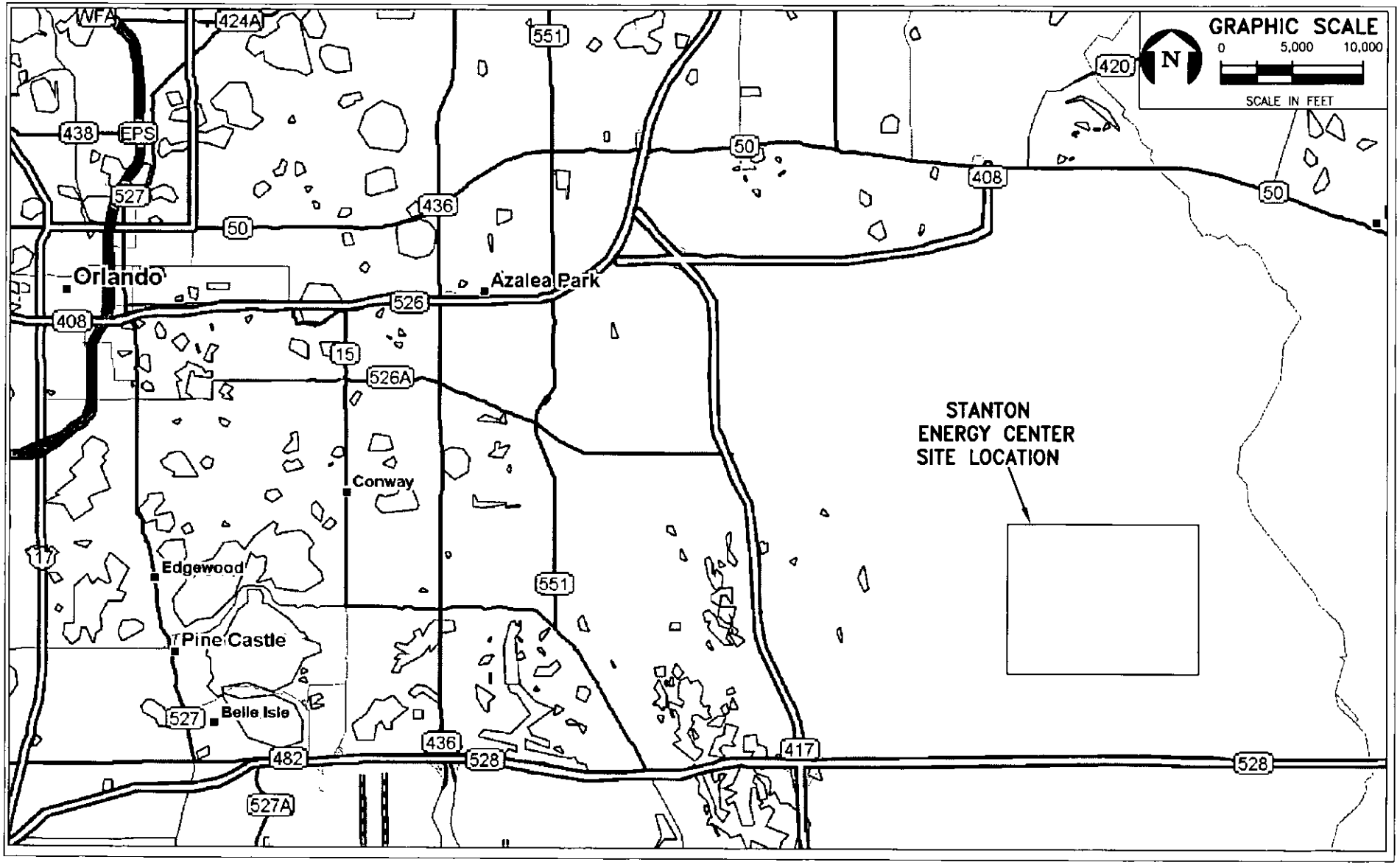

FIGURE 2-2.
STANTON SITE LOCATION RELATIVE TO ORLANDO

Source: DeLorme, 2003; ECT, 2005.

ECT
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M:/ACAD/05 area.mxd

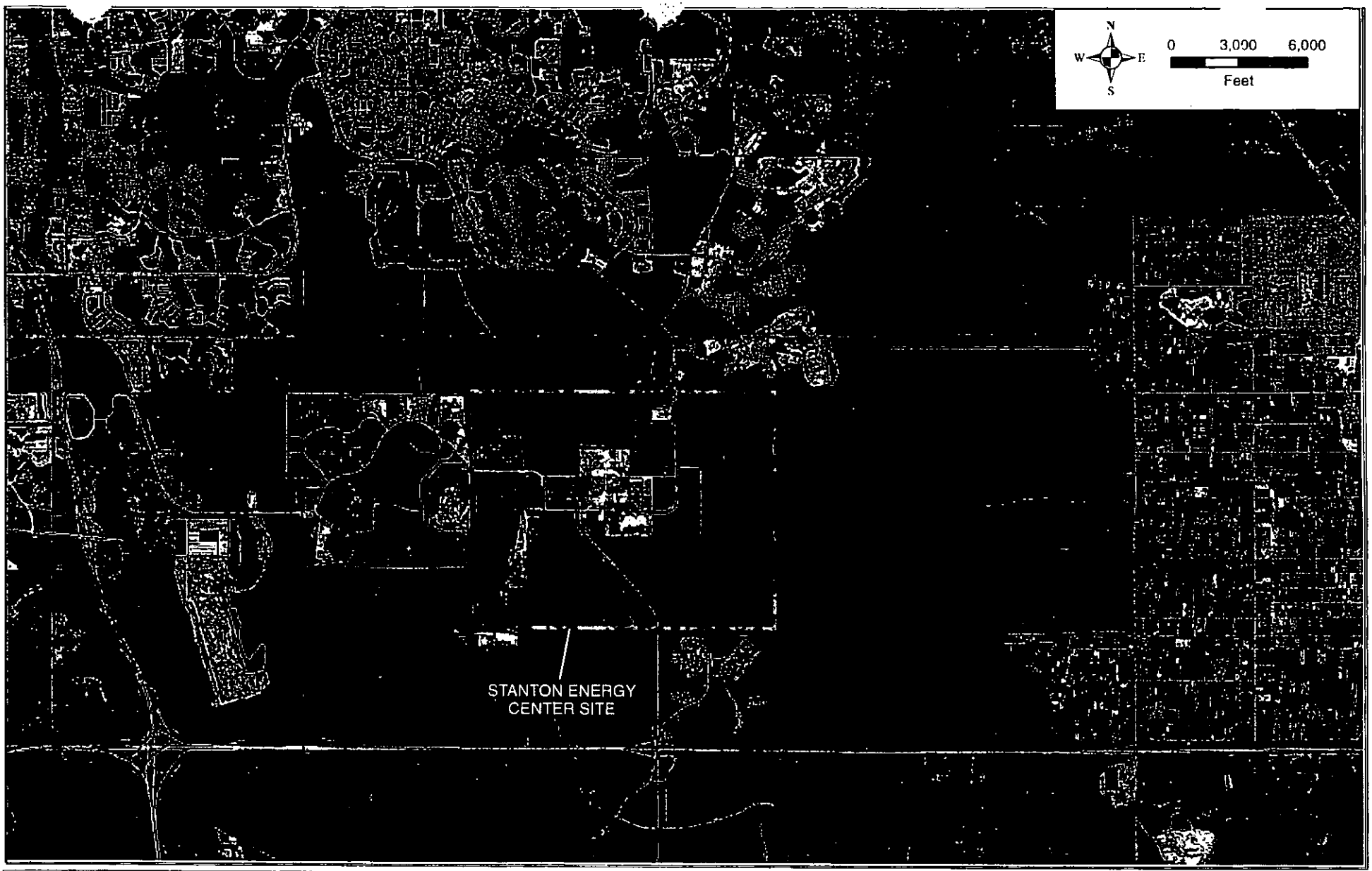

FIGURE 2.3.
2004 AERIAL OF STANTON SITE AND SURROUNDING AREA

Sources: SJRWMD Aerials, 2004; ECT, 2005.

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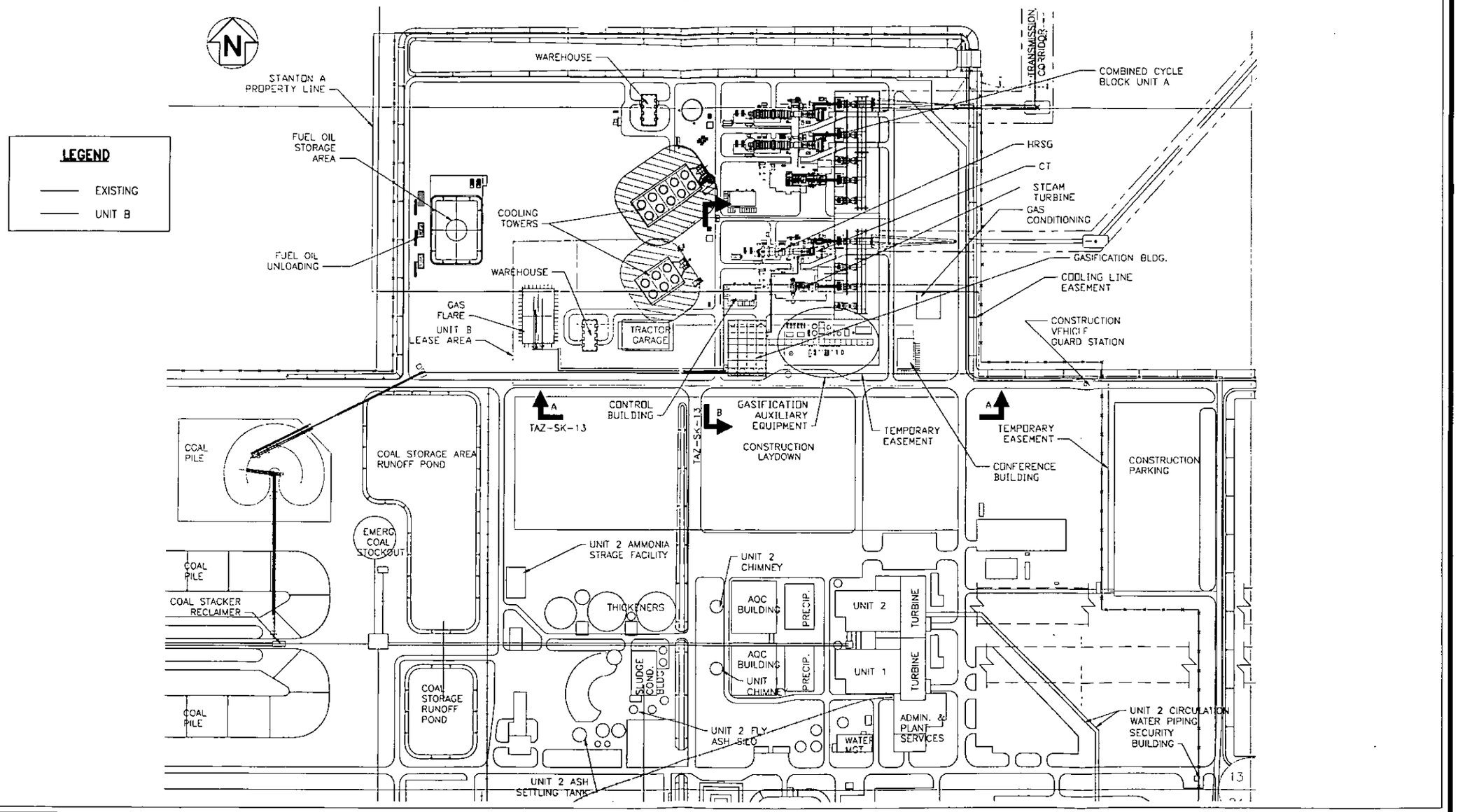

FIGURE 2-4.

DETAILED ARRANGEMENT

Source: SCS, 2006.

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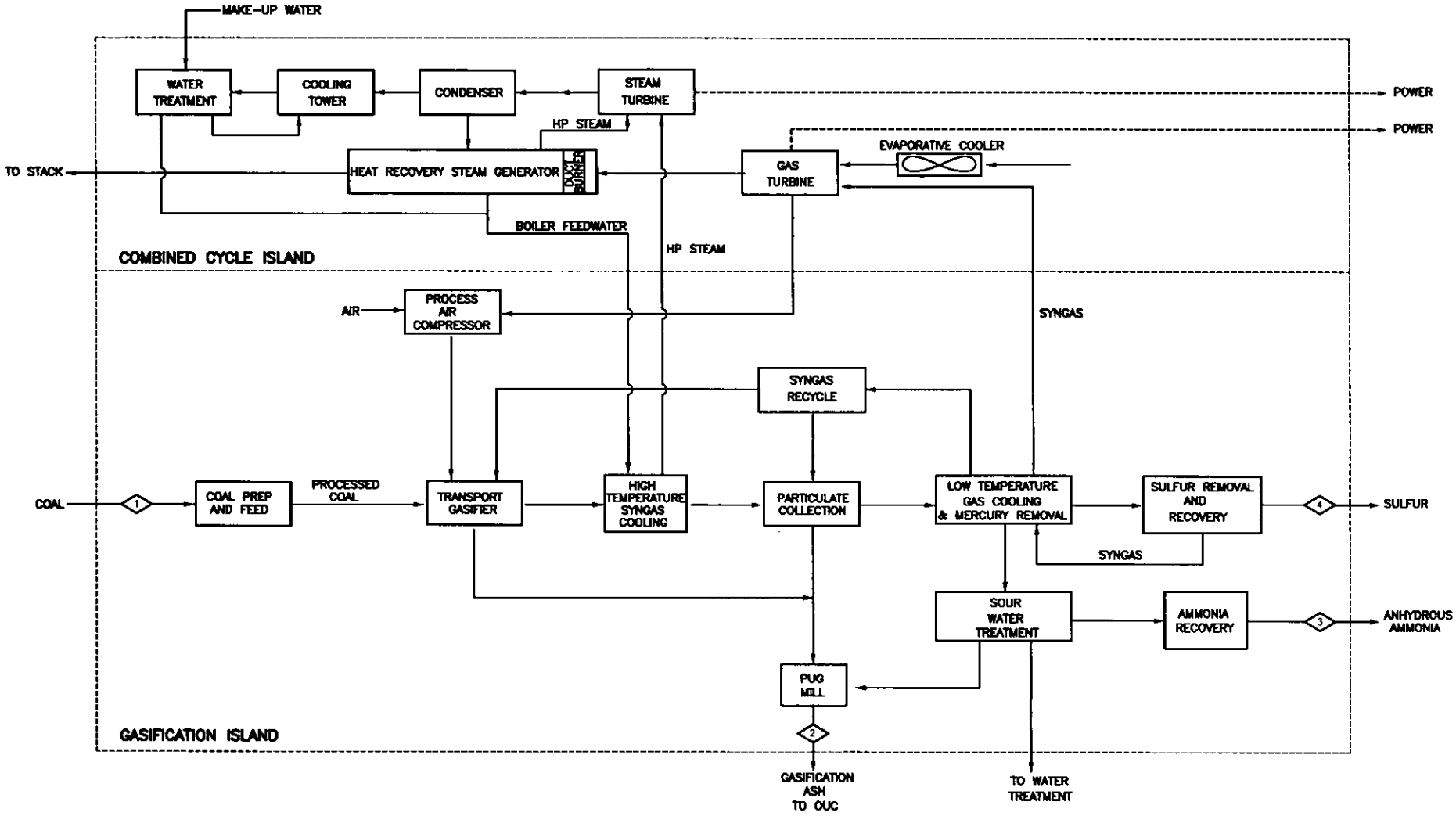

FIGURE 2-5.
OVERALL PROCESS FLOW DIAGRAM

Source: SCS, 2005.

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Major components of Unit B include:

- Coal receiving, storage, handling, and preparation equipment.
- Two air-blown transport gasifiers.
- Syngas treatment equipment, including particulate, sulfur, mercury, and nitrogen compound removal.
- Flare for syngas combustion during startups and plant upsets.
- One combined-cycle unit comprised of one F-Class CT fired with either syngas or natural gas, one HRSG equipped with natural-gas fired DBs, and one ST generator (i.e., 1-on-1 configuration).
- One six-cell mechanical draft, fresh water cooling tower.
- Ancillary equipment, including process water treatment.

The following sections further describe the individual IGCC processes.

2.2.1 GASIFICATION PROCESS

The gasification island will employ two identical gasifier trains. Once the coal enters the gasification island structure, it will be separated to feed the two parallel trains. Each gasification train is designed to produce 50 percent of the total syngas requirement for the CT.

With two exceptions, the equipment in each gasifier train will be completely separate, and the two syngas streams will be combined just prior to combustion in the CT. The two exceptions are a common startup stack and a multipoint flare that will be shared between the two gasifiers. The startup stack will vent emission from the gasifier during startup operations. During startup, the gasifier will fire natural gas until the gasifier temperature reaches a temperature suitable for coal combustion. The multipoint flare will also be used during startup when the gasifier fuel switches from natural gas to coal. Otherwise, the flare will only be used during upset conditions allowing safe release of the pressurized syngas.

Fugitive emissions of gaseous-phase compounds may be generated within the gasification island. The potential sources will be leaks from equipment such as valves, compressor seals, and flanges. These emissions will be minimized by good operating and maintenance practices. In addition, area gas detectors will be used to alert plant staff of fugitive gas emissions.

The design coal feed rate to each gasifier will be approximately 68.5 tons per hour (ton/hr) for a total of 137 ton/hr. The gasification system is designed to process low-sulfur Powder River Basin (PRB) sub-bituminous coal. Carbon conversion is projected to be 97 percent. The syngas sulfur content, as well as the content of other pollutants present in the PRB coal, will be reduced prior to combustion in the CT. Each gasifier will produce approximately 225 ton/hr of syngas (for a total of 450 ton/hr) having a lower heating value (LHV) of approximately 125.7 British thermal units per standard cubic foot (Btu/scf). Table 2-1 summarizes the main inputs to and outputs from the gasifier. The numbers listed in Table 2-1 correspond to the numbers shown in Figure 2-5.

2.2.1.1 Coal Receiving, Storage, Preparation, and Handling

The design coal is sub-bituminous PRB with an as-received higher heating value (HHV) of 8,760 British thermal units per pound (Btu/lb) and 0.26-percent sulfur. The conveyor delivers the coal into a hopper, where a belt conveyor delivers it to a radial-pedestal stacker conveyor that forms a kidney-shaped pile with a capacity of 170,000 tons, equivalent to 45 days of live storage at the design feed rate. The coal from the live-storage section of the pile will be discharged onto a reclaim belt conveyor and then delivered to the crusher shed. After passing through tramp screens, a magnetic separator, and an automatic sampling system, a single crusher reduces the coal size from 3 to 0.75 inch. The crushed coal is transported on a belt conveyor to a tripper conveyor in the process structure and then into crushed coal silos.

A screw conveyor feeds crushed coal from each storage silo to its dedicated pulverizer. The pulverizers are roll-mill crushers using hot gas to dry the coal. The inert, recirculating drying gas enters at the base of the pulverizer, and this mixture of pulverized coal and gas is conveyed to a cyclone, where the majority of the coal is removed and falls through

Table 2-1. Expected Operating Characteristics—Input and Output Quantities Specific to Transport Gasifier Island

		Description	Quantity
	Inputs		
1	Coal	Designed for PRB sub-bituminous coal used to produce syngas	137 ton/hr
	Sand	Used once at initial startup to make up gasifier bed; the bed material may be recycled, reducing/eliminating the need for additional sand; additional requirements of sand to be determined by operational experience	62 tons (for initial startup)
	Natural gas	Used during startup/trips/transitional periods of gasifier operation as needed	50 (flare pilot) to 31,000 lb/hr (during startup)
	Nitrogen	Inerting gas, purge flow	Nitrogen plant capacity = 30 ton/hr
	Outputs		
	Syngas	Coal derived syngas produced by gasifier for combustion in CT	890,000 lb/hr (gasifier island at full load)
2	Gasification-ash (g-ash))	Fine g-ash removed from hot-gas filter vessel (possibly some from gasifier); contains more carbon than combustion ash does	18,300 lb/hr
3	Anhydrous ammonia	Ammonia removed in scrubber and captured in sour water treatment plant	1,960 lb/hr
4	Sulfur	Product of sulfur recovery process	760 lb/hr

Source: ECT, 2006.
SCS, 2005.

a rotary pressure seal into a surge bin. The dusty gas then flows to a baghouse where the coal is separated and discharged through a rotary pressure seal into the same surge bin. An induced-draft fan after the baghouse drives the gas through the drying circuit.

The pulverized coal is transferred from the surge bin by gravity to a high-pressure coal feeder. The coal enters the feeder at atmospheric pressure, and the pressure is then increased to the operating pressure of the gasifier.

The coal receiving, handling, storage, and feed preparation will result in small quantities of fugitive and point PM/PM_{10} emissions. These emissions will be limited by a variety of emission control systems including rail car unloading in the existing Stanton Energy Center enclosed building, enclosure of coal conveyors, and use of baghouse technology at key material transfer points. The existing Stanton Energy Center coal receiving system is equipped with water spraying controls that will be also used to minimize fugitive particulate emissions when handling PRB coal.

2.2.1.2 Transport Gasifier

The design of the transport gasifiers is based on KBR's FCC technology and SCS's operating experience at the PSDF. Each of the two transport gasifiers will be designed to convert the 68.5 ton/hr of PRB coal into approximately 450,000 pounds per hour (lb/hr) of syngas (850 million British thermal units per hour [MMBtu/hr]). The gasifiers will be constructed from refractory-lined pipe.

Nearly 350 ton/hr of compressed air are supplied to the two gasifiers during operation. This air originates from two sources; roughly 25 percent of the air will be extracted from the combined-cycle unit's CT, and the balance is ambient air.

Coal and air are fed into the mixing zone at the base of the gasifier and mixed with gasifier ash recirculated through the gasifier. Gasifier ash is primarily coal ash and unreacted carbon but may contain sand. Oxygen in the air is consumed by carbon present in the recirculating ash, forming primarily CO, and releasing the heat required to maintain reactor temperature. The KBR design for the gasifier results in a syngas with more methane than

that from other fluidized bed gasifiers. The hot recirculating ash heats the coal rapidly, minimizing tar formation.

The syngas and gasification ash pass to a disengager where larger, denser particles are removed by gravity and fall toward the bottom of the gasifier. The syngas from the disengager passes to a cyclone where most of the remaining gasification ash is directed toward the bottom of the gasifier. The syngas leaving the cyclone passes to the high-temperature syngas cooler, and after cooling, passes along a metal alloy pipe to the high temperature, high pressure (HTHP) filter for final particulate removal.

To maintain constant gasifier bed inventory, gasification ash can be removed periodically from the lower region of the standpipe. The gasification ash, still at pressure, flows through a bank of cooling tubes and heat passes into the condensate system. Gasification ash will be wetted to reduce potential fugitive dust emissions during handling.

During startup, natural gas-fired startup burners are used to heat the gasifier to a point where coal combustion can begin. Once the gasifier reaches the necessary temperature, coal feed begins, and the temperature is increased. From the initial startup to this time, the atmosphere in the gasifier is oxidizing, and the gas produced has no heating value (flue gas). Therefore, if the gas were sent to the flare, natural gas would need be added to produce a combustible mixture. Accordingly, the flue gas exhaust will be vented to the startup stack.

Once the gasifier is at the proper temperature, the airflow is reduced until the atmosphere in the gasifier is reducing. At that point, the coal is being gasified and syngas is being produced. Initially, the flow of syngas will be insufficient to send to the CT and therefore will be sent to the flare. Varying amounts of syngas will be combusted by the flare as the syngas production of the gasifier is increased. When the gasification island reaches a syngas production level at which it can support operation of the CT, the syngas will be diverted from the flare to the CT.

The length of time of this entire startup sequence will vary based on a number of factors, including the starting temperature of the gasifier. During a cold start of the gasifier, it is expected it may take up to 24 hours to begin sending syngas to the CT due to the length of time required to heat the gasifier refractory. This would include approximately 17 hours of exhausting flue gas through the startup stack and approximately 7 hours of combusting syngas in the flare. Prior to being exhausted through the startup stack, the flue gas will go through the particulate filtration process. Syngas that is flared will first flow through the gas clean-up processes.

2.2.1.3 High Temperature Syngas Cooling

As shown in Figure 2-5, the syngas stream leaving each gasifier cyclone passes to a high temperature syngas cooler that lowers the syngas temperature before it enters the HTHP filter system. The heat transferred is used to raise the temperature of high-pressure super-heated steam. The heat duty of each syngas cooler is approximately 190 MMBtu/hr.

The syngas cooler consists of three stages: an evaporator, a superheater, and an econo-mizer. The evaporator has a natural circulation steam drum operating at above ST inlet pressure and at saturated temperature. The steam raised in the evaporator is passed to a superheater, where it is heated to the ST inlet temperature. This steam is mixed with the superheated steam exiting the combined-cycle unit's HRSG before passing into the ST. Boiler feed water enters the economizer and is heated to near saturation before entering the steam drum.

All three coolers are shell and tube heat exchangers, with the particulate-laden syngas flowing downward in a single pass through vertical tubes. The cooling fluid, water or steam, flows upward in a single pass through the shell side of the exchanger.

2.2.1.4 Particulate Collection

Particulate-laden syngas leaves the high temperature syngas cooler and enters the HTHP filter system. The filter system uses rigid, barrier-type filter elements to remove essen-tially all of the particulate in the syngas stream. Recycled syngas is used to pulse clean the filters as they accumulate particulate from the unfiltered syngas. The cleaned syngas

particulate loading is projected to be less than 0.1 part per million by weight (ppmw). Downstream of each filter element, a safeguard device is installed to protect the combustion turbine from particulate-related damage in the event of a filter element failure.

Each of the two HTHP gas filter systems removes approximately 5 ton/hr of fine particulate from the syngas stream. The particulate (gasification ash) is cooled and depressurized to atmospheric pressure before leaving the gasifier island.

The syngas streams exit the filter vessels and flow to the low-temperature heat recovery system. The fine ash, still at pressure, flows down through a bank of cooling tubes and the heat is transferred to the condensate system. The cooled solids pass into a proprietary continuous fine ash removal system.

2.2.1.5 Low Temperature Gas Cooling and Mercury Removal

Before the filtered syngas leaving the HTHP filters is combusted in the CT, sulfur, mercury, and nitrogenous-compound content is decreased. Cooling the syngas facilitates removal of these species, along with hydrocarbons, fluorides, and chlorides. Recuperative exchangers are incorporated in the cooling circuits to keep the final *sweet* syngas (syngas with sulfur removed) temperature high and so help preserve thermal efficiency.

The syngas leaves each HTHP filter and is cooled to the operating temperature of the sulfur removal process using high- and medium-temperature recuperators. Both coolers condense water and certain hydrocarbons from the *sour* syngas (i.e., syngas that has not gone through the sulfur removal system). The water dissolves almost all the nitrogenous compounds, chloride, and fluoride present along with lesser amounts of carbon dioxide (CO_2), CO, hydrogen sulfide (H_2S), and carbonyl sulfide (COS). This aqueous mixture is removed from the syngas flow in a knockout drum after the last cooler and passed to the sour water treatment plant. An aqueous scrubber is located downstream of these exchangers to further reduce the ammonia and other constituents in the syngas. The gas then flows into the sulfur removal process for H_2S removal before reentering the low-temperature gas cooling area to be reheated and then combusted in the CT.

As the gas is being cooled, it flows through additional gas cleanup processes. One of these is a COS hydrolysis unit that catalytically converts most of the COS to H_2S. The desulfurization process will not remove COS from the syngas stream, so the COS is converted to H_2S to minimize sulfur emissions. The reaction takes place over an alumina-based catalyst. The second reactor is a packed bed of sulfur-impregnated activated carbon to remove mercury from the syngas.

2.2.1.6 Sulfur Removal and Recovery

Syngas leaves the low-temperature gas cooling system at a temperature slightly above ambient and enters the sulfur removal process. In this process, the syngas is contacted with a solvent that removes a high percentage of the H_2S from the syngas stream. The H_2S in the solvent is converted to elemental sulfur, which is sold as a by-product. The solvent is regenerated and returned to the sulfur removal process. The sweet syngas leaves the contactor at a temperature slightly above ambient and then reenters the low-temperature gas cooling process where the syngas is heated before it is combusted in the CT.

Prior to final recuperation, approximately 2 percent of the sweet syngas is removed and passed to the syngas recycle system. Some of this syngas is sent to the pulse-gas reservoirs and used to pulse clean the HTHP filters, and the remainder is used for aeration in the gasifier.

The combined-cycle unit's CT compressor provides the combustion air for the syngas and approximately 25 percent of the air required by the gasifier at full load. The remaining air required is delivered by a motor-driven process air compressor.

2.2.1.7 Sour Water Treatment and Ammonia Recovery

The water removed by the coal preparation system, the process air compressor intercoolers, water condensed from the syngas in the low-temperature gas cooling process, and water produced in the sulfur removal process is collected and sent to the single sour water treatment and ammonia recovery unit that treats approximately 150 gallons per minute (gpm) of *sour water*. The combined water flow passes to a filter to remove particulate

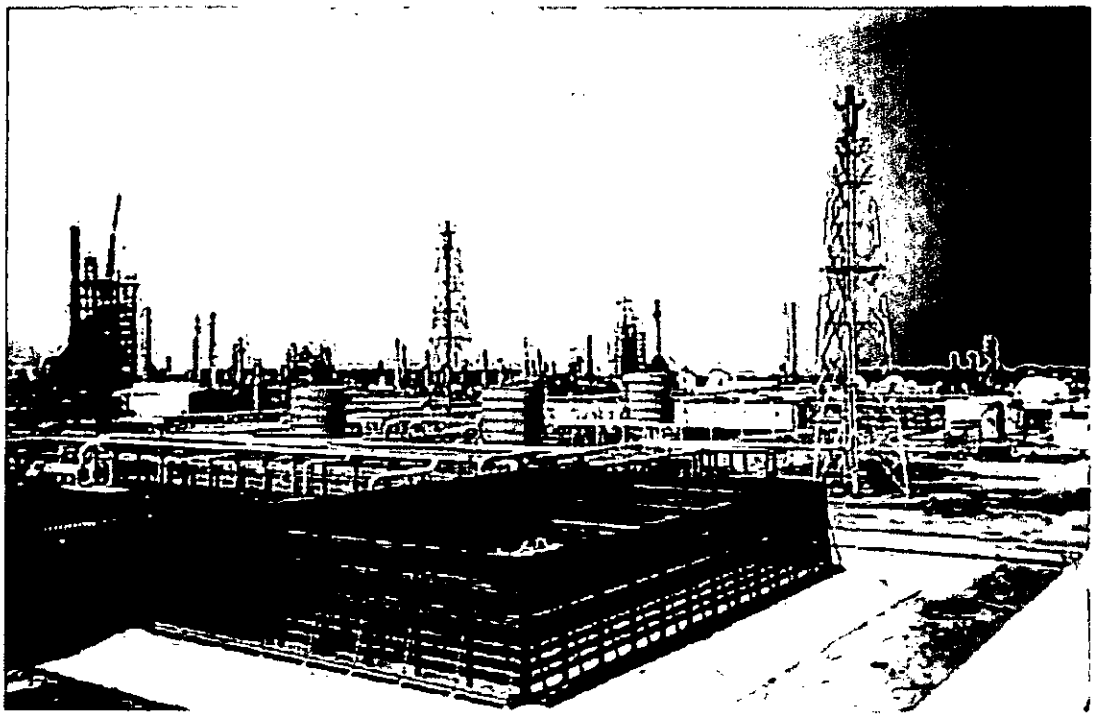
and an activated carbon bed to remove organic material before entering a degassing drum. The ammonia in the water retains most of the dissolved H_2S, and the gas released is mainly light hydrocarbons, which pass to the vent gas recycle header. The filter cake and spent activated carbon will be disposed of in a manner that complies with applicable regulations.

Next, the sour water is heated in a stripped-water recuperator and passed to the steam-heated H_2S stripper where H_2S, hydrogen cyanide (HCN), CO, and CO_2 are released and passed to the vent gas recycle header. The header syngas stream is compressed and injected into the oxidation zone of the gasifier, where the HCN is destroyed. The water from the H_2S stripper discharges to the steam-heated ammonia stripper to produce a concentrated ammonia solution. The water drawn from the bottom of the ammonia stripper passes to the stripped-water recuperator and is pure enough for plant reuse.

The concentrated ammonia solution is further processed in two additional steam-heated strippers, the first releasing any remaining dissolved H_2S into the vent gas recycle header and the second increasing the ammonia concentration to 99.7 percent. The water drawn from the bottom of the columns is sufficiently pure for plant reuse. The ammonia produced is commercial-grade anhydrous ammonia, which OUC and SCS intend to use at Stanton in the other, existing onsite generating units. Excess anhydrous ammonia may be sold in the commercial market.

2.2.1.8 Flare

Although not shown in Figure 2-5, the gasification island will be equipped with a flare to combust syngas during startup and during plant upsets, such as a trip of the combined-cycle unit's CT. A *multipoint* flare system will be used for Stanton Unit B and has been selected in preference to the more conventional stack flare design. The multipoint design, like the stack design, is well proven in the petrochemical industry and has been installed in hundreds, if not thousands of applications. Figure 2-6 shows two photographs of representative applications of the multipoint flare system similar to that planned for Stanton Unit B.



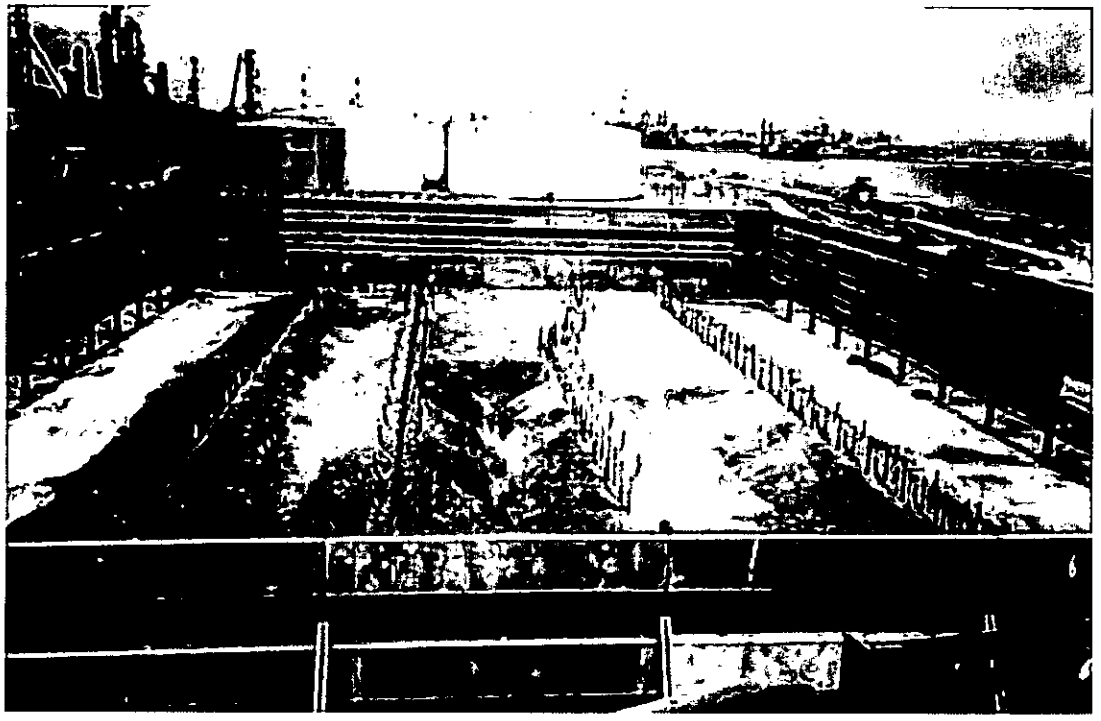


FIGURE 2-6.

TWO REPRESENTATIVE APPLICATIONS OF MULTIPOINT GROUND FLARE SYSTEM

Source: Callidus, 2005.

ECT
Environmental Consulting & Technology, Inc.

Relative to stack flares, the multipoint flare is a newer technology and was developed to resolve aesthetic issues (e.g., visual impacts) related to flares. Instead of having a single stack that is 100 to 200 feet (ft) tall with a single flame that may also be several hundred feet long and visible for many miles, the multipoint flare divides the gas into a number of smaller flames. These flames will be placed behind a thermal barrier fence. The multipoint design places the burners only approximately 10 ft above ground level. For this project the flare system will have a footprint of approximately 214 by 123 ft. The surrounding thermal barrier fence will be 20 ft tall. Flame temperature when fully employed will be approximately 1,800 degrees Fahrenheit (°F), and flame height will rise to approximately 40 ft above the burners at full load. The flame will be smokeless and invisible during the day (only shadows of the heat effects will be visible). At night, the blue/purple flame will be visible for some distance. Eight pilots fired with natural gas at a flow rate of 80 standard cubic feet per hour (scf/hr) per pilot will be on at all times.

The flare for the gasification trains will normally have only minimal emissions associated with the natural gas-fired pilot flame. Higher emission rates will occur during startup and shutdown of the IGCC unit and during facility upsets. Appendix A provides detailed estimates of flare emissions.

2.2.2 COMBINED-CYCLE PROCESS

The Unit B combined-cycle island power block will consist of a CT/generator unit with a dedicated HRSG, a single ST generator (i.e., a 1-on-1 CT/HRSG configuration), and associated auxiliary and control systems. The CT/HRSG unit will be constructed to allow only combined-cycle operation (i.e., the CT will not have a bypass stack allowing simple-cycle operation). The HRSG will be equipped with natural gas-fired DBs to boost power generation capability during periods of peak demand. Figure 2-7 provides a simple schematic of a basic combined-cycle system showing a CT, an HRSG, and other key components.

The Unit B combined-cycle unit will capable of continuous operation for up to 8,760 hr/yr firing either syngas or natural gas. The total nominal generation capacity for

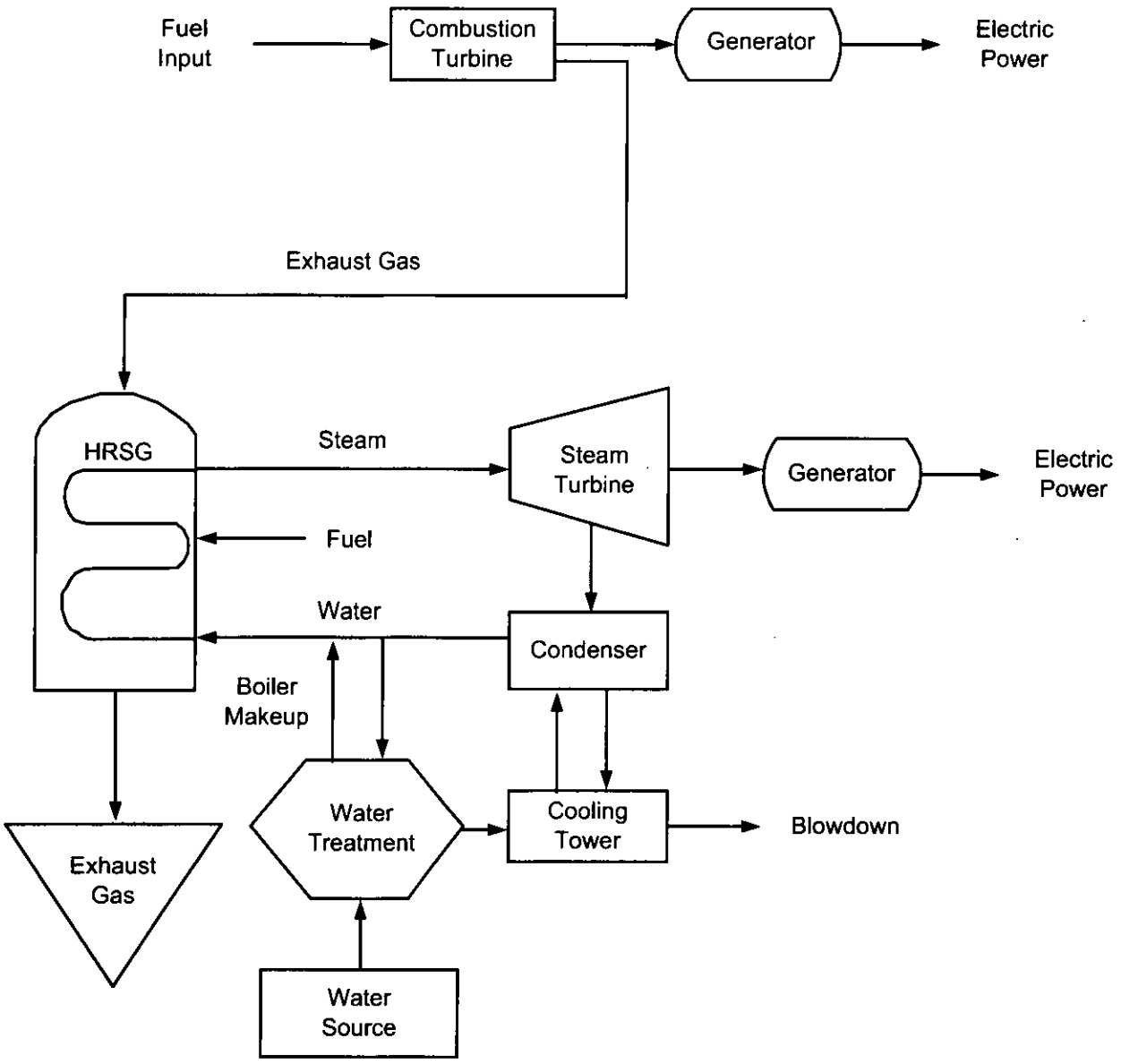


FIGURE 2-7.

SIMPLIFIED FLOW DIAGRAM OF A BASIC COMBINED-CYCLE POWER SYSTEM

Source: ECT, 2005.

ECT
Environmental Consulting & Technology, Inc.

Stanton Unit B will be 285 MW at base load and firing syngas. When fired only with natural gas, Unit B will generate a nominal 310 MW of electricity.

Combustion of syngas and natural gas within the CT and HRSG will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, H_2SO_4 mist, and trace amounts of metallic and organic compounds including HAPs. The CT/HRSG emissions will be the primary source of pollutants from Unit B. Appendix A provides detailed emission estimates for the Unit B combined-cycle unit.

Emission control systems proposed for the CT/HRSG unit include the use of diluent injection and SCR for control of NO_x, good combustion practices for abatement of CO and VOCs, and use of low-sulfur, low-ash gaseous fuels to minimize PM/PM_{10}, SO_2, H_2SO_4 mist, and HAP emissions. Discussions of the specific emission control systems proposed for each Unit B emission source are provided in Section 5.0, Best Available Control Technology.

2.2.2.1 Combustion Turbine

The current IGCC design basis assumes a General Electric (GE) 7FA gas turbine (or CT) will be used. GE has designed and built 20 CTs (primarily 7FA designs) for operation on syngas from oxygen-blown gasifiers, including the Wabash River and Polk Power Station Clean Coal Technology Demonstration Projects, which employ coal-based oxygen-blown IGCC technologies.

The thermal and environmental performance understanding developed from GE's test-stand data and commercial projects have been shared with SCS's engineering staff in preparation for the Unit B design. To prevent flashback caused by the hydrogen content of the syngas, the CT will utilize diffusion flame-type combustors. These combustors are also capable of burning natural gas.

The Unit B F-Class CT will be capable of producing a nominal 160 and 175 MW of electricity firing syngas and natural gas, respectively. The CT will normally operate between

50- and 100-percent load while firing natural gas, and between 75- and 100-percent load while firing syngas.

CTs are advanced technology engines that convert latent fuel energy into mechanical energy using compressed hot gas (i.e., air and products of combustion) as the working medium. CTs deliver mechanical energy by means of a rotating shaft that is used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. In the CT cycle, ambient air is first filtered and then compressed by the CT compressor section. The CT compressor section increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with fuel, which is ignited in the CT's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases expand and drive the CT's turbine section to produce rotary shaft power. The turbine rotor is coupled to an electric generator as well as to the CT combustion air compressor rotor.

The power block will be equipped with a multicell wet evaporative mechanical draft cooling tower for the purpose of providing the cooling necessary to condense the steam that exhausts from the ST. A water-cooled steam surface condenser will also be used, and the condensate will be collected in the hot well of the condenser and pumped back to the HRSG. Cooling water will be supplied to the surface condenser from the multicell cooling tower.

2.2.2.2 Heat Recovery Steam Generator

When CTs are used as simple-cycle (stand-alone) units, the hot combustion gases are released to the atmosphere at approximately 1,000°F after they have passed through the turbine. The efficiency of a power plant's electric power production is significantly improved when the simple-cycle design is modified to include an HRSG and a ST in what is termed a combined-cycle power plant. In a combined-cycle system, the heat in the CT exhaust gases is used to generate steam in an HRSG, where gas temperatures are reduced to approximately 270°F before release to the atmosphere. The steam is then used to drive a ST and generator to produce additional electricity, as previously shown in Figure 2-7.

The Unit B CT exhausts into a conventionally designed, triple-pressure level HRSG. When operating on syngas, the normal HRSG gas exit temperature is above the acid dew point temperature and eliminates problems with wet corrosion.

Condensate from the ST condenser is used for cooling in the gasification process and then returned to the HRSG and further heated before being deaerated. High-, medium-, and low-pressure superheated steam are raised in the HRSG and sent to the ST. High-pressure feed water is also sent from the HRSG to the gasifier island, where it is used in the syngas cooler to raise high-pressure superheated steam, which is also sent to the ST.

High-pressure superheated steam from the syngas cooler and the HRSG enters the ST. Steam exhausted from the high-pressure turbine is reheated in the HRSG, expanded through the intermediate- and low-pressure turbines, and then condensed.

The HRSG unit will be capable of auxiliary DB firing with natural gas. The HRSG unit will furnish steam to one ST for additional nominal 135 MW generation of electricity.

2.2.2.3 Cooling Tower

The Unit B power block will be equipped with a multicell wet evaporative mechanical draft cooling tower for the purpose of providing the cooling necessary to condense the steam that exhausts from the ST. A water-cooled steam surface condenser will also be used, and the condensate will be collected in the hot well of the condenser and pumped back to the HRSG. Cooling water will be supplied to the surface condenser from the multicell cooling tower.

2.3 EMISSIONS AND STACK PARAMETERS

The primary source of Unit B emissions results from the combustion of syngas in the CT. Emissions from the combined-cycle unit stack are primarily NO_x, SO_2, CO, VOC, PM, H_2SO_4 mist, and other trace constituents. Similar constituents will be emitted from the combined-cycle unit when firing natural gas.

Tables 2-2 through 2-4 provide maximum hourly criteria pollutant CT/HRSG emission rates for syngas and natural gas firing. These estimates are based in part on the best information available and best engineering judgment. Since the detailed design of Stanton Unit B will develop with time, these estimates do contain some amount of uncertainty. Maximum hourly emission rates for all pollutants, in units of lb/hr, are projected to occur for CT operations at low ambient temperature (i.e., 20°F), baseload, and syngas firing. Appendix A provides the bases for these emission rates.

Tables 2-5 and 2-6 provide maximum Unit B HAP emission rates for syngas and natural gas firing, respectively. The highest hourly emission rates for each pollutant are prescribed, taking into account load and ambient temperature to develop maximum hourly emission estimates. HAP emissions consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of syngas and natural gas.

Table 2-7 presents projected maximum annualized criteria and HAP emissions for the Stanton Unit B IGCC project.

Tables 2-8 and 2-9 provide stack parameters for the combined-cycle unit for syngas and natural gas firing, respectively. Table 2-10 summarizes stack parameters for the remaining Unit B emission sources.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Two Unit Loads and Three Temperatures (Unit B CT/HRSG)—Syngas, Phase I

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	36.3	4.57	36.1	4.55	228.3	28.77	143.2	18.04	31.0	3.90	Neg.	Neg.
	70	35.8	4.51	35.9	4.52	225.4	28.40	140.5	20.5	26.9	3.38	Neg.	Neg.
	95	34.7	4.37	34.2	4.31	221.4	27.89	140.9	17.76	27.9	3.51	Neg.	Neg.
75	20	25.2	3.18	29.1	3.67	151.9	19.13	73.4	9.25	12.3	1.55	Neg.	Neg.
	70	24.6	3.10	28.3	3.57	148.6	18.72	72.9	9.18	12.4	1.56	Neg.	Neg.
	95	22.5	2.83	26.0	3.27	137.7	17.35	69.7	8.78	11.9	1.49	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Filterable PM/PM_{10}.

Sources: ECT, 2006.
SCS, 2006.

Table 2-3. Maximum Criteria Pollutant Emission Rates for Two Unit Loads and Three Temperatures (Unit B CT/HRSG)—Syngas, Phase II

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	36.3	4.57	36.1	4.55	137.0	17.26	143.2	18.04	31.0	3.90	Neg.	Neg.
	70	35.8	4.51	35.9	4.52	135.2	17.04	140.5	20.5	26.9	3.38	Neg.	Neg.
	95	34.7	4.37	34.2	4.31	132.8	16.74	140.9	17.76	27.9	3.51	Neg.	Neg.
75	20	25.2	3.18	29.1	3.67	91.1	11.48	73.4	9.25	12.3	1.55	Neg.	Neg.
	70	24.6	3.10	28.3	3.57	89.2	11.23	72.9	9.18	12.4	1.56	Neg.	Neg.
	95	22.5	2.83	26.0	3.27	82.6	10.41	69.7	8.78	11.9	1.49	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Filterable PM/PM_{10}.

Sources: ECT, 2006.
SCS, 2006.

Table 2-4. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (Unit B CT/HRSG)—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	23.2	2.93	1.4	0.18	44.6	5.62	140.8	17.74	31.1	3.92	Neg.	Neg.
	70	23.2	2.93	1.4	0.17	42.1	5.30	138.0	17.39	29.3	3.69	Neg.	Neg.
	95	23.2	2.93	1.3	0.17	40.4	5.09	132.3	16.67	28.1	3.54	Neg.	Neg.
75	20	18.2	2.29	0.9	0.12	28.9	3.64	65.9	8.31	12.4	1.56	Neg.	Neg.
	70	18.2	2.29	0.8	0.11	26.0	3.27	65.2	8.21	11.4	1.44	Neg.	Neg.
	95	18.2	2.29	0.8	0.10	24.8	3.12	60.8	7.66	11.5	1.44	Neg.	Neg.
50	20	18.1	2.28	0.7	0.09	22.3	2.81	60.8	7.66	11.0	1.39	0.067	0.008
	70	18.1	2.28	0.7	0.08	20.5	2.58	56.4	7.11	10.3	1.30	0.063	0.008
	95	18.1	2.28	0.6	0.08	19.3	2.43	54.3	6.84	10.0	1.25	0.058	0.007

Note: Neg. = negligible

*Filterable PM/PM_{10}.

Sources: ECT, 2006.
SCS, 2006.

Table 2-5. Maximum Hazardous Air Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Unit B CT/HRSG)—Syngas

Unit Load (%)	Ambient Temp. (°F)	2,Methylnaphthalene		Acenaphthyalene		Acetaldehyde		Antimony		Arsenic		Benzaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.58E-04	1.08E-04	6.20E-05	7.81E-06	4.29E-03	5.41E-04	9.53E-03	1.20E-03	5.01E-03	6.31E-04	6.91E-03	8.71E-04
	70	8.53E-04	1.08E-04	6.16E-05	7.77E-06	4.27E-03	5.38E-04	9.48E-03	1.19E-03	4.98E-03	6.27E-04	6.88E-03	8.66E-04
	95	8.13E-04	1.02E-04	5.87E-05	7.40E-06	4.07E-03	5.12E-04	9.03E-03	1.14E-03	4.74E-03	5.98E-04	6.55E-03	8.25E-04

Unit Load (%)	Ambient Temp. (°F)	Benzene		Benzo(a)anthracene		Benzo(e)pyrene		Benzo(g,h,I)perylene		Beryllium		Cadmium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.16E-02	1.46E-03	5.48E-06	6.91E-07	1.31E-05	1.65E-06	2.26E-05	2.85E-06	2.15E-04	2.70E-05	6.91E-03	8.71E-04
	70	1.15E-02	1.44E-03	5.45E-06	6.87E-07	1.30E-05	1.64E-06	2.25E-05	2.84E-06	2.13E-04	2.69E-05	6.88E-03	8.66E-04
	95	1.10E-02	1.39E-03	5.19E-06	6.54E-07	1.24E-05	1.57E-06	2.15E-05	2.70E-06	2.03E-04	2.56E-05	6.55E-03	8.25E-04

Unit Load (%)	Ambient Temp. (°F)	Carbon Disulfide		Chromium		Cobalt		Formaldehyde		Manganese		Mercury	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.07E-01	1.35E-02	6.44E-03	8.11E-04	1.36E-03	1.71E-04	7.96E-02	1.00E-02	7.39E-03	9.31E-04	2.17E-03	2.73E-04
	70	1.07E-01	1.34E-02	6.40E-03	8.07E-04	1.35E-03	1.70E-04	7.67E-02	9.66E-03	7.35E-03	9.26E-04	2.16E-03	2.72E-04
	95	1.02E-01	1.28E-02	6.10E-03	7.68E-04	1.29E-03	1.62E-04	7.73E-02	9.74E-03	7.00E-03	8.82E-04	2.06E-03	2.59E-04

Note: g/s = gram per second.
lb/hr = pound per hour.

Sources: ECT, 2006.
SCS, 2006.

Table 2-5. Maximum Hazardous Air Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Unit B CT/HRSG)—Syngas (Continued, Page 2 of 2)

Unit Load (%)	Ambient Temp. (°F)	Naphthalene		Nickel		Selenium		Toluene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.27E-03	1.60E-04	9.30E-03	1.17E-03	6.91E-03	8.71E-04	1.77E-03	2.23E-04
	70	1.24E-03	1.57E-04	9.25E-03	1.17E-03	6.88E-03	8.66E-04	1.65E-03	2.08E-04
	95	1.22E-03	1.54E-04	8.81E-03	1.11E-03	6.55E-03	8.25E-04	1.76E-03	2.22E-04

Note: g/s = gram per second.
lb/hr = pound per hour.

Sources: ECT, 2006.
SCS, 2006.

Table 2-6. Maximum Noncriteria Pollutant Emission Rates for 100-Percent Load and Three Temperatures (Unit B CT/HRSG)—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.34E-04	1.05E-04	7.76E-02	9.78E-03	1.24E-02	1.56E-03	2.43E-02	3.06E-03	6.21E-02	7.82E-03	6.18E-01	7.78E-02
	70	7.54E-04	9.50E-05	7.02E-02	8.84E-03	1.12E-02	1.41E-03	2.21E-02	2.79E-03	5.61E-02	7.07E-03	5.65E-01	7.12E-02
	95	7.25E-04	9.14E-05	6.75E-02	8.50E-03	1.08E-02	1.36E-03	2.13E-02	2.68E-03	5.40E-02	6.80E-03	5.43E-01	6.48E-02

Unit Load (%)	Ambient Temperature (°F)	Naphthalene		Polycyclic Aromatic Hydrocarbons (PAHs)		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.81E-03	3.54E-04	4.27E-03	5.38E-04	5.63E-02	7.09E-03	2.54E-01	3.20E-02	1.24E-01	1.56E-02
	70	2.60E-03	3.27E-04	3.86E-03	4.86E-04	5.09E-02	6.41E-03	2.30E-01	2.90E-02	1.12E-01	1.41E-02
	95	2.49E-03	3.14E-04	3.71E-03	4.67E-04	4.89E-02	6.16E-03	2.21E-01	2.78E-02	1.08E-01	1.36E-02

Note: g/s = gram per second.
lb/hr = pound per hour.

Sources: ECT, 2006.
SCS, 2006.

Table 2-7. Unit B Annual Criteria Pollutant Emission Rates

	Annual Emission Rates (ton/yr)					
Pollutant	CT/HRSG	Flare	Startup Stack	Coal Storage and Handling	Cooling Tower	Facility Totals
NO_x*	592.3	5.6	13.5	N/A	N/A	611.4
CO	615.3	25.4	12.9	N/A	N/A	653.5
PM	156.7	0.4	0.4	17.0	~~1.4~~14.0	~~175.9~~188.5
PM_{10}	156.7	0.4	0.4	16.0	~~0.6~~5.8	~~174.0~~179.2
SO_2	157.1	0.7	3.8	N/A	N/A	161.5
VOC	128.3	0.3	0.3	N/A	N/A	128.9
Pb	~~0.02~~0.03	Neg.	Neg,	N/A	N/A	~~0.02~~0.03

Note: Neg.= negligible.
N/A = not applicable.

*Phase II.

Sources: ECT, 2006.
SCS, 2006.

Table 2-7. Unit B Annual Criteria Pollutant Emission Rates

	Annual Emission Rates (ton/yr)					
Pollutant	CT/HRSG	Flare	Startup Stack	Coal Storage and Handling	Cooling Tower	Facility Totals
NO_x*	592.3	5.6	13.5	N/A	N/A	611.4
CO	615.3	25.4	12.9	N/A	N/A	653.5
PM	156.7	0.4	0.4	17.0	1.4	175.9
PM_{10}	156.7	0.4	0.4	16.0	0.6	174.0
SO_2	157.1	0.7	3.8	N/A	N/A	161.5
VOC	128.3	0.3	0.3	N/A	N/A	128.9
Pb	0.02	Neg.	Neg,	N/A	N/A	0.02

Note: Neg.= negligible.
N/A = not applicable.

*Phase II.

Sources: ECT, 2006.
SCS, 2006.

Table 2-8. Stack Parameters for Two Unit Loads and Three Ambient Temperatures—Syngas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	205.0	62.5	189.7	360.8	65.9	20.1	18.5	5.64
	70	205.0	62.5	186.2	358.8	67.6	20.6	18.5	5.64
	95	205.0	62.5	185.6	358.5	65.9	20.1	18.5	5.64
75	20	205.0	62.5	183.5	357.3	53.1	16.2	18.5	5.64
	70	205.0	62.5	183.7	357.4	53.5	16.3	18.5	5.64
	95	205.0	62.5	182.5	356.8	51.2	15.6	18.5	5.64

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: ECT, 2006.
SCS, 2006.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	205.0	62.5	185.9	358.7	71.8	21.9	18.5	5.64
	70	205.0	62.5	185.0	358.2	65.5	20.0	18.5	5.64
	95	205.0	62.5	184.2	357.7	63.0	19.2	18.5	5.64
75	20	205.0	62.5	183.5	357.3	53.6	16.3	18.5	5.64
	70	205.0	62.5	180.5	355.7	49.2	15.0	18.5	5.64
	95	205.0	62.5	180.1	355.4	49.2	15.0	18.5	5.64
50	20	205.0	62.5	182.8	356.9	47.6	14.5	18.5	5.64
	70	205.0	62.5	180.2	355.5	44.5	13.5	18.5	5.64
	95	205.0	62.5	179.0	354.8	42.7	13.0	18.5	5.64

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: ECT, 2006.
SCS, 2006.

Table 2-10. Stack Parameters for Unit B Ancillary Equipment

	Stack/Exhaust Parameters							
	Height		Exit Temperature		Exit Velocity		Diameter	
	ft	meters	°F	K	ft/s	m/s	ft	meters
Coal Mill Silos 1 – 4 (Each Baghouse)	160	48.8	70	294	23.6	7.2	1.5	0.5
Coal Storage Bins 1 – 4 (Each Baghouse)	92	28.1	70	294	23.6	7.2	1.5	0.5
Cooling tower (per cell, 6 cells total)	64	19.5	90	305	25	7.6	34	10.4
Multipoint Flare	10	3.0	N/A	N/A	N/A	N/A	N/A	N/A
Gasifier Startup Stack	184	56.1	N/A	N/A	N/A	N/A	11.7	3.6

Source: ECT, 2006.
SCS, 2006.

3.0 NEW SOURCE REVIEW REQUIREMENTS

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 Code of Federal Regulations [CFR] 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The Stanton Energy Center is located in eastern Orange County approximately 13 miles southeast of the city of Orlando. Orange County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs], SO_2, and NO_2), unclassifiable/attainment (for CO, 1- and 8-hour ozone, and $PM_{2.5}$), and not designated (for lead). Orange County is designated attainment (for ozone, SO_2, CO, and NO_2) and unclassifiable (for PM_{10} and lead) by Section 62-204.340, F.A.C. Orange County is also designated an air quality maintenance area (AQMA) for ozone pursuant to Rule 62-204.340(4)(a)1., F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

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

3.3 PSD NSR APPLICABILITY

The existing Stanton Energy Center is classified as a *major* facility. A modification to a major facility that has potential net emissions equal to or exceeding the significant

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO_2	3-hour[1]		1,300	1,300
	24-hour[1]	365		260
	Annual[2]	80		60
PM_{10}	24-hour[3]	150	150	150
	Annual[4]	50	50	50
$PM_{2.5}$	24-hour[5]	65	65	
	Annual[6]	15	15	
CO	1-hour[1]	40,000		40,000
	8-hour[1]	10,000		10,000
Ozone (ppmv)	1-hour[7]			0.12[9]
	8-hour[8]	0.08	0.08	
NO_2	Annual[2]	100	100	100
Lead	Calendar quarter arithmetic mean	1.5	1.5	1.5

[1]Not to be exceeded more than once per calendar year.
[2]Arithmetic mean.
[3]The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than 1.
[4]The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix K, is less than or equal to 50 $\mu g/m^3$.
[5]98th percentile concentration, as determined in accordance with 40 CFR 50, Appendix N.
[6]Arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix N.
[7]Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H. The 1-hour ozone standard was revoked on June 15, 2005, 1 year following the effective date of the 8-hour ozone standard designations.
[8]Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
[9]Applies only in Jacksonville, Miami-Fort Lauderdale-West Palm Beach, and Tampa-St.Petersburg-Clearwater.

Sources: 40 CFR 50.
Section 62-204.240, F.A.C.

emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Unit B will have potential emissions in excess of the significant emission rate thresholds. Therefore, the project qualifies as a major modification to a major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Table 3-2 provides comparisons of estimated potential annual emission rates for Unit B and the PSD significant emission rate thresholds. As shown in this table, potential emissions of NO_x, CO, VOC, PM, PM_{10}, H_2SO_4 mist, and SO_2 are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix A contains detailed emission rate estimates for Unit B.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by Unit B in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(38), F.A.C., BACT is "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, 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."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

Table 3-2. Projected Unit B Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x (Phase I)	1,006.2	40	Yes
NO_x (Phase II)	611.4	40	Yes
CO	653.5	100	Yes
PM	~~175.9~~188.5	25	Yes
PM_{10}	~~174.0~~179.2	15	Yes
SO_2	161.5	40	Yes
Ozone/VOC	128.9	40	Yes
Lead	~~0.023~~0.03	0.6	No
Mercury	0.0095	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	24.0	7	Yes
H_2S	Negligible	10	No
Total reduced sulfur (including hydrogen sulfide)	Negligible	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Negligible	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2006.

Table 3-2. Projected Unit B Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x (Phase I)	1,006.2	40	Yes
NO_x (Phase II)	611.4	40	Yes
CO	653.5	100	Yes
PM	175.9	25	Yes
PM_{10}	174.0	15	Yes
SO_2	161.5	40	Yes
Ozone/VOC	128.9	40	Yes
Lead	0.023	0.6	No
Mercury	0.0095	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	24.0	7	Yes
H_2S	Negligible	10	No
Total reduced sulfur (including hydrogen sulfide)	Negligible	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Negligible	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2006.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal new source performance standard (NSPS), national emission standard for hazardous air pollutants (NESHAP), or any other emission limitation established by state regulations.

BACT analyses must be conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of "Improving New Source Review (NSR) Implementation." Using the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank-ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable or is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those that the source would potentially emit in significant amounts (i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year generally is appropriate to complete the PSD requirements. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance (QA) requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's Ambient Monitoring Guidelines for PSD (1987a).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 3-3). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to Unit B is discussed in Section 8.2.

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA Guideline on Air Quality Models (GAQM) as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full-source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(231), F.A.C., significant impact level, as presented in Table 3-4.

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

Averaging Time	Pollutant	Significance Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Hydrogen sulfide	0.2
NA	Ozone	100 tpy of VOC emissions

Source: Section 62-212.400, Table 212.400-3, F.A.C.

Table 3-4. Significant Impact Levels

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

Source: Rule 62-210.200(231), F.A.C.

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

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term PSD increments specified in the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

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

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

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which include revised NAAQS for PM_{10} and new NAAQS for $PM_{2.5}$, became effective on September 16, 1997. Due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for state permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

On January 17, 2006, EPA proposed revisions to the primary and secondary NAAQS for PM. EPA proposes to lower the current 24-hour $PM_{2.5}$ standard from 65 to 35 $\mu g/m^3$ and retain the current 15-$\mu g/m^3$ annual $PM_{2.5}$ standard. EPA also proposes to establish a new PM indicator for coarse PM ($PM_{10-2.5}$) with a 24-hour standard of 70 $\mu g/m^3$ and revoke the current 24-hour and annual PM_{10} standards. With respect to the secondary PM NAAQS, EPA proposes to make the $PM_{2.5}$ and $PM_{10-2.5}$ standards identical to the primary standards. Written comments on the proposed PM NAAQS revisions are due to EPA by April 17, 2006.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 3-5.

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

Table 3-5. PSD Allowable Increments ($\mu g/m^3$)

Pollutant	Averaging Time	Class I	Class II	Class III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO_2	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

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

Source: Section 62-204.260, F.A.C.

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

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

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

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

The ambient impact analysis for Unit B is provided in Sections 6.0 (Methodology) and 7.0 (Results).

3.4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

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

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

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

3.5 HAZARDOUS AIR POLLUTANT REQUIREMENTS

Florida relies on the requirements of the CAA with respect to the regulation of hazardous (also known as toxic) air pollutants. These federal requirements include a comprehensive set of technology-based emission standards referred to as NESHAP. These standards establish hazardous air pollutant emission limitations for a wide variety of industrial source categories. Recent NESHAP (i.e., those adopted after the 1990 amendments to the CAA) reflect maximum achievable control technology (MACT). A discussion of the NESHAP program and its applicability to Unit B is provided in Section 4.2.

Although not required by the PSD permitting process, the air quality impact analysis conducted for Unit B also evaluated project air quality impacts with respect to hazardous air pollutants. The results of this analysis are provided in Section 7.5.

4.0 STATE AND FEDERAL EMISSION STANDARDS

4.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA to establish federal emission standards for source categories that cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated nearly 75 standards. The NSPS are codified in 40 CFR 60.

Major components of the Stanton Unit B IGCC project include coal preparation and feeding equipment, two gasifier trains, a flare (to combust syngas during startups and plant upsets) a mechanical draft cooling tower, and one combined-cycle unit. Those NSPS that are applicable to the Unit B project are discussed in the following subsections.

4.1.1 NSPS SUBPART Y—COAL PREPARATION PLANTS

NSPS Subpart Y is applicable to coal preparation plants that process more than 200 tons per day of coal and that are constructed after October 24, 1974. Specific facilities addressed by Subpart Y include thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems. Coal preparation plants are defined as facilities that prepare coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

Unit B will employ two gasifiers to gasify sub-bituminous PRB coal and produce syngas for combustion in the IGCC unit's CT. A detailed description of the PRB coal receiving, storage, handling, and crushing process was previously provided in Section 2.2.1. Since Unit B will process more than 200 tons per day of PRB coal, the Unit B coal processing (including the crusher), conveying, storage, transfer, and loading systems will be subject to the requirements of NSPS Subpart Y.

NSPS Subpart Y 60.252 contains separate PM standards for thermal dryers; pneumatic coal cleaning equipment; and coal processing and conveying equipment, coal storage systems, or coal transfer and loading systems. Unit B will not include a thermal dryer or pneumatic coal cleaning equipment. Accordingly, visible emissions from the Unit B coal processing and conveying equipment (including the crusher), coal storage systems, and coal transfer and loading systems are limited to less than 20-percent opacity as specified by NSPS Subpart Y 60.252(c). Initial opacity performance tests using EPA Reference Method 9 will be required per the general provisions of NSPS Subpart A 60.8 and the specific provisions of NSPS Subpart Y 60.254(a) and (b)(2).

4.1.2 NSPS SUBPARTS GG AND KKKK—NATURAL GAS-FIRED GAS TURBINES

The Unit B CT (or gas turbine) will be capable of firing natural gas for up to 8,760 hr/yr. Subpart GG, which was amended on July 8, 2004, establishes emission limits for natural gas-fired CTs that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated base load at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. When firing natural gas, the Unit B CT qualifies as an electric utility stationary gas turbine and, therefore, will be subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG 60.332(a)(1) and 60.333, respectively. The Subpart GG standard for NO_x is an algorithm that includes factors for gas turbine heat rate and fuel bound nitrogen (FBN). Since natural gas contains essentially no FBN, no FBN allowance will be claimed for the Unit B CT. The Subpart GG NO_x stan-

dard equates to a nominal gas turbine exhaust NO_x concentration limit of 75 ppmvd corrected to 15-percent oxygen with an adjustment for gas turbine heat rate. The Subpart GG SO_2 standard is either a gas turbine exhaust SO_2 concentration limit of 150 ppmvd corrected to 15-percent oxygen or a fuel sulfur content limit of no more than 0.8 weight percent.

On February 18, 2005, EPA issued a proposed NSPS Subpart KKKK that will apply to new CTs that commence construction after February 18, 2005. The proposed rule establishes a NO_x output-based standard of 1.0 pound per megawatt-hour (lb/MWh) of NO_x for CTs greater than 30 MW. Compliance with the NO_x standard will be measured at the HRSG stack and therefore will include any NO_x emissions associated with HRSG DBs. For SO_2, proposed NSPS Subpart KKKK sets an output-based limit of 0.58 lb/MWh based on the use of fuel containing no more than 0.05 weight percent sulfur. Once NSPS Subpart KKKK is finalized, new CTs constructed after February 18, 2005, will be subject to NSPS Subpart KKKK instead of NSPS Subpart GG. Since proposed NSPS Subpart KKKK effectively limits the emissions of both CTs and HRSG DBs (by determining compliance at the HRSG stack), combined-cycle units subject to NSPS Subpart KKKK that include HRSG DBs are exempt from the requirements of NSPS Subparts Da and Db. Since Unit B will commence construction after February 18, 2005, it will be subject to NSPS Subpart KKKK when this NSPS is finalized, and when Unit B (i.e., both CT and HRSG DBs) is firing natural gas.

As discussed in the following subsection, IGCC units are addressed by NSPS Subpart Da (the Utility NSPS) rather than NSPS Subparts GG and KKKK. Accordingly, NSPS Subparts GG and KKKK will not apply to the Unit B CT when fired with syngas.

4.1.3 NSPS SUBPART DA—ELECTRIC STEAM GENERATING UNITS

The Unit B CT will be capable of firing syngas for up to 8,760 hr/yr. In the preamble to EPA's February 28, 2005, proposed revisions to NSPS Subpart Da through Dc, EPA clarified that Subparts Da, Db, or Dc apply to combined-cycle CTs that burn synthetic-coal gas (e.g., IGCC plants). The particular NSPS (Da, Db, or Dc) that would apply to an IGCC plant will depend on the size (i.e., heat input) of the IGCC facility. Since the heat

input to the Unit B CT when firing syngas will exceed 250 MMBtu/hr, NSPS Subpart Da will be applicable to the Unit B CT when firing syngas. In a telephone conversation with Mr. Christian Fellner of EPA's OAQPS Combustion Group, Emissions Standards Division, it was confirmed that Subpart Da would apply to the entire IGCC CC unit (i.e., NSPS Subpart Da would be applicable to the syngas-fired CT as well as the natural gas-fired HRSG DBs).

Applicable NSPS Subpart Da emission standards when the Unit B CT is fired with syngas (including the heat input and emissions from the natural gas-fired HRSG DBs) are summarized as follows:

- PM—0.03 lb/MMBtu and visible emissions no greater than 20-percent opacity (6-minute average), except for one 6-minute period of not more than 27-percent opacity.
- SO_2—1.20 lb/MMBtu and 90-percent reduction, or 70-percent reduction when emissions are less than 0.60 lb/MMBtu on a 30-day rolling average basis.
- NO_x—1.6 lb/MWh gross energy output on a 30-day rolling average basis.
- Mercury – 20×10^{-6} lb/MWh gross energy output on a 12-month rolling average basis.

When the Unit B CT is fired with natural gas, the natural gas-fired HRSG DBs will be subject to NSPS Subpart Da until such time as proposed NSPS Subpart KKKK is finalized. The applicable Subpart Da limits for the Unit B HRSG DBs when the CT is fired with natural gas are as follows:

- PM—0.03 lb/MMBtu and visible emissions no greater than 20-percent opacity (6-minute average), except for one 6-minute period of not more than 27-percent opacity.
- NO_x—1.6 lb/MWh gross energy output on a 30-day rolling average basis.

The NSPS Subpart Da limits for SO_2 and mercury will not apply to the Unit B HRSG DBs during natural gas-firing of the CT.

In summary, the Stanton Unit B CT when firing syngas (including the heat input and emissions from the natural gas-fired HRSG DBs) will be subject to NSPS Subpart Da. The Unit B CT when firing natural gas will be subject to NSPS Subpart GG until proposed NSPS Subpart KKKK is finalized; at that time, the CT will be subject to Subpart KKKK instead of Subpart GG. The Unit B HRSG DBs will be subject to NSPS Subpart Da when the CT is fired with natural gas until proposed NSPS Subpart KKKK is finalized; at that time, the HRSG DBs will be subject to Subpart KKKK instead of Subpart Da.

4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

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

On March 29, 2005, EPA issued a final agency action delisting electric utility steam generating units from the CAA Section 112(c) source category list. Instead of regulating electric utility steam generating unit HAP emissions under the NESHAP program, EPA elected to limit emissions of mercury (the only electric utility steam generating unit HAP considered by EPA to warrant regulation) from coal-fired units using the authority of the

NSPS program as previously described. Accordingly, the Unit B HRSG DBs are not subject to any 40 CFR 61 or 63 NESHAP.

Although electric utility steam generating units (e.g., combined-cycle unit HRSGs) are no longer included on the Section 112(c) list, the source category list presently includes stationary CTs. As required by Section 112 of the CAA, EPA promulgated a final NESHAP for stationary CTs (40 CFR 63, Subpart YYYY) on March 5, 2004. Subpart YYYY applies to gas-fired stationary CTs located at major HAP sources that commence construction after January 14, 2003. The Subpart YYYY 63.6175 definition of natural gas includes syngas as well as pipeline-quality natural gas. The Unit B CT will employ diffusion flame technology and will be located at a major HAP source (i.e., the existing Stanton Energy Center). For new diffusion flame gas-fired CTs, Subpart YYYY limits formaldehyde emissions to no more than 91 parts per billion by volume, dry (ppbvd) corrected to 15-percent oxygen. However, on April 7, 2004, EPA proposed to delist four subcategories of CTs from the CAA Section 112(c) categorical list, including gas-fired diffusion flame CTs. On August 18, 2004, EPA issued a final rule staying the effectiveness of NESHAP Subpart YYYY with respect to lean premix and diffusion flame gas-fired CTs. Until such time as EPA takes final action on the CT subcategory delisting proposal, new lean premix and diffusion flame gas-fired CTs are not required to comply with the requirements of NESHAP Subpart YYYY (other than the initial notifications required by the NESHAP Subpart A 63.6145 general provisions). If the CT subcategories are not ultimately delisted, the stay will be lifted and new (i.e., those that commenced construction after January 14, 2003), lean premix and diffusion flame gas-fired CTs will be required to meet the requirements of NESHAP Subpart YYYY.

4.3 ACID RAIN PROGRAM

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

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

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

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low NO_x burner technologies and to meet new emissions stan-

dards. The ARP NO_x emission reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

Unit B will be subject to the ARP since it is a *new* utility unit (i.e., will commence operation after November 15, 1990) and will serve a generator that produces electricity for sale. As previously noted, new utility units do not receive any SO_2 allowance allocations. Accordingly, Unit B will need to annually obtain SO_2 allowances from the ARP SO_2 allowance market in amounts equal to its actual SO_2 emission rates. The NO_x component of the ARP does not apply to new utility units.

4.4 CLEAN AIR INTERSTATE RULE

On March 10, 2005, EPA issued the final Clean Air Interstate Rule (CAIR). The objective of CAIR is to assist states with $PM_{2.5}$ and 8-hour ozone nonattainment areas to achieve attainment by reducing precursor emissions at sources located in 28 states (including Florida) situated upwind of these nonattainment areas. Based on regional dispersion modeling, EPA determined that these 28 upwind states significantly contribute to $PM_{2.5}$ and 8-hour ozone nonattainment in downwind areas. Florida emission sources are projected to significantly contribute to $PM_{2.5}$ nonattainment areas located in Georgia (Macon and Atlanta) and Alabama (Birmingham) and to an 8-hour ozone nonattainment area in Georgia (Atlanta).

The CAIR reductions of precursor emissions address annual SO_2 and NO_x emissions (for reductions in annual and daily average ambient $PM_{2.5}$ impacts) and ozone season (May through September) NO_x emissions (for reductions in 8-hour average ambient ozone impacts). The SO_2 and NO_x reductions will be implemented by means of a regional two-phase cap-and-trade program. For SO_2, the first cap begins in calendar year 2010 and extends through 2014. For NO_x, the first cap begins in calendar year 2009 and also extends through 2014. The second phase cap for both pollutants becomes effective in calendar year 2015 and thereafter. The SO_2 caps will reduce current ARP SO_2 emissions by 50 percent in Phase I and by 65 percent in Phase II. The NO_x caps reflect NO_x emission rates of 0.15 and 0.125 lb/MMBtu for the first and second phase caps, respectively.

For each phase cap, CAIR assigns SO_2 and NO_x emission budgets (in units of tpy) and in units of tons per ozone season) to each affected upwind state. EPA developed these state emission budgets based on the application of cost-effective control technologies (i.e., flue gas desulfurization [FGD] for SO_2 and SCR for NO_x). The affected states are required to submit revised state implementation plans (SIPs) within 18 months (i.e., by September 11, 2006) for EPA review and approval. The SIPs will provide details as to the procedures that will be used to allocate the state NO_x and SO_2 budgets to individual sources.

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

Florida plans to adopt EPA's model SO_2 and NO_x trading programs and apply CAIR only to electric generating units. However, Florida has also indicated that operation of all air emission control systems will be require year-round (e.g., emission units could not shutdown or curtail) operation of their emission control systems even though their CAIR SO_2 or NO_x allowance allocations may not be exceeded.

EPA's model NO_x trading program includes provisions for allocating NO_x allowances to new utility units (those that are placed in service in 2001 or later) such as Unit B (i.e., a new source set-aside). Similar to the ARP, there are no provisions for a new source set-aside with respect to CAIR SO_2 allowances. For NO_x allowances, new units will be allocated allowances from the new source set-aside until they have established a baseline and are included in the shared pool. Florida's preliminary CAIR implementation plan is to have a five percent set-aside for control years 2009 through 2011, and a three percent set-

aside thereafter. NO_x allowance allocations from the new source set-aside pool would be made to new utility units on a pro-rata basis. Under Florida's preliminary plan, new units will receive allowances from the shared pool starting in 2012.

The FPL Group has challenged several aspects of CAIR, including the inclusion of Florida with respect to the ozone and $PM_{2.5}$ compliance requirements. SO_2 and NO_x reductions are required under CAIR since these air pollutants are considered precursors to $PM_{2.5}$. These challenges include several reconsiderations filed with EPA and petitions filed with the Circuit Court of the District of Columbia. One issue that the FPL Group has raised is that EPA should have established a north-south boundary (placed at 28.66 degrees [°] north latitude) of significant contribution with respect to both ozone and $PM_{2.5}$. The Stanton Energy Center (at 28.48° north latitude) is located slightly south of this suggested north-south boundary. If the FPL Group is successful with its CAIR challenges, the Stanton Energy Center, including Unit B, will not be subject to the CAIR requirements.

4.5 CLEAN AIR MERCURY RULE

On March 15, 2005, EPA issued the final Clean Air Mercury Rule (CAMR). The purpose of CAMR is to reduce national coal-fired power plant mercury emissions from the current level of 48 to 15 tpy by means of a two-phase cap-and trade program. The first phase national mercury cap (with a cap of 38 tpy) becomes effective in 2010, while the second 15-tpy cap becomes effective in 2018 and thereafter.

CAMR also establishes stack mercury emission standards applicable to new sources (i.e., those constructed, modified, or reconstructed after January 30, 2004). For new IGCC electric utility steam generating units, stack mercury emissions must not exceed 0.020 pound per gigawatt-hour (lb/GWh) (reference NSPS Subpart Da 60.45a[b] and Section 4.4.3 herein).

Similar to CAIR, CAMR assigns mercury budgets (in units of tpy) to each state for each phase cap. The first phase mercury cap represents the co-benefits that will be achieved by CAIR (i.e., installation of FGD and SCR controls). The second phase mercury cap is

based on the cumulative effect of FGD/SCR co-benefits and EPA projections regarding the availability and removal efficiency of future mercury controls (e.g., activated carbon injection).

The NSPS program serves as the regulatory authority for CAMR. Accordingly, the revisions to NSPS Subpart Da were effective upon proposal (i.e., January 30, 2004). CAMR also includes a new NSPS, Subpart HHHH, which contains EPA's model mercury trading program. Under the terms of revised NSPS Subpart Da, states have 18 months to submit plans that address the state electric generating unit mercury caps for 2010 and 2018 for EPA review and approval. The state plans will provide details as to the procedures that will be used to allocate the state mercury budgets to individual coal-fired utility units. For each control period, sufficient mercury allowances must be held to cover the actual mercury emissions for all mercury budget units at a source. Although mercury allowances will be allocated on a unit-by-Unit Basis, compliance with the CAMR mercury allowance program is determined on a plantwide basis.

As described previously for the CAIR state SO_2 and NO_x budgets, following SIP approval and allocation of the state mercury budgets to individual emission sources, these sources must possess sufficient mercury allowances to cover their actual emission rates (as continuously measured either by CEMS or sorbent trap monitoring systems.) for each control period beginning in 2010. Emission sources that have actual mercury emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances. Emission sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances. Revised SIPs that address the CAMR requirements are required to be submitted to EPA by November 17, 2006.

Florida has indicated that the state does *not* intend to implement a mercury cap-and-trade program since actual mercury reductions would not be expected to occur in Florida until 2027 due to prior reductions (e.g., repowering of existing coal-fired units with natural gas). Accordingly, Florida intends to meet the CAMR requirements by means of the traditional command-and-control form of regulation. Under Florida's preliminary approach, affected utility units will be assigned a specific stack mercury emission limitation rather

than a mercury allowance allocation. To date, Florida has not proposed any specific mercury emission limitations for the state's coal-fired utility units. However, these unit-specific mercury limitations will need to be assigned such that Florida can demonstrate compliance with the CAMR statewide mercury allocations of 1.233 tpy for 2010 through 2017 and 0.487 tpy for 2018 and thereafter.

In summary, Unit B will need to comply with the NSPS Subpart Da mercury limit for new IGCC electric utility steam generating units as well as future Florida limits (if different) that will be imposed under the CAMR.

4.6 FLORIDA EMISSION STANDARDS

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources—Emission Standards, F.A.C. General pollutant emission limit standards are included in Rule 62-296.320, F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources. Sections 62-296.500 through 62-296.570, F.A.C., establish reasonably available control technology (RACT) requirements for VOC and NO_x emitting facilities. RACT requirements for lead and PM are found in Sections 62-296.600 through 62-296.605, F.A.C., and Sections 62-296.700 through 62-296.712, F.A.C., respectively. Finally, Section 62-204.800, F.A.C., adopts the federal NSPS and NESHAP by reference.

With respect to the Stanton Unit B IGCC project, the general visible emission limitation of 20-percent opacity per Rule 62-296.320(4)(b) will apply to the coal handling and processing point sources. Reasonable precautions to prevent unconfined PM emissions (e.g., the PRB coal storage pile) will be required pursuant to Rule 62-296.320(4)(c), F.A.C. None of the emission standards specified in Sections 62-296.401 through 62-296.417, F.A.C., are applicable to the Unit B IGCC project. The VOC, NO_x, lead, and PM RACT requirements do not apply to emission units that are subject to NSR permitting and therefore are not applicable to the Unit B IGCC project.

NSPS Subparts Da, Y, GG, and KKKK (when finalized) will be applicable to the Unit B IGCC project. The Unit B CT will become subject to NESHAP Subpart YYYY in the

event that EPA decides not to delist the gas-fired diffusion flame CT subcategory from the Section 112(c) list of source categories, as has been proposed, and removes the current stay.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

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

- **R**ACT/**B**ACT/lowest achievable emission rate (**L**AER) **C**learinghouse (RBLC) via the RBLC Information System database.
- EPA NSR Web site.
- EPA Control Technology Center (CTC) Web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT) experience for similar projects.

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

An assessment of energy, environmental, and economic impacts may then be performed. If performed, the economic analysis employs the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Air Pollution Control Cost Manual, Sixth Edition* (EPA, 2002).

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAP (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.). The NSPS, NESHAPS, and Florida emission standards applicable to Unit B were previously discussed in Sections 4.1, 4.2, and 4.6, respectively. All of the BACT emission limitations proposed for Unit B are more stringent than the applicable federal and state standards cited in these sections.

As indicated in Section 3.3, Table 3-2, Unit B projected annual emission rates of NO_x, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM_{10}), products of incomplete combustion (CO and VOC), and acid gases (NO_x, SO_2, and H_2SO_4 mist), respectively.

The Unit B CT will be primarily fired with coal-derived syngas. It will also have the capability of continuously firing natural gas. The Unit B HRSG will include DBs that will be fired exclusively with natural gas. Due to the differences in combustion characteristics between syngas and natural gas, BACT limits are proposed for each fuel where appropriate.

5.2 BACT ANALYSIS FOR PM/PM10

5.2.1 CT/HRSG

Due to their low ash and sulfur contents, syngas and natural gas combustion generate inherently low PM/PM_{10} emissions.

POTENTIAL CONTROL TECHNOLOGIES

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

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

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

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

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

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

None of the previously described control equipment have been applied to IGCC's or to natural gas combined-cycle units because exhaust gas PM/PM_{10} concentrations are inherently low. Moreover, it is not technically appropriate to use these to control PM/PM_{10}. Combined-cycle units operate with a significant amount of excess air, which generates large exhaust gas flow rates. Unit B CT will be fired with either syngas or natural gas. The syngas has previously been subject to high efficiency PM/PM_{10} removal as part of the gasification process. Combustion of syngas and natural gas will generate low PM/PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentrations for Unit B CT/HRSG at baseload and 70°F with DB firing are approximately 0.005 and 0.004 grains per dry standard cubic foot (gr/dscf) while firing syngas and natural gas, respectively. Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low. In addition, such low removal efficiencies would not justify the significant cost of employing these technologies

PROPOSED BACT EMISSION LIMITATIONS

Recent PM/PM_{10} BACT determinations for syngas and natural gas fired CTs are based on the use of clean fuels and good combustion practice. Table 5-1 provides recent PM/PM_{10} BACT determinations for CTs fired with syngas. Since the syngas fired in the Unit B CT results from the gasification of PRB coal, a comparison of the emissions performance of Unit B with PRB coal fired boilers is relevant inasmuch as the Unit B IGCC process represents an alternative to conventional coal-fired power plants. Table 5-2 provides recent PM/PM_{10} BACT determinations for sub-bituminous pulverized coal-fired units. As shown in Tables 5-1 and 5-2, Unit B CT PM/PM_{10} emissions compare favorably with prior BACT determinations.

Because postprocess stack controls for PM/PM_{10} are not appropriate for combined-cycle units, the use of good combustion practices and clean fuels is considered to be BACT. Unit B CT will be fired with either syngas or natural gas. Table 5-3 provides the PM/PM_{10} BACT emission limits proposed for the Unit B CT/HRSG.

5.2.2 FLARE AND GASIFIER STARTUP STACK

The flare will only be used to combust syngas during gasifier startups and process upsets. Eight pilots fired with natural gas will be on at all times. The gasifier startup stack will only be used during gasifier startups and will exhaust the products of combustion of natural gas and coal during the gasifier preheat period. During gasifier startups, the products of fuel combustion will flow through the syngas particulate filtration process prior to being discharged from the gasifier startup stack. PM/PM_{10} emissions from both emission sources will be minor and controlled using good combustion practices. Table 5-3 provides the PM/PM_{10} BACT emission limits proposed for the Unit B flare and gasifier startup stack.

5.2.3 COAL HANDLING

Unit B coal handling PM/PM_{10} emission sources include the PRB coal storage pile, coal transfer, conveying, crushing, and storage. Fugitive PM/PM_{10} emission from the PRB coal storage pile will be controlled by the application of water on an as-needed

Table 5-1. PM/PM_{10} BACT Determinations
Syngas-Fired Combined-Cycle Units

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	PM/PM_{10} (lb/MBtu)
Polk Power Station (TEC)	CT 1	FL	260	1996	0.013
Kentucky Pioneer Energy (Kentucky Pioneer Energy, LLC)	1, 2	KY	197	Jun-01	0.011
Wabash River Generating Station (PSI Energy)	CT 1A	IN	192	1993	
Taylorville Energy Center (Christian County Generation, LLC)	1	IL	677	Pending	0.007
Southern Illinois Clean Energy Center (Steelhead Energy Co., LLC)	1	IL	544	Pending	0.00924
Lima Energy Company (Lima Energy Company)	1	OH	192	Mar-02	0.01
Elm Road Generating (Wisconsin Electric)	1	WI	500	Jan-04	0.011
				Minimum	0.007
				Maximum	0.013
				Average	0.010
				Median	0.011

Source: ECT, 2006.

Table 5-2. PM/PM_{10} BACT Determinations
Sub-Bituminous Pulverized Coal-Fired Plants

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	PM/PM_{10} (lb/MBtu)
Springerville Generating Station (Tucson Electric Power Co.)	3, 4	AZ	400	Apr-02	0.018
Plum Point Energy Station (Plum Point Energy Associates, LLC	1	AR	800	8/20/03	0.018
Comanche Plant Unit 3 (Public Service Company of CO	3	CO	750	Pending	0.019
Longleaf Energy Station (LS Power)	1, 2	GA	600	Pending	0.033
Holcomb Generating Station (Sand Sage Power, LLC)	2	KS	660	4/5/04	0.018
MidAmerican Energy Center Council Bluff (MidAmerican Energy)	4	IA	790	6/17/03	0.025
Big Cajun Power Station Unit 4 (Louisiana Generating, LLC)	4	LA	675	Pending	0.018
Hawthorne Generating Station Unit 5 (Mansas City Power & Light)	1	MO	570	Aug-99	0.018
Weston Bend Generating Station (Great Plains Power Company)	1	MO	820	Nov-01	0.018
Southwest Power Station (City Utilities of Springfield)	2	MO	275	12/15/04	0.018
Roundup Power Project (Bull Mountain Development Co	1, 2	MT	390	7/21/03	0.015
Rocky Mountain Power (Rocky Mountain Power, Inc.	1	MT	113	6/11/02	0.015
Whelan Energy Center (Hastings Utilities)	1	NE	220	Mar-04	0.018
Nebraska City Unit 2 (Omaha Public Power District	2	NE	660	Mar-05	0.018
Desert Rock Energy Facility (Steag Power, LLC)	1, 2	NM	750	Pending	0.012
Cottonwood Energy Center (Chaco Valley Energy, LLC	1	NM	495	Pending	0.020
Mustang Generating Station (Chaco Valley Energy, LLC	1	NM	330	Pending	0.015
Calaveras Plant Spruce Unit 2 (Not subject to SO_2 or NO_x BACT)	2	TX	750	12/05	0.015
Sandy Creek Energy (LS Power)	1	TX	500	Pending	0.033
Intermountain Power (Intermountain Power Service Corp	3	UT	950	10/15/04	0.012
TS Power Plant (Newmont NV Energy Investment, LLC	1	UT	200	May-05	0.038
Weston Unit 4 (Wisconsin Public Service Company	1	WI	500	Oct-04	0.020
WYGEN II (Black Hills Corporation)	1	WY	500	Sep-02	0.012
Black Hills (Black Hills Corporation)	1	WY	80	Jun-99	0.020
Two Elk (Two Elk Generation Partners, L.P.)	1	WY	250	May-03	0.018
				Minimum	0.012
				Maximum	0.038
				Average	0.019
				Median	0.018

Source: ECT, 2006.

Table 5-3. Unit B Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
CT/HRSG (syngas – all operating cases)	0.013 lb/MBtu*
CT/HRSG (natural gas- all operating cases)	0.017 lb/MBtu**
Flare and Gasifier Startup Stack	Clean Fuels, Good Combustion Practice
PRB Coal Handling (Storage Pile)	Application of Water, As Needed
PRB Coal Handling (Transfer, Crushing and Conveying)	Wet Suppression or Enclosure
PRB Coal Handling (Storage)	Fabric Filters
Cooling Tower	0.002 % Drift Rate

* Based on heat input (HHV) to gasifiers.
** Based on heat input (HHV) to CT.

Sources: ECT, 2006.
SCS, 2006.

basis. Each of the PRB coal transfer points will be either equipped with a wet suppression system or completely enclosed. All coal conveyors will be enclosed. The crushing and storage (i.e., silos and bins) operations will be equipped with baghouses designed to achieve an outlet PM/PM_{10} concentration of no more than 0.02 grains per dry standard cubic feet (gr/scf). Due to the relatively minor PM/PM_{10} emissions associated with the PRB coal transfer, conveying, crushing, and storage operations, a visible emissions limit of 5-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-3 provides the PM/PM_{10} BACT emission limits proposed for the Unit B coal handling emission sources.

5.2.4 COOLING TOWER

PM/PM_{10} emissions will also occur due to cooling tower operations. Unit B will include one 6-cell, fresh water cooling tower. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM_{10} emissions because of the fine PM/PM_{10} formed by crystallization of the dissolved solids contained in the droplet.

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

Factors affecting cooling tower PM/PM_{10} emission rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dis-

solved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

PM/PM_{10} emissions from the Unit B cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.002 percent of the cooling tower recirculating water flow. Table 5-3 provides the PM/PM_{10} BACT emission limit proposed for the Unit B cooling tower.

5.3 BACT ANALYSIS FOR CO AND VOC

5.3.1 CT/HRSG

There are two available technologies for controlling CO and VOC from CT/HRSG units: combustion process design and oxidation catalysts.

Combustion Process Design

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

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

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOC to carbon dioxide (CO_2) and water at temperatures approximately 50 percent lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. For natural gas-fired combined-cycle units, the oxidation catalyst would be located within the HRSG where temperatures range from 450 to 1,100°F. To date, there are no oxidation catalyst installations on coal-fired IGCC units.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOC up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F; higher temperatures on the order of 900°F are needed to oxidize VOC. Inlet temperature must be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For natural gas-fired combined-cycle applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency for natural gas-fired CTs is 50 percent. No such data exists for CO and VOC removal efficiencies for coal-fired IGCCs.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons, causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. An oxidation catalyst system would be expected to convert up to 90 percent of the CT exhaust stream SO_2 to SO_3. If ammonia is also present as a result of an SCR control system, SO_3 and ammonia will react to form ammonium bisulfate. If ammonia is not present, SO_3 will combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of SO_2 and excessive formation of either ammonium bisulfate or H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing sulfur.

Technical Feasibility

Proper CT combustor design is considered to be a technically feasible control technology for the Unit B CT/HRSG for both syngas and natural gas firing. It has been demonstrated in both applications.

Oxidation catalysts have not been demonstrated on any coal-fired IGCC unit. As noted previously, oxidation catalysts are susceptible to deactivation due to a variety of impurities. Due to the lack of operating experience and potential catalyst deactivation, the performance and reliability of oxidation catalyst controls applied to syngas fired CT/HRSGs are unknown.

Use of oxidation catalyst controls for the Unit B CT/HRSG is not transferable from a natural gas-fired combined-cycle unit for the following reasons:

- Unit B will be a base-load generation facility and therefore must achieve the capacity factors, availability and reliability associated with base-load units. Any control system that causes forced outages, increases maintenance outage rates, or reduces unit efficiency appreciably is unacceptable since it would prevent Unit B from serving its intended purpose as a base-load generation unit.
- Unit B CT/HRSG will evaluate the viability of a SCR control system to control NO_x emissions. The SCR control system, the first one to be installed on

a coal-fired IGCC unit anywhere in the world, will be evaluated during the 4-year DOE demonstration period. The objective is to demonstrate the operation of SCR on a coal fired IGCC. One of the challenges in operating SCR technology is minimization of ammonia slip. Ammonia slip will react with SO_3 present to form ammonium bisulfate, a sticky liquid that will foul the HRSG heat transfer surfaces, resulting in reduced reliability, availability and efficiency.

- Use of oxidation catalyst will significantly exacerbate the formation of ammonium bisulfate by substantially increasing SO_3, as up to 90 percent of SO_2 will be oxidized to SO_3 by an oxidation catalyst. During syngas firing, this will significantly increase the formation of ammonium bisulfate.
- Although oxidation catalyst technology is considered technically feasible for natural gas-fired CT/HRSG units, it is not feasible for Unit B when firing natural gas since the Unit B HRSG must be available when the CT is fired with either syngas or natural gas. As a base-load unit, it would not be practical to install an oxidation catalyst system on Unit B that would only be used during natural gas-firing; i.e., this approach would require extended outages to remove and replace the catalyst from the HRSG each time the CT fuel is changed from syngas to natural gas.

PROPOSED BACT EMISSION LIMITATIONS

Recent CO and VOC BACT determinations for syngas and natural gas fired CTs are based on the use of clean fuels and good combustion practice. Table 5-4 provides recent CO and VOC BACT determinations for CTs fired with syngas. Table 5-5 provides recent CO and VOC BACT determinations for sub-bituminous pulverized coal units. All syngas-fired CT and PRB coal-fired unit CO BACT determinations are based on good combustion practice. With few exceptions, good combustion practice has also been determined as CO and VOC BACT for natural gas-fired CTs. Oxidation catalysts have been required in cases where CO emissions may be elevated due to planned part load CT operations and/or steam augmentation, e.g., the proposed Calpine Blue Heron project. Regarding Florida CO BACT determinations for combined-cycle units, of note is the determination made by FDEP for the Seminole Electric Cooperative Payne Creek Generating

Table 5-4. CO and VOC BACT Determinations
Syngas-Fired Combined-Cycle Units

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	CO (lb/MBtu)	VOC (lb/MBtu)
Polk Power Station (TEC)	CT 1	FL	260	1996	0.044	0.0017
Kentucky Pioneer Energy (Kentucky Pioneer Energy, LLC)	1, 2	KY	197	Jun-01	0.032	0.0044
Wabash River Generating Station (PSI Energy)	CT 1A	IN	192	1993	0.050	
Taylorville Energy Center (Christian County Generation, LLC)	1	IL	677	Pending	0.007	
Southern Illinois Clean Energy Center (Steelhead Energy Co., LLC)	1	IL	544	Pending	0.009	
Lima Energy Company (Lima Energy Company)	1	OH	192	Mar-02	0.010	0.0082
Elm Road Generating (Wisconsin Electric)	1	WI	500	Jan-04	0.011	
				Minimum	0.007	
				Maximum	0.050	
				Average	0.023	
				Median	0.011	

Source: ECT, 2006.

Table 5-5. CO and VOC BACT Determinations
Sub-Bituminous Pulverized Coal-Fired Plants

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	CO (lb/MBtu)	VOC (lb/MBtu)
Springerville Generating Station (Tucson Electric Power Co	3, 4	AZ	400	Apr-02	0.135	
Plum Point Energy Station (Plum Point Energy Associates, LLC	1	AR	800	8/20/03	0.160	
Comanche Plant Unit 3 (Public Service Company of CO	3	CO	750	Pending	0.150	
Longleaf Energy Station (LS Power)	1, 2	GA	600	Pending	0.150	
Holcomb Generating Station (Sand Sage Power, LLC)	2	KS	660	4/5/04	0.150	
MidAmerican Energy Center Council Bluff (MidAmerican Energy)	4	IA	790	6/17/03	0.154	
Big Cajun Power Station Unit 4 (Louisiana Generating, LLC)	4	LA	675	Pending	0.135	
Hawthorne Generating Station Unit 5 (Mansas City Power & Light)	1	MO	570	Aug-99	0.160	
Weston Bend Generating Station (Great Plains Power Company)	1	MO	820	Nov-01	0.160	
Southwest Power Station (City Utilities of Springfield	2	MO	275	12/15/04	0.160	
Roundup Power Projec (Bull Mountain Development Co	1, 2	MT	390	7/21/03	0.150	
Rocky Mountain Power (Rocky Mountain Power, Inc.	1	MT	113	6/11/02	0.150	
Whelan Energy Center (Hastings Utilities)	1	NE	220	Mar-04	0.150	
Nebraska City Unit 2 (Omaha Public Power District	2	NE	660	Mar-05	0.160	
Desert Rock Energy Facility (Steag Power, LLC)	1, 2	NM	750	Pending	0.100	
Cottonwood Energy Center (Chaco Valley Energy, LLC	1	NM	495	Pending	0.140	
Mustang Generating Station (Chaco Valley Energy, LLC	1	NM	330	Pending	0.160	
Calaveras Plant Spruce Unit 2 (Not subject to SO_2 or NO_x BACT)	2	TX	750	12/05	0.150	
Sandy Creek Energy (LS Power)	1	TX	500	Pending	0.150	
Intermountain Power (Intermountain Power Service Corp	3	UT	950	10/15/04	0.150	
TS Power Plant (Newmont NV Energy Investment, LLC	1	UT	200	May-05	0.150	
Weston Unit 4 (Wisconsin Public Service Company	1	WI	500	Oct-04	0.150	
WYGEN II (Black Hills Corporation)	1	WY	500	Sep-02	0.150	
Black Hills (Black Hills Corporation)	1	WY	80	Jun-99	0.150	
Two Elk (Two Elk Generation Partners, L P.)	1	WY	250	May-03	0.135	
				Minimum	0.100	
				Maximum	0.160	
				Average	0.148	
				Median	0.150	

Source: ECT, 2006

Station. This facility includes two dual fuel (natural gas and distillate fuel oil) Siemens Westinghouse 501F(D) CTs operating in combined- cycle mode. The HRSGs are equipped with both oxidation catalyst and SCR control systems. However, due to concerns with ammonium bisulfate formation, the SCR control systems are *not* required to be functional during combustion of distillate fuel oil; i.e., the permit limit for NO_x during oil-firing does not require use of the SCR system.

Because CO and VOC emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements. The only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of CO emissions from Unit B shows that maximum CO impacts, without oxidation catalyst, will be insignificant. Unit B will be located in an area (Orange County, Florida) that is classified attainment for all criteria pollutants. In 2005, maximum ambient air quality CO concentrations for sites in Orange County were only 22 and 29 percent of the 1- and 8-hour AAQS, respectively. There have been no recorded exceedances of the CO AAQS anywhere in Florida for over 15 years.

As shown in Tables 5-4 and 5-5, Unit B CT/HRSG CO emissions compare favorably with prior BACT determinations. Table 5-6 provides the CO BACT emission limits proposed for the Unit B CT/HRSG based on good combustion practice.

5.3.2 FLARE AND GASIFIER STARTUP STACK

As noted previously, the flare and gasifier startup stack will be used intermittently during gasifier startups and process upsets. CO emissions from both emission sources will be minor and controlled using good combustion practices. Table 5-6 provides the CO BACT emission limits proposed for the Unit B flare and gasifier startup startup stack.

Table 5-6. Proposed Unit B CO and VOC BACT

Emission Source	Proposed CO BACT	
	lb/10^6 Btu	ppmvd†
CT/HRSG (Syngas w/o DB-Firing)	0.040*	17
CT/HRSG (Syngas with DB-Firing)	0.050*	21
CT/HRSG (Natural Gas w/o DB-Firing)	0.050††	25
CT/HRSG (Natural Gas with DB-Firing)	0.060††	28
Flare and Gasifier Startup Startup stack	Good Combustion Practice	

Emission Source	Proposed VOC BACT	
	lb/10^6 Btu	ppmvd
CT/HRSG (Syngas w/o DB-Firing)	0.007*	5.0
CT/HRSG (Syngas with DB-Firing)	0.011*	7.8
CT/HRSG (Natural Gas w/o DB-Firing)	0.010††	7.7
CT/HRSG (Natural Gas with DB-Firing)	0.013††	10.1
Flare and Gasifier Startup Startup stack	Good Combustion Practice	

*based on heat input (HHV) to gasifiers, 24-hour block average.
†corrected to 15% O_2, 24-hour block average.
††based on heat input (HHV) to CT, 24-hour block average.

Sources: ECT, 2006.
SCS, 2006.

5.4 BACT ANALYSIS FOR NOX

5.4.1 CT/HRSG

NO_x emissions from combustion sources are formed by one of three mechanisms: thermal, fuel, and prompt. Essentially all CT NO_x emissions originate as nitric oxide (NO). NO generated by the CT combustion process is subsequently further oxidized downstream of the CT (i.e., within the HRSG) or in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x is formed by the high-temperature reaction of nitrogen with oxygen. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed by the relatively fast reaction between nitrogen, oxygen, and hydrocarbon radicals. Prompt NO_x formation is important in lower temperature combustion processes, but is much less important compared to thermal NOx formation at the high temperatures in the CT.

Fuel NO_x arises from the oxidation of chemically-bound nitrogen contained in the fuel. The conversion of FBN to NO_x depends on the bound nitrogen content of the fuel. Natural gas normally has very little organically-bound nitrogen. However, fuel NO_x is important in the combustion of air-blown syngas, which contains a significant amount of organically-bound nitrogen.

Although some of the nitrogen contained in the PRB coal is converted to molecular nitrogen (N_2), the large majority is converted to compounds that contribute to fuel NO_x formation. Accordingly, the predominant contributor to NO_x emissions during syngas firing is fuel NO_x. For natural gas combustion, the primary contributor to NO_x in the exhaust gas is thermal NO_x. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes available to control fuel NO_x emissions. For this reason, the gas turbine NSPS, for example, contains an allowance for fuel NO_x.

5.4.2 POTENTIAL CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from combined-cycle units include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications:

- Water or steam injection
- Diluent addition.
- Dry low-NO_x (DLN) combustor design.
- XONON™

Postcombustion Exhaust Gas Treatment Systems:

- Selective non-catalytic reduction (SNCR).
- Non-selective catalytic reduction (NSCR).
- SCR.
- EMx™ (formerly SCONOx™)

A description of each of the listed control technologies is provided in the following sections.

Water or Steam Injection

Injection of water or steam into the primary combustion zone of advanced combustors of a CT reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection

rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel.

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

The use of steam injection is not applicable to air-blown IGCCs because of the low heating value of the syngas. The use of water or steam injection in diffusion flame combustors firing natural gas can typically achieve NO_x exhaust concentrations of 25 ppmvd, corrected to 15 percent O_2.

Diluent Addition

Similar to steam or water injection, the addition of a diluent (such as nitrogen) and/or moisture to high heating value syngas can reduce the formation of thermal NO_x by decreasing the peak combustion temperature. Diluent addition has been employed for CTs fired with syngas derived from the oxygen-blown gasification process since there is a readily available source of nitrogen. Diluent injection has also been employed on natural gas fired CTs. Diluent injection will not reduce the formation of fuel NO_x.

The use of diluent addition is not applicable for an air-blown IGCC because of the low heating value of the syngas. Diluent injection is applicable to natural gas firing.

Dry Low-NO_x Combustor Design

A number of CT vendors have developed DLN combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and

average flame temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner.

DLN combustor technology was developed for natural gas-fired CTs and is not currently available for CTs fired with syngas due to the different combustion characteristics of the two fuels. The heat content of syngas (approximately 140 Btu/ft^3, HHV for the air-blown gasification process) is significantly lower than the heat content of natural gas (approximately 1,020 Btu/ft^3, HHV). This difference in fuel heat content requires a much larger volume of syngas to achieve the same CT heat input compared to natural gas. Another major difference is that the major combustible components of syngas are carbon monoxide and hydrogen whereas the major combustible component of natural gas is methane.

The higher flame speed and kinetics of hydrogen combustion prevents the use of current DLN combustor technology for syngas-fired CTs. Because Unit B CT must be capable of firing either syngas or natural gas, DLN combustor technology is not an available control technology for natural gas.

XONON™

The XONON™ Cool Combustion technology, being developed for CTs by Catalytica Energy Systems, Inc. (CESI), employs a catalyst integral to the CT combustor to reduce the formation of NO_x. In a conventional CT combustor, fuel and air are oxidized in the presence of a flame to produce the hot exhaust gases required for power generation. The XONON™ Cool Combustion technology replaces this conventional combustion process with a two-step approach. First, a portion of the CT fuel is mixed with air and burned in a low-temperature pre-combustor. The main CT fuel is then added and oxidation of the total fuel/air mixture stream is completed by means of flameless, catalytic combustion. The catalyst module is located within the CT combustor. NO_x formation is reduced due to the relatively low oxidation temperatures occurring within the pre-combustor and the flameless combustor catalyst module. Information provided by CESI indicates that the XONON™ Cool Combustion technology is capable of achieving CT NO_x exhaust concentrations of 2.5 ppmvd at 15 percent O_2.

Commercial operation of the XONON™ Cool Combustion technology is limited to one small (1.5 MW) base load, natural gas-fired Kawasaki CT operated by the Silicon Valley Power municipal utility. This CT is located in Santa Clara, California. Performance of the XONON™ Cool Combustion technology on larger CTs or on CTs fired with syngas not been demonstrated to date.

XONON™ is not applicable to Unit B because it has not been demonstrated and is not available for this type of unit.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either NH_3 (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O \quad (1)$$

$$4\ NH_3 + 5\ O_2 \rightarrow\ 4NO + 6\ H_2O \quad (2)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F. The exhaust gas temperatures of Unit B are too low for this technology.

Non-Selective Catalytic Reduction

The NSCR process utilizes a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3 percent O_2) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. NSCR has not been applied to IGCCs.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting NH_3 with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \quad (4)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), NH_3/NO_x molar ratio, catalyst reactivity, catalyst age and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions.

As is the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (3) and (4) will not proceed. At temperatures ex-

ceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CCs has been primarily limited to natural gas-fired units. SCR has not been demonstrated on coal-fired IGCCs.

EMx™ (SCONO$_x$™)

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

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:

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

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

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

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the CT/HRSG exhaust stream.

As shown in reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a di-

lute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The EMx™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\,H_2 + CO_2 \rightarrow K_2CO_3 + 4\,H_2O_{(g)} + N_2 \qquad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 80 percent of the catalyst sections will be in the oxidation/absorption cycle, while 20 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 8 minutes.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. The regeneration gas is diluted to under 4-percent hydrogen using steam as a carrier gas; the typical system is designed for 2 percent hydrogen. The regeneration gas reaction is:

$$CH_4 + \tfrac{1}{2}\,O_2 + H_2O \rightarrow CO_2 + 3\,H_2 \qquad (9)$$

For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst

and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

$$CH_4 + 2\,H_2O \rightarrow CO_2 + 4\,H_2 \qquad (10)$$

The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

A gradual decrease in catalyst temperature is indicative of sulfur masking. EmerChem recommends the installation of a sulfur filter to reduce the rate of catalyst masking. The sulfur filter is placed in the inlet natural gas feed prior to the regeneration production skid. The sulfur filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a nonhazardous waste.

The EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. As necessary, an additional catalytic oxidation/absorption system to remove sulfur compounds is installed upstream of the EMx™ catalyst. The sulfur removal catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the EMx™ system. During regeneration of the catalyst, either H_2SO_4 mist or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the process is proprietary. Oxidation/absorption and regeneration reactions are:

$$CO + \tfrac{1}{2}\,O_2 \rightarrow CO_2 \qquad (11)$$

$$SO_2 + \tfrac{1}{2}\,O_2 \rightarrow SO_3 \qquad (12)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \qquad (13)$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O + [\text{SORBER}] \qquad (14)$$

(below 500°F)

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}] \qquad (15)$$

(above 500°F)

A programmable logic controller (PLC) controls the EMx™ system. The controller is programmed to control all essential EMx™ functions including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the EMx™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO_x removal efficiency. A high temperature application of $SCONO_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW Solar CT located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTs, there are currently no CTs larger than 32 MW that have demonstrated successful application of the EMx™ control technology. In addition, there are no syngas-fired CTs that employ the EMx™ control technology.

Technical Feasibility

Water or Steam/Diluent Injection

The use of water or steam/diluent injection is not technically feasible for Unit B CT while firing syngas. Although it is feasible for an oxygen-blown IGCC, the oxygen-blown gasi-

fication process first removes nitrogen from the gasifier inlet air stream and then returns this nitrogen to the syngas as a diluent for thermal NO_x reduction. In contrast, the air-blown gasification process retains the inlet air nitrogen throughout the process. Accordingly, the air-blown gasification process produces a syngas that already includes nitrogen diluent. This difference in gasification processes is reflected in the syngas heat content – the heat content of air-blown gasification syngas is approximately 50 percent lower than the syngas derived from the oxygen-blown gasification process. Further addition of diluent is not technically feasible since the Unit B syngas heat content would be reduced from its already low level to the point where combustion will become unstable. Use of water or steam injection remains technically feasible for natural gas firing.

Dry Low NO_x Combustor Design

Due to the combustion characteristics of syngas, DLN combustor technology is not currently available for syngas-fired CTs. The higher flame speed and kinetics of hydrogen combustion prevents the use of current DLN combustor technology for syngas-fired CTs. Because Unit B CT must be capable of firing both syngas or natural gas, DLN combustor technology is not an available control technology for natural gas.

XONON™

The XONON™ Cool Combustion technology is not yet commercially available for a GE7FA CT. In addition, XONON™ Cool Combustion technology has not been demonstrated on large, heavy-duty CTs and on CTs fired with syngas. Accordingly, the XONON™ Cool Combustion technology is not considered to be a technically feasible control technology for Unit B CT.

SNCR

SNCR is not technically feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in the Unit B CT exhaust gas stream when firing either syngas or natural gas.

NSCR

NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent O_2) environment. Due to high excess air rates, the O_2 content of the Unit B CT exhaust is approximately 11 percent.

SCONO$_x$

The EMx™ control technology has not been commercially demonstrated on large CTs or on CTs fired with syngas. Nor is it an applicable technology. Unit B CT has a nominal generation capacity of 170 MW. Accordingly, Unit B CT is 6.8 times larger than the nominal 25-MW GE LM2500 used at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the EMx™ technology are unknown. Additional concerns with EMx™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, and the relatively brief operating history of the technology.

SCR

SCR has not been demonstrated on any operating coal-derived IGCC. Nor has it been installed on any coal-derived IGCC. The performance and reliability of SCR applied to coal-derived syngas fired CT/HRSGs are unknown.

SCR control technology is commercially available for HRSG installations. However, SCR is not applicable to Unit B when firing syngas, and therefore is not considered technically feasible. SCR would only be considered applicable if it can reasonably be installed on the source type under consideration. To resolve this question, EPA instructs the applicant and reviewing authorities to "compare the physical and chemical characteristics of the exhaust gas stream from the unit under review to those for the unit from which the technology is to be transferred." New Source Review Workshop Manual at B.19. This is because deployment of the technology on a *similar* source type could make the technology applicable if the similar source type is similar in the right way – namely, if the gas streams characteristics are similar enough to presume that it is technically feasible to operate the technology on the new unit. Id.

SCR has never been installed on a coal-fired IGCC, so the "similar source type" in question here is a natural gas fired combined cycle. While an IGCC and a natural gas combined cycle are similar sources in some ways, their gas streams and combustion products are not. This is largely a function of the immutable fact that the Unit B syngas is derived from coal. These differences are directly relevant to the operation of an SCR:

- Although the sulfur contained in the inlet PRB coal will be reduced significantly (see SO2 BACT assessment), the resulting syngas will still contain a sufficient amount of sulfur that, when oxidized to SO_3 in the CT, it will react with excess ammonia from an SCR system to form ammonium bisulfate in the HRSG.
- Research by GE and EPRI has shown that even low concentrations of sulfur (above approximately 2 ppmv) in a CT exhaust are sufficient to result in ammonium bisulfate formation and excessive fouling of HRSG heat transfer surfaces. The estimated sulfur concentration of Unit B exhaust gas when firing syngas will exceed this sulfur content threshold.
- As a base-load unit, Unit B must achieve the capacity factors, availability and reliability associated with base-load units. Any control system that causes forced outages, increases maintenance outage rates or decreases efficiency appreciably is unacceptable since it would prevent Unit B from serving its intended purpose as a base-load generation unit.
- Unit B will employ air-blown gasification technology to produce syngas from sub-bituminous PRB coal. Unit B will be the first application of this gasification technology for power generation and is a demonstration project under the Department of Energy's Clean Coal Power Initiative (CCPI). Actual performance of the Unit B gasification process, including the syngas clean-up components, will not be known with any certainty until the 4-year DOE demonstration period is completed. These uncertainties prevent SCR control technology from being considered applicable to Unit B when operating on syngas.

SCR is technically feasible when operating on natural gas. However, because the applicant intends to evaluate the performance of the SCR on syngas, the design for the SCR cannot be limited to maximizing operation on natural gas.

PROPOSED BACT EMISSION LIMITATIONS

For the Unit B air-blown gasification syngas, the CT vendor (GE) has issued a guarantee for NO_x exhaust concentration from the CT of 40 ppmvd corrected to 15 percent O_2. Although the application of conventional SCR is not considered technically feasible for Unit B while firing syngas, a major objective of the Unit B DOE demonstration project is to evaluate the viability of SCR control technology to syngas-fired CT/HRSG units. To achieve this objective, the following two-phase NO_x reduction program during Unit B syngas-firing is proposed:

Phase I

SCR control technology will be installed and operated during syngas firing. Through a combination of SCR operation and combustion tuning, NO_x concentration of 20 ppmvd, corrected to 15 percent O_2 will be achieved. Based on the GE estimate of 40 ppmvd NO_x for Unit B when fired with syngas, this limit equates to a 50 percent efficient SCR system. At this level of SCR removal efficiency, it is expected that essentially all of the injected ammonia will react with the available NO_x resulting in little, if any, ammonia slip. However, actual SCR operating efficiencies may vary.

The Phase I NO_x limit would be applicable during the 4-year DOE demonstration period. The demonstration period will be used to evaluate the Unit B first-of-a-kind gasification process and SCR control technology with the objective of reducing Unit B CT/HRSG NO_x concentration to the Phase II NO_x limit or lower. A technical report providing the results of the Unit B gasification process and SCR technology evaluation will be submitted to the FDEP following the end of the 4-year DOE demonstration period.

Phase II

A SCR outlet NO_x concentration of 12 ppmvd, corrected to 15 percent O_2.is proposed as the limit that will become effective following completion of the 4-year DOE demonstra-

tion period. This limit will become effective unless the Phase I technical report demonstrates that Unit B cannot technically achieve this level of NO_x control. If the Phase II limit is shown to be unachievable, the final Unit B CT/HRSG NO_x emission limit would be set at the lowest level demonstrated to be achievable and no higher than the Phase I limit.

This two-phase approach will achieve two major milestones in the advancement of IGCC technology:

- Employs SCR control technology for the first time to a coal-based IGCC facility.
- Establishes the lowest NO_x emission limit to date for an IGCC facility.

For Unit B CT/HRSG during natural gas-firing, use of the SCR control technology installed for syngas evaluation purposes is proposed as BACT. Consistent with recent FDEP BACT determinations for natural gas-fired combined cycle units, SCR control technology achieving 80 percent NOx reduction with 5 ppmvd ammonia slip is proposed as NO_x BACT for Unit B during natural gas-firing.

Table 5-7 provides recent NO_x BACT determinations for CTs fired with syngas. Table 5-8 provides recent NO_x BACT determinations for sub-bituminous pulverized coal-fired units. Table 5-9 summarizes the NO_x BACT emission limits proposed for the Unit B CT/HRSG.

5.4.3 FLARE AND GASIFIER STARTUP STARTUP STACK

The flare and gasifier startup stack will be used intermittently during gasifier startups and process upsets. NO_x emissions from both emission sources will be minor and controlled using the good combustion practices. Table 5-9 provides the NO_x BACT emission limits proposed for the Unit B flare and gasifier startup stack.

5.5 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

Fuel treatment technologies are often applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas

Table 5-7. NO_x BACT Determinations
Syngas-Fired Combined-Cycle Units

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	NO_x (lb/MBtu)
Polk Power Station (TEC)	CT 1	FL	260	1996	0.059 (15 ppmvd)
Kentucky Pioneer Energy (Kentucky Pioneer Energy, LLC)	1, 2	KY	197	Jun-01	0.074
Wabash River Generating Station (PSI Energy)	CT 1A	IN	192	1993	0.096 (25 ppmvd)
Taylorville Energy Center (Christian County Generation, LLC)	1	IL	677	Pending	**0.058** (15 ppmvd)
Southern Illinois Clean Energy Center (Steelhead Energy Co., LLC)	1	IL	544	Pending	0.059 (15 ppmvd)
Lima Energy Company (Lima Energy Company)	1	OH	192	Mar-02	**0.097**
Elm Road Generating (Wisconsin Electric)	1	WI	500	Jan-04	0.060 (15 ppmvd)
				Minimum	0.058
				Maximum	0.097
				Average	0.072
				Median	0.060

Source: ECT, 2006.

Table 5-8 NO_x BACT Determinations
Sub-Bituminous Pulverized Coal-Fired Plants

Plant	Unit No	State	Generation Capacity (MW)	Permit Date	NO_x (lb/MBtu)
Springerville Generating Station (Tucson Electric Power Co	3, 4	AZ	400	Apr-02	0.170
Plum Point Energy Station (Plum Point Energy Associates, LLC	1	AR	800	8/20/03	0.090
Comanche Plant Unit 3 (Public Service Company of CO	3	CO	750	Pending	0.100
Longleaf Energy Station (LS Power)	1, 2	GA	600	Pending	0.070
Holcomb Generating Station (Sand Sage Power, LLC,	2	KS	660	4/5/04	0.080
MidAmerican Energy Center Council Bluff (MidAmerican Energy)	4	IA	790	6/17/03	0.070
Big Cajun Power Station Unit 4 (Louisiana Generating, LLC)	4	LA	675	Pending	0.100
Hawthorne Generating Station Unit 5 (Mansas City Power & Light)	1	MO	570	Aug-99	0.080
Weston Bend Generating Station (Great Plains Power Company)	1	MO	820	Nov-01	0.080
Southwest Power Station (City Utilities of Springfield)	2	MO	275	12/15/04	0.080
Roundup Power Project (Bull Mountain Development Co	1, 2	MT	390	7/21/03	0.070
Rocky Mountain Power (Rocky Mountain Power, Inc.	1	MT	113	6/11/02	0.090
Whelan Energy Center (Hastings Utilities)	1	NE	220	Mar-04	0.080
Nebraska City Unit 2 (Omaha Public Power District)	2	NE	660	Mar-05	0.070
Desert Rock Energy Facility (Steag Power, LLC)	1, 2	NM	750	Pending	0.070
Cottonwood Energy Center (Chaco Valley Energy, LLC	1	NM	495	Pending	0.060
Mustang Generating Station (Chaco Valley Energy, LLC	1	NM	330	Pending	0.060
Calaveras Plant Spruce Unit 2 (Not subject to SO_2 or NO_x BACT)	2	TX	750	12/05	0.069
Sandy Creek Energy (LS Power)	1	TX	500	Pending	0.090
Intermountain Power (Intermountain Power Service Corp	3	UT	950	10/15/04	0.070
TS Power Plant (Newmont NV Energy Investment, LLC	1	UT	200	May-05	0.067
Weston Unit 4 (Wisconsin Public Service Company	1	WI	500	Oct-04	0.070
WYGEN II (Black Hills Corporation)	1	WY	500	Sep-02	0.070
Black Hills (Black Hills Corporation)	1	WY	80	Jun-99	0.230
Two Elk (Two Elk Generation Partners, L.P.)	1	WY	250	May-03	0.090
				Minimum	0.060
				Maximum	0.230
				Average	0.087
				Median	0.080

Source: ECT, 2006.

Table 5-9. Proposed Unit B NO_x BACT

Emission Source	Proposed NO_x BACT	
	lb/10^6 Btu	ppmvd†
CT/HRSG (Syngas – Phase I)	0.080*	20
CT/HRSG (Syngas – Phase II)	0.048*	12
CT/HRSG (Natural Gas)	0.018††	5
Flare and Gasifier Startup Startup stack	Good Combustion Practice	

*based on heat input (HHV) to gasifiers, 24-hour block average.
†corrected to 15% O_2, 24-hour block average.
††based on heat input (HHV) to CT, 24-hour block average.

Sources: ECT, 2006.
SCS, 2006.

containing sulfur compounds, a variety of technologies are available to remove these sulfur compounds to acceptable levels. Desulfurization of natural gas is performed by the fuel supplier prior to distribution by pipeline. Similar to natural gas, desulfurization of syngas is conducted via the design of the gasification process prior to its use as a fuel. No additional fuel treatment is necessary due to the low sulfur levels of the syngas and natural gas.

5.5.1 CT/HRSG

POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of postcombustion add-on controls (i.e., flue gas desulfurization (FGD) systems).

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

There have been no applications of FGD technology to CCs fired with syngas and natural gas because these fuels contain very low sulfur contents. The sulfur content of syngas, the primary fuel source for Unit B, is much lower than the fuels (e.g., coal) employed in boilers using FGD systems. In addition, CCs operate with a significant amount of excess air that generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of an FGD system to a CC exhaust stream will result in unreasonably low SO_2 removal efficiencies. Due to low SO_2

exhaust stream concentrations, FGD technology is not considered to be technically feasible for CCs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H_2SO_4 mist emissions is not technically feasible due to the very low CC H_2SO_4 mist exhaust concentrations. For example, the Unit B CT/HRSG will have an H_2SO_4 mist exhaust concentration of 0.00079 gr/scf during syngas-firing.

PROPOSED BACT EMISSION LIMITATIONS

Recent SO_2 BACT determinations for syngas and natural gas fired CTs are based on the use of clean fuels. Table 5-10 provides recent SO_2 BACT determinations for CTs fired with syngas. Table 5-11 provides recent SO_2 BACT determinations for sub-bituminous pulverized coal-fired units.

Because postcombustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Unit B CT/HRSG. This high sulfur removal rate via the Unit B coal gasification process represents the application of new technology and will be a major technical accomplishment due to the relatively low sulfur content of PRB coal. Syngas and natural gas combusted in the Unit B CT will contain less than 20 and 4 parts per million of sulfur by volume (ppmv), respectively. Since reducing the sulfur content of the fuels combusted in the Unit B CT/HRSG also serves to control H_2SO_4 mist emissions, the SO_2 BACT emission limit proposed for syngas firing is considered a surrogate BACT limit for H_2SO_4 mist. Table 5-12 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the Unit B CT/HRSG.

5.5.2 FLARE AND GASIFIER STARTUP STARTUP STACK

The flare and gasifier startup stack will be used intermittently during gasifier startups and process upsets. SO_2 emissions from both emission sources will be minor. Table 5-12 provides the SO_2 and H_2SO_4 mist BACT emission limits proposed for the Unit B flare and gasifier startup startup stack.

Table 5-10. SO_2 BACT Determinations
Syngas-Fired Combined-Cycle Units

Plant	Unit No.	State	Generation Capacity (MW)	Permit Date	SO_2 (lb/MBtu)
Polk Power Station (TEC)	CT 1	FL	260	1996	0.172
Kentucky Pioneer Energy (Kentucky Pioneer Energy, LLC)	1, 2	KY	197	Jun-01	0.032
Wabash River Generating Station (PSI Energy)	CT 1A	IN	192	1993	0.200
Taylorville Energy Center (Christian County Generation, LLC)	1	IL	677	Pending	0.045
Southern Illinois Clean Energy Center (Steelhead Energy Co., LLC)	1	IL	544	Pending	0.033
Lima Energy Company (Lima Energy Company)	1	OH	192	Mar-02	0.021
Elm Road Generating (Wisconsin Electric)	1	WI	500	Jan-04	0.030
				Minimum	0.021
				Maximum	0.200
				Average	0.076
				Median	0.033

Source: ECT, 2006.

Table 5-11. SO_2 BACT Determinations
Sub-Bituminous Pulverized Coal-Fired Plants

Plant	Unit No	State	Generation Capacity (MW)	Permit Date	SO_2 (lb/MBtu)
Springerville Generating Station (Tucson Electric Power Co	3, 4	AZ	400	Apr-02	0.600
Plum Point Energy Station (Plum Point Energy Associates, LLC	1	AR	800	8/20/03	0.160
Comanche Plant Unit 3 (Public Service Company of CO	3	CO	750	Pending	0.100
Longleaf Energy Station (LS Power)	1, 2	GA	600	Pending	0.120
Holcomb Generating Station (Sand Sage Power, LLC)	2	KS	660	4/5/04	0.120
MidAmerican Energy Center Council Bluff (MidAmerican Energy)	4	IA	790	6/17/03	0.100
Big Cajun Power Station Unit 4 (Louisiana Generating, LLC)	4	LA	675	Pending	0.100
Hawthorne Generating Station Unit 5 (Mansas City Power & Light)	1	MO	570	Aug-99	0.120
Weston Bend Generating Station (Great Plains Power Company)	1	MO	820	Nov-01	0.120
Southwest Power Station (City Utilities of Springfield	2	MO	275	12/15/04	0.095
Roundup Power Projec (Bull Mountain Development Co	1, 2	MT	390	7/21/03	0.120
Rocky Mountain Power (Rocky Mountain Power, Inc	1	MT	113	6/11/02	0.150
Whelan Energy Center (Hastings Utilities)	1	NE	220	Mar-04	0.120
Nebraska City Unit 2 (Omaha Public Power District	2	NE	660	Mar-05	0.095
Desert Rock Energy Facility (Steag Power, LLC)	1, 2	NM	750	Pending	0.060
Cottonwood Energy Center (Chaco Valley Energy, LLC	1	NM	495	Pending	0.060
Mustang Generating Station (Chaco Valley Energy, LLC	1	NM	330	Pending	0.072
Calaveras Plant Spruce Unit 2 (Not subject to SO_2 or NO_x BACT)	2	TX	750	12/05	0.100
Sandy Creek Energy (LS Power)	1	TX	500	Pending	0.120
Intermountain Power (Intermountain Power Service Corp	3	UT	950	10/15/04	0.090
TS Power Plant (Newmont NV Energy Investment, LLC	1	UT	200	May-05	0.090
Weston Unit 4 (Wisconsin Public Service Company	1	WI	500	Oct-04	0.100
WYGEN II (Black Hills Corporation)	1	WY	500	Sep-02	0.100
Black Hills (Black Hills Corporation)	1	WY	80	Jun-99	0.200
Two Elk (Two Elk Generation Partners, L.P.)	1	WY	250	May-03	0.132
				Minimum	0.060
				Maximum	0.600
				Average	0.130
				Median	0.100

Source: ECT, 2006.

Table 5-12. Proposed Unit B SO_2 and H_2SO_4 BACT

Emission Source	Proposed SO_2 and H_2SO_4 BACT
CT/HRSG (Syngas)	0.015 lb $SO_2/10^6$ Btu*†
CT/HRSG (Natural Gas)	Pipeline Natural Gas
Flare	Low Sulfur Fuels
Gasifier Startup Startup stack	Low Sulfur Fuels

*based on heat input (HHV) to gasifiers, 24-hour block average.
†surrogate limit for H_2SO_4 mist.

Sources: ECT, 2006.
SCS, 2006.

6.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

As previously noted in Section 3.1, the Stanton Energy Center is located in an area that is designated attainment for all criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. The Florida PSD Class I areas include the Everglades National Park, and the Chassahowitzka, St. Marks, and Bradwell Bay National Wilderness Areas. Accordingly, the Stanton Unit B IGCC project site and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine project air quality impacts with respect to the PSD Class II increments and the NAAQS. Unit B air quality impacts with respect to the PSD Class I areas are addressed in Section 10.0.

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

The approach used to analyze the potential impacts of Unit B, as described in detail in the following subsections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed. In addition, a proposed modeling protocol was presented to FDEP for review and comment. FDEP staff subsequently accepted this modeling protocol. The air quality analysis for the Stanton Unit B project was conducted in accordance with the FDEP approved modeling protocol.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Stanton Unit B will have the potential to emit 611.4 tpy of (Phase II), 653.5 tpy of CO, ~~175.9~~179.2 tpy of ~~PM/~~PM_{10}, 161.5 tpy of SO_2, 128.9 tpy of VOCs, and 24.0 tpy of H_2SO_4 mist. Ta-

6.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

As previously noted in Section 3.1, the Stanton Energy Center is located in an area that is designated attainment for all criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. The Florida PSD Class I areas include the Everglades National Park, and the Chassahowitzka, St. Marks, and Bradwell Bay National Wilderness Areas. Accordingly, the Stanton Unit B IGCC project site and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine project air quality impacts with respect to the PSD Class II increments and the NAAQS. Unit B air quality impacts with respect to the PSD Class I areas are addressed in Section 10.0.

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ble 3-2 previously provided estimated potential annual emission rates for Stanton Unit B. As shown in that table, potential emissions of NO_x, CO, SO_2, PM, and PM_{10} are each projected to exceed the applicable PSD significant emission rate (SER) threshold. Potential emissions from Unit B will be below the applicable PSD SER levels for all other PSD regulated pollutants. Accordingly, Stanton Unit B is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for NO_x, CO, PM, PM_{10}, and SO_2.

6.3 MODEL SELECTION AND USE

Air quality models are applied at two levels: screening and refined. At the screening level, models provide conservative estimates of impacts to determine whether more detailed modeling is required. Screening modeling can also be used to identify worst-case operating scenarios for subsequent refined modeling analysis. The current version of EPA's SCREEN3 Dispersion Model (Version 96043; February 12, 1996) was employed as a screening tool to evaluate the various Unit B CT/HRSG operating scenarios.

The refined level consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides improved estimates of source impacts. The American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) modeling system, together with 5 years of hourly meteorological data from the National Oceanographic and Atmospheric Administration (NOAA) National Climatic Data Center (NCDC) were used in the ambient impact analysis. AERMOD was used to obtain refined impact predictions for short-term periods (i.e., periods equal to or less than 24 hours). AERMOD was also utilized to obtain refined predictions of annual average concentrations.

6.3.1 SCREENING MODEL TECHNIQUES

Unit B will operate under a variety of operating scenarios. These scenarios include different loads and ambient air temperatures and the optional use of supplemental DB firing and inlet air evaporative cooling. Plume dispersion and, therefore, ground-level impacts, will be affected by these different operating scenarios since emission rates, exit temperatures, and exhaust gas velocities will change. Tables A-2 and A-3 in Appendix A provide

the syngas and natural gas operating cases, respectively, that were included in the Unit B air quality impact analysis.

The SCREEN3 dispersion model was used to evaluate each Unit B CT/HRSG operating scenario for each pollutant of concern to identify the scenarios that cause the highest impacts. The SCREEN3 model implements screening methods contained in EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised.* SCREEN3 is a simple model that calculates 1-hour average concentrations over a range of predefined worst-case meteorological conditions. The SCREEN3 model includes algorithms to assess building wake downwash effects and for analyzing concentrations in both simple and complex terrain.

A nominal emission rate of 10.0 grams per second (g/s) was used for all SCREEN3 model runs. The SCREEN3 model results were then adjusted to reflect the maximum emission rate for each operating scenario (i.e., model results were multiplied by the ratio of maximum emission rates [in g/s] to 10.0 g/s). Summaries of the screening modeling results showing, for each Unit B CT/HRSG operating scenario and pollutant evaluated, the SCREEN3 unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted SCREEN3 1-hour average maximum impact are provided in Section 7.3.

6.3.2 REFINED MODEL TECHNIQUES

Regulatory agency recommended procedures for conducting air quality impact assessments are contained in EPA's GAQM. The GAQM is codified in Appendix W of 40 CFR 51. In the November 9, 2005, Federal Register, EPA approved use of AERMOD as a GAQM Appendix A preferred model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model. The latest version of AERMOD (Version 04300) was used to assess Unit B project air quality impacts at receptor locations within 50 km of the project site.

6.4 MODEL OPTIONS

Procedures applicable to the AERMOD modeling system specified in the latest version of the User's Guide for the AMS/EPA Regulatory Model – AERMOD (September 2004) and EPA's November 9, 2005, revisions to the GAQM were followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. Unit B will be located in rural southeastern Orange County. AERMOD options regarding pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected.

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

6.5 NO_2 AMBIENT IMPACT ANALYSIS

For annual NO_2 impacts, the tiered screening approach described in the GAQM, Section 6.2.3, was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO_2. Tier 2 applies an empirically derived NO_2/NO_x ratio of 0.75 to the Tier 1 results.

6.6 TERRAIN CONSIDERATION

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

Site elevation for the Stanton Energy Center is approximately 70 feet above mean sea level (ft-msl). The Unit B CT/HRSG stack height will be 205 ft above grade elevation. Accordingly, terrain elevations above approximately 275 ft would be classified as complex terrain. U.S. Geological Survey (USGS) 7.5-minute series topographic maps were

examined for terrain features in the Unit B impact area (i.e., within an approximate 15-km radius). Based on this examination, terrain in the vicinity of the site is classified as either flat or simple terrain.

In accordance with the GAQM recommendations for AERMOD, each modeled receptor was assigned a terrain elevation based on USGS 7.5-minute digital elevation model (DEM) data and use of the AERMAP (Version 04300) preprocessing program. AERMAP was utilized in accordance with the latest version (December 2005) of the user's guide for the AERMOD terrain preprocessor (AERMAP) and EPA's November 9, 2005, revisions to the GAQM. AERMAP prepares terrain data for use by AERMOD in simple and complex terrain situations. This allows AERMOD to account for terrain using a simplification of the procedure used in the CTDMPLUS model.

6.7 BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters, or a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where: Hg = GEP stack height.
H = height of the structure or nearby structure.
L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require that stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The height proposed for the Stanton Unit B CT/HRSG stack (i.e., 205 ft above grade level), as well as all other project emission sources, will be less than the *de minimis* GEP height of 65 meters (213 ft). Since the stack heights of the Unit B project emission sources will comply with the EPA promulgated final stack height regulations (40 CFR 51), actual project stack heights were used in the modeling analyses.

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the Unit B ambient impact analysis, the complex downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (BPIPPRM) (Version 04274; September 30, 2004). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10° to 360°) building heights (BUILDHGT keyword), lengths (BUILDLEN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD. Dimensions of the building/structures evaluated for the wake effects were determined from engineering layouts and specifications and are shown in Table 6-1. The buildings are shown in three-dimension in Figure 6-1.

6.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access."

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions		
	Width (meters)	Length (meters)	Height (meters)
Unit A ST	18.3	43.2	13.5
Unit A cooling tower	38.2	83.0	18.1
Unit 1A HRSG	12.1	47.5	25.6
Unit 2A HRSG	12.1	47.5	25.6
Unit A administration building	18.3	33.2	5.3
Unit B HRSG	11.7	38.2	34.8
Unit B CT	10.3	28.7	9.7
Unit B fan inlet	9.4	18.0	21.3
Unit B gasifier structure	53.5	73.2	53.1
Unit B cooling tower	37.0	50.8	15.0
Unit B ST	14.2	36.5	9.7
Unit B control building	18.5	33.2	5.1
Unit 1 cooling tower	—	93.5*	131.4
Unit 1 boiler	55.6	78.5	68.6
Unit 2 cooling tower	—	93.5*	131.4
Unit 2 boiler	51.7	80.8	68.6
Unit 2 precipitator	37.4	56.8	33.5
Air quality control building for Unit 2	54.3	67.2	32.0
ST for Units 1 and 2	32.4	158.0	30.5
Coal storage pile	91.4	121.9	10.7

*Diameter.

Sources: SCS, 2005.
ECT, 2006.

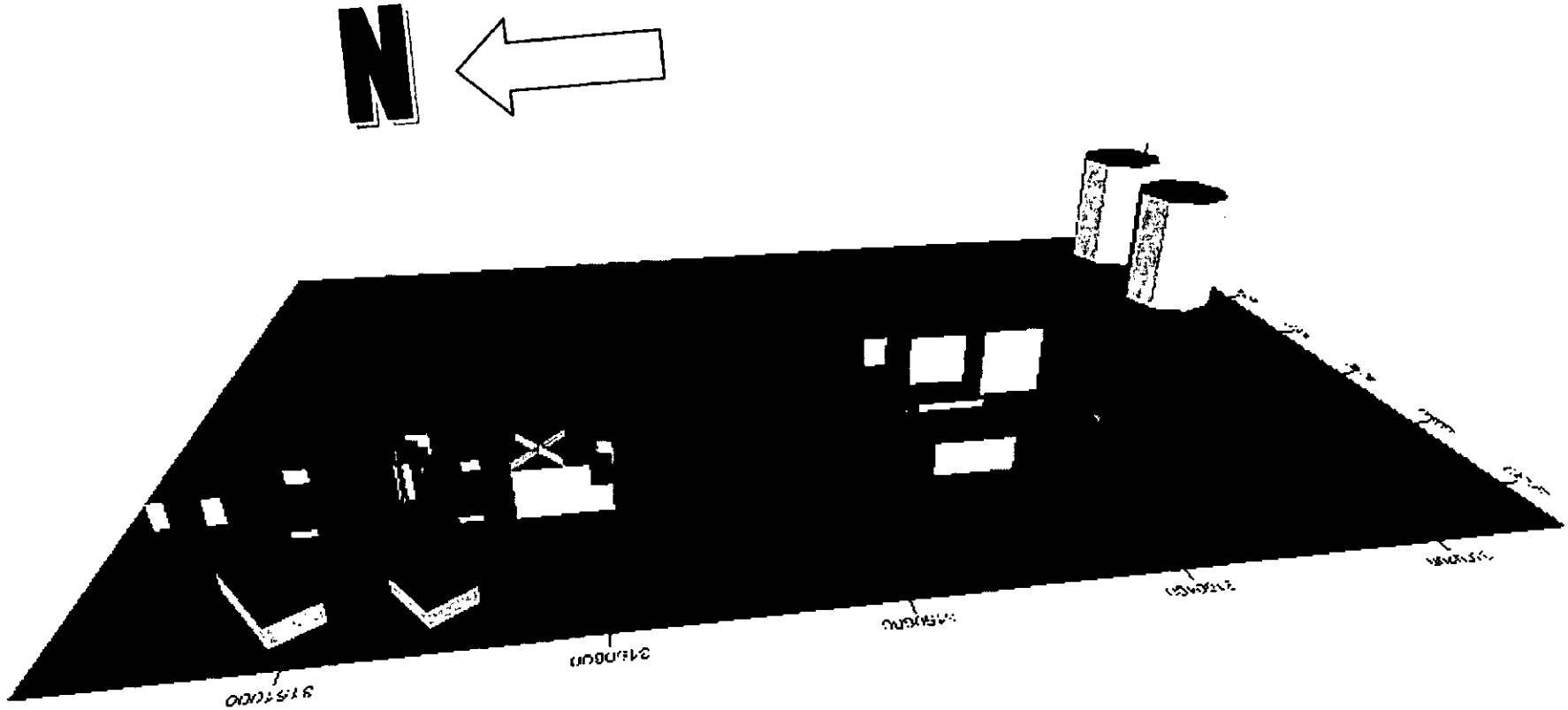

FIGURE 6-1.

BUILDINGS USED IN THE DOWNWASH ANALYSIS

Source: ECT, 2006.

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The entire perimeter of the Stanton Energy Center is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

Consistent with GAQM and FDEP recommendations, the ambient impact analysis used the following receptor grids:

- Fence line receptors—Receptors placed on the site fence line spaced 50 meters apart.
- Near-Field Cartesian Receptors—Receptors between the center of the site and extending out to approximately 3 km at 100-meter spacings.
- Mid-Field Cartesian Receptors—Receptors between 3 km and extending to approximately 6 km at 250-meter spacings.
- Far-Field Cartesian Receptors—Receptors between 6 km and extending to approximately 15 km at 500-meter spacings.

Figure 6-2 illustrates a graphical representation of the near-field receptor grids (out to a distance of 3 km). A depiction of the mid- and far-field receptor grids (from 3 to 15 km) is shown in Figure 6-3.

6.9 METEOROLOGICAL DATA

The AERMOD meteorological preprocessor AERMET (Version 04300) was used to process surface meteorological data collected at the Orlando International Airport (OIA) (Weather Bureau, Air Force and Navy [WBAN] Station No. 1281592801) and upper air data from Tampa Bay/Ruskin (WBAN Station No. 9280112842). Raw surface and upper air data for the years 1996 to 2000 was obtained from NCDC. Missing surface and upper air data (i.e., data gaps) were filled in accordance with EPA guidance.

AERMET creates two files that are used by AERMOD (i.e., surface and profile files). The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature. AERMET was utilized in accordance with the latest version (February 2005) of the

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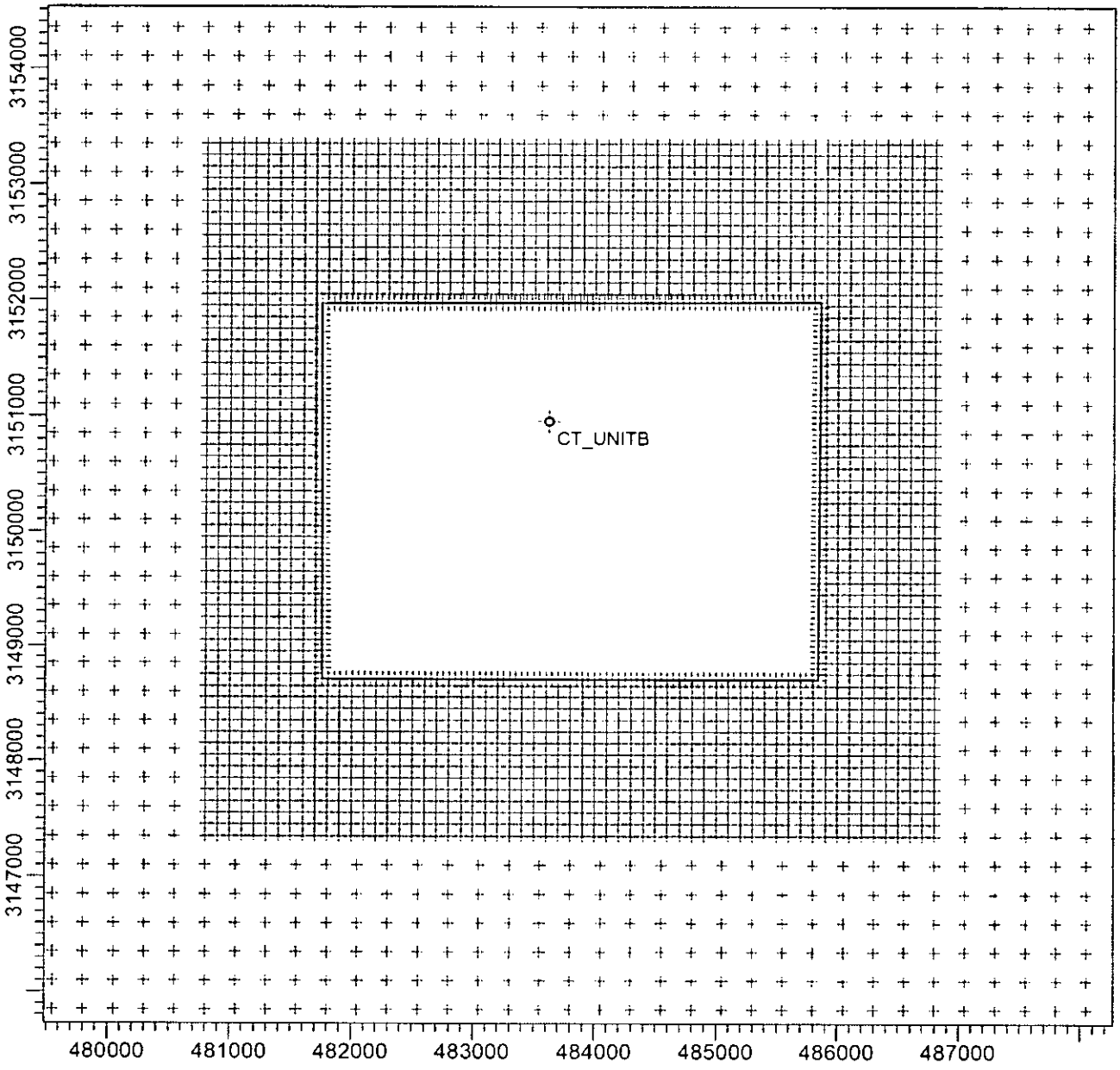

FIGURE 6-2.

NEAR-FIELD RECEPTOR GRID

Source: ECT, 2006.

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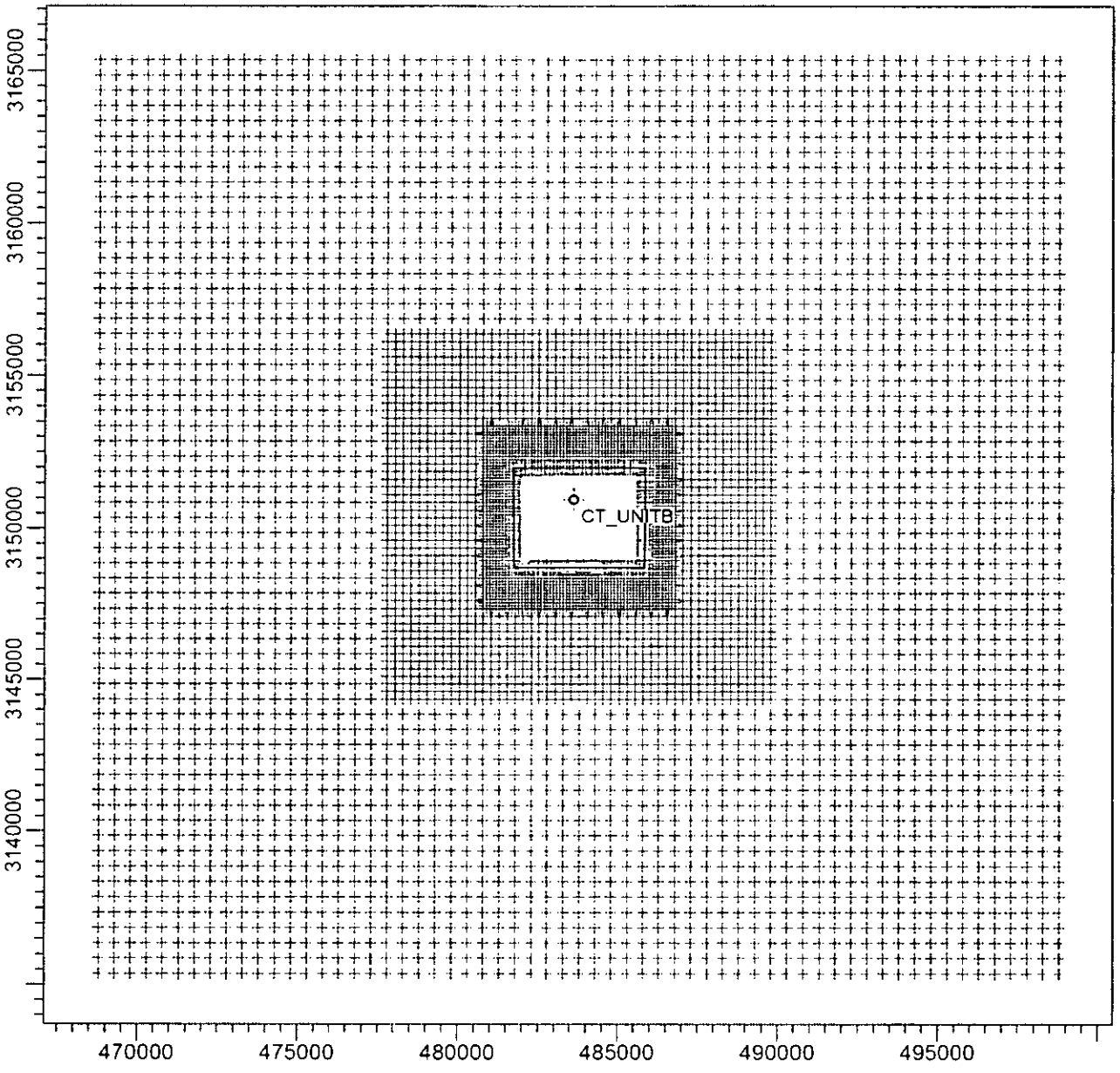

FIGURE 6-3.

FULL RECEPTOR GRID

Source: ECT, 2006.

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User's Guide for the AERMOD Meteorological Preprocessor (AERMET) and EPA's November 9, 2005, revisions to the GAQM.

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

6.9.1 SELECTION OF SURFACE CHARACTERISTICS

The AERMET preprocessing program was used to develop the meteorological data required by AERMOD. Area characteristics in the vicinity of proposed emission sources are important in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface all affect the boundary layer parameter estimates. The AERMET keywords FREQ_SECT, SECTOR, and SITE_CHAR are used to define the surface albedo, Bowen ratio, and surface roughness length (z_o). Figure 6-4 shows the land use in the vicinity of the site that was used to determine the area characteristics.

The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio is an indicator of surface moisture and is used for determining planetary boundary layer parameters for convective conditions. The surface roughness length is related to the height of obstacles to the wind flow and represents the height at which the mean horizontal wind speed is zero.

Guidance contained in the AERMET User's Guide (Tables 4-1 through 4-3), in conjunction with vicinity land use and aerial maps, were used to define the seasonal values of surface albedo, daytime Bowen ratio, and surface roughness length for the Unit B air quality impact assessment. The following specific AERMET parameters were used:

Legend

- 11: Residential, low density - less than 2 dwelling units/acre
- 12: Residential, medium density - 2-5 dwelling units/acre
- 13: Residential, high density - 6 or more dwelling units/acre
- 14: Commercial and services
- 15: Industrial
- 16: Extractive
- 17: Institutional
- 18: Recreational
- 19: Open land
- 21: Cropland and pastureland
- 22: Tree crops
- 23: Feeding operations
- 24: Nurseries and vineyards
- 31: Herbaceous upland nonforested
- 32: Shrub and brushland (wax myrtle or saw palmetto, occasionally scre
- 33: Mixed upland nonforested
- 41: Upland coniferous forests
- 42: Upland hardwood forests
- 43: Upland mixed forest
- 44: Tree plantations
- 51: Streams and waterways
- 52: Lakes
- 53: Reservoirs - pits, retention ponds, dams
- 61: Wetland hardwood forests
- 62: Wetland coniferous forests
- 63: Wetland forested mixed
- 64: Vegetated non-forested wetlands
- 74: Disturbed land
- 81: Transportation
- 82: Communications
- 83: Utilities

FIGURE 6-4.
EXISTING LAND USE ON STANTON SITE AND SURROUNDINGS AS OF 2000

Sources: SJRWMD, 2005; SFWMD, 2005; ECT, 2005

ECT
Environmental Consulting & Technology, Inc.

- After examining upwind fetch distances of 3 km, one sector from 0 to 360° was defined for site characteristics. More than 80 percent of the land use in this area was found to be rural containing swamp (wetlands) and cultivated land use types provided in the AERMET User's Guide.
- Surface characteristics such as albedo, Bowen ratio, and surface roughness were assumed to vary seasonally, and parameters appropriate for the defined land use types were taken from the AERMET User's Guide.

Details of the AERMET input parameters selected for the Unit B air quality analysis are included with the dispersion modeling files provided in Appendix C.

6.10 MODELED EMISSION INVENTORY

6.10.1 ON-PROPERTY SOURCES

In addition to the combined-cycle unit (the primary Unit B emission source), Unit B will include coal receiving, storage, handling, and feed preparation fugitive and point sources of PM/PM_{10}, a flare (for combustion of syngas during startups and plant upsets), and a mechanical draft cooling tower. Each of these Unit B emission sources was addressed in the air quality impact analysis.

Summary tables of maximum short-term emission rates and stack parameters for each Unit B emission source were previously provided in Tables 2-3 through 2-10. Emission rates used for annual average impacts were annualized based on the projected worst-case annual operating mode for the Unit B emission sources. No scaling factors or variable emission rates were used in the ambient impact analysis.

6.10.2 ON-PROPERTY SOURCES

Since Unit B maximum air quality impacts were below the PSD significant impact levels for all PSD pollutants, a full, multisource interactive assessment of NAAQS attainment and PSD Class II increment consumption was not required.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive screening and refined modeling was conducted to assess the air quality impacts resulting from Unit B operations in accordance with the FDEP approved modeling protocol. This section provides the results of the air quality assessment with respect to near-field impacts (i.e., at receptors located within 50-km of the project site). Unit B air quality impacts at the distant PSD Class I areas resulting from long-range transport are addressed in Section 10.0.

7.2 CONCLUSIONS

Comprehensive dispersion modeling using the EPA SCREEN3 (screening) and AERMOD (refined) dispersion models demonstrates that operation of Unit B will result in ambient air quality impacts that are well below the PSD Class II significant impact levels for all pollutants and all averaging periods. Accordingly, a multi-source interactive assessment of air quality impacts with respect to the AAQS and PSD Class II increments was not required.

Assessment of Unit B toxic air pollutant emissions demonstrates that all project ambient air quality impacts for air toxics will be well below the relevant EPA recommended exposure criteria.

7.3 SCREENING MODELING RESULTS

As previously described in Section 6.0, the EPA SCREEN3 dispersion model was used to assess each of the Unit B CT/HRSG operating cases. To aid in assessing the screening results, the operating cases were logically divided into two groups consistent with the emission calculations. Specifically, syngas and natural gas firing operations each have a set of operating conditions defined by CT load, CT inlet air evaporative cooling, and HRSG DB firing. The CT/HRSG operating cases evaluated for the air quality analyses include combinations of load (i.e., 100, 75, and 50 percent), ambient temperature (20, 70, and 95°F), and optional use of CT inlet air evaporative cooling and HRSG DB firing. The specific stack parameters (i.e., stack height, diameter, exhaust gas temperature, and ve-

locity) associated with each operating case were previously shown in Tables 2-8 and 2-9 for syngas and natural gas, respectively.

The specific exhaust gas temperatures and velocities for each operating case were employed in SCREEN3. Since SCREEN3 model results are directly proportional to emission rates, an emission rate of 10.0 g/sec was used for all Unit B CT/HRSG operating cases so that the model results could be easily scaled to reflect the specific emission rates for each modeled pollutant. Modeling was conducted for the Unit B pollutants that are projected to exceed the PSD significant emission rate thresholds as previously shown in Table 3-2; i.e., NO_x, SO_2, PM_{10}, and CO.

The SCREEN3 model results were used to identify the specific CT/HRSG operational cases that would be expected to produce the highest air quality impacts. These worst-case operating cases for each pollutant were then carried forward to the refined modeling analyses.

SCREEN3 model results for NO_2, SO_2, PM_{10}, and CO while firing syngas and natural gas are shown in Tables 7-1 through 7-4, respectively. For each of these pollutants, the syngas operating cases resulted in higher impacts than the natural gas cases.

For NO_2, Table 7-1 shows that Case No. 6-Syn (100-percent load at 70°F, duct firing, and evaporative cooling) results in the highest predicted hourly average concentration of 28.1 $\mu g/m^3$. Therefore, Case No. 6-Syn was selected for the refined NO_2 analyses.

For SO_2, Table 7-2 shows that Case No. 10-Syn (100-percent load at 95°F, duct firing, and evaporative cooling) results in the highest predicted hourly average concentration of 5.41 $\mu g/m^3$. Therefore, Case No. 10-Syn was selected for the refined SO_2 analyses.

Table 7-1. SCREEN3 Model Results - NO_2 Impacts: Annual Average Operating Conditions--Unit B CT/HRSG

Operating Scenarios						1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (^oF)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	Duct Burners[1] (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Syngas Operations									
4-SYN	100	70	23.4	N	N	9.89	2.34	23.1	1,072
5-SYN	100	70	23.7	Y	N	9.88	2.37	23.4	1,072
6-SYN	**100**	**70**	**28.4**	**Y**	**Y**	**9.91**	**2.84**	**28.1**	**1,071**
7-SYN	75	70	18.7	N	N	12.33	1.872	23.1	1,106
B. Natural Gas Operations									
5-NG	100	70	4.03	N	N	9.97	0.403	4.02	1,200
6-NG	100	70	4.07	Y	N	9.91	0.407	4.03	1,071
7-NG	100	70	5.30	Y	Y	10.14	0.530	5.37	1,174
8-NG	75	70	3.27	N	N	13.54	0.327	4.43	1,075
9-NG	50	70	2.58	N	N	14.89	0.258	3.84	1,044

[1] Fired exclusively with natural gas.

Source: ECT, 2006

Table 7-2. SCREEN3 Model Results - SO_2 Impacts--Unit B CT/HRSG

	Operating Scenarios					1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	Duct Burners[1] (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Syngas Operations									
1-SYN	100	20	4.51	N	N	8.60	0.451	3.88	1,115
2-SYN	100	20	4.55	N	Y	8.70	0.455	3.96	1,110
3-SYN	75	20	3.67	N	N	9.79	0.367	3.59	1,074
4-SYN	100	70	4.41	N	N	9.89	0.441	4.36	1,072
5-SYN	100	70	4.48	Y	N	9.88	0.448	4.42	1,072
6-SYN	100	70	4.52	Y	Y	9.91	0.452	4.48	1,071
7-SYN	75	70	3.57	N	N	12.3	0.357	4.40	1,106
8-SYN	100	95	3.97	N	N	13.2	0.397	5.22	1,085
9-SYN	100	95	4.27	Y	N	12.2	0.427	5.20	1,110
10-SYN	**100**	**95**	**4.31**	**Y**	**Y**	**12.6**	**0.431**	**5.41**	**1,100**
11-SYN	75	95	3.27	N	N	16.1	0.327	5.26	1,019
B. Natural Gas Operations									
1-NG	100	20	0.146	N	N	7.79	0.0146	0.114	1,148
2-NG	100	20	0.182	N	Y	8.06	0.0182	0.147	1,136
3-NG	75	20	0.118	N	N	9.79	0.0118	0.115	1,074
4-NG	50	20	0.091	N	N	9.92	0.0091	0.090	1,071
5-NG	100	70	0.131	N	N	9.97	0.0131	0.131	1,200
6-NG	100	70	0.132	N	N	9.91	0.0132	0.131	1,071
7-NG	100	70	0.172	N	Y	10.1	0.0172	0.174	1,174
8-NG	75	70	0.106	N	N	13.5	0.0106	0.144	1,075
9-NG	50	70	0.084	N	N	14.9	0.0084	0.125	1,044
10-NG	100	95	0.121	N	N	13.4	0.0121	0.162	1,078
11-NG	100	95	0.127	N	N	12.8	0.0127	0.163	1,093
12-NG	100	95	0.165	N	Y	13.2	0.0165	0.218	1,082
13-NG	75	95	0.101	N	N	17.0	0.0101	0.172	1,002
14-NG	50	95	0.079	N	N	19.4	0.0079	0.153	962

[1] Fired exclusively with natural gas

Source: ECT, 2006

For PM_{10}, Table 7-3 shows that Case No. 10-Syn (100-percent load at 95°F, duct firing, and evaporative cooling) results in the highest predicted hourly average concentration of 5.48 $\mu g/m^3$. Therefore, Case No. 10-Syn was selected for the remainder of the PM_{10} analyses.

For CO, Table 7-4 shows that Case No. 10-Syn (100-percent load at 95°F, duct firing, and evaporative cooling) results in the highest predicted hourly average concentration of 22.29 $\mu g/m^3$. Therefore, Case No. 10-Syn was selected for the remainder of the CO analyses.

7.4 REFINED MODELING RESULTS

The refined EPA AERMOD modeling system, using five years (1996 – 2000) of hour-by-hour meteorology and comprehensive receptor grids, was employed to evaluate each of the maximum impact operating cases identified by the SCREEN3 model.

Detailed Unit B AERMOD results for each year of meteorology are summarized in Table 7-5 (annual NO_2), Table 7-6 (annual SO_2), Table 7-7 (24-hour SO_2), Table 7-8 (3-hour SO_2), Table 7-9 (annual PM_{10}), Table 7-10 (24-hour PM_{10}), Table 7-11 (8-hour CO), and Table 7-12 (1-hour CO). These tables provide maximum Unit B impacts, the locations of these impacts, and relevant regulatory criteria.

Maximum Unit B air quality impacts using AERMOD and the identified worst-case operating cases are summarized in Table 7-13. The AERMOD results presented in Table 7-13 demonstrates that Unit B air quality impacts, for all pollutants and averaging periods, will be below the PSD significant impact levels previously shown in Table 3-4.

7.5 AIR TOXICS MODELING RESULTS

The refined AERMOD modeling system was also used to assess Unit B impacts with respect to toxic air pollutants. Table 7-14 shows maximum Unit B air quality impacts for a variety of metallic and organic toxic air pollutants in comparison to chronic and acute exposure criteria obtained from EPA's Integrated Risk Information System (IRIS). As shown in Table 7-14, all Unit B ambient impacts with respect to air toxics are well below the EPA recommended exposure criteria.

Table 7-3. SCREEN3 Model Results - PM_{10} Impacts--Unit B CT/HRSG

	Operating Scenarios					1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	Duct Burners[1] (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Syngas Operations									
2-SYN	100	20	4.57	N	Y	8.70	0.457	3.98	1,110
3-SYN	75	20	3.18	N	N	9.79	0.318	3.11	1,074
4-SYN	100	70	3.83	N	N	9.89	0.383	3.79	1,072
5-SYN	100	70	3.88	Y	N	9.88	0.388	3.83	1,072
6-SYN	100	70	4.51	Y	Y	9.91	0.451	4.47	1,071
7-SYN	75	70	3.10	N	N	12.3	0.310	3.82	1,106
8-SYN	100	95	3.44	N	N	13.2	0.344	4.52	1,085
9-SYN	100	95	3.70	Y	N	12.2	0.370	4.51	1,110
10-SYN	**100**	**95**	**4.37**	**Y**	**Y**	**12.6**	**0.437**	**5.48**	**1,100**
11-SYN	75	95	2.83	N	N	16.1	0.283	4.56	1,019
B. Natural Gas Operations									
1-NG	100	20	2.29	N	N	7.79	0.229	1.78	1,148
2-NG	100	20	2.93	N	Y	8.06	0.293	2.36	1,136
3-NG	75	20	2.29	N	N	9.79	0.229	2.24	1,074
4-NG	50	20	2.28	N	N	9.92	0.228	2.26	1,071
5-NG	100	70	2.29	N	N	9.97	0.229	2.28	1,200
6-NG	100	70	2.29	N	N	9.91	0.229	2.27	1,071
7-NG	100	70	2.93	N	Y	10.1	0.293	2.97	1,174
8-NG	75	70	2.29	N	N	13.5	0.229	3.10	1,075
9-NG	50	70	2.28	N	N	14.9	0.228	3.39	1,044
10-NG	100	95	2.29	N	N	13.4	0.229	3.07	1,078
11-NG	100	95	2.29	N	N	12.8	0.229	2.93	1,093
12-NG	100	95	2.93	N	Y	13.2	0.293	3.88	1,082
13-NG	75	95	2.29	N	N	17.0	0.229	3.90	1,002
14-NG	50	95	2.28	N	N	19.4	0.228	4.42	962

[1] Fired exclusively with natural gas.

Source: ECT, 2006

Table 7-4. SCREEN3 Model Results for CO Impacts -- Unit B CT/HRSG

	Operating Scenarios					1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	Duct Burners[1] (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m³)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m³)	Downwind Distance (m)
A. Syngas Operations									
1-SYN	100	20	11.31	N	N	8.60	1.131	9.72	1,115
2-SYN	100	20	18.04	N	Y	8.70	1.804	15.70	1,110
3-SYN	75	20	9.25	N	N	9.79	0.925	9.06	1,074
4-SYN	100	70	11.33	N	N	9.89	1.133	11.20	1,072
5-SYN	100	70	11.42	Y	N	9.88	1.142	11.28	1,072
6-SYN	100	70	17.70	Y	Y	9.91	1.770	17.53	1,071
7-SYN	75	70	9.18	N	N	12.3	0.918	11.32	1,106
8-SYN	100	95	10.45	N	N	13.2	1.045	13.74	1,085
9-SYN	100	95	11.06	Y	N	12.2	1.106	13.47	1,110
10-SYN	**100**	**95**	**17.76**	**Y**	**Y**	**12.6**	**1.776**	**22.29**	**1,100**
11-SYN	75	95	8.78	N	N	16.1	0.878	14.14	1,019
B. Natural Gas Operations									
1-NG	100	20	11.04	N	N	7.79	1.10	8.60	1,148
2-NG	100	20	17.74	N	Y	8.06	1.77	14.31	1,136
3-NG	75	20	8.31	N	N	9.79	0.831	8.13	1,074
4-NG	50	20	7.66	N	N	9.92	0.766	7.59	1,071
5-NG	100	70	9.88	N	N	9.97	0.988	9.85	1,200
6-NG	100	70	9.96	N	N	9.91	1.00	9.87	1,071
7-NG	100	70	17.39	N	Y	10.1	1.74	17.63	1,174
8-NG	75	70	8.21	N	N	13.5	0.821	11.12	1,075
9-NG	50	70	7.11	N	N	14.9	0.711	10.59	1,044
10-NG	100	95	9.21	N	N	13.4	0.921	12.35	1,078
11-NG	100	95	9.54	N	N	12.8	0.954	12.22	1,093
12-NG	100	95	16.67	N	Y	13.2	1.67	22.05	1,082
13-NG	75	95	7.66	N	N	17.0	0.766	13.03	1,002
14-NG	50	95	6.84	N	N	19.4	0.684	13.26	962

[1] Fired exclusively with natural gas

Source: ECT, 2006

Table 7-5. AERMOD Model Results - Maximum Annual Average NO_2 Impacts

Maximum Annual Impacts	1996	1997	**1998**	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.0273	0.0269	**0.0277**	0.0207	0.0214
Unit B CT/HRSG Emission Rate (g/s)	28.40	28.40	**28.40**	28.40	28.40
Tier 1 Impact ($\mu g/m^3$)[2]	0.776	0.763	**0.787**	0.588	0.608
Tier 2 Impact ($\mu g/m^3$)[3]	0.582	0.573	**0.590**	0.441	0.456
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	**1.0**	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	58.2	57.3	**59.0**	44.1	45.6
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	**14.0**	14.0	14.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	**N**	N	N
Receptor UTM Easting (m)	483,577	483,676	**483,676**	483,725	483,775
Receptor UTM Northing (m)	3,151,975	3,151,976	**3,151,976**	3,151,976	3,151,976
Distance From Grid Origin (m)	1,026	1,027	**1,027**	1,031	1,038
Direction From Grid Origin (Vector °)	358	3	**3**	6	9

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate (assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

[3] Tier 1 impact times USEPA national default NO_2/NO_x ratio of 0.75.

Source: ECT, 2006.

Table 7-6. AERMOD Model Results - Maximum Annual Average SO_2 Impacts

Maximum Annual Impacts	1996	1997	**1998**	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.0278	0.0274	**0.0281**	0.0210	0.0215
Unit B CT/HRSG Emission Rate (g/s)	4.31	4.31	**4.31**	4.31	4.31
Adjusted Impact ($\mu g/m^3$)[2]	0.120	0.118	**0.121**	0.091	0.092
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	**1.0**	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	12.0	11.8	**12.1**	9.1	9.2
Receptor UTM Easting (m)	483,577	483,676	**483,676**	483,725	483,824
Receptor UTM Northing (m)	3,151,975	3,151,976	**3,151,976**	3,151,976	3,151,976
Distance From Grid Origin (m)	1,026	1,027	**1,027**	1,031	1,046
Direction From Grid Origin (Vector °)	358	3	**3**	6	11

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2006.

Table 7-7. AERMOD Model Results - Maximum 3-Hour Average SO_2 Impacts

Maximum 3-Hour Impacts	1996	1997	**1998**	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.567	0.700	**0.710**	0.486	0.506
Unit B CT/HRSG Emission Rate (g/s)	4.31	4.31	**4.31**	4.31	4.31
Adjusted Impact ($\mu g/m^3$)[2]	2.44	3.02	**3.06**	2.09	2.18
PSD Significant Impact ($\mu g/m^3$)	25.0	25.0	**25.0**	25.0	25.0
Exceed PSD Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	9.8	12.1	**12.2**	8.4	8.7
Receptor UTM Easting (m)	484,567	483,626	**483,626**	483,676	482,686
Receptor UTM Northing (m)	3,151,979	3,151,975	**3,151,975**	3,151,976	3,151,971
Distance From Grid Origin (m)	1,399	1,025	**1,025**	1,027	1,384
Direction From Grid Origin (Vector °)	43	0	**0**	3	318
Date of Maximum Impact	1/2/96	4/28/97	**1/27/98**	1/02/99	11/24/00
Julian Date of Maximum Impact	02	118	**27**	02	329
Ending Hour of Maximum Impact	2100	0300	**0600**	2100	2400

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2006.

Table 7-8. AERMOD Model Results - Maximum 24-Hour Average SO_2 Impacts

Maximum 24-Hour Impacts	1996	1997	**1998**	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.241	0.273	**0.328**	0.250	0.200
Unit B CT/HRSG Emission Rate (g/s)	4.31	4.31	**4.31**	4.31	4.31
Adjusted Impact ($\mu g/m^3$)[2]	1.04	1.18	**1.41**	1.08	0.86
PSD Significant Impact ($\mu g/m^3$)	5.0	5.0	**5.0**	5.0	5.0
Exceed PSD Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	20.8	23.5	**28.2**	21.6	17.2
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	13.0	13.0	**13.0**	13.0	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	**N**	N	N
Percent of PSD *de minimis* Ambient Impact (%)	8.0	9.0	**10.9**	8.3	6.6
Receptor UTM Easting (m)	483,577	483,725	**483,478**	483,478	482,636
Receptor UTM Northing (m)	3,151,975	3,151,976	**3,151,975**	3,151,975	3,151,971
Distance From Grid Origin (m)	1,026	1,031	**1,034**	1,034	1,418
Direction From Grid Origin (Vector °)	358	6	**352**	352	316
Date of Maximum Impact	10/07/96	04/28/97	**03/08/98**	01/23/99	11/24/00
Julian Date of Maximum Impact	281	118	**67**	23	329

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2006.

Table 7-9. AERMOD Model Results - Maximum Annual Average PM_{10} Impacts

Maximum Annual Impacts	1996	1997	1998	1999	2000
AERMOD Impact (µg/m3)[1]	~~0.2791~~ 0.3075	~~0.3182~~ 0.3463	~~0.3077~~ 0.3331	~~0.2560~~ 0.2763	~~0.2308~~ 0.2502
PSD Significant Impact (µg/m^3)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	~~27.9~~ 30.7	~~31.8~~ 34.6	~~30.8~~ 33.3	~~25.6~~ 27.6	~~23.1~~ 25.0
Receptor UTM Easting (m)	483,527	483,577	483,577	483,181	483,577
Receptor UTM Northing (m)	3,151,975	3,151,975	3,151,975	3,151,973	3,151,975
Distance From Grid Origin (m)	1,029	1,026	1,026	1,114	1,026
Direction From Grid Origin (Vector °)	355	358	358	337	358

[1] Impact for all Unit B PM_{10} emission sourcers.

Source: ECT, 2006.

Table 7-10. AERMOD Model Results - Maximum 24-Hour Average PM_{10} Impacts

Maximum 24-Hour Impacts	1996	1997	1998	1999	2000
AERMOD Impact (µg/m3)[1]	~~2.746~~ 2.748	~~4.268~~ 4.381	~~2.998~~ 3.066	~~3.722~~ 3.862	~~3.345~~ 3.412
PSD Significant Impact (µg/m^3)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	~~54.9~~ 55.0	~~85.4~~ 87.6	~~60.0~~ 61.3	~~74.4~~ 77.2	~~66.9~~ 68.2
PSD *de minimis* Ambient Impact Threshold (µg/m^3)	10.0	10.0	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Receptor UTM Easting (m)	483,500	483,577	484,022	483,600	483,428
Receptor UTM Northing (m)	3,148,706	3,151,975	3,151,977	3,152,050	3,151,974
Distance From Grid Origin (m)	2,247	1,026	1,103	1,100	1,042
Direction From Grid Origin (Vector°)	183	358	21	359	349
Date of Maximum Impact	12/31/96	01/04/97	09/21/98	06/16/99	07/26/00
Julian Date of Maximum Impact	366	04	264	167	208

[1] Impact for all Unit B PM_{10} emission sources.

Source: ECT, 2006.

Table 7-9. AERMOD Model Results - Maximum Annual Average PM_{10} Impacts

Maximum Annual Impacts	1996	**1997**	1998	1999	2000
AERMOD Impact (µg/m3)[1]	0.2791	**0.3182**	0.3077	0.2560	0.2308
PSD Significant Impact (µg/m^3)	1.0	**1.0**	1.0	1.0	1.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	27.9	**31.8**	30.8	25.6	23.1
Receptor UTM Easting (m)	483,527	**483,577**	483,577	483,181	483,577
Receptor UTM Northing (m)	3,151,975	**3,151,975**	3,151,975	3,151,973	3,151,975
Distance From Grid Origin (m)	1,029	**1,026**	1,026	1,114	1,026
Direction From Grid Origin (Vector °)	355	**358**	358	337	358

[1] Impact for all Unit B PM_{10} emission sourcers.

Source: ECT, 2006.

Table 7-10. AERMOD Model Results - Maximum 24-Hour Average PM_{10} Impacts

Maximum 24-Hour Impacts	1996	**1997**	1998	1999	2000
AERMOD Impact (µg/m3)[1]	2.746	**4.268**	2.998	3.722	3.345
PSD Significant Impact (µg/m^3)	5.0	**5.0**	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	54.9	**85.4**	60.0	74.4	66.9
PSD *de minimis* Ambient Impact Threshold (µg/m^3)	10.0	**10.0**	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	**N**	N	N	N
Receptor UTM Easting (m)	483,500	**483,577**	484,022	483,600	483,428
Receptor UTM Northing (m)	3,148,706	**3,151,975**	3,151,977	3,152,050	3,151,974
Distance From Grid Origin (m)	2,247	**1,026**	1,103	1,100	1,042
Direction From Grid Origin (Vector °)	183	**358**	21	359	349
Date of Maximum Impact	12/31/96	**01/04/97**	09/21/98	06/16/99	07/26/00
Julian Date of Maximum Impact	366	04	264	167	208

[1] Impact for all Unit B PM_{10} emission sourcers.

Source: ECT, 2006.

Table 7-11. AERMOD Model Results - Maximum 8-Hour Average CO Impacts

Maximum 8-Hour Impacts	1996	**1997**	1998	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.460	**0.573**	0.539	0.393	0.393
Unit B CT/HRSG Emission Rate (g/s)	17.8	**17.8**	17.8	17.8	17.8
Adjusted Impact ($\mu g/m^3$)[2]	8.17	**10.2**	9.57	6.98	6.98
PSD Significant Impact ($\mu g/m^3$)	500.0	**500.0**	500.0	500.0	500.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	1.6	**2.0**	1.9	1.4	1.4
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	575.0	**575.0**	575.0	575.0	575.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	1.4	**1.8**	1.7	1.2	1.2
Receptor UTM Easting (m)	483,626	**483,676**	482,933	483,478	483,923
Receptor UTM Northing (m)	3,151,975	**3,151,976**	3,151,972	3,151,975	3,151,977
Distance From Grid Origin (m)	1,025	**1,027**	1,232	1,034	1,071
Direction From Grid Origin (Vector °)	0	**3**	326	352	16
Date of Maximum Impact	04/30/96	**04/28/97**	02/16/98	02/01/99	01/23/00
Julian Date of Maximum Impact	121	**118**	47	32	23
Ending Hour of Maximum Impact	0800	**0800**	0800	1600	1600

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2006.

Table 7-12. AERMOD Model Results - Maximum 1-Hour Average CO Impacts

Maximum 1-Hour Impacts	1996	1997	**1998**	1999	2000
Unadjusted AERMOD Impact ($\mu g/m^3$)[1]	0.768	0.763	**0.772**	0.741	0.747
Unit B CT/HRSG Emission Rate (g/s)	17.8	17.8	**17.8**	17.8	17.8
Adjusted Impact ($\mu g/m^3$)[2]	13.6	13.6	**13.7**	13.2	13.3
PSD Significant Impact ($\mu g/m^3$)	2,000.0	2,000.0	**2,000.0**	2,000.0	2,000.0
Exceed PSD Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	0.7	0.7	**0.7**	0.7	0.7
Receptor UTM Easting (m)	483,626	483,725	**483,626**	483,626	483,577
Receptor UTM Northing (m)	3,151,975	3,151,976	**3,151,975**	3,151,975	3,151,975
Distance From Grid Origin (m)	1,025	1,031	**1,025**	1,025	1,026
Direction From Grid Origin (Vector °)	0	6	**0**	0	358
Date of Maximum Impact	06/11/96	09/27/97	**09/03/98**	12/12/99	04/13/00
Julian Date of Maximum Impact	163	270	**246**	346	104
Ending Hour of Maximum Impact	2000	0100	**0500**	0800	1900

[1] Based on modeled emission rate of 1.0 g/s.

[2] Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2006.

Table 7-13. Refined (AERMOD) Modeling Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.59	1
PM_{10}	Annual	~~0.32~~0.35	1
	24-hour	~~4.3~~4.4	5
SO_2	Annual	0.12	1
	24-hour	1.4	5
	3-hour	3.1	25
CO	8-Hour	10.2	500
	1-Hour	13.7	2,000

Source: ECT, 2006.

Table 7-13. Refined (AERMOD) Modeling Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.59	1
PM_{10}	Annual	0.32	1
	24-hour	4.3	5
SO_2	Annual	0.12	1
	24-hour	1.4	5
	3-hour	3.1	25
CO	8-Hour	10.2	500
	1-Hour	13.7	2,000

Source: ECT, 2006.

Table 7-14. AERMOD Model Results - Toxic Air Pollutants; Syngas

Chemical Compound	CT/HRSG Emissions[a] (lb/hr)	CT/HRSG Emissions[a] (g/s)	Inhalation Unit Risk Factor[b] $(ug/m^3)^{-1}$	Reference Concentration[b] (ug/m^3)	Cancer Risk[c]	Hazard Coefficient[d]
2-Methylnaphthalene	8.58E-04	1.08E-04	NA	NA	NA	NA
Acenaphthyalene	6.19E-05	7.81E-06	NA	NA	NA	NA
Acetaldehyde	4.29E-03	5.41E-04	2.20E-06	9.00E+00	3.35E-11	1.69E-06
Antimony	9.53E-03	1.20E-03	NA	2.00E-01	NA	1.69E-04
Arsenic	5.01E-03	6.31E-04	4.30E-03	5.00E-01	7.63E-08	3.55E-05
Benzaldehyde	6.91E-03	8.71E-04	NA	NA	NA	NA
Benzene	1.16E-02	1.46E-03	7.80E-06	3.00E+01	3.21E-10	1.37E-06
Benzo(a)anthracene	5.48E-06	6.91E-07	1.10E-04	NA	2.14E-12	NA
Benzo(e)pyrene	1.31E-05	1.65E-06	8.86E-04	NA	4.12E-11	NA
Benzo(g,h,i)perylene	2.26E-05	2.85E-06	NA	NA	NA	NA
Beryllium	2.15E-04	2.70E-05	2.40E-03	2.00E-02	1.82E-09	3.80E-05
Cadmium	6.91E-03	8.71E-04	1.80E-03	2.00E-01	4.41E-08	1.22E-04
Carbon Disulfide	1.07E-01	1.35E-02	NA	7.00E+02	NA	5.43E-07
Chromium*	6.44E-03	8.11E-04	1.20E-02	8.00E-03	2.74E-07	2.85E-03
Cobalt	1.36E-03	1.71E-04	NA	NA	NA	NA
Formaldehyde	7.96E-02	1.00E-02	1.30E-05	NA	3.67E-09	NA
Lead	6.91E-03	8.72E-04	NA	9.00E-02	NA	2.72E-04
Manganese	7.39E-03	9.31E-04	NA	5.00E-02	NA	5.23E-04
Mercury	2.17E-03	2.73E-04	NA	3.00E-01	NA	2.56E-05
Naphthalene	1.27E-03	1.60E-04	NA	3.00E+00	NA	1.50E-06
Nickel	9.30E-03	1.17E-03	2.40E-04	5.00E-02	7.91E-09	6.59E-04
Selenium	6.91E-03	8.71E-04	NA	5.00E-01	NA	4.90E-05
Toluene	1.77E-03	2.23E-04	NA	5.00E+02	NA	1.25E-08
TOTAL					4.08E-07	4.75E-03
Risk Indicators					1.00E-06	1.00E+00
Percent of Indicator					41%	0.47%

[a] Provided by SCS.

[b] Provided by EPA Integrated Risk Information System (IRIS).

[c] Unit risk factor multiplied by maximum annual average impact determined by AERMOD at an 1 g/s emission rate.

[d] Maximum AERMOD annual average impact divided by reference concentration.

Notes:
NA = Not Available
* conservatively assumed all chromium to be hexavalent.

Sources: ECT, 2006.
EPA, 2006.
SCS, 2006.

Table 7-15. AERMOD Model Results - Toxic Air Pollutants; Natural Gas

Chemical Compound	CT/HRSG Emissions (lb/hr)	CT/HRSG Emissions (g/s)	Inhalation Unit Risk Factor[a] $(ug/m^3)^{-1}$	Reference Concentration[a] (ug/m^3)	Cancer Risk[b]	Hazard Coefficient[c]
1,3-Butadiene	8.34E-04	1.05E-04	3.00E-05	2.00E+00	8.87E-11	1.48E-06
Acetaldehyde	7.76E-02	9.78E-03	2.20E-06	9.00E+00	6.05E-10	3.05E-05
Acrolein	1.24E-02	1.56E-03	NA	2.00E-02	NA	2.20E-03
Benzene	2.43E-02	3.06E-03	7.80E-06	3.00E+01	6.72E-10	2.87E-06
Ethylbenzene	6.21E-02	7.82E-03	NA	1.00E+03	NA	2.20E-07
Formaldehyde	6.18E-01	7.78E-02	1.30E-05	NA	2.84E-08	NA
Naphthalene	2.81E-03	3.54E-04	NA	3.00E+00	NA	3.32E-06
PAH	4.27E-03	5.38E-04	NA	NA	NA	NA
Propylene Oxide	5.63E-02	7.09E-03	3.70E-06	3.00E+01	7.38E-10	6.65E-06
Toluene	2.54E-01	3.20E-02	NA	5.00E+02	NA	1.80E-06
Xylenes	1.24E-01	1.56E-02	NA	1.00E+02	NA	4.39E-06
TOTAL					3.05E-08	2.25E-03
Risk Indicators					1.00E-06	1.00E+00
Percent of Indicator					3%	0.22%

[a] Provided by EPA Integrated Risk Information System (IRIS).

[b] Unit risk factor multiplied by maximum annual average impact determined by AERMOD at an 1 g/s emission rate.

[c] Maximum AERMOD annual average impact divided by reference concentration.

Notes:
NA = Not Available

Sources: ECT, 2006.
EPA, 2006.
SCS, 2006.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air quality monitoring station is located on North Primrose Avenue in Orlando, Orange County, approximately 19 km northwest of the Stanton Energy Center. This station monitors the ambient air for PM_{10} and $PM_{2.5}$. The nearest ambient air quality monitoring station that monitors for 1- and 8-hour average ozone is located on Winegard Road in Orlando, approximately 21 km west of the project site. The nearest NO_2 ambient air quality monitoring station is located at the intersection of Morse Boulevard and Denning Street in Winter Park, Orange County, approximately 23 km northwest of the project site. The nearest CO ambient air quality monitoring station is located on Orange Avenue in Orlando, approximately 21 km northwest of the project site. The nearest ambient air quality monitoring station for lead is situated in Tampa, Hillsborough County, approximately 150 km west of the Stanton Energy Center. All of the Orange County ambient air quality monitoring stations are operated by the Orange County Environmental Protection Division (OCEPD). The Hillsborough County site that monitors ambient air for lead is operated by the Hillsborough County Environmental Protection Commission (HCEPC). Summaries of the 2000 through 2004 ambient air quality data for these monitoring stations are provided in Table 8-1.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

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

Table 8-1. Summary of 2000 through 2004 Ambient Air Quality Monitoring Data

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (µg/m³)				
	County	City								1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
PM_{10}	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	24-hour	61	46	39		150*	30.7
							2001	24-hour	60	46	41		150*	30.7
							2002	24-hour	60	33	30		150*	22.0
							2003	24-hour	61	30	28		150*	20.0
							2004	24-hour	56	41	27		150*	27.3
							2000	Annual	61			21	50†	42.0
							2001	Annual	60			20	50†	40.0
							2002	Annual	60			17	50†	34.0
							2003	Annual	61			18	50†	36.0
							2004	Annual	56			18	50†	36.0
		Orlando	North Primrose Avenue	120951004	19	295	2000	24-hour	60	37	37		150*	24.7
							2001	24-hour	59	48	43		150*	32.0
							2002	24-hour	61	35	31		150*	23.3
							2003	24-hour	61	56	47		150*	37.3
							2004	24-hour	59	41	36		150*	27.3
							2000	Annual	60			21	50†	42.0
							2001	Annual	59			22	50†	44.0
							2002	Annual	61			18	50†	36.0
							2003	Annual	61			20	50†	40.0
							2004	Annual	59			19	50†	38.0
			Sheriff's Department	120950007	24	278	2000	24-hour	61	48	44		150*	32.0
							2001	24-hour	61	53	50		150*	35.3
							2002	24-hour	61	41	38		150*	27.3
							2003	24-hour	59	39	37		150*	26.0
							2000	Annual	61			27	50†	54.0
							2001	Annual	61			23	50†	46.0
							2002	Annual	61			23	50†	46.0
							2003	Annual	59			21	50†	42.0
	Brevard	Titusville	Tico Airport	120090004	37	84	2000	24-hour	48	35	34		150*	23.3
							2001	24-hour	357	96	55		150*	64.0
							2002	24-hour	334	66	38		150*	44.0
							2003	24-hour	354	170	79		150*	113.3
							2004	24-hour	334	61	46		150*	40.7
							2000	Annual	48			17	50†	34.0
							2001	Annual	357			19	50†	38.0
							2002	Annual	334			17	50†	34.0
							2003	Annual	354			19	50†	38.0
							2004	Annual	334			17	50†	34.0

Table 8-1. Summary of 2000 through 2004 Ambient Air Quality Monitoring Data (Continued, Page 2 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (μg/m³)				
	County	City								1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
$PM_{2.5}$	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	24-hour	345	35	34		65*	53.8
							2001	24-hour	336	61	41		65*	93.8
							2002	24-hour	353	26	25		65*	40.0
							2003	24-hour	357	23	22		65*	35.4
							2004	24-hour	326	28	26		65*	43.1
							2000	Annual	345			11.9	15†	79.3
							2001	Annual	336			10.7	15†	71.3
							2002	Annual	353			9.5	15†	63.3
							2003	Annual	357			9.3	15†	62.0
							2004	Annual	326			9.9	15†	66.0
		Orlando	North Primrose Avenue	120951004	19	295	2000	24-hour	353	35	34		65*	53.8
							2001	24-hour	353	52	41		65*	80.0
							2002	24-hour	349	30	27		65*	46.2
							2003	24-hour	345	23	21		65*	35.4
							2004	24-hour	307	38	26		65*	58.5
							2000	Annual				12	15†	80.0
							2001	Annual				10.9	15†	72.7
							2002	Annual				9.7	15†	64.7
							2003	Annual				9.4	15†	62.7
							2004	Annual				10.1	15†	67.3
SO_2	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	3-hour	8,420	109.7	70.5		1,300‡	8.4
							2001	3-hour	8,401	83.6	70.5		1,300‡	6.4
							2002	3-hour	8,571	34.0	28.7		1,300‡	2.6
							2003	3-hour	8,647	31.3	28.7		1,300‡	2.4
							2004	3-hour	8,324	36.6	23.5		1,300‡	2.8
							2000	24-hour	8,420	34.0	23.5		365‡	9.3
							2001	24-hour	8,401	36.6	20.9		365‡	10.0
							2002	24-hour	8,571	13.1	13.1		365‡	3.6
							2003	24-hour	8,647	15.7	10.4		365‡	4.3
							2004	24-hour	8,324	13.1	13.1		365‡	3.6
							2000	Annual	8,420			7.8	80†	9.8
							2001	Annual	8,401			5.2	80†	6.5
							2002	Annual	8,571			2.6	80†	3.3
							2003	Annual	8,647			2.6	80†	3.3
							2004	Annual	8,324			2.6	80†	3.3

Table 8-1. Summary of 2000 through 2004 Ambient Air Quality Monitoring Data (Continued, Page 3 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (µg/m³)				
	County	City								1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
NO_2	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	Annual	8,470			22.5	100†	22.5
							2001	Annual	8,495			22.5	100†	22.5
							2002	Annual	8,485			20.7	100†	20.7
							2003	Annual	8,437			20.7	100†	20.7
							2004	Annual	8,418			18.8	100†	18.8
CO	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	1-hour	8,542	8,571	8,571		40,000‡	21.4
							2001		8,438	9,143	3,086		40,000‡	22.9
							2002		8,619	4,343	4,000		40,000‡	10.9
							2003		8,667	2,971	2,629		40,000‡	7.4
							2004		8,460	2,743	2,743		40,000‡	6.9
							2000	8-hour	8,542	5,371	2,743		10,000‡	53.7
							2001		8,438	2,400	2,286		10,000‡	24.0
							2002		8,619	3,200	2,857		10,000‡	32.0
							2003		8,667	1,714	1,714		10,000‡	17.1
							2004		8,460	1,829	1,829		10,000‡	18.3
		Orlando	Orange Avenue	120951005	21	289	2000	1-hour	8,619	5,143	5,143		40,000‡	12.9
							2001		8,572	4,800	4,343		40,000‡	12.0
							2002		8,530	5,143	5,029		40,000‡	12.9
							2003		8,551	3,886	3,657		40,000‡	9.7
							2004		8,596	4,686	3,086		40,000‡	11.7
							2000	8-hour	8,619	2,971	2,971		10,000‡	29.7
							2001		8,572	2,743	2,400		10,000‡	27.4
							2002		8,530	3,314	2,857		10,000‡	33.1
							2003		8,551	2,286	2,286		10,000‡	22.9
							2004		8,596	2,171	2,057		10,000‡	21.7
Ozone	Orange	Winer Park	Morris Boulevard	120952002	23	306	2000	1-hour	242	214	208		235**	90.9
							2001	1-hour	228	196	182		235**	83.4
							2002	1-hour	237	208	196		235**	88.4
							2003	1-hour	244	186	178		235**	79.2
							2004	1-hour	233	178	174		235**	75.9
							2000	8-hour***	242	165	159		157††	97.8
							2001	8-hour***	228	159	153		157††	94.8
							2002	8-hour***	237	153	149		157††	94.0
							2003	8-hour***	244	149	145		157††	N/A
							2004	8-hour***	233	151	149		157††	N/A

Table 8-1. Summary of 2000 through 2004 Ambient Air Quality Monitoring Data (Continued, Page 4 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (µg/m³)				
	County	City								1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
Ozone (cont.)		Orlando	Winegard Road	120950008	21	262	2000	1-hour	245	212	198		235**	90.0
							2001	1-hour	241	186	184		235**	79.2
							2002	1-hour	228	206	200		235**	87.5
							2003	1-hour	244	182	174		235**	77.5
							2004	1-hour	163	194	184		235**	82.5
							2000	8-hour***	245	159	155		157††	96.1
							2001	8-hour***	241	153	153		157††	94.0
							2002	8-hour***	228	147	145		157††	92.3
							2003	8-hour***	244	145	145		157††	N/A
							2004	8-hour***	163	147	145		157††	N/A
Lead	Orange	Winer Park	Morris Boulevard	120952002	23	306	1994 to 1996	24-hour	182	0.0	0		1.5†	0.0
		Orlando	Sheriff's Department	120950007	24	278	1994 to 1996	24-hour	182	0.00	0		1.5†	0.0

*98th percentile.
†Arithmetic mean.
‡2nd high.
**4th highest day with hourly value exceeding standard over a 3-year period.
††4th highest daily maximum 8-hour concentation over a 3-year period.
***Monitor values represent 3rd and 4th highest 8-hour concentrations.

Sources: FDEP, 2005.
EPA, 2005.
ECT, 2005.

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

8.1.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 3.7 $\mu g/m^3$. This concentration is below the 10 $\mu g/m^3$ *de minimis* level ambient impact level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.1.2 SO_2

The maximum 24-hour SO_2 impact was predicted to be 1.4 $\mu g/m^3$. This concentration is below the 13 $\mu g/m^3$ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO_2 is appropriate in accordance with the PSD regulations.

8.1.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.6 $\mu g/m^3$. This concentration is below the 14-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

8.1.4 CO

The maximum 8-hour CO impact was predicted to be 10.2 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following sections.

9.1 GROWTH IMPACT ANALYSIS

9.1.1 PROJECT GROWTH IMPACTS

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

Impacts associated with construction of Unit B will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

Unit B is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, Unit B is projected to generate approximately 72 new jobs during the commissioning and U.S. Department of Energy (DOE) demonstration period; 53 of these positions will remain as the long-term operations crew. This number of new personnel will not significantly affect growth in the area. The increase in coal and natural gas demand due to the operation of Unit B will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.1.2 AREA GROWTH SINCE 1977

U.S. Census Bureau data shows that the population of the Orlando metropolitan area has roughly doubled between 1980 and 2000. The Orlando area population, as of April 2003, was 1,755,000. The rate of population growth in the area declined from 2000 to 2003, reflecting the effect of the economic slowdown beginning in early 2001 and very slow growth during most of 2002.

The Orlando area is home to several major theme parks, including Walt Disney World and Universal Studios and is a major tourist destination. In addition, numerous business conventions and meetings are held in the Orlando area. A local study attributed one-quarter of all its visitors to business, including meetings and conventions.

As a tourism-dominated region, there is little major industrial activity in the Orlando region. The major air quality impact of the growth that has occurred in the Orlando area is predominantly due to an increase in mobile source activity. However, the reductions in mobile source tailpipe emissions and improvements in fuel quality since the late 1970s has resulted in improvements in the area's air quality. Although the Orlando area was once classified as an ozone nonattainment area, it is presently classified as attainment for all criteria pollutants.

Accordingly, it is concluded that air quality in the Orlando area has not deteriorated since 1977. As discussed in Section 7.0, the relatively minor emissions associated with Unit B will result in insignificant air quality impacts.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the Stanton Energy Center due to Unit B operations will be below the applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the Stanton Energy Center are anticipated. The following sections discuss potential impacts on the nearest Class I area, the Chassahowitzka NWR.

9.2.1 IMPACTS ON SOILS

The U.S. Department of Agriculture (USDA) (1991a and 1991b) lists the primary soil type in the Chassahowitzka NWR as Weekiwachee-Durbin muck. This soil type is characterized by high levels of sulfur and organic content. Sulfur levels may approach 4 percent in the upper soil layer. Daily flooding by high tides cause the pH to vary between 6.1 and 7.8.

Typically, SO_2 represents the greatest threat to soil since this pollutant causes increased sulfur content and decreased pH. However, for the Unit B project, given the relatively low levels of SO_2 emitted, the distance from the source, the naturally high sulfur content of the

Class I area soils, and the pH variability caused by tidal influences, no impacts to soils are expected.

9.2.2 IMPACTS ON VEGETATION

The Chassahowitzka NWR is a complex ecosystem of vegetation assemblages that depend on the subtle interplay of slight changes in elevation, salinity, hydroperiod, and edaphic factors for distribution, extent, and species composition. The mosaic of plant communities at the Chassahowitzka NWR is represented by pine woods and hammock forests within areas of higher ground, various fresh water forested and nonforested wetlands situated within lowland depressions that are inundated/saturated with fresh water for at least part of the year (mixed swamp, marsh, etc.), and brackish to salt water wetlands such as salt marsh and mangrove swamp distributed at lower elevations on land normally inundated by tidal action and freshwater pulses from upland surface water runoff. The predominant flora associated with these associations is typically common to the central Florida region and characterized by a high diversity of terrestrial, wetland, and aquatic species. Common vascular taxa within the Chassahowitzka NWR would include slash pine, laurel oak, live oak, cabbage palm, sweet gum, red maple, saw palmetto, and gallberry in the inland areas and needlerush, red mangrove, cordgrass, and saltgrass in the brackish to marine reaches.

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of the Stanton Energy Center due to Unit B operations would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka NWR due to emissions from Unit B will be far less, as presented previously. The potential for damage at the Chassahowitzka NWR could, therefore, be considered negligible given the much lower air pollution impacts predicted at Chassahowitzka NWR relative to the immediate Stanton Energy Center plant vicinity and the absence of any plant species at Chassahowitzka NWR that would be especially sensitive to the very low predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

Wildlife resources in the 30,500-acre Chassahowitzka NWR are fairly typical of central Florida's Gulf Coast. The eastern portions of the site are fringed by hardwood swamp habi-

tats, but the primary habitats are the estuarine and brackish marshes along with the saltwater bays containing many mangrove-covered islands. These habitats support large numbers of resident and migratory waterfowl, water birds, and shorebirds. Wading birds are also quite common. Deer, raccoons, black bears, otters, and bobcats are the notable mammals. Alligators are numerous. Bald eagles and the West Indian manatee are the primary endangered/threatened species utilizing the area.

Air pollution impacts to wildlife have been reported in the literature, although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by Unit B will cause injury or death to wildlife. Concentrations of pollutants will be low, emissions will be dispersed over a large area, and mobility of wildlife will minimize their exposure to any unusual concentrations caused by equipment malfunction or unique weather patterns.

Bioaccumulation, particularly of mercury, has been a concern in Florida. There is increasing evidence that mercury may be naturally evolved in Florida and that, combined with man-made sources, is becoming bioaccumulated in certain fish and wildlife. It is unknown what naturally occurring levels may be present in onsite fish and wildlife. However, the likelihood that the small amount attributable to Unit B would all be methylated, end up in the food chain, and then consumed by predators is considered negligible.

The acid rain effects on wildlife in Florida are primarily those related to aquatic animals. Acidified water may prevent fish egg hatching, damage larvae, and lower immunity factors in adult fish (Barker, 1983). Acid rain can also result in release of metals (especially alumi-

num) from lake sediments; this can cause a biochemical deterioration of fish gills leading to death by suffocation. However, the sensitivity of Florida lakes to acid rain is in question. Florida lakes have a wide natural range of pH (from 4 to 8.8 pH units). Most well-buffered lakes are in central and south Florida, and rainfall is in the pH range of 4.8 to 5.1. According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. Air emissions from Unit B that could contribute to the formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife at Chassahowitzka NWR.

In conclusion, it is unlikely the projected air emission levels from Stanton Unit B will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWR.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for Unit B. Visible emissions from the CT/HRSG stack, the primary Unit B emission source, will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from Unit B will be low due to the use of low sulfur syngas and pipeline quality natural gas. Unit B will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACT RESULTS

10.1 OVERVIEW

Comprehensive screening and refined modeling was conducted to assess the air quality impacts resulting from Unit B operations in accordance with the FDEP approved modeling protocol. This section provides the results of the Unit B air quality assessment with respect to long-range transport impacts at distant PSD Class I areas. Unit B air quality impacts in the vicinity of the project site were previously addressed in Section 7.0.

PSD Class I areas located within 300 km of Unit B include the Okefenokee NWR in Georgia, and the Chassahowitzka NWR and Everglades National Park in Florida. The Stanton Energy Center is located 250 km (155 miles) south of the Okefenokee NWR and 288 km (179 miles) north of the Everglades National Park. The nearest PSD Class I area is the Chassahowitzka NWR, situated approximately 144 km (90 miles) to the northwest of the project site. Since the other two PSD Class I areas are located at much greater distances from Stanton, the Class I impact analysis was confined to the Chassahowitzka NWR.

10.2 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the Unit B project will result in ambient air quality impacts at the Chassahowitzka NWR that are below the PSD Class I significant impact levels for all pollutants and all averaging periods. Accordingly, a multisource interactive assessment of air quality impacts with respect to the PSD Class I increments was not required.

In addition, Unit B maximum regional haze impacts will be below the relevant Federal Land Manager (FLM) screening level guidelines. Therefore, further analysis of these air quality related values (AQRVs) was not required.

10.3 GENERAL APPROACH

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, the *Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report*, and EPA's *Guideline on Air Quality Models*. The CALPUFF model was employed in a screening mode using five years (1996 through 2000) of meteorology and a conservative receptor grid as recommended by the National Park Service for Class I screening analyses. The CALPUFF suite of programs, including the POSTUTIL and CALPOST post-processing programs, was employed to develop estimates of Unit B project impacts on the Chassahowitzka NWR for PSD increments, regional haze, and deposition.

10.4 MODEL SELECTION AND USE

The nearest PSD Class I area to the Stanton site is the Chassahowitzka NWR, located approximately 144 km northwest of the project site. Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as AERMOD, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

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

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

would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments. The Phase 2 recommendations, issued in December 1998, are contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the *FLAG Phase I Report* dated December 2000. The Phase 2 IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a *preferred* model (i.e., a model listed in Appendix A to Appendix W of 40 CFR Part 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants. The CALPUFF Modeling System consists of three main components: (a) CALMET, (b) CALPUFF, and (c) CALPOST. Each of these components is described in the following sections.

10.5 CALMET

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

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

- Penn State/NCAR Mesoscale Model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed).

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

In accordance with the procedures specified in the IWAQM Phase 2 report, CALPUFF was used in a screening mode for the Unit B PSD Class I analysis using 5 years of hour-by-hour single station meteorological data collected at the Orlando International Airport (for surface observations) and Ruskin (for upper air data) and the EPA's PCRAMMET meteorological pre-processing program. Since Unit B PSD Class I impacts (using CALPUFF in its conservative screening mode) were shown to be below the PSD Class I significance levels, use of refined CALMET data was not required.

10.6 CALPUFF

CALPUFF is a transport and puff model that advects *puffs* of material from an emission source. These *puffs* undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also utilize non-gridded meteorological data similar to that used by a steady-state dispersion model such as AERMOD. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models.

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

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

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase 2 report and EPA's Guideline on Air Quality Models. Options selected include modeling of six species (SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}), chemical transformation using the MESOPUFF II scheme, wet removal, and a 5-km spacing meteorological and computational grid. The meteorological and computational grids include the Unit B emission sources and receptor grid. The current version of CALPUFF (Version 5.711BA, Level 051216~~040716~~) was used in the Chassahowitzka NWR air quality impact assessments. An example CALPUFF output file is included in Appendix C. This output file shows all of the CALPUFF options employed for the Unit B Class I area impact analysis.

10.7 POSTUTIL

POSTUTIL is a post-processing program used to process the concentration generated by CALPUFF. POSTUTIL was used to recompute the HNO_3/NO_3 concentration partition, consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes. The current version of POSTUTIL (Version 1.3, Level 030402) was used in the Chassahowitzka NWR air quality impact assessments. An example POSTUTIL output file is included in Appendix C. This output file shows all of the POSTUTIL options employed for the Unit B Class I area impact analysis.

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10.8 CALPOST

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

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

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the FLAG Phase I Report. Background light extinction Method 6 was selected to develop visibility impacts; this method uses speciated particulate concentration data and seasonal relative humidity adjustment factors. The current version of CALPOST (Version 5.51, Level 030709) was used in the Chassahowitzka NWR air quality impact assessments. An example CALPOST output file is included in Appendix C. This output file shows all of the CALPOST options employed for the Unit B Class I area impact analysis.

10.9 RECEPTOR GRID

For CALPUFF screening analyses, the IWQAM Phase 2 report recommends a receptor grid consisting of two rings centered on the emission source. The first ring has a radius equal to the distance from the emission source to the nearest edge of the Class I area. The second ring has a radius equal to the distance from the emission source to the farthest edge of the Class I area. For the Unit B Chassahowitzka NWR assessment, the nearest

and farthest ring distances are 143.7 and 154.6 km, respectively. These distances correspond to the nearest and furthest discrete Chassahowitzka NWR receptors obtained from the NPS website. For each ring, receptors were placed at 2-degree intervals for a total of 360 polar receptors. The locations of the screening receptors, as well as the CALPUFF meteorological and computational grids for the Chassahowitzka NWR impact analyses, are shown on Figure 10-1.

10.10 METEOROGICAL DATA

For the Unit B CALPUFF screening mode analysis, five years (1996 through 2000) of hour-by-hour meteorology was utilized. This meteorological dataset, comprised of surface and upper air data from the OIA (WBAN Station No. 12815~~13967~~) and Ruskin, FL (WBAN Station No. 92801~~03948~~) stations, respectively, was obtained from the NCDC and processed using EPA's PCRAMMET meteorological data pre-processing program. The base PCRAMMET data was supplemented with precipitation, solar radiation, and relative humidity data from the OIA station.

The following input parameters were used in the PCRAMMET pre-processing program:

- Minimum Monin-Obukhov length: 2.0 meters.
- Anemometer height: 10 meters.
- Measurement site roughness length: 0.0725 meters.
- Application site roughness length: 0.2625 meters.
- Noon time Albedo: 0.215.
- Bowen ratio: 0.875.
- Anthropogenic heat flux: 0 W/m^2.
- Fraction of radiation absorbed by ground: 0.15.

10.11 MODELED EMISSION SOURCES

Modeled emission sources included only the Unit B CT/HRSG unit – the primary Unit B emission source. The Unit B point and fugitive coal handling and cooling tower emission sources will have minor PM_{10} emission rates and low release heights. Accordingly, these

and farthest ring distances are 143.7 and 154.6 km, respectively. These distances correspond to the nearest and furthest discrete Chassahowitzka NWR receptors obtained from the NPS website. For each ring, receptors were placed at 2-degree intervals for a total of 360 polar receptors. The locations of the screening receptors, as well as the CALPUFF meteorological and computational grids for the Chassahowitzka NWR impact analyses, are shown on Figure 10-1.

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M:/ACAD/051131/Class 1 rings.mxd

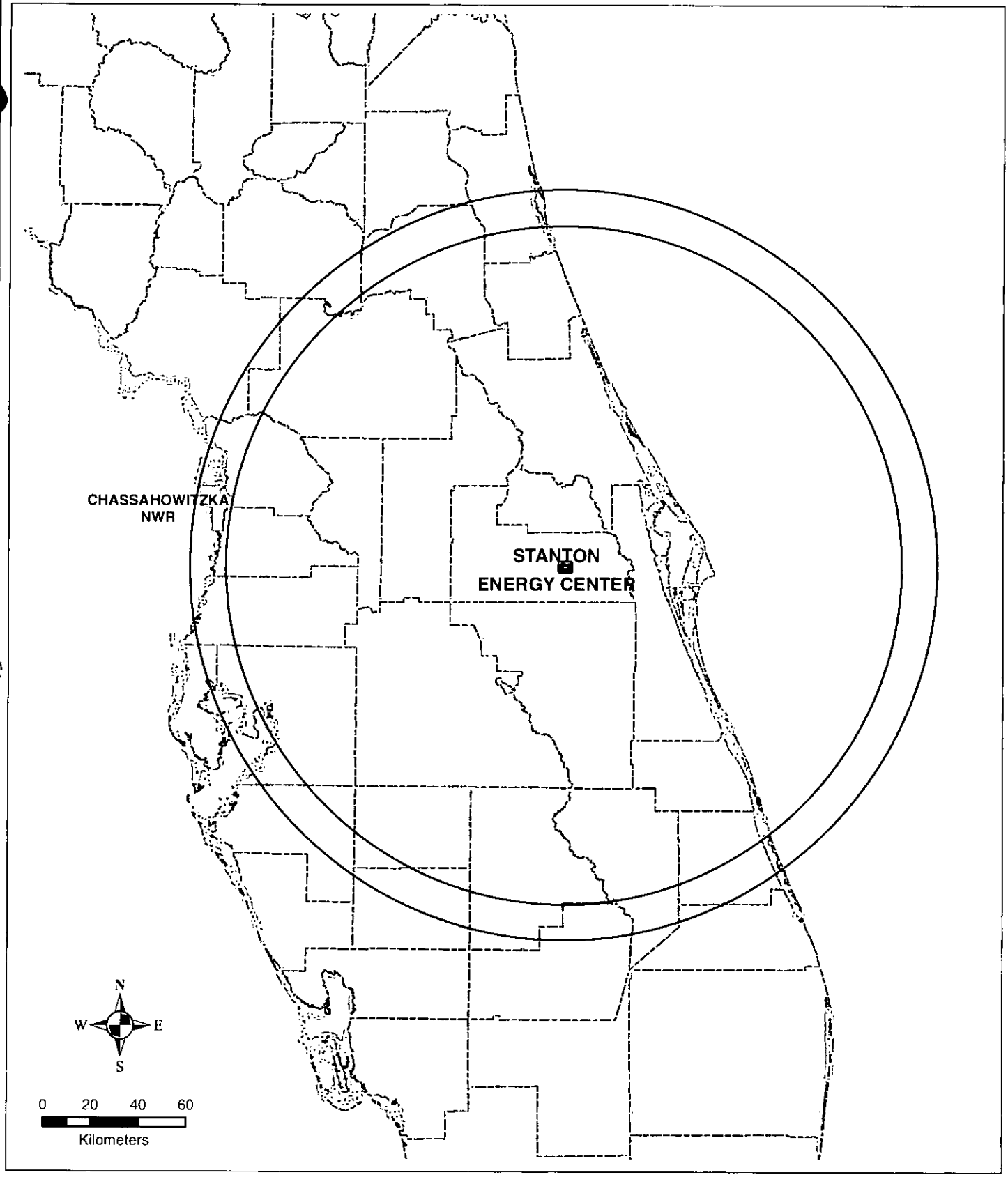

FIGURE 10-1.
LOCATION OF CHASSAHOWITZKA NWR

Sources: FGDL, 2003; ECT, 2006.

ECT
Environmental Consulting & Technology, Inc.

emission sources will have a negligible impact at the Chassahowitzka NWR The Unit B flare was not included in the PSD Class I analysis since it will only operate during gasifier startups and process upsets.

Emissions and stack data for Unit B CT/HRSG operating Case No. 2-Syn (i.e., 100 percent load at 20°F with DB firing) were used in the PSD Class I analysis since this operating case results in the highest emission rates. Use of this operating case will conservatively over-estimate air quality impacts (particularly with respect to 8-hour and longer averaging periods) since operations at an ambient temperature of 20°F will seldom occur at the central Florida project location. The specific Unit B CT/HRSG emission rates and stack parameters used in the CALPUFF modeling assessments are summarized in Table 10-1.

10.12 MODEL RESULTS

Unit B CALPUFF/CALPOST screening modeling results for Class I PSD increments, regional haze (i.e., visibility), and deposition impacts at the Chassahowitzka NWR are discussed in the following sections.

10.12.1 PSD CLASS I INCREMENTS

Unit B maximum annual NO_2, SO_2, and PM_{10} impacts are summarized on Tables 10-2, 10-3, and 10-4, respectively. Maximum 3- and 24-hour SO_2 impacts are summarized on Tables 10-5 and 10-6, respectively. Maximum 24-hour PM_{10} impacts are summarized on Table 10-7. These tables provide the highest impact for each pollutant and averaging period, the location of the highest impact, the time of occurrence for short-term (3- and 24-hour average) impacts, and the PSD Class I significant impact levels.

The critical pollutant and averaging period was determined to be the 24-hour average SO_2 impact. The maximum Unit B 24-hour average SO_2 impact at the Chassahowitzka NWR is projected to be ~~0.044~~0.038 $\mu g/m^3$, or only ~~22~~19 percent of the EPA PSD Class I significant impact level.

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The critical pollutant and averaging period was determined to be the 24-hour average SO_2 impact. The maximum Unit B 24-hour average SO_2 impact at the Chassahowitzka NWR is projected to be 0.044 $\mu g/m^3$, or only 22 percent of the EPA PSD Class I significant impact level.

Table 10-1. CALPUFF Emission Source Data—Stanton Unit B

Parameter	Units	Value
Stack height	ft	205
Stack diameter	ft	18.5
Stack velocity	ft/sec	65.9
Stack temperature	°F	185.5
SO_2 emissions	lb/hr	36.1
H_2SO_4 emissions	lb/hr	5.5
NO_x emissions	lb/hr	228.3
PM_{10} emissions	lb/hr	36.3

Source: ECT, 2006.

Table 10-2. CALPUFF Model Results-Annual NO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	~~0.0042~~ 0.0053	~~0.0049~~ 0.0073	~~0.0034~~ 0.0052	~~0.0069~~ 0.0093	**~~0.0085~~ 0.0108**
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.1	0.1	**0.1**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	~~4.2~~ 5.3	~~4.9~~ 7.3	~~3.4~~ 5.2	~~6.9~~ 9.3	**~~8.5~~ 10.8**
Receptor UTM Easting (km)	483.2	458.2	~~453.3~~ 434.1	483.2	**473.2**
Receptor UTM Northing (km)	3,007.2	3,009.3	~~3,010.3~~ 3,015.8	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector °)	180	190	~~192~~ 200	180	**184**

Source: ECT, 2006.

Revised March 17, 2006

Table 10-3. CALPUFF Model Results-Annual SO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0014	~~0.0015~~ 0.0018	~~0.0011~~ 0.0014	~~0.0020~~ 0.0022	**~~0.0024~~ 0.0027**
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.1	0.1	**0.1**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	1.4	~~1.5~~ 1.8	~~1.1~~ 1.4	~~2.0~~ 2.2	**~~2.4~~ 2.7**
Receptor UTM Easting (km)	~~483.2~~ 351.9	453.3	434.1	478.2	**473.2**
Receptor UTM Northing (km)	~~3,007.2~~ 3,092.4	3,010.3	3,015.8	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	~~180~~ 246	192	200	182	**184**

Source: ECT, 2006.

Table 10-4. CALPUFF Model Results-Annual PM_{10}

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	~~0.0018~~ 0.0019	~~0.0020~~ 0.0022	~~0.0017~~ 0.0018	~~0.0026~~ 0.0027	~~**0.0031**~~ **0.0033**
PSD Class I Significant Impact ($\mu g/m^3$)	0.2	0.2	0.2	0.2	**0.2**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	~~0.9~~ 0.9	~~1.0~~ 1.1	~~0.8~~ 0.9	~~1.3~~ 1.4	~~1.5~~ **1.6**
Receptor UTM Easting (km)	493.2	453.3	~~513.1~~ 434.1	478.2	**473.2**
Receptor UTM Northing (km)	3,294.2	3,010.3	~~3,291.4~~ 3,015.8	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	4	192	~~12~~ 200	182	**184**

Source: ECT, 2006.

Table 10-5. CALPUFF Model Results, 3-Hour SO_2

Maximum Annual Impacts	1996	1997	1998	1999	2000
Modeled Impact ($\mu g/m^3$)	~~0.1144~~ 0.1149	~~0.0969~~ 0.1120	~~0.1111~~ 0.1051	~~0.0963~~ 0.1009	~~0.1009~~ 0.1053
PSD Class I Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	~~11.4~~ 11.5	~~9.7~~ 11.2	~~11.1~~ 10.5	~~9.6~~ 10.1	~~10.1~~ 10.5
Receptor UTM Easting (km)	~~503.2~~ 483.2	550.7	~~546.1~~ 438.8	~~483.2~~ 458.2	~~468.2~~ 473.2
Receptor UTM Northing (km)	~~3,008.5~~ 3,007.2	3,277.7	~~3,292.1~~ 3,014.2	~~3,007.2~~ 3,009.3	~~3,007.9~~ 3,007.5
Distance From Unit B (km)	144	143	~~154~~ 144	144	144
Direction From Unit B (Vector°)	~~172~~ 180	28	~~24~~ 198	~~180~~ 190	~~186~~ 184

Source: ECT, 2006.

Revised March 17, 2006

Table 10-6. CALPUFF Model Results, 24-Hour SO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	~~0.0314~~ 0.0274	~~0.0316~~ 0.0300	~~0.0262~~ 0.0286	~~0.0276~~ 0.0287	~~**0.0443**~~ **0.0379**
PSD Class I Significant Impact ($\mu g/m^3$)	0.2	0.2	0.2	0.2	**0.2**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	~~15.7~~ 13.7	~~15.8~~ 15.0	~~13.1~~ 14.3	~~13.8~~ 14.3	~~**22.1**~~ **18.9**
Receptor UTM Easting (km)	~~488.2~~ 555.1	~~453.3~~ 448.4	~~503.2~~ 448.4	~~473.2~~ 483.2	**468.2**
Receptor UTM Northing (km)	~~3,294.5~~ 3,275.3	~~3,010.3~~ 3,290.3	~~3,293.2~~ 3,011.4	~~3,007.5~~ 3,007.2	**3,007.9**
Distance From Unit B (km)	~~144~~ 143	144	144	144	**144**
Direction From Unit B (Vector°)	~~2~~ 30	~~192~~ 346	~~8~~ 194	~~184~~ 180	**186**

Source: ECT, 2006.

Table 10-7. CALPUFF Model Results, 24-Hour PM_{10}

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	~~0.0426~~ 0.0341	~~0.0375~~ 0.0369	~~0.0328~~ 0.0348	~~0.0326~~ 0.0335	~~**0.0535**~~ **0.0451**
PSD Class I Significant Impact ($\mu g/m^3$)	0.3	0.3	0.3	0.3	**0.3**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	~~14.2~~ 11.4	~~12.5~~ 12.3	~~10.9~~ 11.6	~~10.9~~ 11.2	~~**17.8**~~ **15.0**
Receptor UTM Easting (km)	488.2	~~453.3~~ 498.2	~~343.8~~ 448.4	~~483.2~~ 478.2	**468.2**
Receptor UTM Northing (km)	3,294.5	~~3,010.3~~ 3,007.9	~~3,116.1~~ 3,011.4	3,007.2	**3,007.9**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	2	~~192~~ 174	~~256~~ 194	~~180~~ 182	**186**

Source: ECT, 2006.

The CALPUFF/CALPOST results demonstrate that maximum Unit B impacts at the Chassahowitzka NWR will be less than the EPA Class I PSD significant impact levels for all pollutants and averaging periods.

10.12.2 REGIONAL HAZE

Unit B maximum 24-hour regional haze impacts are summarized on Table 10-8. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and particulate matter fine [PMF]) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in Units of km and dv, and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be ~~4.2~~4.8 percent, which is below the 5 percent FLM screening level value.

10.8.3 SULFUR AND NITROGEN DEPOSITION

Unit B annual sulfur and nitrogen deposition rates are summarized on Tables 10-9 and 10-10, respectively. These tables provide the CALPUFF/POSTUTIL/CALPOST modeled total (wet and dry) deposition rates impact for nitrogen and sulfur in units of microgram/square meter/second ($\mu g/m^2/s$) and kilogram/hectare/year (kg/ha/yr). The maximum annual nitrogen and sulfur deposition rates are ~~0.186~~0.0022 and ~~0.105~~0.00087 kg/ha/yr, respectively.

10.13 SUMMARY

Table 10-11 provides a summary of maximum Unit B Chassahowitzka NWR air quality impacts, the PSD Class I area EPA significant impact levels, and FLM guidelines.

Table 10-8. CALPUFF Model Results, Regional Haze Impacts

Maximum 24-Hour Average Impacts	Units	1996		1997		1998		1999		2000	
B_{ext-s} - SO_4	Mm^{-1}	~~0.102~~	0.092	~~0.066~~	0.136	~~0.076~~	0.102	~~0.075~~	0.084	~~0.106~~	**0.137**
B_{ext-s} - NO_3	Mm^{-1}	~~0.685~~	0.503	~~0.351~~	0.475	~~0.175~~	0.433	~~0.338~~	0.401	~~0.366~~	**0.451**
B_{ext-s} - PMF	Mm^{-1}	~~0.127~~	0.280	~~0.082~~	0.369	~~0.121~~	0.348	~~0.123~~	0.322	~~0.148~~	**0.451**
B_{ext-s} - Total	Mm^{-1}	~~0.914~~	0.875	~~0.499~~	0.980	~~0.372~~	0.883	~~0.536~~	0.807	~~0.620~~	**1.039**
B_{ext-b} - Background	Mm^{-1}	21.6		~~21.6~~	22.0	21.6		21.6		~~22.0~~	**21.6**
Visual Range, Background	km	181.4		~~181.4~~	177.7	181.4		181.4		~~177.7~~	**181.4**
Visual Range, Background	mi	112.7		~~112.7~~	110.4	112.7		112.7		~~110.4~~	**112.7**
Visual Range, Background	dv	7.7		~~7.7~~	7.9	7.7		7.7		~~7.9~~	**7.7**
Relative Humidity Factor (FRH)	-	3.40		~~3.40~~	3.90	3.40		3.40		~~3.90~~	**3.40**
No. of Days with B_{ext} >5.0 %	-	0		0		0		0		0	
Largest B_{ext} change	%	~~4.24~~	4.06	~~2.31~~	4.45	~~1.73~~	4.09	~~2.48~~	3.74	~~2.82~~	**4.82**
NPS Significant Impact, Bext change	%	5.00		5.00		5.00		5.00		5.00	
Exceed NPS Significant Impact	Y/N	N		N		N		N		N	
Percent of NPS Significant Impact	%	~~84.8~~	81.2	~~46.2~~	89.0	~~34.6~~	81.8	~~49.6~~	74.8	~~56.4~~	**96.4**
No. of Days with Delta Deciview >0.5 %	-	0		0		~~1.0~~	0.0	~~1.0~~	0.0	~~1.0~~	**0.0**
Largest Delta Deciview Change	-	~~0.415~~	0.398	~~0.229~~	0.435	~~0.171~~	0.401	~~0.245~~	0.367	~~0.278~~	**0.471**
Receptor UTM Easting (km)	km	~~602.3~~	605.1	~~596.4~~	498.2	~~443.6~~	448.4	~~493.2~~	488.2	~~478.2~~	**468.2**
Receptor UTM Northing (km)	km	~~3,070.5~~	3,074.7	~~3,062.4~~	3,007.9	~~3,012.7~~	3,011.4	~~3,007.5~~	3,007.2	~~3,007.2~~	**3,007.9**
Distance From Unit B (km)	km	143.4		~~143.4~~	143.8	143.9		143.8		143.8	
Direction From Unit B (Vector °)	Vector °	~~124~~	122	~~128~~	174	~~196~~	194	~~176~~	178	~~182~~	**186**

Source: ECT, 2006.

Table 10-9. CALPUFF Model Results, Total Nitrogen Deposition

Maximum Annual Impacts	1996		1997		1998		1999		2000	
Total Dry and Wet Nitrogen Deposition (ug/m^2/s)		0.0000080		0.0000105		0.0000083		0.0000107		0.0000121
Total Dry and Wet Nitrogen Deposition (kg/ha/yr)	~~0.072~~	0.00148	~~0.160~~	0.00194	~~0.128~~	0.00153	~~0.163~~	0.00198	~~0.186~~	0.00223
PSD Class I Significant Impact (kg/ha/y)	0.01		0.01		0.01		0.01		0.01	
Exceed PSD Class I Significant Impact (Y/N)	~~Y~~	N	~~Y~~	N	~~Y~~	N	~~Y~~	N	~~Y~~	N
Percent of PSD Significant Impact (%)	~~716.0~~	14.8	~~1,597.2~~	19.4	~~1,279.0~~	15.3	~~1,632.0~~	19.8	~~1,857.9~~	22.3
Receptor UTM Easting (km)		473.2		438.8		596.4		473.2		473.2
Receptor UTM Northing (km)		3,294.2		3,014.2		3,239.3		3,007.5		3,007.5
Distance From Unit B (km)		143.6		143.9		143.3		143.8		143.8
Direction From Unit B (Vector o)		355.8		198.1		51.9		184.2		184.2

Source: ECT, 2006.

Table 10-10. CALPUFF Model Results, Total Sulfur Deposition

Maximum Annual Impacts	1996		1997		1998		1999		2000	
Total Dry and Wet Sulfur Deposition (μg/m²/s)		0.0000040		0.0000046		0.0000045		0.0000046		0.0000047
Total Dry and Wet Sulfur Deposition (kg/ha/yr)	~~0.074~~	0.00073	~~0.095~~	0.00086	~~0.086~~	0.00083	~~0.105~~	0.00086	~~0.081~~	0.00087
PSD Class I Significant Impact (kg/ha/y)	0.01		0.01		0.01		0.01		0.01	
Exceed PSD Class I Significant Impact (Y/N)	~~Y~~	N	~~Y~~	N	~~Y~~	N	~~Y~~	N	~~Y~~	N
Percent of PSD Significant Impact (%)	~~741.3~~	7.3	~~949.4~~	8.6	~~855.6~~	8.3	~~1,049.7~~	8.6	~~810.6~~	8.7
Receptor UTM Easting (km)		493.2		559.3		596.4		541.6		473.2
Receptor UTM Northing (km)		3,294.2		3,272.7		3,239.3		3,282.1		3,007.5
Distance From Unit B (km)		143.6		143.4		143.3		143.4		143.8
Direction From Unit B (Vector o)		3.8		31.9		51.9		23.9		184.2

Source: ECT, 2006.

Table 10-11. CALPUFF Model Chassahowitzka NWR Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	~~0.0085~~0.011	0.1
PM_{10}	Annual	~~0.0031~~0.0033	0.2
	24-hour	~~0.054~~0.045	0.3
SO_2	Annual	~~0.0024~~0.0027	0.1
	24-hour	~~0.044~~0.038	0.2
	3-hour	~~0.11~~0.12	1.0

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	~~0.186~~0.0022	0.01
Sulfur	Annual	~~0.105~~0.00087	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change B_{ext})	Significant Impact (% Change B_{ext})
Regional haze	24-Hour	~~4.2~~4.8	5.0

Source: ECT, 2006.

Table 10-2. CALPUFF Model Results-Annual NO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0042	0.0049	0.0034	0.0069	**0.0085**
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.1	0.1	**0.1**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	4.2	4.9	3.4	6.9	**8.5**
Receptor UTM Easting (km)	483.2	458.2	453.3	483.2	**473.2**
Receptor UTM Northing (km)	3,007.2	3,009.3	3,010.3	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	180	190	192	180	**184**

Source: ECT, 2006.

Table 10-3. CALPUFF Model Results-Annual SO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0014	0.0015	0.0011	0.0020	**0.0024**
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.1	0.1	**0.1**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	1.4	1.5	1.1	2.0	**2.4**
Receptor UTM Easting (km)	483.2	453.3	434.1	478.2	**473.2**
Receptor UTM Northing (km)	3,007.2	3,010.3	3,015.8	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector^o)	180	192	200	182	**184**

Source: ECT, 2006.

Table 10-4. CALPUFF Model Results-Annual PM_{10}

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0018	0.0020	0.0017	0.0026	**0.0031**
PSD Class I Significant Impact ($\mu g/m^3$)	0.2	0.2	0.2	0.2	**0.2**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	0.9	1.0	0.8	1.3	**1.5**
Receptor UTM Easting (km)	493.2	453.3	513.1	478.2	**473.2**
Receptor UTM Northing (km)	3,294.2	3,010.3	3,291.4	3,007.2	**3,007.5**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector^o)	4	192	12	182	**184**

Source: ECT, 2006.

Table 10-5. CALPUFF Model Results, 3-Hour SO_2

Maximum Annual Impacts	**1996**	1997	1998	1999	2000
Modeled Impact ($\mu g/m^3$)	**0.1144**	0.0969	0.1111	0.0963	0.1009
PSD Class I Significant Impact ($\mu g/m^3$)	**1.0**	1.0	1.0	1.0	1.0
Exceed PSD Class I Significant Impact (Y/N)	**N**	N	N	N	N
Percent of PSD Significant Impact (%)	**11.4**	9.7	11.1	9.6	10.1
Receptor UTM Easting (km)	**503.2**	550.7	546.1	483.2	468.2
Receptor UTM Northing (km)	**3,008.5**	3,277.7	3,292.1	3,007.2	3,007.9
Distance From Unit B (km)	**144**	143	154	144	144
Direction From Unit B (Vector°)	**172**	28	24	180	186

Source: ECT, 2006.

Table 10-6. CALPUFF Model Results, 24-Hour SO_2

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0314	0.0316	0.0262	0.0276	**0.0443**
PSD Class I Significant Impact ($\mu g/m^3$)	0.2	0.2	0.2	0.2	**0.2**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	15.7	15.8	13.1	13.8	**22.1**
Receptor UTM Easting (km)	488.2	453.3	503.2	473.2	**468.2**
Receptor UTM Northing (km)	3,294.5	3,010.3	3,293.2	3,007.5	**3,007.9**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	2	192	8	184	**186**

Source: ECT, 2006.

Table 10-7. CALPUFF Model Results, 24-Hour PM_{10}

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Modeled Impact ($\mu g/m^3$)	0.0426	0.0375	0.0328	0.0326	**0.0535**
PSD Class I Significant Impact ($\mu g/m^3$)	0.3	0.3	0.3	0.3	**0.3**
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	14.2	12.5	10.9	10.9	**17.8**
Receptor UTM Easting (km)	488.2	453.3	343.8	483.2	**468.2**
Receptor UTM Northing (km)	3,294.5	3,010.3	3,116.1	3,007.2	**3,007.9**
Distance From Unit B (km)	144	144	144	144	**144**
Direction From Unit B (Vector°)	2	192	256	180	**186**

Source: ECT, 2006.

The CALPUFF/CALPOST results demonstrate that maximum Unit B impacts at the Chassahowitzka NWR will be less than the EPA Class I PSD significant impact levels for all pollutants and averaging periods.

10.12.2 REGIONAL HAZE

Unit B maximum 24-hour regional haze impacts are summarized on Table 10-8. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and particulate matter fine [PMF]) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in Units of km and dv, and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be 4.2 percent, which is below the 5 percent FLM screening level value.

10.8.3 SULFUR AND NITROGEN DEPOSITION

Unit B annual sulfur and nitrogen deposition rates are summarized on Tables 10-9 and 10-10, respectively. These tables provide the CALPUFF/POSTUTIL/CALPOST modeled total (wet and dry) deposition rates impact for nitrogen and sulfur in units of microgram/square meter/second ($\mu g/m^2/s$) and kilogram/hectare/year (kg/ha/yr). The maximum annual nitrogen and sulfur deposition rates are 0.186 and 0.105 kg/ha/yr, respectively.

10.13 SUMMARY

Table 10-11 provides a summary of maximum Unit B Chassahowitzka NWR air quality impacts, the PSD Class I area EPA significant impact levels, and FLM guidelines.

Table 10-8. CALPUFF Model Results, Regional Haze Impacts

Maximum 24-Hour Average Impacts	Units	1996	1997	1998	1999	2000
B_{ext-s} - SO_4	Mm^{-1}	0.102	0.066	0.076	0.075	0.106
B_{ext-s} - NO_3	Mm^{-1}	0.685	0.351	0.175	0.338	0.366
B_{ext-s} - PMF	Mm^{-1}	0.127	0.082	0.121	0.123	0.148
B_{ext-s} - Total	Mm^{-1}	0.914	0.499	0.372	0.536	0.620
B_{ext-b} - Background	Mm^{-1}	21.6	21.6	21.6	21.6	22.0
Visual Range, Background	km	181.4	181.4	181.4	181.4	177.7
Visual Range, Background	mi	112.7	112.7	112.7	112.7	110.4
Visual Range, Background	dv	7.7	7.7	7.7	7.7	7.9
Relative Humidity Factor (FRH)	-	3.40	3.40	3.40	3.40	3.90
No. of Days with B_{ext} >5.0 %	-	0	0	0	0	0
Largest B_{ext} change	%	4.24	2.31	1.73	2.48	2.82
NPS Significant Impact, Bext change	%	5.00	5.00	5.00	5.00	5.00
Exceed NPS Significant Impact	Y/N	N	N	N	N	N
Percent of NPS Significant Impact	%	84.8	46.2	34.6	49.6	56.4
No. of Days with Delta Deciview >0.5 %	-	0	0	1.0	1.0	1.0
Largest Delta Deciview Change	-	0.415	0.229	0.171	0.245	0.278
Receptor UTM Easting (km)	km	602.3	596.4	443.6	493.2	478.2
Receptor UTM Northing (km)	km	3,070.5	3,062.4	3,012.7	3,007.5	3,007.2
Distance From Unit B (km)	km	143.4	143.4	143.9	143.8	143.8
Direction From Unit B (Vector°)	Vector°	124	128	196	176	182

Source: ECT, 2006.

Table 10-9. CALPUFF Model Results, Total Nitrogen Deposition

Maximum Annual Impacts	1996	1997	1998	1999	**2000**
Total Dry and Wet Nitrogen Deposition (kg/ha/yr)	0.072	0.160	0.128	0.163	**0.186**
PSD Class I Significant Impact (kg/ha/yr)	0.01	0.01	0.01	0.01	**0.01**
Exceed PSD Class I Significant Impact (Y/N)	Y	Y	Y	Y	**Y**
Percent of PSD Significant Impact (%)	716.0	1,597.2	1,279.0	1,632.0	**1,857.9**

Source: ECT, 2006.

Table 10-10. CALPUFF Model Results, Total Sulfur Deposition

Maximum Annual Impacts	1996	1997	1998	**1999**	2000
Total Dry and Wet Nitrogen Deposition (kg/ha/yr)	0.074	0.095	0.086	**0.105**	0.081
PSD Class I Significant Impact (kg/ha/yr)	0.01	0.01	0.01	**0.01**	0.01
Exceed PSD Class I Significant Impact (Y/N)	Y	Y	Y	**Y**	Y
Percent of PSD Significant Impact (%)	741.3	949.4	855.6	**1,049.7**	810.6

Source: ECT, 2006.

Table 10-11. CALPUFF Model Chassahowitzka NWR Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.0085	0.1
PM_{10}	Annual	0.0031	0.2
	24-hour	0.054	0.3
SO_2	Annual	0.0024	0.1
	24-hour	0.044	0.2
	3-hour	0.11	1.0

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	0.186	0.01
Sulfur	Annual	0.105	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change B_{ext})	Significant Impact (% Change B_{ext})
Regional haze	24-Hour	4.2	5.0

Source: ECT, 2006.

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APPENDIX A

STANTON UNIT B EMISSION RATE CALCULATIONS

Appendix A - Stanton Unit B Emission Rate Calculations
List of Tables

Source: ECT, 2006.

Revised March 17, 2006

Table A-1. Stanton Unit B
Annual Emission Rate Summary - Phase I

Pollutant	Annual Potential Emissions (tpy)					
	CT/HRSG	Flare	Startup Stack	Cooling Tower	Coal Storage Pile	Coal & Fly Ash Handling	Unit B Totals
Criteria Pollutants							
NO_x	987.1	5.6	13.5	N/A	N/A	N/A	1,006.2
CO	615.3	25.4	12.9	N/A	N/A	N/A	653.5
VOC	128.3	0.3	0.3	N/A	N/A	N/A	128.9
SO_2	157.1	0.7	3.8	N/A	N/A	N/A	161.5
PM	156.7	0.4	0.4	~~1.4~~ 14.0	2.0	15.0	~~175.9~~ 188.5
PM_{10}	156.7	0.4	0.4	~~0.6~~ 5.8	1.0	15.0	~~174.0~~ 179.2
Pb	~~0.02~~ 0.03	Neg.	Neg.	N/A	N/A	N/A	~~0.023~~ 0.030

N/A - not applicable
Neg. - negligible

Sources: ECT, 2006.
SCS, 2006.

Revised March 17, 2006

Table A-1. Stanton Unit B (continued)
Annual Emission Rate Summary - Phase II

Pollutant	Annual Potential Emissions (tpy)						
	CT/HRSG	Flare	Startup Stack	Cooling Tower	Coal Storage Pile	Coal & Fly Ash Handling	Unit B Totals
Criteria Pollutants							
NO_x	592.3	5.6	13.5	N/A	N/A	N/A	611.4
CO	615.3	25.4	12.9	N/A	N/A	N/A	653.5
VOC	128.3	0.3	0.3	N/A	N/A	N/A	128.9
SO_2	157.1	0.7	3.8	N/A	N/A	N/A	161.5
PM	156.7	0.4	0.4	~~1.4~~ 14.0	2.0	15.0	~~175.9~~ 188.5
PM_{10}	156.7	0.4	0.4	~~0.6~~ 5.8	1.0	15.0	~~174.0~~ 179.2
Pb	~~0.02~~ 0.03	Neg.	Neg.	N/A	N/A	N/A	~~0.023~~ 0.030

N/A - not applicable
Neg. - negligible

Sources: ECT, 2006.
SCS, 2006.

Table A-1. Stanton Unit B
Annual Emission Rate Summary - Phase I

Pollutant	Annual Potential Emissions (tpy)						
	CT/HRSG	Flare	Startup Stack	Cooling Tower	Coal Storage Pile	Coal & Fly Ash Handling	Unit B Totals
Criteria Pollutants							
NO_x	987.1	5.6	13.5	N/A	N/A	N/A	1,006.2
CO	615.3	25.4	12.9	N/A	N/A	N/A	653.5
VOC	128.3	0.3	0.3	N/A	N/A	N/A	128.9
SO_2	157.1	0.7	3.8	N/A	N/A	N/A	161.5
PM	156.7	0.4	0.4	1.4	2.0	15.0	175.9
PM_{10}	156.7	0.4	0.4	0.6	1.0	15.0	174.0
Pb	0.02	Neg.	Neg.	N/A	N/A	N/A	0.023

N/A - not applicable
Neg. - negligible

Sources: ECT, 2006.
SCS, 2006.

Table A-1. Stanton Unit B (continued)
Annual Emission Rate Summary - Phase II

Pollutant	Annual Potential Emissions (tpy)						
	CT/HRSG	Flare	Startup Stack	Cooling Tower	Coal Storage Pile	Coal & Fly Ash Handling	Unit B Totals
Criteria Pollutants							
NO_x	592.3	5.6	13.5	N/A	N/A	N/A	611.4
CO	615.3	25.4	12.9	N/A	N/A	N/A	653.5
VOC	128.3	0.3	0.3	N/A	N/A	N/A	128.9
SO_2	157.1	0.7	3.8	N/A	N/A	N/A	161.5
PM	156.7	0.4	0.4	1.4	2.0	15.0	175.9
PM_{10}	156.7	0.4	0.4	0.6	1.0	15.0	174.0
Pb	0.02	Neg.	Neg.	N/A	N/A	N/A	0.023

N/A - not applicable
Neg. - negligible

Sources: ECT, 2006.
SCS, 2006.

Table A-2. Stanton Unit B CT/HRSG Operating Cases - Syngas

Case No.	Southern Case No.	Ambient Temperature (°F)	CT Inlet Air Temperature (°F)	Unit B - Syngas Load		Evaporative Cooling	Duct Burner Firing[1]	Annual Profile #1 (hr/yr)
				100 %	75 %			
		Winter						
1 - Syn	15	20	20	✔				
2 - Syn	15a	20	20	✔			✔	
3 - Syn	21	20	20		✔			
		Annual Average						
4 - Syn	17	70	70	✔				
5 - Syn	18	70		✔		✔		
6 - Syn	18a	70		✔		✔	✔	8,760
7 - Syn	23	70	70		✔			
		Summer						
8 - Syn	19	95	95	✔				
9 - Syn	20	95		✔		✔		
10 - Syn	20a	95		✔		✔	✔	
11 - Syn	24	95	95		✔			

[1] Duct burner is fired exclusively with natural gas.

Source: SCS, 2006.

Table A-3. Stanton Unit B CT/HRSG Operating Cases - Natural Gas

Case No.	Southern Case No.	Ambient Temperature (°F)	CT Inlet Air Temperature (°F)	Unit B - Nat. Gas Load 100 %	Unit B - Nat. Gas Load 75 %	Unit B - Nat. Gas Load 50 %	Evaporative Cooling	Duct Burner Firing	Annual Profile #2 (hr/yr)
		Winter							
1 - NG	1	20	20	✔					
2 - NG	1a	20	20	✔				✔	
3 - NG	7	20	20		✔				
4 - NG	11	20	20			✔			
		Annual Average							
5 - NG	3	70	70	✔					
6 - NG	4	70		✔			✔		
7 - NG	4a	70		✔			✔	✔	8,760
8 - NG	9	70	70		✔				
9 - NG	13	70	70			✔			
		Summer							
10 - NG	5	95	95	✔					
11 - NG	6	95		✔			✔		
12 - NG	6a	95		✔			✔	✔	
13 - NG	10	95	95		✔				
14 - NG	14	95	95			✔			

[1] Duct burner is fired exclusively with natural gas.

Source: SCS, 2006.

Table A-4A. Stanton Unit B CT/HRSG
Criteria and Sulfuric Acid Mist Short-Term Emission Rates - Syngas; Phase I

Amb. Temp.	Case	Southern	CT Load	PM/PM_{10}[1]		SO_2		H_2SO_4[2]		Lead	
(°F)	No.	Case #	(%)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1 - Syn	15	100	31.0	3.90	35.8	4.51	5.48	0.69	0.0052	0.0007
	2 - Syn	15a	100	36.3	4.57	36.1	4.55	5.52	0.70	0.0052	0.0007
	3 - Syn	21	75	25.2	3.18	29.1	3.67	4.46	0.56	0.0043	0.0005
70	4 - Syn	17	100	30.4	3.83	35.0	4.41	5.36	0.68	0.0051	0.0006
	5 - Syn	18	100	30.8	3.88	35.6	4.48	5.45	0.69	0.0052	0.0007
	6 - Syn	18a	100	35.8	4.51	35.9	4.52	5.49	0.69	0.0052	0.0007
	7 - Syn	23	75	24.6	3.10	28.3	3.57	4.34	0.55	0.0042	0.0005
95	8 - Syn	19	100	27.3	3.44	31.5	3.97	4.83	0.61	0.0046	0.0006
	9 - Syn	20	100	29.4	3.70	33.9	4.27	5.19	0.65	0.0050	0.0006
	10 - Syn	20a	100	34.7	4.37	34.2	4.31	5.24	0.66	0.0050	0.0006
	11 - Syn	24	75	22.5	2.83	26.0	3.27	3.97	0.50	0.0038	0.0005
			Maximums	36.3	4.57	36.1	4.55	5.52	0.696	0.0052	0.00066

Temp.	Case	Southern	Load	NO_x			CO			VOC[4]		
(°F)	No.	Case #	(%)	(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)
20	1 - Syn	15	100	20.0	188.5	23.75	15.6	89.7	11.31	4.6	15.0	1.90
	2 - Syn	15a	100	20.0	228.3	28.77	20.6	143.2	18.04	7.8	31.0	3.90
	3 - Syn	21	75	20.0	151.9	19.13	15.9	73.4	9.25	4.7	12.3	1.55
70	4 - Syn	17	100	20.0	185.4	23.36	15.9	89.9	11.33	4.7	15.3	1.92
	5 - Syn	18	100	20.0	188.3	23.73	15.8	90.7	11.42	4.7	15.4	1.94
	6 - Syn	18a	100	20.0	225.4	28.40	20.5	140.5	17.70	6.9	26.9	3.38
	7 - Syn	23	75	20.0	148.6	18.72	16.1	72.9	9.18	4.8	12.4	1.56
95	8 - Syn	19	100	20.0	168.9	21.28	16.1	83.0	10.45	4.8	14.1	1.78
	9 - Syn	20	100	20.0	181.7	22.90	15.9	87.8	11.06	4.8	15.0	1.89
	10 - Syn	20a	100	20.0	221.4	27.89	20.9	140.9	17.76	7.2	27.9	3.51
	11 - Syn	24	75	20.0	137.7	17.35	16.6	69.7	8.78	5.0	11.9	1.49
			Maximums	20.0	228.3	28.77	20.9	143.2	18.04	7.8	31.0	3.90

[1] Filterable PM as measured by EPA RM 5 or 17.

[2] Based on 10% conversion of SO_2 to H_2SO_4.

[3] Corrected to 15% O_2.

[4] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2006
SCS, 2006.

Table A-4B. Stanton Unit B CT/HRSG
Criteria and Sulfuric Acid Mist Short-Term Emission Rates - Syngas; Phase II

Amb. Temp.	Case	Southern	CT Load	PM/PM_{10}[1]		SO_2		H_2SO_4[2]		Lead	
(°F)	No.	Case #	(%)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1 - Syn	15	100	31.0	3.90	35.8	4.51	5.48	0.69	0.0052	0.0007
	2 - Syn	15a	100	36.3	4.57	36.1	4.55	5.52	0.70	0.0052	0.0007
	3 - Syn	21	75	25.2	3.18	29.1	3.67	4.46	0.56	0.0043	0.0005
70	4 - Syn	17	100	30.4	3.83	35.0	4.41	5.36	0.68	0.0051	0.0006
	5 - Syn	18	100	30.8	3.88	35.6	4.48	5.45	0.69	0.0052	0.0007
	6 - Syn	18a	100	35.8	4.51	35.9	4.52	5.49	0.69	0.0052	0.0007
	7 - Syn	23	75	24.6	3.10	28.3	3.57	4.34	0.55	0.0042	0.0005
95	8 - Syn	19	100	27.3	3.44	31.5	3.97	4.83	0.61	0.0046	0.0006
	9 - Syn	20	100	29.4	3.70	33.9	4.27	5.19	0.65	0.0050	0.0006
	10 - Syn	20a	100	34.7	4.37	34.2	4.31	5.24	0.66	0.0050	0.0006
	11 - Syn	24	75	22.5	2.83	26.0	3.27	3.97	0.50	0.0038	0.0005
			Maximums	36.3	4.57	36.1	4.55	5.52	0.696	0.0052	0.00066

Temp.	Case	Southern	Load	NO_x			CO			VOC[4]		
(°F)	No.	Case #	(%)	(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)
20	1 - Syn	15	100	12.0	113.1	14.25	15.6	89.7	11.31	4.6	15.0	1.90
	2 - Syn	15a	100	12.0	137.0	17.26	20.6	143.2	18.04	7.8	31.0	3.90
	3 - Syn	21	75	12.0	91.1	11.48	15.9	73.4	9.25	4.7	12.3	1.55
70	4 - Syn	17	100	12.0	111.2	14.02	15.9	89.9	11.33	4.7	15.3	1.92
	5 - Syn	18	100	12.0	113.0	14.24	15.8	90.7	11.42	4.7	15.4	1.94
	6 - Syn	18a	100	12.0	135.2	17.04	20.5	140.5	17.70	6.9	26.9	3.38
	7 - Syn	23	75	12.0	89.2	11.23	16.1	72.9	9.18	4.8	12.4	1.56
95	8 - Syn	19	100	12.0	101.4	12.77	16.1	83.0	10.45	4.8	14.1	1.78
	9 - Syn	20	100	12.0	109.0	13.74	15.9	87.8	11.06	4.8	15.0	1.89
	10 - Syn	20a	100	12.0	132.8	16.74	20.9	140.9	17.76	7.2	27.9	3.51
	11 - Syn	24	75	12.0	82.6	10.41	16.6	69.7	8.78	5.0	11.9	1.49
			Maximums	12.0	137.0	17.26	20.9	143.2	18.04	7.8	31.0	3.90

[1] Filterable PM as measured by EPA RM 5 or 17.

[2] Based on 10% conversion of SO_2 to H_2SO_4.

[3] Corrected to 15% O_2.

[4] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2006
SCS, 2006.

Table A-5. Stanton Unit B CT/HRSG
Criteria and Sulfuric Acid Mist Short-Term Emission Rates - Natural Gas

Amb. Temp.	Case	Southern	CT Load	PM/PM_{10}[1]		SO_2[2]		H_2SO_4[3]		Lead[4]	
(°F)	No.	Case #	(%)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1 - NG	1	100	18.2	2.29	1.2	0.15	0.18	0.022	0.00094	0.00012
	2 - NG	1a	100	23.3	2.93	1.4	0.18	0.22	0.028	0.00094	0.00012
	3 - NG	7	75	18.2	2.29	0.9	0.12	0.14	0.018	0.00076	0.00010
	4 - NG	11	50	18.1	2.28	0.7	0.09	0.11	0.014	0.00059	0.00007
70	5 - NG	3	100	18.2	2.29	1.0	0.13	0.16	0.020	0.00084	0.00011
	6 - NG	4	100	18.2	2.29	1.0	0.13	0.16	0.020	0.00085	0.00011
	7 - NG	4a	100	23.2	2.93	1.4	0.17	0.21	0.026	0.00085	0.00011
	8 - NG	9	75	18.2	2.29	0.8	0.11	0.13	0.016	0.00069	0.00009
	9 - NG	13	50	18.1	2.28	0.7	0.08	0.10	0.013	0.00054	0.00007
95	10 - NG	5	100	18.2	2.29	1.0	0.12	0.15	0.019	0.00078	0.00010
	11 - NG	6	100	18.2	2.29	1.0	0.13	0.15	0.019	0.00082	0.00010
	12 - NG	6a	100	23.2	2.93	1.3	0.17	0.20	0.025	0.00082	0.00010
	13 - NG	10	75	18.1	2.29	0.8	0.10	0.12	0.015	0.00065	0.00008
	14 - NG	14	50	18.1	2.28	0.6	0.08	0.10	0.012	0.00051	0.00006
			Maximums	23.3	2.93	1.4	0.18	0.22	0.028	0.00094	0.00012

Temp.	Case	Southern	Load	NO_x			CO			VOC		
(°F)	No.	Case #	(%)	(ppmvd)[5]	(lb/hr)	(g/sec)	(ppmvd)[5]	(lb/hr)	(g/sec)	(ppmvd)[5]	(lb/hr)[6]	(g/sec)
20	1 - NG	1	100	5.0	35.8	4.50	20.5	87.7	11.04	6.7	16.4	2.07
	2 - NG	1a	100	5.0	44.6	5.62	26.2	140.8	17.74	10.1	31.1	3.92
	3 - NG	7	75	5.0	28.9	3.64	19.3	65.9	8.31	6.4	12.4	1.56
	4 - NG	11	50	5.0	22.3	2.81	23.3	60.8	7.66	7.4	11.0	1.39
70	5 - NG	3	100	5.0	32.0	4.03	20.6	78.4	9.88	6.8	14.8	1.87
	6 - NG	4	100	5.0	32.3	4.07	20.5	79.0	9.96	6.8	15.0	1.89
	7 - NG	4a	100	5.0	42.1	5.30	27.2	138.0	17.39	10.1	29.3	3.69
	8 - NG	9	75	5.0	26.0	3.27	21.2	65.2	8.21	6.5	11.4	1.44
	9 - NG	13	50	5.0	20.5	2.58	23.6	56.4	7.11	7.6	10.3	1.30
95	10 - NG	5	100	5.0	29.7	3.74	20.6	73.1	9.21	6.8	13.9	1.75
	11 - NG	6	100	5.0	31.1	3.91	20.4	75.7	9.54	6.8	14.4	1.82
	12 - NG	6a	100	5.0	40.4	5.09	27.2	132.3	16.67	10.1	28.1	3.54
	13 - NG	10	75	5.0	24.8	3.12	20.7	60.8	7.66	6.8	11.5	1.44
	14 - NG	14	50	5.0	19.3	2.43	24.1	54.3	6.84	7.7	10.0	1.25
			Maximums	5.0	44.6	5.62	27.2	140.8	17.74	10.1	31.1	3.92

[1] Filterable PM as measured by EPA RM 5 or 17.

[2] Based on natural gas sulfur content of 0.22 gr/100 scf.

[3] Based on 10% conversion of SO_2 to H_2SO_4.

[4] Natural Gas Combustion, Table 1.4-2, AP-42, 3/98.

[5] Corrected to 15% O_2.

[6] Expressed as methane.

Sources: ECT, 2006
SCS, 2006.

Table A-6. Stanton Unit B CT/HRSG
Criteria and Sulfuric Acid Mist Annual Emission Rates - Syngas and Natural Gas

Annual Profile	Case No.	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
#1 - Syngas	6-Syn	8,760	225.4	987.1	140.5	615.3	26.9	117.6
#2 - Nat. Gas	7-NG	8,760	42.1	184.4	138.0	604.4	29.3	128.3
Maximums				**987.1**		**615.3**		**128.3**

Annual Profile	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM_{10}		SO_2		H_2SO_4		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
#1 - Syngas	6-Syn	8,760	35.8	156.7	35.9	157.1	5.5	24.0	0.005	0.023
#2 - Nat. Gas	7-NG	8,760	23.2	101.8	1.4	6.0	0.2	0.9	0.001	0.004
Maximums				**156.7**		**157.1**		**24.0**		**0.023**

Sources: ECT, 2006
SCS, 2006.

Table A-6. Stanton Unit B CT/HRSG - Phase II
Criteria and Sulfuric Acid Mist Annual Emission Rates - Syngas and Natural Gas

Annual Profile	Case No.	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
#1 - Syngas	6-Syn	8,760	135.2	592.3	140.5	615.3	26.9	117.6
#2 - Nat. Gas	7-NG	8,760	42.1	184.4	138.0	604.4	29.3	128.3
Maximums				**592.3**		**615.3**		**128.3**

Annual Profile	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM_{10}		SO_2		H_2SO_4		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
#1 - Syngas	6-Syn	8,760	35.8	156.7	35.9	157.1	5.5	24.0	0.005	0.023
#2 - Nat. Gas	7-NG	8,760	23.2	101.8	1.4	6.0	0.2	0.9	0.001	0.004
Maximums				**156.7**		**157.1**		**24.0**		**0.023**

Sources: ECT, 2006
SCS, 2006.

Table A-7. Stanton Unit B CT/HRSG
Hazardous Air Pollutants - Syngas

Parameter	Units	CT		DB
		100%, 20 °F	100%, 70 °F	100%
Maximum Heat Input (HHV):	10^6 Btu/hr	2,384	2,371	532
Maximum Annual Hours:	hrs/yr		8,760	8,760

Pollutant	CT Emission Factor[1] ($lb/10^6$ Btu)	DB Emission Factor[2,3] ($lb/10^6$ Btu)	Maximum CT (lb/hr)	Maximum DB (lb/hr)	CT & DB Total[4] (lb/hr)	CT & DB Total[5] TPY
1,3-Butadiene	N/A	N/A	N/A	N/A	N/A	N/A
2-Methylnaphthalene	3.6E-07	N/A	8.58E-04	N/A	8.58E-04	3.74E-03
Acenaphthylene	2.6E-08	N/A	6.20E-05	N/A	6.20E-05	2.70E-04
Acetaldehyde	1.8E-06	N/A	4.29E-03	N/A	4.29E-03	1.87E-02
Acrolein	N/A	N/A	N/A	N/A	N/A	N/A
Antimony	4.0E-06	N/A	9.53E-03	N/A	9.53E-03	4.15E-02
Arsenic	2.1E-06	N/A	5.01E-03	N/A	5.01E-03	2.18E-02
Benzaldehyde	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Benzene	4.4E-06	2.1E-06	1.05E-02	1.09E-03	1.16E-02	5.05E-02
Benzo(a)anthracene	2.3E-09	N/A	5.48E-06	N/A	5.48E-06	2.39E-05
Benzo(e)pyrene	5.5E-09	N/A	1.31E-05	N/A	1.31E-05	5.71E-05
Benzo(g,h,I)perylene	9.5E-09	N/A	2.26E-05	N/A	2.26E-05	9.86E-05
Beryllium	9.0E-08	N/A	2.15E-04	N/A	2.15E-04	9.35E-04
Cadmium	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Carbon Disulfide	4.5E-05	N/A	1.07E-01	N/A	1.07E-01	4.67E-01
Chromium	2.7E-06	N/A	6.44E-03	N/A	6.44E-03	2.80E-02
Cobalt	5.7E-07	N/A	1.36E-03	N/A	1.36E-03	5.92E-03
Ethylbenzene	N/A	N/A	N/A	N/A	N/A	N/A
Formaldehyde	1.7E-05	7.4E-05	4.05E-02	3.91E-02	7.96E-02	3.48E-01
Manganese	3.1E-06	N/A	7.39E-03	N/A	7.39E-03	3.22E-02
Mercury	9.1E-07	N/A	2.17E-03	N/A	2.17E-03	9.45E-03
Naphthalene	4.0E-07	6.0E-07	9.53E-04	3.18E-04	1.27E-03	5.55E-03
Nickel	3.9E-06	N/A	9.30E-03	N/A	9.30E-03	4.05E-02
Polycyclic Aromatic Hydrocarbons (PAHs)	N/A	N/A	N/A	N/A	N/A	N/A
Propylene Oxide	N/A	N/A	N/A	N/A	N/A	N/A
Selenium	2.9E-06	N/A	6.91E-03	N/A	6.91E-03	3.01E-02
Toluene	N/A	3.3E-06	N/A	1.77E-03	1.77E-03	7.76E-03
Xylene	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Individual HAP						0.5
Total HAPs						1.2

Notes:

CT = Combustion Turbine

DB = Duct Burner

[1] Emission factors from *A Study of Toxic Emissions from a Coal-Fired Gasification Plant*

[2] - EPA AP-42, Table 1.4-3, March 1998.

[3] - EPA AP-42, Table 1.4-4, March 1998.

[4] - Based on baseload and 20°F temperature.

[5] - Based on baseload and 70°F temperature.

Sources: ECT, 2006
SCS, 2006.

Table A-8. Stanton Unit B CT/HRSG
Hazardous Air Pollutants - Natural Gas

Parameter	Units	CT		DB
		100%, 20 °F	100%, 70 °F	100%
Maximum Heat Input (HHV):	10^6 Btu/hr	1,940	1,754	531
Maximum Annual Hours:	hrs/yr		8,760	8,760

Pollutant	CT Emission Factor[1] ($lb/10^6$ Btu)	DB Emission Factor[3,4] ($lb/10^6$ Btu)	Maximum CT (lb/hr)	Maximum DB (lb/hr)	CT & DB Total[5] (lb/hr)	CT & DB Total[6] TPY
1,3-Butadiene	4.3E-07	N/A	8.34E-04	N/A	8.34E-04	3.30E-03
2-Methylnaphthalene	N/A	N/A	N/A	N/A	N/A	N/A
Acenaphthylene	N/A	N/A	N/A	N/A	N/A	N/A
Acetaldehyde	4.0E-05	N/A	7.76E-02	N/A	7.76E-02	3.07E-01
Acrolein	6.4E-06	N/A	1.24E-02	N/A	1.24E-02	4.92E-02
Antimony	N/A	N/A	N/A	N/A	N/A	N/A
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzaldehyde	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.2E-05	2.1E-06	2.33E-02	1.09E-03	2.44E-02	9.70E-02
Benzo(a)anthracene	N/A	N/A	N/A	N/A	N/A	N/A
Benzo(e)pyrene	N/A	N/A	N/A	N/A	N/A	N/A
Benzo(g,h,i)perylene	N/A	N/A	N/A	N/A	N/A	N/A
Beryllium	N/A	N/A	N/A	N/A	N/A	N/A
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Carbon Disulfide	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	3.2E-05	N/A	6.21E-02	N/A	6.21E-02	2.46E-01
Formaldehyde[2]	3.0E-04	7.4E-05	5.82E-01	3.91E-02	6.21E-01	2.48E+00
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	N/A	N/A	N/A	N/A	N/A	N/A
Naphthalene	1.3E-06	6.0E-07	2.52E-03	3.18E-04	2.84E-03	1.14E-02
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons (PAHs)	2.2E-06	N/A	4.27E-03	N/A	4.27E-03	1.69E-02
Propylene Oxide	2.9E-05	N/A	5.63E-02	N/A	5.63E-02	2.23E-01
Selenium	N/A	N/A	N/A	N/A	N/A	N/A
Toluene	1.3E-04	3.3E-06	2.52E-01	1.77E-03	2.54E-01	1.01E+00
Xylene	6.4E-05	N/A	1.24E-01	N/A	1.24E-01	4.92E-01
Maximum Individual HAP						2.5
Total HAPs						4.9

Notes:
CT = Combustion Turbine
DB = Duct Burner

[1] - EPA AP-42, Table 3.1-3, April 2000.
[2] - CT Factor is based on the average of EPA AP-42 test data for large, heavy duty CTs.
[3] - EPA AP-42, Table 1.4-3, March 1998.
[4] - EPA AP-42, Table 1.4-4, March 1998.
[5] - Based on baseload and 20°F temperature.
[6] - Based on baseload and 70°F temperature.

Sources: ECT, 2006
SCS, 2006.

Table A-9. Stanton Unit B CT/HRSG
Hazardous Air Pollutants - Totals

Pollutant	Syngas Total (ton/yr)	Natural Gas Total (ton/yr)	Maximum Total (ton/yr)
1,3-Butadiene	N/A	3.30E-03	3.30E-03
2-Methylnaphthalene	3.74E-03	N/A	3.74E-03
Acenaphthyalene	2.70E-04	N/A	2.70E-04
Acetaldehyde	1.87E-02	3.07E-01	3.07E-01
Acrolein	N/A	4.92E-02	4.92E-02
Antimony	4.15E-02	N/A	4.15E-02
Arsenic	2.18E-02	N/A	2.18E-02
Benzaldehyde	3.01E-02	N/A	3.01E-02
Benzene	5.05E-02	9.70E-02	9.70E-02
Benzo(a)anthracene	2.39E-05	N/A	2.39E-05
Benzo(e)pyrene	5.71E-05	N/A	5.71E-05
Benzo(g,h,I)perylene	9.86E-05	N/A	9.86E-05
Beryllium	9.35E-04	N/A	9.35E-04
Cadmium	3.01E-02	N/A	3.01E-02
Carbon Disulfide	**4.67E-01**	N/A	4.67E-01
Chromium	2.80E-02	N/A	2.80E-02
Cobalt	5.92E-03	N/A	5.92E-03
Ethylbenzene	N/A	2.46E-01	2.46E-01
Formaldehyde	3.48E-01	**2.48E+00**	**2.48E+00**
Manganese	3.22E-02	N/A	3.22E-02
Mercury	9.45E-03	N/A	9.45E-03
Naphthalene	5.55E-03	1.14E-02	1.14E-02
Nickel	4.05E-02	N/A	4.05E-02
Polycyclic Aromatic Hydrocarbons (PAHs)	N/A	1.69E-02	1.69E-02
Propylene Oxide	N/A	2.23E-01	2.23E-01
Selenium	3.01E-02	N/A	3.01E-02
Toluene	7.76E-03	1.01E+00	1.01E+00
Xylene	N/A	4.92E-01	4.92E-01
Maximum Individual HAP	0.5	2.5	2.5
Total HAPs	1.0	4.5	5.1

Sources: ECT, 2006
SCS, 2006.

Table A-10. Stanton Unit B
Fuel Flow Rates - PRB Coal to Gasifiers

	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature			
CT Load (%)	100	100	75	100	100	100	75	100	100	100	75
Case No.	1 - Syn	2 - Syn	3 - Syn	4 - Syn	5 - Syn	6 - Syn	7 - Syn	8 - Syn	9 - Syn	10 - Syn	11 - Syn
Southern Case No.	15	15a	21	17	18	18a	23	19	20	20a	24
Heat Input - LHV (10^6 Btu/hr)	2,284.7	2,284.7	1,859.5	2,238.7	2,272.3	2,272.3	1,811.4	2,013.6	2,164.6	2,164.6	1,658.2
Heat Input - HHV (10^6 Btu/hr)	2,383.7	2,383.7	1,940.1	2,335.7	2,370.8	2,370.8	1,889.9	2,100.9	2,258.4	2,258.4	1,730.1
Fuel Rate (lb/hr)	271,987	271,987	221,369	266,510	270,517	270,517	215,640	239,714	257,691	257,691	197,409
Fuel Rate (ton/hr)	135.993	75.552	61.491	74.031	75.143	75.143	59.900	66.587	71.581	71.581	54.836

Sources: ECT, 2006
SCS, 2006.

Table A-11. Stanton Unit B CT/HRSG
Fuel Flow Rates - Syngas

A. Syngas Fuel Flow Rates - CT

	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature			
CT Load (%)	100	100	75	100	100	100	75	100	100	100	75
Case No.	1 - Syn	2 - Syn	3 - Syn	4 - Syn	5 - Syn	6 - Syn	7 - Syn	8 - Syn	9 - Syn	10 - Syn	11 - Syn
Southern Case No.	15	15a	21	17	18	18a	23	19	20	20a	24
Heat Input - LHV (10^6 Btu/hr)	1,697.4	1,697.4	1,381.6	1,663.2	1,688.2	1,688.2	1,345.7	1,496.0	1,608.2	1,608.2	1,232.0
Heat Input - HHV (10^6 Btu/hr)	1,805.2	1,805.2	1,469.3	1,768.8	1,795.4	1,795.4	1,431.2	1,591.0	1,710.3	1,710.3	1,310.2
Fuel Rate (lb/hr)	883,498	883,498	719,102	865,683	878,701	878,701	700,455	778,664	837,052	837,052	641,236
Fuel Rate (lb/sec)	245.416	245.416	199.751	240.467	244.084	244.084	194.571	216.296	232.514	232.514	178.121
Fuel Rate (10^6 ft^3/hr)	13.078	13.078	10.644	12.814	13.007	13.007	10.368	11.526	12.390	12.390	9.492

B. Natural Gas Flow Rates - DB

	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature			
CT Load (%)	100	100	75	100	100	100	75	100	100	100	75
Case No.	1 - Syn	2 - Syn	3 - Syn	4 - Syn	5 - Syn	6 - Syn	7 - Syn	8 - Syn	9 - Syn	10 - Syn	11 - Syn
Southern Case No.	15	15a	21	17	18	18a	23	19	20	20a	24
Heat Input - LHV (10^6 Btu/hr)		479.7				446.4				477.4	
Heat Input - HHV (10^6 Btu/hr)		531.7				494.8				529.3	
Fuel Rate (lb/hr)		22,826				21,242				22,720	
Fuel Rate (lb/sec)		6.341				5.900				6.311	
Fuel Rate (10^6 ft^3/hr)		0.517				0.481				0.515	

Sources: ECT, 2006
SCS, 2006.

Table A-12. Stanton Unit B CT/HRSG
Fuel Flow Rates - Natural Gas

A. Natural Gas Fuel Flow Rates - CT

	20°F Ambient Temperature				70°F Ambient Temperature					95°F Ambient Temperature				
CT Load (%)	100	100	75	50	100	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG	13 - NG	14 - NG
Southern Case No.	1	1a	7	11	3	4	4a	9	13	5	6	6a	10	14
Heat Input - LHV (10^6 Btu/hr)	1,750.4	1,750.4	1,413.4	1,094.1	1,564.8	1,582.2	1,582.2	1,272.6	1,002.0	1,453.3	1,521.2	1,521.2	1,212.0	943.7
Heat Input - HHV (10^6 Btu/hr)	1,940.4	1,940.4	1,566.8	1,212.8	1,734.6	1,753.9	1,753.9	1,410.7	1,110.8	1,611.0	1,686.3	1,686.3	1,343.6	1,046.1
Fuel Rate (lb/hr)	83,295	83,295	67,258	52,062	74,461	75,289	75,289	60,557	47,683	69,155	72,387	72,387	57,676	44,906
Fuel Rate (lb/sec)	23.138	23.138	18.683	14.462	20.684	20.914	20.914	16.821	13.245	19.210	20.108	20.108	16.021	12.474
Fuel Rate (10^6 ft^3/hr)	1.887	1.887	1.524	1.180	1.687	1.706	1.706	1.372	1.081	1.567	1.640	1.640	1.307	1.018

B. Natural Gas Flow Rates - DB

	20°F Ambient Temperature				70°F Ambient Temperature					95°F Ambient Temperature				
CT Load (%)	100	100	75	50	100	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG	13 - NG	14 - NG
Southern Case No.	1	1a	7	11	3	4	4a	9	13	5	6	6a	10	14
Heat Input - LHV (10^6 Btu/hr)		434.1					479.4					456.3		
Heat Input - HHV (10^6 Btu/hr)		481.2					531.5					505.9		
Fuel Rate (lb/hr)		20,656					22,814					21,715		
Fuel Rate (lb/sec)		5.738					6.337					6.032		
Fuel Rate (10^6 ft^3/hr)		0.468					0.517					0.492		

Sources: ECT, 2006
SCS, 2006.

Table A-13. Stanton Unit B CT/HRSG
Exhaust Flow Rates - Syngas

A. Exhaust Composition

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %										
		20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature			
		100	100	75	100	100	100	75	100	100	100	75
	Case No.	1 - Syn	2 - Syn	3 - Syn	4 - Syn	5 - Syn	6 - Syn	7 - Syn	8 - Syn	9 - Syn	10 - Syn	11 - Syn
	Southern Case No.	15	15a	21	17	18	18a	23	19	20	20a	24
Ar	39.944	0.73	0.72	0.74	0.72	0.73	0.72	0.74	0.74	0.73	0.72	0.73
N_2	28.013	75.42	74.63	75.46	74.42	74.31	73.60	74.44	74.14	73.78	73.01	74.20
O_2	31.999	10.95	8.73	11.09	10.97	10.89	8.88	11.07	11.04	10.84	8.63	11.30
CO_2	44.010	8.35	9.31	8.23	8.09	8.13	9.01	8.00	7.96	8.04	9.00	7.74
H_2O	18.015	4.55	6.60	4.49	5.80	5.94	7.79	5.76	6.13	6.61	8.63	6.03
	Totals	100.00	100.00	100.01	100.00	100.00	100.00	100.01	100.01	100.00	100.00	100.00
Exhaust MW (lb/mole)		29.42	29.28	29.41	29.25	29.24	29.12	29.25	29.20	29.16	29.02	29.19
Exhaust Flow (lb/sec)		1,097.6	1,103.9	897.0	1,108.1	1,118.6	1,124.5	897.5	1,024.4	1,087.6	1,093.9	858.5
Exhaust Temperature (°F)		189.7	185.5	183.5	190.4	190.7	186.2	183.7	187.7	189.8	185.6	182.5
(K)		360.8	358.4	357.3	361.2	361.3	358.8	357.4	359.7	360.8	358.5	356.8
Exhaust O_2 (Vol %, Dry)		11.47	9.35	11.61	11.65	11.58	9.63	11.75	11.76	11.61	9.45	12.03

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)										
	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature			
	100	100	75	100	100	100	75	100	100	100	75
Case No.	1 - Syn	2 - Syn	3 - Syn	4 - Syn	5 - Syn	6 - Syn	7 - Syn	8 - Syn	9 - Syn	10 - Syn	11 - Syn
Southern Case No.	15	15a	21	17	18	18a	23	19	20	20a	24
ACFM	1,058,407	1,062,715	856,826	1,075,816	1,086,895	1,089,765	862,447	992,006	1,058,300	1,062,559	825,162
Velocity (fps)	65.6	65.9	53.1	66.7	67.4	67.6	53.5	61.5	65.6	65.9	51.2
Velocity (m/s)	20.0	20.1	16.2	20.3	20.5	20.6	16.3	18.7	20.0	20.1	15.6
SCFM, Dry[1]	823,270	814,096	673,320	824,964	831,836	823,298	668,518	761,192	805,297	796,165	638,976
ACFM (15% O_2, Dry)	1,614,349	1,942,953	1,288,375	1,589,619	1,615,335	1,920,016	1,260,951	1,442,415	1,556,690	1,884,143	1,166,377
SCFM (15% O_2, Dry)	1,315,562	1,593,654	1,060,040	1,294,014	1,314,341	1,573,134	1,037,154	1,179,081	1,268,379	1,545,177	961,158

[1] At 68 °F.

Sources: ECT, 2006
SCS, 2006.

Table A-14. Stanton Unit B CT/HRSG
Exhaust Flow Rates - Natural Gas

A. Exhaust Composition

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %													
		20°F Ambient Temperature				70°F Ambient Temperature					95°F Ambient Temperature				
		100	100	75	50	100	100	100	75	50	100	100	100	75	50
	Case No.	1 - NG	2 - NG	3 - NG	4 - NG	6 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG	13 - NG	14 - NG
	Southern Case No.	1	1a	7	11	3	4	4a	9	13	5	6	6a	10	14
Ar	39.944	0.83	0.82	0.84	0.85	0.82	0.83	0.82	0.88	0.85	0.82	0.82	0.81	0.83	0.84
N_2	28.013	69.36	68.75	69.25	71.24	68.65	68.58	67.85	73.89	70.52	68.48	68.24	67.52	68.92	70.45
O_2	31.999	11.72	9.87	11.29	12.83	11.61	11.58	9.35	12.71	12.79	11.60	11.50	9.29	11.70	12.90
CO_2	44.010	3.52	4.36	3.73	3.22	3.48	3.49	4.51	3.64	3.14	3.48	3.48	4.49	3.47	3.08
H_2O	18.015	14.57	16.19	14.90	11.87	15.44	15.53	17.48	8.88	12.70	15.64	15.97	17.88	15.08	12.73
	Totals	100.00	100.00	100.01	100.01	100.00	100.01	100.00	100.00	100.00	100.00	100.01	100.00	100.00	100.00
Exhaust MW (lb/mole)		27.69	27.58	27.67	27.96	27.59	27.58	27.46	28.32	27.86	27.56	27.53	27.41	27.63	27.85
Exhaust Flow (lb/sec)		1,127.2	1,133.0	850.7	764.9	1,014.7	1,023.9	1,030.2	803.9	714.4	947.7	984.8	990.8	784.7	687.3
Exhaust Temperature (°F)		194.1	185.9	183.5	182.8	188.7	190.1	185.0	180.5	180.2	187.0	188.6	184.2	180.1	179.0
(K)		363.2	358.7	357.3	356.9	360.8	361.0	358.2	355.7	355.5	359.3	360.2	357.7	355.4	354.8
Exhaust O_2 (Vol %, Dry)		13.72	11.78	13.27	14.56	13.73	13.71	11.32	13.95	14.65	13.75	13.69	11.32	13.78	14.78

B. Exhaust Flow Rates

	Flow Rates (ft³/min)														
	20°F Ambient Temperature				70°F Ambient Temperature					95°F Ambient Temperature					
	100	100	75	50	100	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	6 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG	13 - NG	14 - NG
Southern Case No.	1	1a	7	11	3	4	4a	9	13	5	6	6a	10	14
ACFM	1,162,847	1,158,360	863,750	787,864	1,043,477	1,053,704	1,056,676	793,842	716,899	971,302	1,012,993	1,016,806	793,903	688,591
Velocity (fps)	72.1	71.8	53.6	47.6	64.7	65.3	65.5	49.2	44.5	60.2	62.8	63.0	49.2	42.7
Velocity (m/s)	22.0	21.9	16.3	14.5	19.7	19.9	20.0	15.0	13.5	18.4	19.1	19.2	15.0	13.0
SCFM, Dry[1]	804,107	795,805	604,781	557,383	719,054	724,882	715,799	597,941	517,591	670,524	694,849	686,205	557,647	497,916
ACFM (15% O_2, Dry)	1,209,138	1,500,986	950,988	727,411	1,072,312	1,084,821	1,415,283	852,247	662,913	992,908	1,040,853	1,356,044	813,855	623,167
SCFM (15% O_2, Dry)	978,717	1,230,380	782,448	599,146	873,846	883,495	1,161,748	704,492	548,240	812,516	849,649	1,114,504	673,177	516,337

[1] At 68 °F.

Sources: ECT, 2006
SCS, 2006.

Table A-15. Stanton Unit B
Flare Emission Rates

A. Flare Pilot

Natural Gas Usage	50	lb/hr
	0.0011	10^6 ft^3/hr
	1.2	10^5 Btu/hr
Annual Hours	8,760	hr/yr

Pollutant	Emissions ($lb/10^6$ Btu)[1]	(lb/hr)	(tpy)
PM_{10}	0.0075	0.009	0.04
CO	0.0824	0.096	0.42
SO_2	0.0059	0.007	0.03
NO_x	0.0980	0.114	0.50
VOC	0.0054	0.006	0.03

A. Gasifier Startups (Simultaneous Cold Start of Gasifiers A + B)

Annual Startup Events	20	events/yr
Natural Gas Usage	75,000	lb/event
	1.70	10^6 ft^3/event
	1,747	10^6 Btu/event
Syngas Usage	909,160	lb/event
	13.46	10^6 ft^3/event
	1,857	10^6 Btu/event

	Flare Emissions					
	Natural Gas		Syngas		NG + Syngas	Flare + Pilot
Pollutant	($lb/10^6$ Btu)[1]	(lb/event)	($lb/10^6$ Btu)[2,3]	(lb/event)	(tpy)	(tpy)
PM_{10}	0.0075	13.018	0.0075	13.8	0.27	0.31
CO	0.0824	143.880	0.8314	1,544.1	16.88	17.30
SO_2	0.0059	10.277	0.0164	30.5	0.41	0.44
NO_x	0.0980	171.285	0.1278	237.3	4.09	4.59
VOC	0.0054	9.421	0.0054	10.0	0.19	0.22

B. Gasifier Startups (Staggered Cold Start of Gasifiers A + B)

Annual Startup Events	20	events/yr
Natural Gas Usage	75,000	lb/event
	1.70	10^6 ft^3/event
	1,747	10^6 Btu/event
Syngas Usage	1,623,500	lb/event
	24.03	10^6 ft^3/event
	3,316	10^6 Btu/event

	Flare Emissions					
	Natural Gas		Syngas		NG + Syngas	Flare + Pilot
Pollutant	($lb/10^6$ Btu)[1]	(lb/event)	($lb/10^6$ Btu)[2,3]	(lb/event)	(tpy)	(tpy)
PM_{10}	0.0075	13.018	0.0075	24.7	0.38	0.42
CO	0.0824	143.880	0.7096	2,353.2	24.97	25.39
SO_2	0.0059	10.277	0.0164	54.5	0.65	0.68
NO_x	0.0980	171.285	0.1009	334.8	5.06	5.56
VOC	0.0054	9.421	0.0054	17.9	0.27	0.30

[1] Section 1.4 (Natural Gas Combustion), AP-42, July 1998.

[2] CO, SO_2, and NO_x - SCS, 2006.

[3] PM_{10} and VOC - Section 1.4 (Natural Gas Combustion), AP-42, July 1998.

Sources: ECT, 2006
SCS, 2006.

A. Gasifier Startups (Simultaneous Cold Start of Gasifiers A + B)

Annual Startup Events	20	events/yr
Coal Usage (both gasifiers)	300	ton/event
Natural Gas Usage (both gasifiers)	238,108	lb/event
	5.40	10^6 ft^3/event
	5,547	10^6 Btu/event

Pollutant	Gasifier Startup Stack Emissions (lb/10^6 Btu)[1]	(lb/event)[2]	(tpy)
PM_{10}	0.0075	41.328	0.41
CO	0.0824	1,285.175	12.85
SO_2	0.0059	380.628	3.81
NO_x	0.0980	1,353.470	13.53
VOC	0.0054	29.909	0.30

B. Gasifier Startups (Staggered Cold Start of Gasifiers A + B)

Annual Startup Events	20	events/yr
Coal Usage (both gasifiers)	300	ton/event
Natural Gas Usage (both gasifiers)	162,916	lb/event
	3.69	10^6 ft^3/event
	3,795	10^6 Btu/event

Pollutant	Gasifier Startup Stack Emissions (lb/10^6 Btu)[1]	(lb/event)[2]	(tpy)
PM_{10}	0.0075	28.277	0.28
CO	0.0824	1,217.873	12.18
SO_2	0.0059	370.324	3.70
NO_x	0.0980	1,285.135	12.85
VOC	0.0054	20.464	0.20

[1] Section 1.4 (Natural Gas Combustion, AP-42, July 1998.

[2] CO, SO_2, and NO_x - SCS, 2006.

Sources: ECT, 2006
SCS, 2006.

POTENTIAL EMISSION INVENTORY WORKSHEET

Stanton Energy Center Unit B

Table A-17
Unit B-CTW

Revised March 17, 2006

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Mechanical Draft Cooling Tower
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	Unit B Cooling Tower

EMISSION ESTIMATION EQUATIONS

PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) / 10^6) x 60 min/hr

PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM_{10} Emission (lb/hr) = PM Emissions (lb/hr) x PM_{10}/PM Fraction

PM_{10} Emission (ton/yr) = PM_{10} Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2006.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	6	
Recirculating Water Flow Rate:	~~8,600~~ 86,000	gal/min
Drift Loss Rate:	0.002	%
Total Dissolved Solids (TDS):	3,704	ppmw
PM_{10}/PM Fraction:	0.414	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)				Potential Emission Rates (Total)			
	(lb/hr)		(tpy)		(lb/hr)		(tpy)	
PM	~~0.05~~	0.53	~~0.23~~	2.33	~~0.32~~	3.19	~~1.40~~	13.97
PM_{10}	~~0.022~~	0.220	~~0.10~~	0.96	~~0.13~~	1.32	~~0.58~~	5.78

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	SCS, 2006.
Recirculating Water Flow Rate (gpm)	SCS, 2006.
Drift Loss Rate (%)	SCS, 2006.
Total Dissolved Solids (ppmw)	SCS, 2006.
PM_{10}/PM Fraction:	ECT, 2006.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	SCS	Jan-06
Data Entered by:	T.Davis, ECT	Jan-06
Reviewed by:	T.Davis, ECT	Jan-06

POTENTIAL EMISSION INVENTORY WORKSHEET

Stanton Energy Center Unit B

Table A-17 Unit B-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Mechanical Draft Cooling Tower
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	Unit B Cooling Tower

EMISSION ESTIMATION EQUATIONS

PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) / 1) x 60 min/hr

PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM_{10} Emission (lb/hr) = PM Emissions (lb/hr) x PM_{10}/PM Fraction

PM_{10} Emission (ton/yr) = PM_{10} Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2006.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	6	
Recirculating Water Flow Rate:	8,600	gal/min
Drift Loss Rate:	0.002	%
Total Dissolved Solids (TDS):	3,704	ppmw
PM_{10}/PM Fraction:	0.414	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.05	0.23	0.32	1.40
PM_{10}	0.022	0.10	0.13	0.58

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	SCS, 2006.
Recirculating Water Flow Rate (gpm)	SCS, 2006.
Drift Loss Rate (%)	SCS, 2006.
Total Dissolved Solids (ppmw)	SCS, 2006.
PM_{10}/PM Fraction:	ECT, 2006.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	SCS	Jan-06
Data Entered by:	T.Davis, ECT	Jan-06
Reviewed by:	T.Davis, ECT	Jan-06

Table A-18. Stanton Unit B CT/HRSG
Cooling Tower PM/PM_{10} Fractions

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM_{10} Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	3,704	ppmw
Cooling Tower PM_{10} Density (assumed NaCl):	2.2	g/cm^3

Particle Size Distribution:

Droplet Diameter (µm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (µm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	1.94E-12	8.82E-19	1.190	0.000
20	4.19E-15	4.19E-09	1.55E-11	7.05E-18	2.379	0.196
30	1.41E-14	1.41E-08	5.24E-11	2.38E-17	3.569	0.226
40	3.35E-14	3.35E-08	1.24E-10	5.64E-17	4.759	0.514
50	6.54E-14	6.54E-08	2.42E-10	1.10E-16	5.948	1.816
60	1.13E-13	1.13E-07	4.19E-10	1.90E-16	7.138	5.702
70	1.80E-13	1.80E-07	6.65E-10	3.02E-16	8.327	21.348
90	3.82E-13	3.82E-07	1.41E-09	6.43E-16	10.707	49.812
110	6.97E-13	6.97E-07	2.58E-09	1.17E-15	13.086	70.509
130	1.15E-12	1.15E-06	4.26E-09	1.94E-15	15.465	82.023
150	1.77E-12	1.77E-06	6.55E-09	2.98E-15	17.845	88.012
180	3.05E-12	3.05E-06	1.13E-08	5.14E-15	21.414	91.032
210	4.85E-12	4.85E-06	1.80E-08	8.16E-15	24.982	92.468
240	7.24E-12	7.24E-06	2.68E-08	1.22E-14	28.551	94.091
270	1.03E-11	1.03E-05	3.82E-08	1.74E-14	32.120	94.689
300	1.41E-11	1.41E-05	5.24E-08	2.38E-14	35.689	96.288
350	2.24E-11	2.24E-05	8.32E-08	3.78E-14	41.637	97.011
400	3.35E-11	3.35E-05	1.24E-07	5.64E-14	47.586	98.340
450	4.77E-11	4.77E-05	1.77E-07	8.03E-14	53.534	99.071
500	6.54E-11	6.54E-05	2.42E-07	1.10E-13	59.482	99.071
600	1.13E-10	1.13E-04	4.19E-07	1.90E-13	71.378	100.000

Linear Interpolation:

Droplet Diameter (µm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (µm)	Mass Fraction (%)
70	1.80E-13	1.80E-07	6.65E-10	3.02E-16	8.327	21.348
90	3.82E-13	3.82E-07	1.41E-09	6.43E-16	10.707	49.812
					10.000	**41.357**

Mass Fraction of Cooling Tower PM ≤ PM_{10}:	0.414

Sources: ECT, 2006
SCS, 2006.

POTENTIAL EMISSION INVENTORY WORKSHEET

Stanton Energy Center Unit B

Table A-19

EMISSION SOURCE TYPE

FUGITIVE PM - ACTIVE OUTDOOR PRB COAL STORAGE — **Figure:**

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Fugitive PM - Active Outdoor PRB Coal Storage Pile
Emission Control Method(s)/ID No.(s):	Moist Material
Emission Point ID:	FUG-PM

EMISSION ESTIMATION EQUATIONS

PM/PM_{10} Emission (lb/hr) = Emission Factor (lb PM/PM_{10}/acre/day) x Storage Pile Area (acres) x (1 day/24 hrs)

PM/PM_{10} Emission (ton/yr) = Emission Factor (lb PM/PM_{10}/acre/day) x Storage Pile Area (acres) x Storage Period (dys/yr) x (1 ton/2,000 lb)

Source: ECT, 2006.

INPUT DATA AND EMISSIONS CALCULATIONS

Storage Pile Material Type	Source ID	Period of Storage (dys/yr)	Pile Area (acre)	Uncontrolled Emission Factor (lb PM/acre/dy)	Control Efficiency (%)	Controlled Emission Factor (lb PM/acre/dy)	Potential PM Emission Rates (lb/hr)	Potential PM Emission Rates (tpy)
PRB Coal	PRB-1	365	2.755	13.2	70.0	3.96	0.455	1.991

Storage Pile Material Type	Source ID	Period of Storage (dys/yr)	Pile Area (acre)	Uncontrolled Emission Factor (lb PM_{10}/acre/dy)	Control Efficiency (%)	Controlled Emission Factor (lb PM_{10}/acre/dy)	Potential PM_{10} Emission Rates (lb/hr)	Potential PM_{10} Emission Rates (tpy)
PRB Coal	PRB-1	365	2.755	6.3	70.0	1.89	0.217	0.950

SOURCES OF INPUT DATA

Parameter	Data Source
Uncontrolled Emission Factors	Section 8.19.1-1, AP-42, September 1991.
Control Efficiency	Watering, as necessary.
Pile Size (acre)	SCS, 2006.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	SCS	**Date:**	Feb-06
Evaluated by:	T. Davis	**Date:**	Feb-06
Data Entered by:	T. Davis	**Date:**	Feb-06

Table A-20. Stanton Unit B
Coal & Fly Ash Handling PM/PM_{10} Emissions - Storage

Emission Source	Baghouse Flow Rate (scf/min)	PM/PM_{10} Emissions (gr/scf)	(lb/hr)	(tpy)
Coal Mill Silo No. 1	2,500	0.020	0.43	1.9
Coal Mill Silo No. 2	2,500	0.020	0.43	1.9
Coal Mill Silo No. 3	2,500	0.020	0.43	1.9
Coal Mill Silo No. 4	2,500	0.020	0.43	1.9
Coal Storage Bin No. 1	2,500	0.020	0.43	1.9
Coal Storage Bin No. 2	2,500	0.020	0.43	1.9
Coal Storage Bin No. 3	2,500	0.020	0.43	1.9
Coal Storage Bin No. 4	2,500	0.020	0.43	1.9
Fly Ash Storage Silo	2,500	0.020	0.43	1.9
Totals	**20,000**	**N/A**	**3.43**	**15.0**

Sources: ECT, 2006
SCS, 2006.

APPENDIX B

FDEP PERMIT APPLICATION FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes 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/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **OUC/Southern Power Company– Orlando Gasification LLC**
2. Site Name: **Curtis H. Stanton Energy Center**
3. Facility Identification Number: **0950137**
4. Facility Location...
   Street Address or Other Locator: **5100 South Alafaya Trail**
   City: **Orlando** County: **Orange** Zip Code: **32831**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Denise M. Stalls, Director Environmental Affairs**
2. Application Contact Mailing Address
   Organization/Firm: **Orlando Utilities Commission**
   Street Address: **P.O. Box 3193**
   City: **Orlando** State: **Florida** Zip Code: **32802**
3. Application Contact Telephone Numbers...
   Telephone: **(407) 737-4236** ext. Fax: **(407) 384-4020**
4. Application Contact Email Address: **dstalls@ouc.com**

Application Processing Information (DEP Use)

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

APPLICATION INFORMATION

Purpose of Application

This application for air permit is 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 an integrated gasification combined-cycle (IGCC) facility to be located at the existing Stanton Energy Center in Orlando, Orange County, Florida. A detailed description of the Unit B IGCC project is provided in Section 2.0.

Unit B is being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
030	Unit B Combined-Cycle Combustion Turbine	AC1A	N/A
031	Unit B Flare	AC1A	N/A
032	Unit B Gasifier Startup Stack	AC1A	N/A
033	Unit B Cooling Tower	AC1A	N/A
034	Unit B Material (Coal and Gasification Ash) Storage and Handling	AC1A	N/A

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

Note: The Stanton Energy Center is a FPPSA certified site. Application processing fee has been submitted to the Siting Coordination Office (SCO) within the FDEP's Energy Office pursuant to the FEPPSA.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name:
   Frederick F. Haddad, Jr.
2. Owner/Authorized Representative Mailing Address
   Organization/Firm: **Orlando Utilities Commission**
   Street Address: **P.O. Box 3193**
   City: **Orlando** State: **Florida** Zip Code: **32802**
3. Owner/Authorized Representative Telephone Numbers
   Telephone: **(407) 244-8732** ext. Fax: **(407) 275-4120**
4. Owner/Authorized Representative Email Address: **fhaddad@ouc.com**
5. Owner/Authorized Representative Statement:

   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 and revisions thereof and all other requirements identified in this application to which the facility 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.

   Signature

   February 14, 2006
   Date

APPLICATION INFORMATION

Application Responsible Official Certification **NOT APPLICABLE**

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

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

   ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

   ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

   ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

   ☐ The designated representative at an Acid Rain source.

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 Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   _____ _____
   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Thomas W. Davis**
   Registration Number: 36777
2. Professional Engineer Mailing Address
   Organization/Firm: **Environmental Consulting & Technology, Inc.**
   Street Address: **3701 Northwest 98th Street**
   City: **Gainesville** State: **FL** Zip Code: **32606**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 332-6230** ext. **11351** Fax: **(352) 332-6722**
4. Professional Engineer Email Address: **tdavis@ectinc.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis
Signature

2/17/06
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates...		2. Facility Latitude/Longitude...	
Zone **17** East (km) **483.6** North (km) **3,151.1**		Latitude (DD/MM/SS) **28/29/17** Longitude (DD/MM/SS) **81/10/03**	
3. Governmental Facility Code: **4**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Denise M. Stalls, Director Environmental Affairs**
2. Facility Contact Mailing Address Organization/Firm: **Orlando Utilities Commission** Street Address: **P.O. Box 3193** City: **Orlando** State: **Florida** Zip Code: **32802**
3. Facility Contact Telephone Numbers: Telephone: **(407) 737-4236** ext. Fax: **(407) 384-4020**
4. Facility Contact Email Address: **dstalls@ouc.com**

Facility Primary Responsible Official NOT APPLICABLE

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

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

Facility Regulatory Classifications

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

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

FACILITY INFORMATION

List of Pollutants Emitted by Facility

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

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps **NOT APPLICABLE**

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID:_____ [ ] 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) [X] Attached, Document ID:_____ [ ] 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) [X] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for FESOP Applications NOT APPLICABLE

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☐ Attached, Document ID:_____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. List of Insignificant Activities (Required for initial/renewal applications only):
   ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought):
   ☐ Attached, Document ID:_____
   ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications):
   ☐ Attached, Document ID:_____
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only):
   ☐ Attached, Document ID:_____
   ☐ Equipment/Activities On site 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

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Combined-cycle unit comprised of one "F" Class combustion turbine (CT) and one heat recovery steam generator (HRSG) equipped with duct burners (DBs). The CT may be fired with either syngas or pipeline natural gas. The HRSG DBs will be fired exclusively with pipeline natural gas.

3. Emissions Unit Identification Number: **030 (Unit B CT/HRSG)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☒ Yes ☐ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **285 (syngas), 310 (natural gas)** MW **(nominal)**

11. Emissions Unit Comment:
Generator nameplate ratings are nominal generation capacities for the Unit B combined-cycle unit when fired with syngas or natural gas.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Syngas

NO_x – Selective Catalytic Reduction (SCR) [139]

Natural Gas

NO_x – Wet Injection, SCR [028, 139]

2. Control Device or Method Code(s): **Syngas (139), Natural Gas (028, 139)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **2,383.7** million Btu/hr, **HHV**	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year

6. Operating Capacity/Schedule Comment:

Maximum heat input shown above is the total gasifier heat input at 100% load and 20°F ambient temperature, on a higher heating value basis (HHV).

Maximum heat input for the Unit B CT during natural gas-firing is 1,940.4 x 10^6 Btu/hr at 100% load and 20°F ambient temperature, HHV basis.

Maximum heat input for the Unit B HRSG DBs is 531.7x 10^6 Btu/hr at 100% load and 20°F ambient temperature, HHV basis. The Unit B HRSG DBs will be fired exclusively with pipeline natural gas.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Unit B CT/HRSG**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **205** feet	7. Exit Diameter: **18.5** feet
8. Exit Temperature: **190** °F	9. Actual Volumetric Flow Rate: **1,089,800** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet	
13. Emission Point UTM Coordinates Zone: **17** East (km): **483.62** North (km): **3,150.95**	14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)	
15. Emission Point Comment: **Exit temperature (Field 8) and volumetric flow rate (Field 9) for are syngas Operating Case No. 6 – 100% load, 20oF ambient temperature, CT inlet air evaporative cooling, and HRSG duct burner firing.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with coal-derived syngas.**		
2. Source Classification Code (SCC): **1-01-019-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **13.078**	5. Maximum Annual Rate: **114,563.3**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **<0.1**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **138, HHV**
10. Segment Comment:		

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

1. Segment Description (Process/Fuel Type): **Combustion turbine and heat recovery steam generator duct burners fired with pipeline natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **2.404**	5. Maximum Annual Rate: **21,059.0**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,028 HHV**
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	**028**	**139**	**EL**
2 - CO			**EL**
3 – VOC			**EL**
4 – SO2			**EL**
5 – PM			**EL**
6 – PM10			**EL**
7 – SAM			**EL**
8 – HG			**EL**
Notes: **SAM - sulfuric acid mist**	**028 – water or steam injection**	**139 - SCR**	**EL – emissions limited**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **50% (PI), 70% (PII)-Syngas** **80% - Natural Gas**
3. Potential Emissions: **228.3** lb/hour **987.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential emissions represent proposed Phase I limits. Proposed Phase II potential emissions are 137.0 lb/hr and 592.3 ton/yr.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.080 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **228.3** lb/hour **987.1** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing during Phase I.**	

Allowable Emissions Allowable Emissions **2** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **228.3** lb/hour **987.1** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing during Phase I.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **3** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **Following DOE Demonstration Period**
3. Allowable Emissions and Units: **0.048 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **137.0** lb/hour **592.3** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing during Phase II.**	

Allowable Emissions Allowable Emissions **4** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **Following DOE Demonstration Period**
3. Allowable Emissions and Units: **12 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **137.0** lb/hour **592.3** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing during Phase II.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **5** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.018 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **44.6** lb/hour **184.4** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing.**	

Allowable Emissions Allowable Emissions **6** of **6**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **44.6** lb/hour **184.4** tons/year
5. Method of Compliance: **NO_x CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **143.2** lb/hour **615.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.040 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **90.7** lb/hour **N/A** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing without duct burner firing.**	

Allowable Emissions Allowable Emissions **2** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **17 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **90.7** lb/hour **N/A** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing without duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **3** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.050 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **143.2** lb/hour **615.3** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing with duct burner firing.**	

Allowable Emissions Allowable Emissions **4** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **21 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **143.2** lb/hour **615.3** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing with duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **5** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.050 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **87.7** lb/hour **N/A** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing without duct burner firing.**	

Allowable Emissions Allowable Emissions **6** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **87.7** lb/hour **N/A** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing without duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 7 of 8

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.060 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **140.8** lb/hour **604.4** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing with duct burner firing.**	

Allowable Emissions Allowable Emissions 8 of 8

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **28 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **140.8** lb/hour **604.4** tons/year
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing with duct burner firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **31.1** lb/hour **128.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.007 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **15.4** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing without duct burner firing.**	

Allowable Emissions Allowable Emissions **2** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **15.4** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing without duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **3** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.011 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **31.0** lb/hour **117.6** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average. Limit is applicable to syngas-firing with duct burner firing.**	

Allowable Emissions Allowable Emissions **4** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **7.8 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.0** lb/hour **117.6** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to syngas-firing with duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **5** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.010 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **16.4** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing without duct burner firing.**	

Allowable Emissions Allowable Emissions **6** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **7.7 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **16.4** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing without duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **7** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.013 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **31.1** lb/hour **128.3** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing with duct burner firing.**	

Allowable Emissions Allowable Emissions **8** of **8**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10.1 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.1** lb/hour **128.3** tons/year
5. Method of Compliance: **EPA Reference Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing with duct burner firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **36.1** lb/hour **157.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.015 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **36.1** lb/hour **157.1** tons/year
5. Method of Compliance: **Applicable 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average and is applicable to syngas-firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Pipeline Natural Gas**	4. Equivalent Allowable Emissions: **1.4** lb/hour **6.0** tons/year
5. Method of Compliance: **Applicable 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **36.3** lb/hour **156.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.013 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **36.3** lb/hour **157.7** tons/year
5. Method of Compliance: **EPA Reference Method 5 or 17.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average and is applicable to syngas-firing.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.017 lb/10^6 Btu**	4. Equivalent Allowable Emissions: **23.3** lb/hour **101.8** tons/year
5. Method of Compliance: **EPA Reference Method 5 or 17.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to combined-cycle unit, 24-hour block average. Limit is applicable to natural gas-firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **5.5** lb/hour **24.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.015 lb/10^6 Btu (SO_2)**	4. Equivalent Allowable Emissions: **5.5** lb/hour **24.0** tons/year
5. Method of Compliance: **Applicable 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on heat input (HHV) to gasifiers, 24-hour block average and is applicable to syngas-firing. Use of SO_2 limit is proposed as a surrogate limit for H_2SO_4 mist.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Pipeline Natural Gas**	4. Equivalent Allowable Emissions: **0.22** lb/hour **0.9** tons/year
5. Method of Compliance: **Applicable 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions is applicable to natural gas-firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **HG**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.0022** lb/hour **0.0095** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.91 lb / 10^{12} Btu** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (CAMR)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **20 x 10^{-6} lb / MWh**	4. Equivalent Allowable Emissions: **0.0057** lb/hour **0.025** tons/year
5. Method of Compliance: **Applicable 40 CFR Part 60 Subpart Da procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Field 3 allowable emissions based on 12-month rolling average and is applicable during syngas-firing.**	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

Complete 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 Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **1** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor **2** of **4**

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **NO_x diluent CEM requirements of 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **3** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **Hg**
3. CMS Requirement:	[x] Rule [ ] Other
4. Monitor Information Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Required by 40 CFR Part 60, Subpart Da (CAMR). Specific CEMS information will be provided to FDEP when available.**	

Continuous Monitoring System: Continuous Monitor **4** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [x] Other
4. Monitor Information Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Specific CEMS information will be provided to FDEP when available.**	

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)
   [X] Attached, Document ID: **Fig. 2-5, 2-8** [ ] 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)
   [X] Attached, Document ID: **SCA Section 3.3, Fig. 3-3-1, 3-3-2**

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)
   [X] Attached, Document ID: **Section 2.0** [ ] Previously Submitted, Date _____

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

EMISSIONS UNIT INFORMATION
Section [1] of [5]

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))
   [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) **To be provided to FDEP when available.**
   [ ] Attached, Document ID: _____ [ ] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. Identification of Applicable Requirements
   [ ] Attached, Document ID: _____
2. Compliance Assurance Monitoring
   [ ] Attached, Document ID: _____ [ ] Not Applicable
3. Alternative Methods of Operation
   [ ] Attached, Document ID: _____ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   [ ] Attached, Document ID: _____ [ ] Not Applicable
5. Acid Rain Part Application
   [ ] Certificate of Representation (EPA Form No. 7610-1)
      [ ] Copy Attached, Document ID:
   [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Not Applicable

EMISSIONS UNIT INFORMATION
Section [1] of [5]

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Multipoint flare used to combust syngas during gasification process startups and upsets. All syngas that will be flared will first flow through the gas clean-up processes.

3. Emissions Unit Identification Number: **031 (Unit B Flare)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Flaring [023]

2. Control Device or Method Code(s): **023**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **N/A** million Btu/hr,	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	
Flare will be used to combust syngas during gasification process startups and upsets.	

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: **Flare**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **10** feet	7. Exit Diameter: **N/A** feet
8. Exit Temperature: **N/A** °F	9. Actual Volumetric Flow Rate: **N/A** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm		12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates Zone: East (km): **N/A** North (km): **N/A**		14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)
15. Emission Point Comment: **Multipoint flare will have a footprint of approximately 214 ft. by 123 feet and will equipped with a thermal barrier fence 20 ft. tall.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Flaring of syngas during gasification process startups and upsets.**		
2. Source Classification Code (SCC): **N/A**	3. SCC Units: **N/A**	
4. Maximum Hourly Rate: **Variable**	5. Maximum Annual Rate: **Variable**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX			**WP**
2 – CO			**WP**
3 – VOC			**WP**
4 – SO2			**WP**
5 – PM			**WP**
6 – PM10			**WP**
Notes:			**WP – work practice**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **129** lb/hour **5.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **787** lb/hour **25.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **17** lb/hour **0.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **4.1** lb/hour **0.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **3.0** lb/hour **0.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

Complete 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 Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment	

H. CONTINUOUS MONITOR INFORMATION NOT APPLICABLE

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

Continuous Monitoring System: Continuous Monitor of

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

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: **Fig. 2-5, 2-8** [ ] 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)
   [X] Attached, Document ID: **SCA Section 3.3, Fig. 3-3-1, 3-3-2**

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)
   [X] Attached, Document ID: **Section 2.0** [ ] Previously Submitted, Date _____

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

EMISSIONS UNIT INFORMATION
Section [2] of [5]

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))
   [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   [ ] Attached, Document ID: _____ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. Identification of Applicable Requirements
   [ ] Attached, Document ID: _____
2. Compliance Assurance Monitoring
   [ ] Attached, Document ID: _____ [ ] Not Applicable
3. Alternative Methods of Operation
   [ ] Attached, Document ID: _____ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   [ ] Attached, Document ID: _____ [ ] Not Applicable
5. Acid Rain Part Application
   [ ] Certificate of Representation (EPA Form No. 7610-1)
      [ ] Copy Attached, Document ID:
   [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [ ] Not Applicable

Additional Requirements Comment

EMISSIONS UNIT INFORMATION
Section [3] of [5]

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Gasifier startup stack used to exhaust fuel combustion products during gasification process startups. All gas that will be exhausted will first flow through the syngas particulate filtration process.

3. Emissions Unit Identification Number: **032 (Unit B Gasifier Startup Stack)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   N/A

2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **N/A** million Btu/hr,	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	
Gasifier startup stack used to exhaust fuel combustion products during gasification process startups.	

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: **Gasifier Startup Stack**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **184** feet	7. Exit Diameter: **11.7** feet
8. Exit Temperature: **N/A** °F	9. Actual Volumetric Flow Rate: **N/A** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm		12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates Zone: East (km): **N/A** North (km): **N/A**		14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Exhausting of fuel combustion products during gasification process startups.**		
2. Source Classification Code (SCC): **N/A**	3. SCC Units: **N/A**	
4. Maximum Hourly Rate: **Variable**	5. Maximum Annual Rate: **Variable**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX			**WP**
2 – CO			**WP**
3 – VOC			**WP**
4 – SO2			**WP**
5 – PM			**WP**
6 – PM10			**WP**
Notes:			**WP – work practice**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **178.5** lb/hour **13.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **178** lb/hour **12.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **69.6** lb/hour **3.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **2.4** lb/hour **0.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **1.8** lb/hour **0.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **SCS Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Clean Fuels, Good Combustion Practice**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

Complete 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 Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment	

H. CONTINUOUS MONITOR INFORMATION NOT APPLICABLE

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

Continuous Monitoring System: Continuous Monitor of

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

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: **Fig. 2-5, 2-8** [ ] 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)
   [X] Attached, Document ID: **SCA Section 3.3, Fig. 3-3-1, 3-3-2**

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)
   [X] Attached, Document ID: **Section 2.0** [ ] Previously Submitted, Date _____

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

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))
   [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   [ ] Attached, Document ID: _____ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. Identification of Applicable Requirements
   [ ] Attached, Document ID: _____
2. Compliance Assurance Monitoring
   [ ] Attached, Document ID: _____ [ ] Not Applicable
3. Alternative Methods of Operation
   [ ] Attached, Document ID: _____ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   [ ] Attached, Document ID: _____ [ ] Not Applicable
5. Acid Rain Part Application
   - [ ] Certificate of Representation (EPA Form No. 7610-1)
     - [ ] Copy Attached, Document ID:_
   - [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
     - [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   - [ ] Not Applicable

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Unit B fresh water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

3. Emissions Unit Identification Number: **033 (Unit B Cooling Tower)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Drift eliminators (015)

2. Control Device or Method Code(s): **015**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: ~~8,600~~**86,000** **gal/min**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **N/A** million Btu/hr,	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year

6. Operating Capacity/Schedule Comment:

Field 1 maximum process rate is the cooling tower water recirculation rate.

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **8,600 gal/min**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **N/A** million Btu/hr,	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	
Field 1 maximum process rate is the cooling tower water recirculation rate.	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Cooling Tower**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Cooling tower consists of 6 cells.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **64** feet	7. Exit Diameter: **34** feet
8. Exit Temperature: **N/A** °F	9. Actual Volumetric Flow Rate: **N/A** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet	
13. Emission Point UTM Coordinates Zone: East (km): **N/A** North (km): **N/A**	14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)	
15. Emission Point Comment: **Cooling tower consists of 6 cells with 6 individual exhaust fans. Stack height and diameter data provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.**		

EMISSIONS UNIT INFORMATION
Section [4] of [5]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Cooling Tower – process cooling, mechanical draft**		
2. Source Classification Code (SCC): **3-85-001-01**	3. SCC Units: **Million gallons throughput**	
4. Maximum Hourly Rate: ~~0.52~~5.16	5. Maximum Annual Rate: ~~4,520~~45,202	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Cooling Tower – process cooling, mechanical draft**		
2. Source Classification Code (SCC): **3-85-001-01**	3. SCC Units: **Million gallons throughput**	
4. Maximum Hourly Rate: **0.52**	5. Maximum Annual Rate: **4,520**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – PM	**015**		**NS**
2 – PM10	**015**		**NS**
Notes:	**015 – mist eliminators**		**NS – no standard**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: ~~0.32~~3.2 lb/hour ~~1.4~~14.0 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.002-percent drift loss**	4. Equivalent Allowable Emissions: ~~0.32~~3.2 lb/hour ~~1.4~~14.0 tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: ~~0.13~~1.3 lb/hour ~~0.6~~5.8 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.002-percent drift loss**	4. Equivalent Allowable Emissions: ~~0.13~~1.3 lb/hour ~~0.6~~5.8 tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.32** lb/hour **1.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.002-percent drift loss**	4. Equivalent Allowable Emissions: **0.32** lb/hour **1.4** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.13** lb/hour **0.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **N/A** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.002-percent drift loss**	4. Equivalent Allowable Emissions: **0.13** lb/hour **0.6** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

Complete 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 Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment	

H. CONTINUOUS MONITOR INFORMATION NOT APPLICABLE

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

Continuous Monitoring System: Continuous Monitor of

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

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: **Fig. 2-5, 2-8** [ ] 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)
   [X] Attached, Document ID: **SCA Section 3.3, Fig. 3-3-1, 3-3-2**

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)
   [X] Attached, Document ID: **Section 5.0** [ ] Previously Submitted, Date _____

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

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))
   [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   [ ] Attached, Document ID: _____ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. Identification of Applicable Requirements
   [ ] Attached, Document ID: _____
2. Compliance Assurance Monitoring
   [ ] Attached, Document ID: _____ [ ] Not Applicable
3. Alternative Methods of Operation
   [ ] Attached, Document ID: _____ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   [ ] Attached, Document ID: _____ [ ] Not Applicable
5. Acid Rain Part Application
   [ ] Certificate of Representation (EPA Form No. 7610-1)
      [ ] Copy Attached, Document ID:
   [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Not Applicable

EMISSIONS UNIT INFORMATION
Section [4] of [5]

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Unit B material (coal and gasification ash) storage and handling. Activities include coal receiving, coal pile storage, coal conveying and transfer, coal crushing, crushed coal storage (silos and bins), and gasification ash storage (silo).

3. Emissions Unit Identification Number: **034 (Unit B Material Handling and Storage)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Coal Pile - Dust suppression by water sprays, as necessary (061)

Coal Receiving, Conveying, Transfer, and Crushing - Enclosure (054)

Coal and Gasification Ash Storage Silos – Fabric Filter (018)

2. Control Device or Method Code(s): **061, 054, 018**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **137 ton/hr (gasifier coal feed rate)**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **N/A** million Btu/hr,	
4. Maximum Incineration Rate: **N/A** pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	

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: **Material Handling**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Emission points include coal receiving, coal storage pile, coal conveying and transfer, coal crushing, crushed coal storage (silos and bins), and gasification ash storage (silo).**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **F, V**	6. Stack Height: **92** feet	7. Exit Diameter: **1.5** feet
8. Exit Temperature: **70** °F	9. Actual Volumetric Flow Rate: **2,500** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet	
13. Emission Point UTM Coordinates Zone: East (km): **N/A** North (km): **N/A**	14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)	
15. Emission Point Comment: **Representative stack data provided in Fields 6, 7, and 8 are for the crushed coal storage bins. Further information regarding the material handling point source stack parameters is provided in Section 2.0, Table 2-10.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **Coal Input to Gasifiers**		
2. Source Classification Code (SCC): **3-05-102-03**	3. SCC Units: **Tons Transferred**	
4. Maximum Hourly Rate: **137**	5. Maximum Annual Rate: **41,200,120**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – PM	**061, 054, 018**		**NS**
2 – PM10	**061, 054, 018**		**NS**
Notes:	**061 – dust suppression by water sprays** **054 – enclosure** **018 – fabric filter**		**NS – no standard**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **3.4** lb/hour **15.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **1.0** to **2.0** tons/year	
6. Emission Factor: **0.020 gr/scf (storage silo baghouses)** Reference: **Engineering Estimate**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential emission rates shown in Field 3 represent estimated PM/PM10 emissions from the coal and gasification storage silo baghouses.** **Fugitive emission estimates shown in Field 5 estimated PM/PM10 emissions from the coal storage pile.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Good Operating Practices**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **The specific controls proposed for the material storage and handling emission sources are discussed in Section 5.2.3.**	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

Complete 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 Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment	

H. CONTINUOUS MONITOR INFORMATION NOT APPLICABLE

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

Continuous Monitoring System: Continuous Monitor of

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

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: **Fig. 2-5, 2-8** [ ] 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)
   [X] Attached, Document ID: **SCA Section 3.3, Fig. 3-3-1, 3-3-2**

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)
   [X] Attached, Document ID: **Section 5.0** [ ] Previously Submitted, Date _____

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

EMISSIONS UNIT INFORMATION
Section [5] of [5]

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))
   [x] Attached, Document ID: **Section 5.0** [ ] Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   [x] Attached, Document ID: **Section 6.0** [ ] Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   [ ] Attached, Document ID: _____ [x] Not Applicable

Additional Requirements for Title V Air Operation Permit Applications NOT APPLICABLE

1. Identification of Applicable Requirements
   [ ] Attached, Document ID: _____
2. Compliance Assurance Monitoring
   [ ] Attached, Document ID: _____ [ ] Not Applicable
3. Alternative Methods of Operation
   [ ] Attached, Document ID: _____ [ ] Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   [ ] Attached, Document ID: _____ [ ] Not Applicable
5. Acid Rain Part Application
   [ ] Certificate of Representation (EPA Form No. 7610-1)
      [ ] Copy Attached, Document ID:
   [ ] Acid Rain Part (Form No. 62-210.900(1)(a))
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date: _____
   [ ] Not Applicable

Additional Requirements Comment

APPENDIX C

DISPERSION MODELING FILES

Air quality dispersion modeling files have been provided to the Florida Department of Environmental Protection.

Stanton Unit B IGCC Project
Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
SCREEN3	14	Y-NG.DAT	SCREEN3 Input Files - Natural Gas Cases 1 - 14
	14	Y-NG.OUT	SCREEN3 Output Files - Natural Gas Cases 1 - 14
		Y = 1 - 14	
	11	X-SYN.DAT	SCREEN3 Input Files - Syngas Cases 1 - 11
	11	X-SYN.OUT	SCREEN3 Output Files - Syngas Cases 1 - 11
		X = 1 - 11	
Subtotal Files	50		
MET DATA/ AERMOD MET DATA	10	STANTYY.PFL	Meteorological Data - Orlando/Ruskin profile files
		STANTYY.SFC	Meteorological Data - Orlando/Ruskin surface with PBL parameters files
		YY = 96 - 00	
MET DATA/ CALPUFF SCREEN ISC MET DATA	5	STAYYCAL.MET	Meteorological Data - Orlando/Ruskin, 1996 - 2000
		YY = 96 - 00	
GEP	1	UNIT B.BPI	Building Profile Input Program (BPIP) input file
	1	UNIT B.BPO	Building Profile Input Program (BPIP) output file - brief
	1	UNIT B.SUM	Building Profile Input Program (BPIP) output file - detailed
Subtotal Files	3		
AERMOD	5	UBYYNOx.APN	AERMOD input files, Case 6 Syngas Annual NO_x
	5	UBYYNOx.APO	AERMOD output files, Case 6 Syngas Annual NO_x
	5	UBYYPM.APN	AERMOD input files, Case 10 Syngas 24-Hour & Annual PM_{10}
	5	UBYYPM.APO	AERMOD output files, Case 10 Syngas 24-Hour & Annual PM_{10}
	5	UBYYC10.APN	AERMOD input files, Case 10 Syngas 1-, 3-, 8-, and 24-Hour & Annual
	5	UBYYC10.APO	AERMOD input files, Case 10 Syngas 1-, 3-, 8-, and 24-Hour & Annual
		YY = 96 - 00	
Subtotal Files	30		
CALPUFF/PUFF-INP	5	BYY.INP	CALPUFF input files
		YY = 96 - 00	
CALPUFF/PUFF-OUT	5	BYY.CON	CALPUFF output concentration files
	5	BYY.LST	CALPUFF output concentration list files
	5	BDFXYY.DAT	CALPUFF output dry deposition flux files
	5	BWFXYY.DAT	CALPUFF output wet deposition flux files
		YY = 96 - 00	
Subtotal Files	20		
CALPUFF/POST-UTIL	5	UTILYYDEP.INP	POSTUTIL input total deposition flux files
	5	UTILYYDEP.LST	POSTUTIL output total deposition flux list files
	5	BTFLXYY.DAT	POSTUTIL output total dry and wet deposition flux files
		YY = 96 - 00	
Subtotal Files	15		
CALPUFF/POST-INP	5	YYNDEP.POI	CALPOST input nitrogen deposition files
	5	YYSDEP.POI	CALPOST input sulfur deposition files
	5	YYPM.POI	CALPOST input PM_{10} files
	5	YYSO2.POI	CALPOST input SO_2 files
	5	YYNO2.POI	CALPOST input NO_2 files
	5	YYVIS.POI	CALPOST input regional haze files
		YY = 96 - 00	
Subtotal Files	30		
CALPUFF/POST-OUT	5	YYNDEP.POL	CALPOST input nitrogen deposition files
	5	YYSDEP.POL	CALPOST input sulfur deposition files
	5	YYPM.POL	CALPOST input PM_{10} files
	5	YYSO2.POL	CALPOST input SO_2 files
	5	YYNO2.POL	CALPOST input NO_2 files
	5	YYVIS.POL	CALPOST input regional haze files
		YY = 96 - 00	
Subtotal Files	30		
Total Files	198		

Source: ECT, 2006.