Prevention of Significant Air Quality Deterioration Review of Southern LNG Inc. – Elba Island LNG Terminal Located near Savannah, Georgia (Chatham County)

PRELIMINARY DETERMINATION
SIP and Title V Permit Application No. TV-16697
February 2007

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program (SSPP)
Prepared by
Jeng-Hon Su – Combustion Unit
Modeling Approved by: Richard Monteith Data and Modeling Unit
Reviewed and Approved by:
John Yntema – Combustion Unit Coordinator James Capp – SSPP Manager
Heather Abrams – Chief, Air Protection Branch

SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Southern LNG, Inc. – Elba Island LNG Terminal for a permit to expand its Elba Island LNG Terminal (hereinafter the "Elba III Terminal Expansion") to meet the increased need for new natural gas delivery infrastructure to serve markets in the United States. The proposed project will include the construction and operation of six 121.4 MM Btu/hr natural gas fired liquefied natural gas (LNG) vaporizers with ID Nos. V009 – V014, two new LNG storage tanks with ID Nos. D-5 and D-6, each with a capacity of 1.25 million barrels of LNG, which is roughly equivalent to 4.2 billion cubic feet [Bcfe] of vaporized natural gas, one 11.74 MM Btu/hr natural gas fired heated vent stack heater with ID No. B002, and associated LNG pumps and piping.

The proposed project will result in increases in air pollutant emissions from the facility. The sources of these increases in emissions include the six new LNG vaporizers with ID Nos. V009 – V014 and the heated vent stack heater with ID No. B002.

The modification of the Southern LNG, Inc. Elba Island LNG Terminal due to this project will result in an emissions increase in nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter and particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM/PM_{10}), and volatile organic compounds (VOCs). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The NOx and CO emissions increases were above the PSD significant level thresholds.

Southern LNG, Inc. – Elba Island LNG Terminal is located in Chatham County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC) in accordance with Section 107 of the Clean Air Act, as amended August 1977.

The EPD review of the data submitted by Southern LNG, Inc. Elba Island LNG Terminal related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of NOx and CO, as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit Amendment should be issued to Southern LNG, Inc. Elba Island LNG Terminal for the Elba III Terminal Expansion. Various conditions are being incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A.

1.0 INTRODUCTION

On April 6, 2006, Southern LNG, Inc. Elba Island LNG Terminal (hereafter "the facility") submitted an application for an air quality permit for the Elba III Terminal Expansion. The facility is located at Elba Island near Savannah, Chatham County.

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1 below:

Table 1-1: Emissions Increases from the Project

Pollutant	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	6.04	25	No
PM_{10}	6.04	15	No
VOC	17.5	40	No
NO_X	123	40	Yes
CO	100	100	Yes
SO_2	1.91	40	No
TRS	N/A	10	No
Pb	N/A	0.6	No
Fluorides	N/A	3	No
H_2S	N/A	10	No
SAM	N/A	7	No

Since the Elba III Terminal Expansion only involves addition of new emission units and does not involve removal or modification of any existing emission unit, potential emissions increases in Table 1-1 only include potential emissions from the six new LNG vaporizers with ID Nos. V009 – V014 and the heated vent stack heater with ID No. B002. The facility did not submit any past actual emission data for this modification project.

Based on the information presented in Table 1-1 above, the facility's proposed modification, as specified in Georgia Air Quality Application No. TV-16697, is classified as a major modification under PSD because the potential emissions of NOx and CO exceed their corresponding PSD significant emission rates.

Through its new source review procedures, EPD has evaluated the facility's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

Facility (Permitting) History

The Elba Island LNG Terminal is an existing baseload LNG marine import terminal. It is linked to the eastern end of Southern Natural Gas Company's (SNG) pipeline system, which transports natural gas throughout the Southeast. Downstream of the Elba Island terminal, SNG has interconnections with the interstate pipelines of other natural gas companies.

Construction of the Elba Island LNG Terminal began in 1973, and it was commissioned for operation in 1978. Construction of emission sources (e.g., generator engines, turbines, heaters, and boilers) pre-dated air permitting requirements under State and Federal PSD requirements. In 1976, Southern LNG submitted an air permit application to EPD to construct the vaporizers prior to the facility being first commissioned for operation in July 1977. The facility also included three LNG tanks with ID Nos. D001, D002, and D003 with a combined capacity of 1,200,000 barrels (4 Bcfe vaporized natural gas equivalent). The air permit to construct the vaporizers was issued in September 1976, and a permit to operate the vaporizers was issued in March 1979.

Between 1978 and 1980, 55 shipments of LNG were received at Elba Island. Baseload import operations were suspended in 1980 due to a price dispute with the foreign supplier. The facility provided peaking service using the remaining inventory of LNG. After depleting the LNG inventory in 1982 through providing peaking services, the facility was operated in standby mode and maintained in a state of readiness for recommissioning as a baseload import terminal. The standby mode operations included maintaining a nitrogen purge on all cryogenic equipment, to prevent corrosion, and preventative maintenance for all combustion equipment.

In September 2000, Southern LNG submitted a PSD application to the Division to recommission the Elba Island LNG Terminal to meet a market need for additional supplies of natural gas service starting in 2001 (the Elba I Project). On January 24, 2001, EPD issued Air Quality Permit No. 4922-051-0003-P-01-0 to Southern LNG, Inc. for the construction and operation of five 88.1 MM Btu/hr natural gas fired vaporizers with ID Nos. V001 – V005, replacing the existing five vaporizers, and the reactivation of the LNG terminal. This permit established NOx and CO best available control technology (BACT) emission limits for the new vaporizers with ID Nos. V001 – V005. Initial startup of the recommissioned terminal was on December 1, 2001. The five new vaporizers with ID Nos. V001 – V005 provided a maximum combined sendout rate of 675 million cubic feet per day (MMcfd).

In May 2001, Southern LNG, Inc. submitted an application to the Division to allow the full-time operation of the existing reciprocating engines and gas turbines which power electrical generators. The facility had initially estimated that these units would operate no more than 500 hours per year, but later determined that they would operate more often, thus requiring this permitting. Permit Amendment No. 4922-051-0003-P-01-1 dated September 27, 2001 established NOx emission limits on these units to ensure that the ambient air quality modeling conducted in the initial PSD review would not be compromised.

In July 2002, the Division issued Permit Amendment No. 4922-051-0003-P-01-2, revising the NOx limit on the turbines from 0.4 pound per million Btu to 0.53 pound per million Btu because the performance testing demonstrated that the turbines could not meet 0.4 lb/MM Btu. To ensure that annual emissions could not exceed the modeled levels, a natural gas consumption limit for the turbines was established.

Southern LNG, Inc. submitted another PSD application (No. 13722) on April 15, 2002 for expanding operations at this facility (the Elba II Project) by installing three 121.4 MM Btu/hr natural gas fired vaporizers with ID Nos. V006 – V008, one 1,000,000 barrel (3.3 Bcfe of vaporized natural gas) LNG tank with ID No. TNK4, a marine slip, additional LNG unloading facilities, and associated LNG pumps and piping. The addition of the three vaporizers would give the facility a total of eight vaporizers, with a combined heat input capacity of 804.7 MM Btu/hr. The addition of the 1,000,000 barrel LNG tank would increase the total LNG storage capacity of the facility to 2,200,000 barrels (7.3 Bcfe of vaporized natural gas). The expansion project would enable the terminal to increase its "send out" capacity to 1,215 million cubic feet (MMcf) of vaporized natural gas per day. On February 27, 2003, EPD issued Permit Amendment No. 4922-051-0003-P-01-3 to Southern LNG, Inc. This permit amendment established NOx and CO BACT emission limits for the three vaporizers with ID Nos. V006 – V008. The new emission units included in the Elba II modification project began service on February 1, 2006.

Southern LNG, Inc. submitted their initial Title V permit application on November 18, 2002, and updated this application on June 30, 2003. The initial Title V permit (No. 4922-051-0003-V-02-0) was issued to Southern LNG, Inc. – Elba Island LNG Terminal on May 5, 2004.

The facility submitted a Title V minor modification, without construction, permit application (No. TV-16567) dated January 10, 2006 requesting the re-designation of the existing generator engines with ID Nos. G001 and G002 back to emergency generators (i.e., the operating hours for each engine driven generator would remain below 500 hours per twelve consecutive month period). Title V Permit Amendment No. 4922-051-0003-V-02-1 was issued on June 23, 2006. As a result of this modification, the facility-wide potential-to-emit (PTE) for every individual hazardous air pollutant (HAP) became less than 10 tpy and the PTE for total HAPs became less than 25 tpy. Thus, the facility became a minor source for single and combined HAPs.

Process Description

Baseload LNG import operations comprise three distinct processes: (1) unloading of LNG from cryogenic tankers; (2) storage of LNG; and (3) vaporization of LNG and sendout of natural gas to the interstate pipeline system.

LNG Unloading

LNG is transported in cryogenic tankers at its normal boiling point of –260°F and at a volume approximately 600 times less than its vaporized equivalent at ambient conditions. LNG is unloaded at the Elba Island LNG Terminal from cryogenic tankers via four chicksan unloading arms. A fifth chicksan arm is dedicated to vapor balance return service to the cryogenic tankers. All unloading pumps are maintained on the tanker and powered by the tanker's power source. Only a small quantity of VOC emissions results from the unloading process during normal operation because of the vapor balance system.

LNG Storage

LNG unloaded from the tankers is pumped into the three 400,000-barrel LNG storage tanks (ID Nos. D001 – D003) and one 1,000,000-barrel LNG storage tank (ID No. TNK4). The LNG storage tanks are aboveground and double-wall aluminum/steel tanks with a maximum operating pressure of 2 pounds per square inch gauge (psig). The LNG storage tanks are insulated and the boil-off of LNG vapors provides refrigeration to maintain LNG temperature in the tanks at –260°F. LNG vapors that boil off and gather in the vapor space of the tank are removed and delivered by a boil-off gas compressor driven by an electric motor to the downstream pipeline system or reliquefied and put back in the stream to be pumped and vaporized. No air emissions from the Elba Island LNG Terminal will result from the LNG storage process during normal operation.

LNG Vaporization and Sendout

Prior to delivery into the interstate pipeline system, the LNG must first be vaporized into gaseous natural gas, and then pumped at pipeline operating temperature and pressure for transmission. Electric motor-driven pumps are used to move LNG from the four LNG storage tanks (ID Nos. D001 – D003 and TNK4) to the eight natural gas fired vaporizers (ID Nos. V001 – V008). Vaporization is achieved as LNG is brought into indirect contact with a heated glycol-water solution. Vaporized natural gas exits the vaporizers and is delivered to a metering station at approximately 30 to 40°F, prior to send-out to the interstate pipeline system.

Each of the five vaporizers with ID Nos. V001 – V005 installed in 2001 as part of the Elba I Project comprises a natural gas fired submerged combustion device with a rated heat input rate of 88.1 MM Btu/hr. The combined vaporization capacity of these five vaporizers is approximately 675 MMcf of vaporized natural gas per day. As specified in existing Conditions 3.3.4 and 3.3.6 of the initial Title V Permit (No. 4922-051-0003-V-02-0), Vaporizers V001 – V005 are subject to NOx and CO BACT emission limits of 0.114 and 0.164 pounds per million Btu, respectively.

Each of the three vaporizers with ID Nos. V006 – V008 as part of Elba II Expansion Project comprises a natural gas fired submerged combustion device with a rated heat input rate of 121.4 MM Btu/hr. As specified in existing Conditions 3.3.5 and 3.3.6 of the initial Title V Permit (No. 4922-051-0003-V-02-0), Vaporizers V006 – V008 are subject to NOx and CO BACT emission limits of 0.08 and 0.164 pounds per million Btu, respectively. Each vaporizer with ID Nos. V006 – V008 has a vaporization capacity of 180 MMcf of vaporized natural gas per day. The combined additional vaporization capacity of these three vaporizers is approximately 540 MMcf of vaporized natural gas per day. Accordingly, the combined sendout capacity of the entire facility is currently 1.215 Bcfd, following commissioning of the Elba II Terminal Expansion in February 2006.

Auxiliary Equipment

Primary electrical power is provided to the island by the local utility, Georgia Power Company, McIntosh Steam-Electric Generating Plant, Rincon (previously Savannah Electric), and is delivered to a utility substation located on the South Channel side of the island near the bridge terminus. Transformers provide voltage reduction for uses throughout the facility. Southern LNG, Inc. uses natural gas fired generator sets to provide electric power for LNG operations during emergency conditions when electric power is not available from the commercial grid. The generator sets are driven by two 3,920 horsepower (hp) (each) 4 cycle, clean-burn, reciprocating internal combustion engines (RICEs) with ID Nos. G001 and G002 and two 3,800 hp (each) stationary gas turbines with ID Nos. G003 and G004. As discussed previously, Title V Permit Amendment No. 4922-051-0003-V-02-1 was issued on June 23, 2006 to re-classify G001 and G002 as emergency generators so that the operating hours for each engine driven generator would remain below 500 hours per twelve consecutive month period. When each turbine generator with ID Nos. G003 and G004 operates more than 500 hours during any twelve consecutive month period, according to existing Condition 3.2.2.b of the initial Title V Permit (No. 4922-051-0003-V-02-0), they are subject to a NOx emission limit of 0.53 pound per million Btu to assure the validity of the PSD NAAQS model. G003 and G004 are also subject to a combined annual natural gas consumption limit of 519.8 million cubic feet, which is specified in existing Condition 3.2.3 of the initial Title V Permit.

Additional auxiliary equipment operated at the facility includes two 1.25 MM Btu/hr (each) natural gas fired fuel gas heaters and one 11.7 MM Btu/hr natural gas fired heater used to heat gases that are occasionally vented from an LNG storage tank. Also, a 215 hp diesel fired water deluge pump for fire suppression is located at the facility, and a second, 700 hp diesel fired water deluge pump engine was installed for fire suppression, as part of the Elba II Expansion. A gasoline-fired air compressor is also used for utility purposes. It is anticipated that operations of the firewater pump and air compressors will not exceed 1,000 hours per year each since this equipment would be operated only during unusual emergency situations.

The air emissions of typical natural gas combustion products from operations of vaporizers, turbines, engines and auxiliary fuel burning equipment include NOx, CO, and VOC. There are emissions of PM_{10} and SO_2 but concentrations are very low due to the inherent clean-burning nature of natural gas, which fuels this equipment.

Proposed Modification

According to Application No. TV-16697, the facility's proposal for the Elba III Terminal Expansion Project includes the installation of six LNG vaporizers with ID Nos. V009 – V014, two new LNG storage tanks with ID Nos. D-5 and D-6, one 11.74 MM Btu/hr natural gas fired heated vent stack heater with ID No. B002, and associated LNG pumps and piping.

Each of the two new LNG storage tanks will provide an additional capacity of 1.25 million barrels of LNG, which is roughly equivalent to 4.2 billion cubic feet (Bcfe) of vaporized natural gas, to the terminal. After Tanks D-5 and D-6 are installed, the facility-wide LNG storage capacity will become 4,700,000 barrels (approximately 15.7 Bcfe of vaporized natural gas).

Each of the six vaporizers with ID Nos. V009 – V014, which are part of the Elba III Expansion Project, comprises a natural gas fired submerged combustion device with a rated heat input rate of 121.4 MM Btu/hr. Each vaporizer (ID Nos. V009 – V014) will have a vaporization capacity of 180 MMcf of vaporized natural gas per day. Because one of the six vaporizers will be maintained as a "hot spare," these vaporizers will add approximately 900 MMcfd of natural gas sendout capacity to bring the facility-wide vaporization capacity to approximately 2.115 Bcfd (2,115 MMcfd). Since Vaporizers V009 – V014 will be subject to the NOx emission standard specified in New Source Performance Standard (NSPS) Subpart Db, as well as NOx and CO BACT emission limits, the facility must use either a Continuous Emission Monitoring System (CEMS) or a Predictive Emission Monitoring System (PEMS) to monitor NOx and CO emissions.

The 11.74 MM Btu/hr natural gas fired heated vent stack heater with ID No. B002 will be used to heat gases that are occasionally vented from an LNG storage tank.

The facility's permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

Common Control Issue

U.S Environmental Protection Agency (U.S. EPA) and Georgia Environmental Protection Division (GA EPD) had meetings on March 23 and June 1, 2006. Both U.S. EPA and GA EPD were concerned about emissions from LNG unloading and vessel hoteling at berth. As discussed previously, all LNG unloading pumps are maintained on the tanker and powered by the tanker's power source. Initially, U.S. EPA and GA EPD believed that this Prevention of Significant Deterioration (PSD) application should include emissions from LNG unloading and vessel hoteling at berth and apply them, along with emissions from the new on-land emission units (ID Nos. V009 – V014 and B002), toward PSD applicability. Thus, the Division sent Southern LNG, Inc. a letter dated June 5, 2006, requesting that the facility update their Title V and PSD application and include vessel emissions at the berth.

In response, the facility submitted a letter dated July 26, 2006 and attached "Statement of Facts on Common Control," in which the facility claimed that the emissions from the vessels, while unloading LNG with its onboard equipment and hoteling, and the emissions from their land-based facility should not be aggregated for a PSD review because their land-based facility and the LNG ships at berth are not under "common control" and therefore should not be considered as one single source under Title V and PSD.

"Statement of Facts on Common Control" first provided basic background information of the facility, its clients, and the LNG ships. Then it discussed the common control issue and used the Georgia EPD's Site Determination Guidance to show why emissions from the vessels, while unloading LNG and hoteling, should not be included as part of the stationary source at the Elba Island LNG Terminal or modeled for permitting purposes. Below is an abstract of the information presented in "Statement of Facts on Common Control":

- According to Items 9 – 13 of the statement, Southern LNG Inc. (SLNG) operates an LNG import terminal under the Federal Energy Regulatory Commission's (FERC) regulations for open-access transportation of natural gas. Two companies, BG LNG Services LLC (BGLS) and Shell NA LNG LLC (SNALNG), are SLNG's main customers and own the natural gas. SLNG does not own the natural gas; it just transports and holds natural gas for BGLS and SNALNG.

- According to Items 18 – 21 of the statement, SLNG is a wholly owned subsidiary of Southern Natural Gas (SNG), which in turn is a wholly owned subsidiary of El Paso Corporation. Neither SLNG nor its parent companies own a controlling interest in or is under common control with BGLS or SNALNG.

- According to Items 17 and 23 – 26 of the statement, BGLS and SNALNG make their own arrangements to have their LNG transported to the Elba Island LNG Terminal. None of the LNG ships is owned, operated, or managed by SLNG. Although the parents of BGLS and SNALNG, BG Group Plc and Royal Dutch Shell Plc, may through separate subsidiaries in combination with other independent entities manage some of the LNG ships, the vast majority of the LNG ships are owned, operated, and managed by other entities.

- According to Items 35 – 83 of the statement, the facility used the scoring system in Georgia EPD's Site Determination Guidance and evaluated whether the SLNG Elba Island facility and the LNG ships (at berth) should be considered as one source. According to the information provided in the statement, the facility scored a total of zero (0) under the Common Control subcategory. Under the Common Control subcategory, since their score is less than 200, EPD guidance indicates that common control does not likely exist.

Although the Division may not agree with the facility's statement that the permitting history of SLNG has shown a settled practice between GA EPD and SLNG on vessel unloading/hoteling emissions, the Division agrees with the facility that there is no common control between Southern Natural Gas Inc. – Elba Island LNG Terminal and the LNG ships that deliver LNG to the terminal. Emissions from the LNG ships when unloading LNG and hoteling should not be considered toward PSD applicability nor included in SLNG's potential to emit.

However, emissions from the LNG ships when unloading LNG and hoteling must still be included in the modeling for ambient air quality reviews and additional impact analyses. These emissions are considered as secondary emissions. Secondary emissions mean emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. Since the proposed six new vaporizers and two new LNG storage tanks will increase the facility's LNG storage and natural gas sendout capacities, more LNG ships will be called to deliver more LNG. It is expected that emissions from unloading LNG and vessel hoteling will increase as a result of this proposed modification. In order to safeguard Georgian's health, safety, and welfare, additional modeling that includes both emissions from the facility's land-based facility and LNG vessels when unloading LNG and hoteling is required.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) specifies that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

The LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 are subject to Georgia Rule 391-3-1-.02(2)(d), "Fuel Burning Equipment."

Georgia Rule 391-3-1-.02(2)(d)3. limits the opacity of the emissions from the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 to twenty (20) percent. The allowable PM emission rates from the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 are specified by Georgia Rule 391-3-1-.02(2)(d)2.(ii), as follows:

$P = 0.5 * (10 / R)^{0.5}$

Where P equals the allowable PM emission rate in pounds per million BTU and R equals the heat input in million BTUs per hour.

At design heat input rates, the allowable particulate emission rates and calculations regarding the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 are shown in the following table.

ID No.	Heat Input Rate (R) (MM Btu/hr)	Allowable PM Emission Rate (P) (lbs PM / MM Btu heat input)	Fuel
V009	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
V010	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
V011	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
V012	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
V013	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
V014	121.4	$P = 0.5 * (10 / 121.4)^{0.5} = 0.144$	Natural Gas
B002	11.74	$P = 0.5 * (10 / 11.74)^{0.5} = 0.461$	Natural Gas

Compliance with Rule (d) is always expected because the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 fire natural gas only, and natural gas is considered a clean fuel.

Georgia Air Quality Rule 391-3-1-.02(2)(g)2 prohibits firing any fuel that contains greater than 2.5 percent sulfur, by weight, for fuel burning sources having a heat input below 100 MM Btu/hr. It also prohibits firing any fuel that contains greater than 3.0 percent sulfur, by weight, for fuel burning sources having a heat input of 100 MM Btu/hr or greater. Compliance with GA Rule (g) is always expected because the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 fire natural gas only, and natural gas contains minimal, negligible sulfur content.

Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation.

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[1] The first core requirement is that the determination must follow a "top-down" selection approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria and supported by the record and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing a top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[2] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward: if the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

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[1] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR 38272.

[2] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonberry, L.L.C., Rockingham County, New Hampshire, authored by the U.S. EPA Region I, Air Permits Program.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under review. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

As mentioned before, the Manual also requires available technologies to be applicable to the source type under construction before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally a sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow for an applicant to make a demonstration on the contrary. For example, an applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site, and operating problems related to the specific circumstances of the source) make a control technically infeasible.

According to the Environmental Appeals Board (see In re: Kawaihae Cogeneration Project, 7 E.A.D. 107 at page 1996, EAB 1997), the section on "collateral environmental impacts" of a proposed technology has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." The Appeals Board continues, "The Administration has explained that the primary purpose of the collateral impacts clause is… to temper the stringency of the technological requirements whenever one or more of the specified collateral impacts – energy, environmental, or economic – renders the use of the most effective technology inappropriate." Lastly, the Appeals Board states, "Unless it is demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology."

The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

- Step 1: Identification of all control technologies;
- Step 2: Elimination of technically infeasible options;
- Step 3: Ranking of remaining control technologies by control effectiveness;
- Step 4: Evaluation of the most effective controls and documentation of results; and
- Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

New Source Performance Standards

Federal Rule – 40 CFR 60 Subparts A and Db

The six 121.4 MM Btu/hr LNG vaporizers with ID Nos. V009 – V014 will be subject to New Source Performance Standards (NSPS) as found in 40 CFR Part 60, in particular Subpart A "General Provisions" and Subpart Db "Standards of Performance for Industrial Commercial Institutional Steam Generating Units."

Applicability: NSPS Subpart Db is an applicable requirement for the LNG vaporizers with ID Nos. V009 – V014 because each vaporizer will have a design heat input capacity greater than 100 MM Btu/hr and will be constructed after June 19, 1984.

Emission Standard: This NSPS specifies an emission standard for NOx and SO_2 from each LNG vaporizer with ID Nos. V009 – V014 as noted in the following table:

Pollutant	Standard	Legal Authority
NOx	86 ng/J (0.20 lb/MM Btu) based on a 30-day rolling average	40 CFR 60.44b(a)(1) 40 CFR 60.44b(i)
SO_2	87 ng/J (0.20 lb/MM Btu) on a 30-day rolling average	40 CFR 60.42b(k) 40 CFR 60.42b(e)

Note that the NOx emission standard was an existing NSPS Subpart Db requirement and was not modified after Subpart Db was amended on February 27, 2006.

Because NSPS Subpart Db was amended on February 27, 2006, the LNG vaporizers with ID Nos. V009 – V014 will be subject to the SO_2 emission standard specified in 40 CFR 60.42b(k) (0.20 lb/MM Btu) since they will be constructed after February 28, 2005 and will fire natural gas. The LNG vaporizers with ID Nos. V009 – V014 will potentially be subject to the PM emission standard specified in 40 CFR 60.43b(h)(1) (0.030 lb/MM Btu); however, 40 CFR 60.43b(h)(5) will exempt them from being subject to this PM standard because firing natural gas would emit less than 0.32 lb/MM Btu SO_2 as shown below. The LNG vaporizers with ID Nos. V009 – V014 will not be subject to the opacity standard specified in 40 CFR 60.43b(f) because they fire natural gas exclusively.

SO_2 Emission Factor (Natural Gas, U.S. EPA AP-42 Table 1.4-2) = 0.6 lbs/10^6 ft^3 N.G.

SO_2 Emission Rate
= (0.6 lbs/10^6 ft^3 N.G.) * (10^6 ft^3 N.G. / 1,020 MM Btu)
= 0.000588 lb SO_2 / MM Btu < 0.32 lb SO_2 / MM Btu

Compliance Demonstration:

NOx Emission Standard

40 CFR 60.46b(c) and (e) require the facility to demonstrate initial compliance with the NOx emission standard in an initial performance test during 30 successive vaporizer operating days. After the initial performance test is completed, 40 CFR 60.46b(e)(4) also requires the facility to determine compliance with the NOx emission standard through the use of a 30-day performance test upon request by the Division.

According to 40 CFR 60.48b(b) and 60.48b(g)(2), the facility must use a Continuous Emission Monitoring System (CEMS) to continuously monitor NOx emissions from the LNG vaporizers with ID Nos. V009 – V014. Upon request, the facility is allowed to use a NOx Predictive Emission Monitoring

System (PEMS) instead of a NOx CEMs. For the operation of the LNG vaporizers with ID Nos. V009 – V014, the facility will also be subject to other record keeping requirements specified in 40 CFR 60.49b.

SO2 Emission Standard

As discussed previously, the LNG vaporizers with ID Nos. V009 – V014 will fire natural gas exclusively, and firing natural gas would emit less than 0.32 lb/MM Btu SO_2. According to 40 CFR 60.45b(k), the facility may demonstrate compliance with the SO_2 emission standard by maintaining records of fuel supplier certifications of sulfur content of the fuel burned in the LNG vaporizers with ID Nos. V009 – V014. 40 CFR 60.47b(g) exempts the facility from conducting SO_2 emission monitoring if they maintain fuel supplier certifications.

Federal Rule – 40 CFR 60 Subparts A and Dc

The 11.74 MM Btu/hr natural gas fired heated vent stack heater with ID No. B002 will be subject to New Source Performance Standards (NSPS) as found in 40 CFR Part 60, in particular Subpart A "General Provisions" and Subpart Dc "Standards of Performance for Small Industrial Commercial Institutional Steam Generating Units."

Applicability: NSPS Subpart Dc is an applicable requirement for the heated vent stack heater with ID No. B002 because it will have a design heat input capacity of 100 MM Btu/hr or less, but greater than or equal to 10 MM Btu/hr, being constructed after June 9, 1989.

Emission Standard: NSPS Subpart Dc does not define any emission standard for the heated vent stack heater with ID No. B002 because of its small capacity and its firing natural gas only.

Compliance Demonstration: The Permittee is subject to the reporting and record keeping requirement of 40 CFR 60.48c(g). This portion of NSPS Subpart Dc requires the recording of the amount of fuel combusted in Heated Vent Stack Heater B002 during each calendar month because it fires natural gas exclusively.

Federal Rule – 40 CFR 60 Subpart Kb

40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessel (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, applies to storage tanks, based on the tank dimensions and the material being stored. After the amendment to 40 CFR 60 Subpart Kb was promulgated on October 15, 2003, 40 CFR 60.110b(a) specifies that Subpart Kb applies to each storage vessel with a capacity greater than 75 m3 (19,815 gallons) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. 40 CFR 60.110b(b) exempts any storage vessel with a capacity greater than 151 m3 (39,894 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). Although the capacity of the 1,250,000-barrel (approximately 52,500,000 gallons) LNG storage tanks (ID Nos. D-5 and D-6) is greater than 39,894 gallons, the true vapor pressure of LNG is much lower than 3.5 kPa; therefore, the new LNG storage tanks with ID Nos. D-5 and D-6 will not be subject to NSPS Subpart Kb.

National Emissions Standards For Hazardous Air Pollutants

None of the new equipment proposed in Application No. TV-16697 will be subject to any maximum available control technology (MACT) standard under 40 CFR Part 61.

As discussed previously, the facility submitted a Title V minor modification without construction permit application (No. TV-16567) dated January 10, 2006 requesting the re-designation of the existing generator engines with ID Nos. G001 and G002 to emergency generators. When the Title V Permit Amendment (No. 4922-051-0003-V-02-1) was issued, the facility became a minor source for single and combined HAPs. Therefore, none of the new equipment proposed in Application No. TV-16697 will be subject to any MACT standard under 40 CFR Part 63.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002 associated with the proposed project would most likely result from a malfunction of the equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

According to 40 CFR 60.42b(g) and 60.44b(h), the NSPS Subpart Db NOx and SO_2 emission limits apply at all times, including periods of startup, shutdown, and malfunction. According to a letter from EPA Region IV dated on January 12, 2001, the Clean Air Act definition of BACT with respect to the PSD program and the definition of BACT found in federal PSD regulations incorporated by reference in Georgia's rules [40 CFR 52.21(b)(12)] make no provision for excluding emissions occurring during startup and shutdown. It is also stated that startup and shutdown of process equipment are part of normal operation of a source and should be accounted for in the design and implementation, or the operating procedures, for the process and control equipment.

EPD has enforcement discretion to verify that[3]

- To the maximum extent practicable the air pollution control equipment, process equipment, or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;
- Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded;
- The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;
- All possible steps were taken to minimize the impact of the excess emissions on ambient air quality; and
- The excess emissions are not part of a recurring pattern indicative of inadequate design, operation, or maintenance.

[3] EPA Memorandum dated September 28, 1982 entitled, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions" from Kathleen M. Bennett to Regions I-X.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units onsite may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

Therefore, this applicability evaluation only addresses the LNG vaporizers with ID Nos. V009 – V014 and heated vent stack heater with ID No. B002, none of which employ any air pollution control devices; therefore, the CAM requirements are not triggered by the proposed modification.

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in increased emissions of a number of pollutants, including NOx, CO, VOC, PM/PM_{10}, and SO_2. However, only the increased emissions for NOx and CO are significant and trigger PSD review. These pollutants are emitted by the process equipment undergoing physical modifications under the proposed project.

LNG Vaporizers V009 – V014 - Background

Each of the LNG vaporizers with ID Nos. V009 – V014 comprises a natural gas fired submerged combustion device with a rated heat input rate of 121.4 MM Btu/hr. Southern LNG anticipates that these vaporizers will be placed in service not earlier than 2009 and not later than 2012.

A LNG submerged combustion vaporizer (SCV) is a unique type of indirect-fired heat exchanger. Each LNG SCV consists of a lone burner along with a heat exchanger coil contained in a single vessel in a water tank. It is designed to burn natural gas and discharge natural gas combustion products into a water bath which is used as the heat transfer medium for vaporizing LNG in the tube coil. The heat exchanger tube coil is immersed in the water tank above the exhaust gas sparger system. The exhaust gas/water mixture scrubs the surface of the tube coil at an extremely high velocity, resulting in a very high outside heat transfer coefficient. In base load applications, water bath and exhaust temperature are approximately 60°F.

In addition to SCV, Southern LNG also considered alternative vaporization technologies for the proposed Elba III Terminal Expansion Project during the initial design phase. Other technologies considered were open rack vaporizers (ORV) and shell and tube vaporizers (STV). ORV use ambient seawater as the source of heat to vaporize LNG. Emissions from the ORV process are minimal because it does not rely on combustion of fuel to vaporize LNG. However, water discharged from the ORV process would be up to 20°F cooler than the seawater; discharging the cooler water back to the sea would impact on the surrounding marine habitat. Therefore, ORV are typically limited to off-shore installations and are not technically feasible for the Elba Island LNG Terminal. In a STV system, heat is usually supplied to the LNG vaporizer by a closed circuit with a suitable heat transfer medium, often a glycol-water solution. STV are generally smaller in size compared to SCV or ORV. Similar to SCV, STV generate combustion emissions, and post-combustion control devices are typically installed on STV to reduce NOx and CO emissions. The primary drawback to STV is the reduced thermal efficiency as compared to SCV or ORV. Southern LNG estimates that STV would require at least double the fuel combustion to derive the necessary heat. The inefficiency of STV and associated excess fuel costs make STV an inferior alternative to SCV for LNG vaporization at Elba Island.

Primary emissions from the submerged combustion vaporizers with ID Nos. V009 – V014 are NOx, CO, VOC, PM/PM_{10}, and SO_2. Because only NOx and CO emissions increases from the vaporizers have triggered PSD applicability, only NOx and CO emissions were evaluated for Best Available Control Technology (BACT). The increase in VOC, PM/PM_{10}, and SO_2 emissions from the vaporizers that will result from the proposed modification does not exceed the PSD significant modification threshold; therefore VOC, PM/PM_{10}, and SO_2 emissions from the vaporizers were not evaluated for BACT-level controls. The following analysis applies to potential control technologies available for SCV systems.

LNG Vaporizers V009 – V014 – NOx Emissions

NOx is formed three different ways in combustion processes. The principal mechanism of NOx formation from firing natural gas is thermal NOx. Thermal NOx arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NOx is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature. A second mechanism which produces NOx is termed prompt NOx. Prompt NOx forms within the combustion flame and is usually negligible when compared to the amount of thermal NOx formed. The third NOx formation mechanism is termed fuel NOx, and fuel NOx stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen.

Natural gas has negligible fuel-bound nitrogen, so fuel NOx emissions from firing natural gas is negligible. Accordingly, virtually all NOx emissions from the operation of natural gas fired vaporizers with ID Nos. V009 – V014 will be thermal NOx.

Step 1: Identify all control technologies

Southern LNG considered NOx emissions control techniques/technologies as noted below.

Option 1: Selective Catalytic Reduction (SCR)
Option 2: Combustion Modifications
Option 3: Water or Steam Injection
Option 4: Good Combustion Practices

Option 1: Selective Catalytic Reduction (SCR)

SCR refers to the process whereby NOx is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because ammonia preferentially reacts with NOx rather than oxygen, although oxygen enhances the reaction and is a necessary component of the process. NOx emissions in the exhaust are reduced to nitrogen (N_2) and water vapor, while aqueous ammonia is oxidized to N_2. The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The optimum operating temperature for an SCR is 475 to 850°F. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NOx concentration, the temperature, the ammonia injection rate, and the type of catalyst. SCR units typically achieve 80% NOx reduction with an ammonia slip of 5 to 10 ppm.

Option 2: Combustion Modifications

Combustion modifications refer to the general approach of increasing the air/fuel ratio of the mixture prior to ignition so that the peak and average temperature within the combustor will be less than the temperature with a stoichiometric mixture. Decreasing the peak and average temperature in the combustor will decrease the formation of thermal NOx. Increasing the air/fuel ratio is most commonly achieved via two forms of combustion staging – lean/lean and rich/lean.

Two-stage lean/lean combustion is essentially *fuel-staged* combustion in which each sequential stage burns lean. Two-stage lean/lean combustion allows the unit to operate with an extremely lean mixture and with a stable flame that is not easily extinguished. Two-stage rich/lean combustion is essentially *air-staged* combustion in which the primary stage is operated rich while the secondary stage is operated lean. The fuel rich mixture will first produce lower temperatures compared to stoichiometric temperature along with higher concentrations of carbon monoxide (CO) and hydrogen (H_2) due to incomplete combustion. The fuel rich mixture decreases the amount of oxygen available for NOx generation as the increased H_2 and CO concentration would compete with the nitrogen for oxygen in the lean combustion air. Before entering the secondary combustion zone, the exhaust of the primary combustion zone is quenched by large amounts of air, thereby creating a lean mixture. The combustion of the lean mixture is then completed in the secondary zone. Stage-air and stage-fuel combustion modifications can achieve NOx reductions of up to 70%.

Option 3: Water or Steam Injection

Water or steam injection controls NOx emissions by increasing the thermal mass via dilution to reduce the adiabatic and peak flame temperature in the NOx forming regions as well as absorbing the latent heat of vaporization in the flame zone itself. The water or steam is typically injected at a water-to-fuel ratio of less than one. Depending on the initial NOx levels, water or steam injection could reduce NOx emissions by approximately 40%. However, both VOC and CO emissions are increased by large rates of water or steam injection. The choice between water and steam is usually driven by the availability of steam, as steam has fewer operational problems and a better heat rate. In addition, the required use of low mineral content water can be a significant cost item, as can be maintaining the reliability of water injection pumps under continuous operation for long periods of time.

Water injection for NOx control is an integral part of the T-Thermal Sub-X 120-180 "Single Burner" LNG vaporizers (ID Nos. V009 – V014) design philosophy. A single, mechanically atomized water injection nozzle is integral with the main fuel gas injector. It is designed to inject water together with the fuel gas so that the peak flame temperature may be reduced to minimize the kinetic rate conversion of atmospheric nitrogen to nitrogen oxides. The quantity of water injected is directly proportional to the flue gas-firing rate through the main flue gas injector. The control system maintains this set ratio through all firing ranges.

Option 4: Good Combustion Practices

Good combustion practices involve parametric monitoring to ensure the emission unit continually operates as close to optimum (i.e., minimum emissions) conditions as practicable. Potential control parameters include air/fuel ratio, fuel specification, and combustion temperature and pressure. Other aspects of good combustion practices include officially documented operating procedures which include provisions for startup, shutdown, and malfunctions; officially documented and adhered to maintenance procedures; routinely scheduled evaluations, inspections, and overhaul as appropriate; operating logs; and adequate personnel training on operating procedures.

Most good combustion practices have been developed not as pollution control options *per se* but as economic incentives to improve fuel efficiency and avoid costs associated with equipment failure. Good combustion practices are typically source-specific, site-specific, or both. In terms of source-specific practices, for example, all manufacturers provide their customers with preventative maintenance recommendations that specify a logical sequence of inspections and repair actions that are necessary to ensure good performance and to prevent equipment failures. Alternatively, site-specific good combustion practices are often developed relying on the extensive experience gained through years of operation to identify when changes in the monitored parameters indicate the need for maintenance. Good combustion practices are typically employed to maintain the particular combustion scenario (e.g., lean, ultra lean, air-staged, fuel-staged, stoichiometric, rich, etc.) desired. Finally, good combustion practices typically represent the baseline emissions scenario against which all add-on control options are assessed.

<u>Step 2: Eliminate technically infeasible options</u>

Option 1: Selective Catalytic Reduction (SCR)

As detailed above, the SCR process is very temperature sensitive with maximum NOx reduction occurring in the range of 475 to 850°F. The exhaust temperature of the LNG vaporizers is approximately 60°F, well below even the lowest temperature range at which the desired chemical reactions would take place. To raise the temperature of the exhaust gas stream to accommodate this control option would require duct burners whose own NOx emissions would largely negate any reductions in LNG vaporizer NOx emissions. Sound physical, chemical, and engineering principles preclude the successful use of SCR for LNG vaporizer NOx emission reduction and eliminate this control option from further consideration.

Option 2: Combustion Modifications

The most unique feature of the proposed vaporizers is the TX burner developed and patented by John Thurley in 1975 for use in submerged combustion applications. It uses a highly specialized extension of the vortex principle used in previous combustor designs over the years. The TX burner is of all metal construction with no refractory. It comprises an upper and lower volute connected by a conical center section. Combustion air is fed tangentially into the upper volute that is equipped with a two-stage pilot burner system. The main fuel/air is injected axially upwards from the lower volute and proper combustion takes place in the central conical section of the burner. The downward vortex motion of the combustion air, created by its tangential entry and spiral path around the periphery of the combustion section, keeps the metal skin cool. In addition, immersion of the whole of the lower volute and the majority of the conical section of the burner in the water bath, together with a system of water cooling arranged around the exposed part, enables a low burner skin operating temperature. The high rotational energy transmitted to the air by the upper volute design also aids complete combustion of the injected fuel.

Combustion modifications to reduce NOx emissions, such as staged fuel combustion, have not been applied to LNG SCV due to the process requirement for a tight vortex flame pattern. A tight vortex flame pattern is necessary in order to facilitate complete combustion in the compact combustion chamber (prior to immersion of the flue gases within the water bath) if problems with premature flame quenching are to be avoided. Sound physical, chemical, and engineering principles preclude the successful use of combustion modifications for LNG SCV NOx emission reduction and thus eliminate this control option from further consideration.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Table 4-1: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
Option 3	Water or Steam Injection	Variable due to design
Option 4	Good Combustion Practices	Variable due to design

Step 4: Evaluating the Most Effective Controls and Documentation

The top candidates for LNG SCV NOx control, water or steam injection and good combustion practices, cannot be shown to be inappropriate due to energy, environmental, and/or economic impacts and cannot be eliminated from further consideration.

Step 5: Selection of BACT

As noted earlier, the LNG SCV units proposed for the Elba Island LNG Terminal are unique emission units. The U.S. EPA RBLC search engine was utilized to review LNG SCV RACT/BACT/LAER determinations since 1992 for which a NOx control technology and corresponding NOx emission limit were established. One determination, corresponding to the Elba II Terminal Expansion permitted in 2002, was found. BACT for the SCV units installed as part of the 2002 expansion was determined to be 0.08 lb NOx per million Btu.

Although only one representative source was found in the RBLC, Southern LNG is aware that the Federal Energy Regulatory Commission (FERC) maintains a database of current and proposed LNG projects. As part of the FERC application process, each applicant is required to submit an Environmental Impact Statement (EIS). The EIS includes proposed emission rates from each source. Southern LNG reviewed information that is publicly available from the FERC.

Southern LNG submitted a summary of the reviewed data in Table 5-4 of the PSD application. The NOx emission data ranges from 0.0370 to 0.0800 lb NOx per million Btu, with one exception of 0.0243 lb/MM Btu. This 0.0243 lb/MM Btu NOx limit was proposed as BACT for the Cabrillo Port facility in California, which is generally regarded as Lowest Achievable Emission Rate (LAER) in other regions of the country. Note that the emissions data have not been verified with the source, and may not represent the final RACT/BACT/LAER limits established during the permitting processes, many of which are still ongoing. In fact, some of the proposed projects may not have received final permit limits from the Air permitting agency. Southern LNG believes that the FERC database represents the most current and reliable source of public information to research SCV emissions data and determine a technically feasible level for the Elba III Terminal Expansion Project. The Division found several records on FERC website that matched the list shown in Table 5-4. However, the Division could not verify the emission data due to lack of contact information. Since EPA's RBLC database includes only one determination, which is the Elba II determination, and NOx emission limits found in FERC database are all as stringent or more stringent than NOx BACT limit of the Elba II determination, the Division agrees with the facility to use the FERC database to research SCV emissions data and determine a technically feasible NOx emissions level for the Elba III Terminal Expansion Project.

As SCV is a specialized application, very few vendors have the expertise and resources to support Southern LNG's proposed expansion project. As the most effective remaining control option is water injection, which is integral to the SCV, Southern LNG contacted vendors and found that the lowest emissions performance specification was 30 ppmvd NOx at 3 percent oxygen. The facility could not find a lower emission rate than what the SCV vendor (with the lowest available NOx emission rate) provided. The BACT analysis for the pollutant (NOx) and emission unit (T-Thermal SUB-X 120-180 "Single Burner" LNG Vaporizer), which is now under review, establishes an equivalent NOx emission rate of 0.037 lb/MM Btu by using the equations listed in 40 CFR 60 Appendix A Method 20.

$$E = C_d * F_d * 20.9 / (20.9 - \%O_2) \qquad \text{Eq. 20-6}$$

Where,
- E = Mass Emission Rate of Pollutant (lb/MM Btu)
- C_d = Pollutant Concentration (lb/scf or ppm)
- Conversion Factor from ppm to lb/scf for NOx = $1.194 * 10^{-7}$
- F_d = 8,710 dscf / MM Btu (for natural gas)
- $\%O_2$ = 3 percent

$$E = 30 * 8{,}710 * 20.9 * 1.194 * 10^{-7} / (20.9 - 3) = 0.037 \text{ lb NOx/MM Btu}$$

Based on information collected from those SCV vendors, Southern LNG does not believe that a NOx emission rate below 30 ppmvd at 3 percent oxygen has been proven in practice. Although Southern LNG recognizes that SCV technology may improve over time, none of the vendors the facility contacted can commit to meet an emission performance specification that has not yet been proven in practice, and Southern LNG has determined this proposal does represent a technically feasible alternative at this time. Therefore, Southern LNG has determined that 0.037 lb NOx/MM Btu, which is equivalent to 30 ppmvd NOx at 3 percent oxygen, represents BACT for the proposed Elba III Terminal Expansion.

Conclusion – NOx Control

The Division has determined that Southern LNG's proposal to minimize the emissions of NOx by using water injection, which is integral to the SCV, as determined by top-down BACT, constitutes BACT. The Division has also determined the NOx BACT emission limit to be 0.037 lb NOx/MM Btu for the LNG vaporizers with ID Nos. V009- V014. According to the FERC SCV NOx RACT/BACT/LAER emission data provided in Table 5-4 of the PSD application (report), this 0.037 lb NOx/MM Btu BACT limit also matches the lowest (except the Cabrillo Port facility in California) of the NOx emission limits being currently proposed to FERC.

Summary – NOx Control Technology Review for LNG Vaporizers V009 – V014

To fulfill the PSD permitting requirements for NOx, a BACT analysis was conducted for the new LNG Vaporizers V009 – V014. The BACT selection for LNG Vaporizers V009 – V014 is summarized below in Table 4-2:

Table 4-2: BACT Summary for the Proposed New LNG Vaporizers V009 – V014

Pollutant	Control Technology	Proposed BACT Limit
NOx	Water Injection	0.037 lb NOx/MM Btu

LNG Vaporizers V009 – V014 – CO Emissions

CO emissions result from incomplete combustion due to insufficient residence time at a sufficiently high temperature to complete the final step in the hydrocarbon fuel oxidation. The oxidation of CO to carbon dioxide (CO_2) is a slow reaction compared to most hydrocarbon fuel oxidation reactions. For natural gas combustion sources, CO emissions are usually higher when the unit is run at low loads. Overall, minimum CO formation occurs at slightly lean air/fuel mixtures but increases rapidly with decreasing combustion temperature. Of course, NOx formation decreases rapidly with decreasing combustion temperature, making joint control of CO and NOx a technological challenge.

Step 1: Identify all control technologies

Southern LNG considered CO emissions control techniques/technologies as noted below.

Option 1: Catalytic Oxidation
Option 2: Good Combustion Practices

Option 1: Catalytic Oxidation

Catalytic oxidation involves passing the exhaust gas through a platinum catalyst bed and oxidizing CO to CO_2 and VOC to water (H_2O) and CO_2. As with SCR systems for NOx control, the catalytic oxidation process for CO control is very temperature sensitive with maximum CO reduction occurring in the range of 850 to 1,100°F to achieve 90 to 95 percent conversion of CO.

Option 2: Good Combustion Practices

Good combustion practices involve parametric monitoring and controlling the operating parameters of the LNG vaporizers to ensure the emission unit continually operates as close to optimum (i.e., minimum emissions) conditions as practicable. See Option 4 of NOx control technology for a more detailed description of good combustion practices.

Step 2: Eliminate technically infeasible options

Option 1: Catalytic Oxidation

As discussed above, the catalytic oxidation process is very temperature sensitive with maximum CO reduction occurring in the range of 850 to 1,100°F. The exhaust temperature of the LNG vaporizers is approximately 60°F, well below even the lowest temperature range at which the desired chemical reactions would take place. To raise the temperature of the exhaust gas stream to accommodate this control option would require duct burners whose own CO emissions would largely negate any reductions in LNG vaporizer CO emissions. Sound physical, chemical, and engineering principles preclude the successful use of catalytic oxidation for LNG vaporizer CO control and eliminate this control option from further consideration.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

Table 4-3: Ranking of Control Technology

Control Technology Ranking	Control Technology	Control Efficiency
Option 2	Good Combustion Practices	Variable due to Design

Step 4: Evaluating the Most Effective Controls and Documentation

The top and only candidate for LNG SCV CO control, good combustion practices, cannot be shown to be inappropriate due to energy, environmental, and/or economic impacts and cannot be eliminated from further consideration.

Step 5: Selection of BACT

As discussed earlier, the LNG SCV units proposed for the Elba Island LNG Terminal are unique emission units. The U.S. EPA RBLC search engine was utilized to review LNG SCV RACT/BACT/LAER determinations since 1992 for which a CO control technology and corresponding CO emission limit were established. One determination, corresponding to the Elba II Terminal Expansion permitted in 2002, was found. BACT for the SCV units installed as part of the 2002 expansion was determined to be 0.164 lb CO per million Btu.

Although only one representative source was found in the RBLC, Southern LNG is aware that FERC maintains a database of current and proposed LNG projects. As part of the FERC application process, each applicant is required to submit an Environmental Impact Statement (EIS). The EIS includes proposed emission rates from each source. Southern LNG reviewed information publicly available from FERC.

Southern LNG submitted a summary of the reviewed data in Table 5-7 of the PSD application. The CO emission data ranges from 0.0300 to 0.164 lb CO per million Btu, with one exception of 0.0182 lb/MM Btu. This 0.0182 lb/MM Btu CO limit was proposed as BACT for the Sempra Energy/Cameron LNG facility in Louisiana (previously known as Hackberry LNG). However, Southern LNG was not able to determine the basis or supporting documentation for the proposed CO emission rate. Note that the emissions data have not been verified with the source and may not represent the final RACT/BACT/LAER limit established during the permitting process. In fact, some of the proposed projects may not have received final permit limits from the Air permitting agency. Southern LNG believes that the FERC database represents the most current and reliable source of public information to research SCV emissions data and determine a technically feasible level for the Elba III Terminal Expansion Project. The Division found several records on FERC website that matched the list shown in Table 5-7. However, the Division could not verify the emission data due to lack of contact information. Since EPA's RBLC database includes only one determination, which is the Elba II determination, and CO emission limits found in FERC database are all as stringent or more stringent than CO BACT limit of the

Elba II determination, the Division agrees with the facility to use the FERC database to research SCV emissions data and determine a technically feasible CO emissions level for the Elba III Terminal Expansion Project.

As SCV is a specialized application, very few vendors have the expertise and resources to support Southern LNG's current expansion project. As the most effective remaining control option is good combustion practices, which is integral to the SCV, Southern LNG contacted vendors and found that the lowest emissions performance specification was 40 ppmvd CO at 3 percent oxygen. The facility could not find a lower emission rate than what the SCV vendor (with the lowest available CO emission rate) provided. The BACT analysis for the pollutant (CO) and emission unit (T-Thermal SUB-X 120-180 "Single Burner" LNG Vaporizer) under review establishes an equivalent CO emission rate of 0.030 lb/MM Btu by using the equations listed in 40 CFR 60 Appendix A Method 20.

$E = C_d * F_d * 20.9 / (20.9 - \%O_2)$ Eq. 20-6

Where, Conversion Factor from ppm to lb/scf for CO = $7.268 * 10^{-8}$
$\%O_2 = 3$ percent

$E = 40 * 8{,}710 * 20.9 * 7.268 * 10^{-8} / (20.9 – 3) = 0.030$ lb CO/MM Btu

Based on information collected from those SCV vendors, Southern LNG does not believe that CO emission below 40 ppmvd at 3 percent oxygen has been proven in practice. Although Southern LNG recognizes that SCV technology may improve over time, none of the vendors the facility contacted can commit to meet an emission performance specification that has not yet been proven in practice. Therefore, Southern LNG has determined that 0.030 lb CO/MM Btu, which is equivalent to 40 ppmvd CO at 3 percent oxygen, represents BACT for the proposed Elba III Terminal Expansion.

Conclusion – CO Control

The Division has determined that Southern LNG's proposal to minimize the emissions of CO by using good combustion practices, as determined by top-down BACT, constitutes BACT. The Division has also determined the CO BACT emission limit to be 0.030 lb CO/MM Btu for the LNG vaporizers with ID Nos. V009- V014. According to the FERC SCV CO RACT/BACT/LAER emission data provided in Table 5-7 of the PSD application (report), this 0.030 lb CO/MM Btu BACT limit also matches the lowest (except the Hackberry facility in Louisiana) of the CO emission limits being currently proposed to FERC.

Summary – CO Control Technology Review for LNG Vaporizers V009 – V014

To fulfill the PSD permitting requirements for CO, a BACT analysis was conducted for the new LNG Vaporizers V009 – V014. The BACT selection for the LNG Vaporizers V009 – V014 is summarized below in Table 4-4:

Table 4-4: BACT Summary for the Proposed New LNG Vaporizers V009 – V014

Pollutant	Control Technology	Proposed BACT Limit
CO	Good Combustion Practices	0.030 lb CO/MM Btu

Heated Vent Stack Heater B002 - Background

In addition to the six vaporizers that will be installed as part of the Elba III Terminal Expansion project, Southern LNG will also install a heated vent stack heater with ID No. B002. This unit is a small boiler (11.74 MM Btu/hr) fired on natural gas exclusively and used to heat a glycol solution for warming natural gas in the event of an emergency situation. Emissions from Heated Vent Stack Heater B002 will be less than 5 tpy of any pollutant under anticipated utilization. Given the small quantity of emissions, use of add-on controls would be cost prohibitive for this unit. RBLC entries for similar units show good design/operation as BACT for all pollutants. Therefore, Southern LNG proposed good design/operation as BACT for Heated Vent Stack Heater B002 for all pollutants. This unit is not considered further in this analysis.

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

As discussed in Section 4.0 of this preliminary determination, LNG Vaporizers with ID Nos. V009 – V014 will be subject to a NOx BACT limit of 0.037 lb/mm Btu and a CO BACT limit of 0.030 lb/MM Btu. Within 60 days after achieving the maximum production rate at which each LNG vaporizer with ID Nos. V009 – V014 will be operated, but not later than 180 days after the initial startup, the facility will be required by new Conditions 4.2.7 and 4.2.8 to conduct performance tests for the emissions of NOx and CO on each LNG vaporizer with ID Nos. V009 – V014 to demonstrate compliance with the corresponding BACT limits.

As discussed in Section 3.0 of this preliminary determination, LNG Vaporizers with ID Nos. V009 – V014 will be subject to NSPS Subpart Db. 40 CFR 60.46b(c) and (e) requires the facility to demonstrate initial compliance with the NOx emission standard in an initial performance test during 30 successive vaporizer operating days. After the initial performance test is completed, 40 CFR 60.46b(e)(4) also requires the facility to determine compliance with the NOx emission standard through the use of a 30-day performance test upon request by the Division. These testing requirements have been included in new Condition 4.2.9.

Monitoring Requirements:

According to 40 CFR 60.48b(b) and 60.48b(g)(2), the facility must use either a Continuous Emission Monitoring System (CEMS) or a Predictive Emission Monitoring System (PEMS) to continuously monitor NOx emissions from the LNG vaporizers with ID Nos. V009 – V014. This monitoring protocol is required in order to ensure the continuous compliance with NSPS Subpart Db NOx emission limit (0.20 lb/MM Btu) specified in new Condition 3.3.8.b and has been included in new Condition 5.2.8.a.

LNG Vaporizers with ID Nos. V009 – V014 will be subject to the NOx BACT limit (0.037 lb/MM Btu) specified in new Condition 3.3.9.a. Data generated by the CEMS or PEMS required by new Condition 5.2.8.a is also to be used to ensure the continuous compliance with this NOx BACT limit.

LNG Vaporizers with ID Nos. V009 – V014 will be subject to the CO BACT limit (0.030 lb/MM Btu) specified in new Condition 3.3.9.b. The facility must also use either a CEMS or a PEMS to continuously monitor CO emissions from the LNG vaporizers with ID Nos. V009 – V014 for determining the continuous compliance with this CO BACT limit. The CO CEMS (or PEMS) has been required in new Condition 5.2.8.b.

If the facility chooses to use a PEMS to monitor NOx and/or CO emissions, they must calibrate their PEMS by conducting an annual Relative Accuracy Test Audit (RATA) on each PEMS as specified in Performance Specification 2 or 4A, as applicable, contained in the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**. Such RATA must be performed between January 16 and March 15 of each year. This requirement has been included in new Condition 5.2.8.c.

According to 40 CFR 60.49b(d), for the operations of LNG vaporizers with ID Nos. V009 – V014, the facility must record and maintain records of the amounts of each fuel combusted in each vaporizer during each day. Since these LNG vaporizers are capable of firing natural gas only, the facility must install, calibrate, maintain, and operate a natural gas consumption meter to continuously measure and record the quantity of natural gas, in cubic feet, burned in each LNG vaporizer with ID Nos. V009 – V014 during each day. This monitoring requirement has been included in new Condition 5.2.9.a.

As discussed previously, the facility is subject to the reporting and record keeping requirement of 40 CFR 60.48c(g) for the operation of Heated Vent Stack Heater B002. Therefore, the facility must install, calibrate, maintain, and operate a natural gas consumption meter to continuously measure and record the quantity of natural gas, in cubic feet, burned in Heated Vent Stack Heater B002. Data must be recorded for each calendar month. This monitoring requirement has been included in new Condition 5.2.9.b.

CAM Applicability:

As discussed in Section 3.0 of this preliminary determination, CAM is not applicable and is not being triggered by the proposed modification because none of the additional emission units (ID Nos. V009 – V014 and B002) involved in the Elba III Terminal Expansion project will be equipped with any add-on emission control devices. Therefore, no CAM provisions are being incorporated into the facility's permit.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5,}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the Elba Island LNG Terminal triggers PSD review for NO_2 and CO. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS for NO_2 and CO and PSD Increment standards for NO_2. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information submitted on September 1 and October 31, 2006.

Modeling Requirements

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*.

The proposed project will cause net emission increases of NO_2 and CO that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the NO_2 and CO emissions increases at the Elba Island LNG Terminal would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established monitoring significant level (MSL). The MSL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the MSL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. For the Elba III Terminal Expansion Project, the maximum impacts due to NO_2 and CO emission increases are assessed against the associated monitoring *de minimis* levels.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
NO_X	Annual	1	14
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS, listed in Table 6-2 below, are equivalent for NO_X, PM_{10}, and SO_2; no secondary NAAQS have been developed for CO.

Table 6-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
NO_X	Annual	100/100	0.053 / 0.053
CO	8-Hour	40,000/--	9 / None
	1-Hour	10,000/--	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the MSL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the Elba Island LNG Terminal, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for NO_X, SO_2, and PM_{10}; no increments have been established for CO. The PSD Increments are further broken into Class I, II, and III Increments. The Elba Island LNG Terminal is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
NO_X	Annual	2.5	25

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the MSL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline date has been set for NO_2 as April 12, 1991. Therefore, in Chatham County, emission changes at major sources since February 8, 1988, and at minor sources since April 12, 1991, are considered increment affecting for this analysis. Note that each county has its own minor source baseline date and minor sources in regional inventory are evaluated accordingly to determine whether they should be considered “Increment-affecting.”

Note that this PSD Increment Analysis includes potential emissions from all sources at the Elba Island LNG Terminal, not just those sources having NO_2 emission changes since the major source baseline date. Southern LNG conservatively modeled potential emissions from facility-wide sources in prior PSD analyses in 2000 and 2002 to demonstrate the impacts associated with the terminal following recommissioning of base load operation. Although modeling of all facility-wide sources was conducted, it should not be inferred from this analysis that NOx emission increases occurring before February 8, 1988 (e.g., other than from the LNG vaporizers with ID Nos. V001 – V014 constructed as part of the Elba I, Elba II, and Elba III Terminal Expansions) are increment consuming.

Modeling Methodology

Selection of Model

Two levels of air quality dispersion model sophistication exist: screening and refined dispersion modeling. Normally, screening modeling is first performed to determine the need for refined modeling. When results from a screening model indicate potentially adverse impacts, a refined modeling analysis is performed. A refined modeling analysis can provide a more accurate estimate of a source’s impact; it requires more detailed and precise input data than does a screening model. Given the magnitude of emissions increases from the proposed project, only refined modeling was used to predict impacts.

A refined dispersion model requires several data inputs, including the quantity of emissions, meteorological history, and the initial conditions (e.g., velocity, flowrate, and temperature) of the stack exhaust to the atmosphere. Building structures that obstruct wind flow near emission points might cause stack discharges to become caught in the turbulent wakes of these structures, leading to downwash of the plumes. In addition, wind blowing around a building creates zones of turbulence that are greater than if the building were absent. These effects of building downwash inhibit dispersion and generally cause higher ground level pollutant concentrations. Therefore, data regarding building configurations near emission sources are also input into the model.

The latest version (04269) of the **I**ndustrial **S**ource **C**omplex model with **P**lume **RI**se **M**odel **E**nhancements (ISC-PRIME) was selected for modeling in the Elba III Terminal Expansion project by Southern LNG. The PRIME algorithms have been coupled with the regulatory ISCST3 model (version 02035) to form the ISC-PRIME model. Elba I and II had used ISC-PRIME and had received approval from EPA Region IV by use of Alternative Model Guidance 40 CFR Part 51 Appendix W; therefore, no new approval was needed for this modeling exercise.

Treatment of Terrain

Topographical features of the area immediately surrounding the facility are not in complex terrain, but it is very close to sea level. Complex terrain is defined as any terrain elevation exceeding stacktop height. Complex terrain is further sub-categorized into intermediate terrain (terrain elevation less than final plume rise height) and true complex terrain (terrain elevation greater than final plume rise height). A designation of terrain at a particular receptor is source dependent, since it depends on an individual source's release height. Because no complex terrain is located in the modeling domain, an evaluation of terrain types was not warranted for this analysis. The ISC-PRIME model was run in regulatory default mode with the elevated terrain heights option enabled.

Meteorological Data

The meteorological data used was from the surface station in Savannah, GA and the upper air station in Waycross, GA for the period from 1982 through 1986. The anemometer height at the Savannah National Weather Service (NWS) station during this period was 30 feet (9.144 meters).

Land Use Analysis

The land type near the facility needed to be classified as either urban or rural so that appropriate dispersion parameters could be used within the ISC-PRIME modeling analysis. Two land classification procedures, one based on land-use criteria and the other based on population density, can be used to determine the appropriate application of either urban or rural dispersion coefficients in a modeling analysis. Of the two, the land-use procedure is preferred by U.S. EPA.

As recommended by the Division for previous modeling analyses conducted at the facility, a simplified Auer land use analysis was performed for the area surrounding the facility by drawing a 3-km circle around the center of the facility (please refer to the area map provided in Appendix A of the permit application). Since over 50 percent of the land in the area within the 3-km radius is shown as undeveloped land on the USGS map, the land use was classified as rural for this analysis. Accordingly, rural dispersion coefficients and mixing heights were specified in the ISC-PRIME model.

Receptor Grids

In the air dispersion modeling analyses, ground-level concentrations were calculated within three discrete Cartesian receptor grids and at receptors placed along the property line. The property line receptors were spaced 50 meters apart, starting at an arbitrary point on the boundary. Southern LNG has determined that the mean low water boundary of Elba Island represents the boundary line. Southern LNG owns the entirety of Elba Island and limits public access to the island via a single controlled-access road and bridge. Unauthorized public access to Elba Island could only be gained by entering Southern LNG's property from the Savannah River or South Channel. Therefore, the ambient air boundary was determined to be the mean low water line and discrete receptors were modeled around this boundary accordingly.

The three Cartesian grids covered a region extending from all edges of the facility boundary to the point where impacts from the project were determined to be no longer significant. The receptor grids that were used in this analysis included the following:

1. A property line grid (or fine grid) consisting of evenly spaced receptors 50 meters apart that were placed along the respective facility boundary;

2. A fine grid containing receptors spaced 100 meters apart that extended one kilometer from the facility boundary, exclusive of on-site receptors;

3. A medium grid containing receptors spaced 500 meters apart that extend approximately five kilometers from the facility boundary, exclusive of on-site receptors;

4. A course grid containing receptors spaced 1,000 meters apart that extended ten kilometers from the facility boundary, exclusive of receptors on-site and on the fine grid.

Representation of Emission Sources

Coordinate System

In all PSD modeling analyses input and output files, the location of emission sources, structures, and receptors were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 km). The central location of the facility is approximately 501 km East and 3550 km North in Zone 17. Because the area of the facility where structures and emission units are located is flat, a single base elevation was used in the model data files for all sources. The base elevation for the facility is approximately 20 feet (6.1 meters) above sea level.

Source Types and Parameters

The ISCST3 dispersion model allows for emissions units to be represented as point, area, or volume sources. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses. There are several types of point sources at the facility, including unobstructed vertical, angled vertical, horizontal, and downward releases.

All point sources were modeled with actual stack parameters, except for gas exit velocity. For unobstructed vertical releases, the actual velocity was modeled. For point sources with angled vertical releases, only the vertical component of the exit velocity was modeled. For horizontal and downward releases, discharges were modeled at a velocity of 0.003 feet per second (0.001 meters per second), in accordance with U.S. EPA guidance. As a conservative representation of such sources, the actual stack diameter was modeled, and stack-tip downwash was enabled as a regulatory default option, even though U.S. EPA guidance suggests that such sources should be modeled by turning off stack-tip downwash. Using the default representation is more conservative, since the model will subtract from the physical release height of the source due to stack-tip downwash, even though the effect does not occur for horizontal stacks. A summary of source parameters used in the modeling analysis is included in Section 6 of the PSD application dated April 6, 2006, and additional information dated September 1, 2006 and October 31, 2006.

The emission rates modeled in the significance analysis were set equal to the emission increases associated with the Elba III Terminal Expansion project. The particulate matter emission rates calculated as part of the PSD permit application were refined to determine the PM10 fraction and to include the condensable particulate matter. Several other refinements were made to the particulate matter emissions calculations as well. Appendix C of the PSD application dated April 6, 2006 contains details of the revised emission increase calculations for the facility used in the analysis and lists the emission rates modeled in the significance analysis.

The emission rates modeled in the full impact analysis were set equal to the potential emissions of the facility, which were provided with the permit application. For this modeling analysis, the particulate matter emission rates calculated as part of the permit application were refined to determine the PM10 fraction and to include condensable particulate matter. Several other refinements were made to the particulate matter emission calculations and short-term potential emission rates where required. Detailed data on the potential emission rates modeled in the full impact analysis is provided in Appendix C of the PSD application dated April 6, 2006.

GEP Stack Height Analysis
The U.S. EPA has promulgated stack height regulations that restrict the use of stack heights in excess of "Good Engineering Practice" (GEP) in air dispersion modeling analyses. Under these regulations, that portion of a stack in excess of the GEP height is generally not creditable when modeling to determine source impacts. This requirement essentially prevents the use of excessively tall stacks to reduce ground level pollutant concentrations. In general, the lowest GEP stack height for any source is 65 meters by default. According to Section 6.2.7 of the PSD application dated April 6, 2006, there are no stacks at the facility whose height exceeds 65 meters. Therefore, no GEP stack height analysis was warranted and all point sources were modeled at their actual release heights.

Modeling Results

The Significance Analysis for NO_2 was conducted using the following approach. Emission increases from the Elba III Terminal Expansion project were modeled to determine the maximum off-site impact due to the project for each of five years of meteorological data evaluated. Potential emissions that reflect the proposed BACT limit were modeled in the Significance Analysis. Emission increases of CO from the Elba III Terminal Expansion project that reflect the proposed CO BACT limit were also modeled in the CO Significance Analysis to determine the maximum 1-hour and 8-hour average off-site impacts due to the new project.

Table 6-4 show that the proposed project will not cause ambient impacts of CO above the appropriate MSLs. Because CO emissions increases from the proposed project result in ambient impacts less than the MSLs, no further PSD analyses were conducted for CO.

However, ambient impacts above the MSL were predicted for NO_2 for the annual averaging periods, requiring NAAQS and Increment analyses be performed for NO_2.

Table 6-4: Class II Significance Analysis Results – Comparison to MSLs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
NO_2	Annual	**1986**	500.7	3550	5.404	1	Yes
CO	1-hour	**1984**	500.9	3550	184.2	2000	No
	8-hour	**1982**	501.0	3551	82.7	500	No

Data for worst year provided only.
Class II Significance Analysis results for NOx and CO found by GA EPD are different than the facility's finding because GA EPD used a property line grid consisting of evenly spaced receptors 100 meters apart.

Significant Impact Area
For any off-site pollutant impact calculated in the Significance Analysis that exceeds the MSL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding MSL was determined to be less than 2.5 kilometers for NO_2. To be conservative, regional source inventories for both of these pollutants were prepared for sources located within 52.5 kilometers of the facility.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Elba Island LNG Terminal requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD and South Carolina Department of Health and Environmental Control (DHEC). Elba Island LNG Terminal reviewed the data received and calculated the distance from the facility to each facility in the inventory. All sources more than 52.5 km outside the facility were excluded.

Note that the "20D Rule" was not used. Data from all facilities within 52.5 kilometers of the facility were used.

The regional source inventory used in the analysis is included in the permit application and the attached modeling report.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility, combined with the secondary emissions of vessels at berth and emissions of sources included in a regional source inventory, were modeled together. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the annual averaging period, the impact shown is the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO_2	Annual	**1986**	501	3550	21.94	13.3	35.24	100	No

Data for worst year provided only.

As indicated in Table 6-5 above, the total modeled impact for the annual averaging period for NO_2 does not exceed the corresponding NAAQS. All of the other total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was exceeded. The results are presented in Table 6-6.

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
NO_2	Annual	**1986**	501	3550	19.30	25	No

Data for worst year provided only

Table 6-6 demonstrates that the predicted impact is below the corresponding increment for NO_2 for annual averaging periods, even with the conservative modeling assumption that all NAAQS sources were Increment sources. This result demonstrates that Elba Island LNG Terminal, in conjunction with all other increment-affecting sources in the surrounding area, will not consume more than the available PSD NO_2 increment.

Ambient Monitoring Requirements

The impacts for NO_2 and CO quantified in Table 6-4 of the Class II Significance Analysis are also compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if pre-construction ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding *de minimis* concentrations, no pre-construction monitoring is required for NO_2 or CO.

Table 6-7: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	**1986**	500.9	3450	14	5.404	No
CO	1-hour	**1984**	500.9	3550.4	575	184.2	No

Data for worst year provided only

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

The three Class I areas within approximately 200 kilometers of the facility are the Wolf Island NWR, located approximately 85 kilometers south of the facility; Okefenokee NWR, located approximately 165 kilometers south-southwest of the facility; and Cape Romain NWR, located approximately 165 kilometers northeast of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of all three of these Class I areas.

In conducting the Class I Area Analysis, Southern LNG made an evaluation of major increment consuming and expanding sources at the facility. The results of this evaluation are presented in Tables 6-8 and 6-10 below:

Table 6-8: Summary of Major Increment-Consuming Sources

Emission Unit	Increment Consuming?	Emission Rates (tpy)
	NOx	NOx
Generator Engine G001	Yes	6.48
Generator Engine G002	Yes	6.48
Turbine Generator G003	Yes	93.0
Turbine Generator G004	Yes	93.0
LNG Vaporizer V001	Yes	44.0
LNG Vaporizer V002	Yes	44.0
LNG Vaporizer V003	Yes	44.0
LNG Vaporizer V004	Yes	44.0
LNG Vaporizer V005	Yes	44.0
LNG Vaporizer V006	Yes	42.5
LNG Vaporizer V007	Yes	42.5
LNG Vaporizer V008	Yes	42.5
LNG Vaporizer V009	Yes	19.7
LNG Vaporizer V010	Yes	19.7

Emission Unit	Increment Consuming?	Emission Rates (tpy)
	NOx	NOx
LNG Vaporizer V011	Yes	19.7
LNG Vaporizer V012	Yes	19.7
LNG Vaporizer V013	Yes	19.7
LNG Vaporizer V014	Yes	19.7
Fuel Gas Heater H001	Yes	0.520
Fuel Gas Heater H002	Yes	0.520
Heated Vent Stack Heater B001	Yes	4.89
Heated Vent Stack Heater B002	Yes	4.89
Fire Pump Engine X001	Yes	1.67
Fire Pump Engine X002	Yes	4.20
Air Compressor A001	Yes	0.00825
	Totals:	681

Table 6-9 below provides the information used to calculate potential emissions from the above major increment-consuming sources at Elba Island LNG Terminal. Since all emission units at Elba Island LNG Terminal are installed after the NOx major source baseline date (February 8, 1988), all of them are considered major increment-consuming sources.

Table 6-9: Data for Calculating Potential Emissions from Major Increment-Consuming Sources

ID No.	NOx Emission Factors/Limits	Capacity	Hours of Operation per Year	NOx PTE
G001	3 g/hp-hr	3,920 hp	500	6.48 tpy
G002	3 g/hp-hr	3,920 hp	500	6.48 tpy
G003	0.53 lb/MM Btu	40.07 MM Btu/hr	8,760	93.0 tpy
G004	0.53 lb/MM Btu	40.07 MM Btu/hr	8,760	93.0 tpy
V001	0.114 lb/MM Btu	88.1 MM Btu/hr	8,760	44.0 tpy
V002	0.114 lb/MM Btu	88.1 MM Btu/hr	8,760	44.0 tpy
V003	0.114 lb/MM Btu	88.1 MM Btu/hr	8,760	44.0 tpy
V004	0.114 lb/MM Btu	88.1 MM Btu/hr	8,760	44.0 tpy
V005	0.114 lb/MM Btu	88.1 MM Btu/hr	8,760	44.0 tpy
V006	0.08 lb/MM Btu	121.4 MM Btu/hr	8,760	42.5 tpy
V007	0.08 lb/MM Btu	121.4 MM Btu/hr	8,760	42.5 tpy
V008	0.08 lb/MM Btu	121.4 MM Btu/hr	8,760	42.5 tpy
V009	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
V010	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
V011	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
V012	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
V013	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
V014	0.037 lb/MM Btu	121.4 MM Btu/hr	8,760	19.7 tpy
H001	0.095 lb/MM Btu	1.25 MM Btu/hr	8,760	0.520 tpy
H002	0.095 lb/MM Btu	1.25 MM Btu/hr	8,760	0.520 tpy
B001	0.095 lb/MM Btu	11.74 MM Btu/hr	8,760	4.89 tpy
B002	0.095 lb/MM Btu	11.74 MM Btu/hr	8,760	4.89 tpy
X001	0.031 lb/hp-hr	215 hp	500	1.67 tpy
X002	0.024 lb/hp-hr	700 hp	500	1.67 tpy
A001	0.011 lb/hp-hr	15 hp	100	0.00825 tpy

Table 6-10: Summary of Major Increment-Expanding Sources

Emission Unit	Increment Expanding?	Emission Rates (tpy)
	NOx	NOx
N/A	N/A	N/A
	Totals:	N/A

Table 6-11 summarizes the net changes in increment consumption values since the NOx major baseline dates of February 8, 1988. As indicated in the table, since there was no increment expansion, the net change in increment-affecting emissions is positive for NOx. Therefore, the overall impact on air quality at nearby Class I areas due to emissions changes from the facility since the baseline dates to the completion of the Elba III Terminal Expansion project has shown increased emissions of NOx.

Table 6-11: Summary of Net Change in Increment Consumption

	Pollutant
	NOx
Increment-Consuming Emission Rates (tpy)	681
Increment-Expanding Emission Rates (tpy)	0
Net Increment Affecting Emissions (tpy)	681

<u>Model and Parameter Selection:</u>

The preferred model for analyzing long-range pollutant transport (i.e., distances greater than 50 kilometers) is the CALPUFF modeling system. The latest U.S. EPA-approved version (Version 040716) of the CALPUFF model was used to determine the possible impacts of the Elba III Terminal Expansion Project on Class I Increment and AQRV at the three identified Class I areas in the vicinity of the facility. The beta version of CALPUFF was used to avoid many known bugs in the preceding regulatory Version 030402. Most notably, the Class I analysis was conducted using a Lambert Conformal Coordinate (LCC) system representation, which is appropriate for a modeling domain of the size considered in this analysis. LCC system representation is not supported in the previous regulatory Version 030402.

CALPUFF is a multi-layer, multi-species, non-steady-state, Lagrangian puff model, which can simulate the effects of temporal and spatial-varying meteorological conditions on pollutant transport, transformation, and removal. For this refined analysis, meteorological fields generated by CALMET were used as inputs to the CALPUFF model to ensure that the effects of terrain and spatially varying surface characteristics on meteorology were considered.

In addition to the meteorological data, the CALPUFF model uses several other input files to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, and output options). The air quality modeling was performed using CALPUFF default options unless otherwise noted, as specified in the federal *Guideline* and IQAQM documents. During a telephone conference among Federal Land Management (FLM), GA EPD modelers, Southern LNG, and the facility's consultants in December 2005, FLM specified that the facility must use meteorological data of 1990, 1992, and 1996 in the CALPUFF model, as it was typical to use this data, until June 2006. Detailed information on the modeling domain, meteorological data, background concentrations, and model implementation are included in the Class I PSD Increment and Air Quality Related Values Analysis submitted with the permit application.

Results – Class I Significance Analysis Results

As indicated in Table 6-12 below, the significance level is not exceeded for any of the pollutants.

Table 6-12: Class I Significance Analysis Results – Comparison to MSLs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
NO_2	Annual (Wolf Island NWR)	**1996**	169	173	0.00210	0.1	No
NO_2	Annual (Okefenokee NWR)	**1992**	75	139	0.00313	0.1	No
NO_2	Annual (Cape Romain NWR)	**1992**	319	346	0.000521	0.1	No

Results – Class I Increment Analysis

The results of the Class I PSD Increment Analysis prepared by the Division are presented below in Table 6-13. The increment is not exceeded for any of the pollutants.

Table 6-13: Class I Increment Analysis Summary

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
NO_2	Annual (Wolf Island NWR)	**1996**	169	173	0.00809	2.5	No
NO_2	Annual (Okefenokee NWR)	**1992**	88	130	0.00120	2.5	No
NO_2	Annual (Cape Romain NWR)	**1992**	319	346	0.00201	2.5	No

Results – Deposition Analysis:

The maximum predicted sulfur and nitrogen depositions at the Wolf Island NWR, Okefenokee NWR, and Cape Romain NWR areas are presented in Table 6-14. The results of the deposition analysis show that the predicted sulfur and nitrogen deposition impacts are well below the threshold screening values.

Table 6-14: Sulfur and Nitrogen Deposition Impacts

Class I Area & Species	Deposition Assessment Threshold (kg/ha/yr)	1990 Modeled Deposition (kg/ha/yr)	1992 Modeled Deposition (kg/ha/yr)	1996 Modeled Deposition (kg/ha/yr)
Wolf Island NWR				
Total Sulfur	0.01	0.0000150	0.0000170	0.0000211
Total Nitrogen	0.01	0.000300	0.000350	0.000380
Okefenokee NWR				
Total Sulfur	0.01	0.00000520	0.00000800	0.00000680
Total Nitrogen	0.01	0.000130	0.000190	0.000150
Cape Romain NWR				
Total Sulfur	0.01	0.0000100	0.0000120	0.0000180
Total Nitrogen	0.01	0.000170	0.000220	0.000290

Results – Regional Haze Analysis

The 24-hour average visibility impacts predicted by Method 2 for the Wolf Island NWR, Okefenokee NWR, and Cape Romain NWR Class I areas are presented in Tables 6-15 and 6-16 below. Table 6-15 first presents the 24-hour average peak visibility change using the U.S. EPA background concentrations and Method 2 processing. These results indicate that the 5 percent threshold is not exceeded for the 24-hour averaging periods for Okefenokee NWR and Cape Romain NWR Areas. However, these results indicate that the 5 percent threshold is exceeded for the 24-hour averaging periods for Wolf Island NWR Area.

Table 6-15: Peak 24-Hour Average Visibility Degradation – Method 2

Class I Area & Metric	Critical Single Source Extinction Change	1990 Modeled Extinction Change	1992 Modeled Extinction Change	1996 Modeled Extinction Change	3-Year 98th Percentile
Wolf Island NWR					
Visibility Extinction (%)	5	6.9	4.4	5.5	
98th Percentile	5	2.2	1.3	2.2	1.9
Days Over 5% Threshold	--	3	0	2	
Okefenokee NWR					
Visibility Extinction (%)	5	2.9	4.7	1.4	
98th Percentile	5	0.78	0.64	0.49	0.64
Days Over 5% Threshold	--	0	0	0	
Cape Romain NWR					
Visibility Extinction (%)	5	1.2	0.94	1.2	
98th Percentile	5	0.53	0.52	0.45	0.50
Days Over 5% Threshold	--	0	0	0	

Table 6-15 then summarizes the same model results interpreted using the 98th percentile metric as promulgated by U.S. EPA for determination causation and contribution of visibility impairment under the Regional Haze Rule. There are no visibility impairment events exceeding 5 percent change at the 98th percentile for the three years of meteorological data modeled, indicating that the frequency and duration of the exceedances of the 24-hour averaging periods presented above in Table 6-15 is not significant.

Table 6-16 summarizes the model results processed using Method 7, which shows no exceedance of the 5 percent 24-hour average visibility for the Wolf Island NWR.

Table 6-16: Peak 24-Hour Average Visibility Degradation – Method 7

Class I Area & Metric	Critical Single Source Extinction Change	1990 Modeled Extinction Change	1992 Modeled Extinction Change	1996 Modeled Extinction Change
Wolf Island NWR				
Visibility Extinction (%)	5	1.10	2.50	4.99
Days Over 5% Threshold	--	0	0	0

Based on the results of the modeling presented in Tables 6-15 and 6-16 above, Southern LNG concluded and EPD confirmed that the facility does not cause or significantly contribute to visibility impairment at the Wolf Island NWR, Okefenokee NWR, and Cape Romain NWR Class I areas.

7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

The effect of a proposed project's emissions on local soils and vegetation is often addressed through comparison of modeled impacts to the secondary NAAQS. The secondary NAAQS were established to protect general public welfare and the environment. Impacts below the secondary NAAQS are assumed to indicate a lack of adverse impacts on soils and vegetation. As discussed in Part 6.0 of this determination, the modeled ambient impacts associated with the proposed project are below the MSLs. Therefore, no negative impacts on soils and vegetation are anticipated to result from the implementation of the proposed project.

Growth

The purpose of a growth analysis is to predict how much new growth is likely to occur as a result of the project and the resulting air quality impacts from this growth. No adverse impacts on growth are anticipated from the project since any workforce growth and associated residential and commercial growth that would be associated with the proposed project (expected to be minimal) would not cause a quantifiable impact on the air quality of the area surrounding the facility.

Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the facility, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the Elba Island LNG Terminal:

Table 7-1: List of "Sensitive Receptors" within the SIA of the Elba Island LNG Terminal

"Sensitive Receptors" Location	Distance to Elba Island LNG Terminal (km)
Wormsloe Historic Site	11.5
Savannah Hunter Army Airfield	13.3
Skidaway Island State Park	13.8
Savannah International Airport	18.9
Fort McAllister Historic Park	28.0
Hilton Head (SC) Airport	31.4
Beaufort County (SC) Airport	49.2

Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NO_X and PM_{10} emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and has determined that the visual impact criteria (*delta E* and *Contrast*) at the affected sensitive receptors are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area for the Class II area of interest, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

Table 7-2: VISCREEN Analysis Results

"Sensitive Receptors" Location	Result
Wormsloe Historic Site	Did not Pass Viscreen
Savannah Hunter Army Airfield	Did not Pass Viscreen
Skidaway Island State Park	Did not Pass Viscreen
Savannah International Airport	Passed Viscreen
Fort McAllister Historic Park	Passed Viscreen
Hilton Head (SC) Airport	Passed Viscreen
Beaufort County (SC) Airport	Passed Viscreen

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application, also shown in Table 7-2 above, and determined that the visual impact criteria (*delta E* and *Contrast*) at the affected sensitive receptors are exceeded at three of the sensitive receptors as a result of the proposed project. Therefore, a Level III analysis is required for these receptors. The following input parameters were modeled through PLUVUE II:

Table 7-3: LEVEL-3 PLUVUE-II ANALYSIS INPUT PARAMETERS

Parameter	Value	Reference/Comment
PLUVUE-II Run Title	Site-Specific	Sensitive receptor name
Wind Speed (mph)	Site-Specific	Worst case parameters determined in Level-2 VISCREEN analysis
Pasquill-Gifford Stability Class Index		
Index for Wind Speed Measurement Height	1	7 m above ground level
Mixing Depth (meters)	Time-of-day Dependent	10th percentile of rural mixing height values for 1982-1986 meteorological data set for selected times of day
Relative Humidity (percent)	Time-of-day and Season Dependent	Mean relative humidity for Savannah by month and time-of-day
Number of Downwind Distances Modeled	8	Chosen to assess plume visibility at locations near the source and at and beyond the sensitive receptor
Downwind Distances Modeled	1, 2.5, 5, 7.5, 10, 12.5, 15, and *x*	*x* denotes the distance of the sensitive receptor: Wormsloe Historic Site *x* = 11.5 km Savannah Hunter Army Airfield *x* = 13.3 km Skidaway Island State Park *x* = 13.8 km
Total SO_2 Emissions (tons per day)	6.23	Short-term potential emissions from stationary sources and vessels at berth
Total NO_x Emissions (tons per day)	4.47	
Total PM Emissions (tons per day)	0.60	
Flue Gas Flow Rate (acfm) per stack	67,332.1	Stack parameters for typical LNG Carrier since the majority of emissions come from these stacks
Flue Gas Exit Temperature (°F)	181.4	
Flue Gas Exhaust Velocity (meters per second)	14.00	
Stack Height (feet)	123.0	
Flue Gas Oxygen Content (mole percent)	3.0	Default value
Units	27	23 stationary source emission points plus four representative stacks for vessel operations
Ambient Temperature (°F)	52.5	Mean daily dry bulb temperature for February, May, August, and November, respectively, for Savannah
	73.2	
	81.1	
	58.2	
Ambient [NO_x] (parts per million)	0.045	Maximum observed concentrations reported in Georgia EPD's *2004 Ambient Air Surveillance Report* for Savannah, or where no monitors are located in Savannah, statewide
Ambient [NO_2] (parts per million)	0.017	
Ambient [O_3] (parts per million)	0.040 (default)	
Ambient [SO_2] (parts per million)	0.022	
Ambient [PM_{10}] (micrograms per cubic meter)	22.8	
Ambient Background Visual Range (km)	25.0	Savannah area reference value
UTM Coordinates and Elevation of Observer	495.3, 3539.3, 0	Wormsloe Historic Site
	495.8, 3536.5, 0	Skidaway Island State Park
	488.5, 3543.6, 0	Savannah Hunter Army Airfield
UTM Coordinates and Elevation of Source	500.4, 3549.5, 0	Elba Island LNG Terminal
Month and Day of Simulation	2/1	Multiple conditions simulated to represent Winter, Spring, Summer, and Fall
	5/1	
	8/1	
	11/1	
Time of Day	700	7am to represent "F" Stability Index 10am to represent "D" Stability Index
	1000	
	1300	
	1600	
Base Time Zone	5	During Standard Time (February and November)
	4	During Daylight Savings Time (May and August)
Terrain Elevations along Plume Trajectory (meters)	0.0	Flat Terrain Assumption

Parameter	Value	Reference/Comment
Distance to Background Terrain (km)	25.0	Set equivalent to background visual range
Wind Direction (azimuth degrees from which wind blows)	WNW, NW, NNW, N, NNE, NE, ENE, E, ESE, SE, SSE	Range of wind directions modeled to simulate various plume angles relative to observers

The plume was found to be delta E greater than 2 for 2.8% at Hunter Army Airfield and Wormsloe Historic Site & 3.4% at Skidaway Island State Park. The low percentages suggest that Elba III Terminal Expansion project will not have a significant impairment at any sensitive receptor.

Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program under the authority provided by the provisions of *Georgia Rules for Air Quality Control* 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*." The *Guideline* implies that a pollutant is identified as a TAP if any of the following toxicity determined values have been established for that pollutant:

- U.S. EPA Integrated Risk Information System (IRIS) reference concentration (RfC) or unit risk
- Occupational Safety and Health Administration (OSHA) Permissible Exposure Limits (PEL)
- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values (TLV)
- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limits (REL)
- Lethal Dose –50% (LD_{50}) Standards

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAPs evaluated are restricted to those that may increase due to the proposed project. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the fact that natural gas is fed to the main combustion sources at Elba Island LNG Terminal, and fuel oils are fed to some of the engines at Elba Island LNG Terminal and combustion sources in the vessels at berth; there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

AP-42 emission factors found in Chapters 1.3, 1.4, 3.1, 3.2, 3.3, and 3.4 are used to calculate TAP emissions from the onland facility and the vessels at berth.

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Southern LNG referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

Initial Screening Analysis Technique

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAPs, the analyses were initiated with the secondary screening technique.

Secondary Screening Analysis Technique

For those pollutants that do not pass the initial screening modeling, Georgia TAP Modeling Guidelines recommend additional screening prior to using ISCST3 refined modeling. The second screening technique involves modeling the particular pollutants from each appropriate stack and adding the impact results from each of the stacks. The total impact is then compared to the AAC. That is, a unit emission rate of 1 g/s was modeled from each stack (or representative stack). MGLC impacts from the unit emission rate were scaled using the actual emissions of a particular TAP from a particular stack for each of the modeled stacks using the equation shown below. The impacts from each stack for a particular TAP were added to reach a total impact, which was then compared to the AAC for that pollutant.

$$Q_2/Q_1 \times (X_1) = X_2$$

where:
Q_1 = the modeled stack emission rate (1 g/s)
Q_2 = the emission rate of individual TAP
X_1 = the MGLC for 1 g/s
X_2 = the MGLC for the individual TAP

For those impacts that were smaller than the pollutant AAC, no significant impact is anticipated, and further modeling was not necessary. For those pollutants that indicated a significant impact is possible, refined modeling was performed to further evaluate the potential for significant impacts. The majority of the TAPs screened out and did not require additional refined modeling.

Refined Modeling Methodology

For those pollutants indicating a possible significant impact during the secondary screening, a refined modeling analysis was performed using the modeling setup established for the criteria pollutant PSD modeling analysis. The methodology was the same as presented for the PSD modeling analysis except that downwash was excluded from the TAP analysis, per the Georgia EPD *Guideline*. The results of the modeling analyses of these toxic pollutants are presented in Table 7-4 below. The maximum impacts of all pollutants are below the applicable AAC.

Table 7-4: Toxic Air Pollutants Modeling Analyses

POLLUTANT	Chronic Averaging Period	Maximum Annual/24-hr Concentration (μg/m^3)	Annual/24-hr AAC (μg/m^3)	Max 15-Min Concentration (μg/m^3)	15-Min AAC (μg/m^3)
Acenaphthene	24 hour	2.20E-04	4.14E+01	N/A	N/A
Acenaphthylene	24 hour	3.90E-04	1.17E+02	N/A	N/A
Acetaldehyde	Annual	2.52E-03	4.55E+00	7.89E+00	4.50E+03
Acetylene	N/A	N/A	N/A	6.40E+01	2.66E+05
Acrolein	Annual	1.53E-03	2.00E-02	4.85E+00	2.30E+01
Anthracene	24 hour	1.40E-04	4.76E-01	N/A	N/A
Antimony	24 hour	2.83E-03	1.19E+00	N/A	N/A
Arsenic	Annual	3.00E-05	2.33E-04	4.69E-03	2.00E-01
Barium	24 hour	6.45E-03	1.19E+00	N/A	N/A
Benzene	Annual	9.50E-04	1.28E-01	4.15E-01	1.60E+03
Benz(a)anthracene	24 hour	1.20E-04	1.38E+01	N/A	N/A
Benzo(a)pyrene	24 hour	9.00E-05	4.76E-01	N/A	N/A
Benzo(b)fluoranthene	24 hour	2.00E-04	4.76E-01	N/A	N/A
Benzo(k)fluoranthene	24 hour	6.40E-04	4.76E-01	N/A	N/A
Beryllium	Annual	< 1.00E-06	4.17E-03	1.45E-04	5.00E-01
Biphenyl	24 hour	1.14E-02	2.38E+00	N/A	N/A
1,3-Butadiene	Annual	2.40E-04	3.57E-02	2.52E-01	1.11E+03
Butane	24 hour	2.04E+00	4.52E+03	N/A	N/A
Butyraldehyde	24 hour	1.71E-02	1.72E+02	N/A	N/A
Cadmium	Annual	1.60E-04	5.56E-03	1.29E-02	3.00E+01
Carbon Tetrachloride	Annual	1.00E-05	6.67E-01	3.47E-02	1.57E+04
Chlorobenzene	24 hour	1.28E-03	8.33E+02	N/A	N/A
Chloroethane	Annual	6.93E-03	1.00E+04	N/A	N/A
Chloroform	Annual	1.00E-05	4.35E-01	2.69E-02	2.40E+04
Chromium	24 hour	2.06E-03	2.38E+00	N/A	N/A
Chromium (VI)	Annual	< 1.00E-06	8.33E-05	8.84E-04	1.00E+01
Chrysene	24 hour	1.70E-04	4.76E-01	N/A	N/A
Cobalt	24 hour	3.27E-03	2.38E-01	N/A	N/A
Copper	24 hour	1.64E-03	2.38E-01	N/A	N/A
Cyclohexane	24 hour	1.04E-01	2.50E+03	5.60E-01	1.38E+05
Cyclopentane	24 hour	7.37E-02	4.10E+03	N/A	N/A
Dibenz(a,h)anthracene	24 hour	1.40E-04	1.61E+01	N/A	N/A
Dichlorobenzene	Annual	1.70E-04	8.00E+02	N/A	N/A
1,3-Dichloropropene	Annual	1.00E-05	2.50E+00	N/A	N/A
Ethylbenzene	Annual	6.00E-04	1.00E+03	4.12E-02	5.43E+04
Ethylene dibomide	Annual	1.00E-05	4.55E-02	4.18E-02	2.50E+04
Ethylene dichoride	Annual	1.00E-05	3.85E-01	2.23E-02	4.05E+04
Ethylidene dichloride	24 hour	9.90E-04	9.52E+02	N/A	N/A
Flourides (as F)	24 hour	2.01E-02	5.95E+00	N/A	N/A
Fluoranthene	24 hour	2.50E-04	4.76E-01	N/A	N/A
Formaldehyde	Annual	2.73E-01	7.69E-01	4.99E+01	2.45E+02

POLLUTANT	Chronic Averaging Period	Maximum Annual/24-hr Concentration (μg/m^3)	Annual/24-hr AAC (μg/m^3)	Max 15-Min Concentration (μg/m^3)	15-Min AAC (μg/m^3)
n-Hexane	Annual	1.53E-03	2.00E+02	N/A	N/A
Indeno(1,2,3-c)pyrene	24 hour	1.50E-04	4.76E-01	N/A	N/A
Isobutane	24 hour	5.46E-02	4.52E+03	N/A	N/A
Lead	24 hour	1.06E-03	1.19E-01	N/A	N/A
Manganese	Annual	7.00E-05	5.00E-02	1.07E-02	5.00E+02
Mercury	Annual	4.00E-05	3.00E-01	3.05E-03	1.00E+01
Methanol	24 hour	6.44E-01	6.19E+02	5.20E+00	3.28E+04
Methylcyclohexane	24 hour	3.11E-01	4.76E+03	N/A	N/A
Methylene Chloride	Annual	1.00E-05	2.13E+01	1.89E-02	4.34E+04
2-Methylnaphthalene	24 hour	1.43E-03	1.13E+02	N/A	N/A
Molybdenum	24 hour	1.70E-03	1.19E+01	N/A	N/A
Naphthalene	Annual	1.40E-04	3.00E+00	7.03E-02	7.90E+03
Nickel	Annual	6.30E-04	4.17E-03	N/A	N/A
n-Nonane	24 hour	2.98E-02	2.50E+03	N/A	N/A
n-Octane	24 hour	1.07E-01	5.60E+03	6.72E-01	1.80E+05
n-Pentane	24 hour	3.25E+00	7.02E+03	2.39E+01	1.80E+05
Phenanthrene	24 hour	1.72E-03	4.76E-01	N/A	N/A
Phenol	24 hour	1.79E-03	4.52E+01	2.27E-02	6.00E+03
Phosphorus	24 hour	5.11E-03	2.38E-01	N/A	N/A
Propane	24 hour	2.29E+00	4.29E+03	N/A	N/A
Propanol	24 hour	9.52E-03	1.19E+03	5.65E-02	6.14E+04
Propylene dichloride	Annual	1.00E-05	4.00E+00	2.54E-02	5.08E+04
Propylene oxide	Annual	1.00E-04	2.70E+00	N/A	N/A
Pyrene	24 hour	2.20E-04	4.76E-01	N/A	N/A
Selenium	24 hour	3.70E-04	4.76E-01	N/A	N/A
Styrene	Annual	1.32E-03	1.00E+03	1.11E-01	8.52E+04
1,1,2,2-Tetrachloroethane	Annual	1.00E-05	5.80E-01	N/A	N/A
Toluene	Annual	2.46E-03	4.00E+02	3.85E-01	1.13E+05
1,1,2-Trichloroethane	Annual	1.00E-05	1.60E-01	N/A	N/A
Trimethylamine	24 hour	< 1.00E-06	2.86E+01	< 1.00E-06	3.60E+03
1,2,3-Trimethylbenzene	24 hour	2.46E-02	2.93E+02	N/A	N/A
1,2,4-Trimethylbenzene	24 hour	2.46E-02	2.93E+02	N/A	N/A
1,3,5-Trimethylbenzene	24 hour	4.09E-02	2.93E+02	N/A	N/A
2,2,4-Trimethylpentane	24 hour	7.11E-02	3.45E+02	N/A	N/A
Vinyl Chloride	Annual	< 1.00E-06	2.27E-01	1.41E-02	1.39E+03
Xylenes	Annual	1.71E-03	1.00E+02	1.74E-01	1.71E-03

Maximum annual concentration result for formaldehyde found by GA EPD is different than the facility's finding because GA EPD used a property line grid consisting of evenly spaced receptors 100 meters apart.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4922-051-0003-V-02-2.

Section 1.0: Modification Description

Southern LNG Inc. – Elba Island LNG Terminal (hereinafter facility) proposes to expand the terminal (Elba III Terminal Expansion) to meet the increased need for new natural gas delivery infrastructure to serve markets in the United States. The proposed expansion will include the construction of six 121.4 MM Btu/hr natural gas fired liquefied natural gas (LNG) vaporizer boilers (ID Nos. V009 – V014), two LNG storage tanks (ID Nos. D-5 and D-6), an 11.74 MM Btu/hr natural gas fired heated vent stack heater (ID No. B002), and associated LNG pumps and piping. The facility anticipates that the Elba III Terminal Expansion will be placed in service between 2009 and 2012.

Section 2.0: Requirements Pertaining to the Entire Facility

No conditions in Section 2.0 are being added, deleted or modified as part of this permit action.

Section 3.0: Requirements for New Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
V009	LNG Vaporizer No. 9	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A
V010	LNG Vaporizer No. 10	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A
V011	LNG Vaporizer No. 11	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A
V012	LNG Vaporizer No. 12	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A
V013	LNG Vaporizer No. 13	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A
V014	LNG Vaporizer No. 14	40 CFR 60 Subpart A 40 CFR 60 Subpart Db 40 CFR 52.21 - BACT 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.8, 3.3.9, 3.4.5, 4.2.7, 4.2.8, 4.2.9, 5.2.8, 5.2.9.a, 6.2.6, 6.2.7, 6.2.8, 6.2.9.a, 6.2.10, 6.2.11	N/A	N/A

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	Description	Applicable Requirements/Standards	Corresponding Permit Conditions	ID No.	Description
B002	Heated Vent Stack Heater No. 2	40 CFR 60 Subpart A 40 CFR 60 Subpart Dc 391-3-1-.02(2)(d) 391-3-1-.02(2)(g)	3.2.4, 3.3.1, 3.3.2, 3.4.5, 5.2.9.b, 6.2.9.b	N/A	N/A

* Generally applicable requirements contained in this permit may also apply to emission units listed above.

New Condition 3.2.4 requires the facility to fire natural gas exclusively in LNG Vaporizers V009 – V014 and Heated Vent Stack Heater B002. The facility stated that LNG Vaporizers V009 – V014 and Heated Vent Stack Heater B002 are capable of firing natural gas only. The facility then conducted the NOx and CO BACT analysis based on firing natural gas only in these emission units, so if the facility ever wishes to fire any fuel other than natural gas in LNG Vaporizers V009 – V014 and/or Heated Vent Stack Heater B002, the facility must submit a Title V modification application that attaches additional BACT analyses including, but not necessarily limited to, NOx and CO emissions. Since natural gas contains a minimal and negligible concentration of sulfur, and LNG Vaporizers V009 – V014 and Heated Vent Stack Heater B002 can fire natural gas only, the citation block of this condition includes GA Rule 391-3-1-02(2)(g) as subsumed.

Existing Condition 3.3.1 subjects the existing LNG vaporizers with ID Nos. V001 – V008 to NSPS Subpart A. This condition has been modified to also include the new LNG vaporizers with ID Nos. V009 – V014 and Heated Vent Stack Heater No. 2 (ID No. B002).

Existing Condition 3.3.2 subjects the existing LNG vaporizers with ID Nos. V001 – V005 to NSPS Subpart Dc. This condition has been modified to also include Heated Vent Stack Heater No. 2 (ID No. B002). However, there are no applicable NSPS Subpart Dc emission or operating standards for a boiler of the size of Heated Vent Stack Heater No. 2 (ID No. B002).

As discussed in Section 3.0 of this preliminary determination, LNG Vaporizers V009 – V014 will be subject to the NSPS Subpart Db NOx and SO_2 emission limits, each on a 30 rolling day average basis. The NSPS Subpart Db NOx and SO_2 emission limits have been included in new Condition 3.3.8 of the proposed Title V permit amendment and PSD permit.

New Condition 3.3.9 includes both NOx and CO BACT limits for the LNG vaporizers with ID Nos. V009 – V014. Note that the NOx and CO BACT limits are 3-hour rolling average emission limits.

New Condition 3.4.5 contains the GA Rule 391-3-1-.02(2)(d) PM emission and opacity limits for the LNG vaporizers with ID Nos. V009 – V014 and Heated Vent Stack Heater No. 2 (ID No. B002).

Section 4.0: Requirements for Testing

As discussed in Sections 4.0 and 5.0 of this preliminary determination, LNG vaporizers with ID Nos. V009 – V014 will be subject to a NOx BACT limit of 0.037 lb/mm Btu and a CO BACT limit of 0.030 lb/MM Btu. Within 60 days after achieving the maximum production rate at which each LNG vaporizer with ID Nos. V009 – V014 will be operated, but not later than 180 days after the initial startup, the facility will be required by new Conditions 4.2.7 and 4.2.8 to conduct performance tests for the emissions of NOx and CO on each LNG vaporizer with ID Nos. V009 – V014 to demonstrate compliance with the corresponding BACT limits.

As discussed in Sections 3.0 and 5.0 of this preliminary determination, NSPS Subpart Db requires the facility to demonstrate initial compliance with the NSPS Subpart Db NOx emission standard in an initial performance test during 30 successive vaporizer operating days. After the initial performance test is completed, 40 CFR 60.46b(e)(4) also requires the facility to determine compliance with the NOx emission standard, through the use of a 30-day performance test, upon request by the Division. During periods when performance tests are not requested, the facility must calculate new 30-day rolling average NOx emissions rate every day per NSPS Subpart Db. These testing requirements have been included in new Condition 4.2.9.

Section 5.0: Requirements for Monitoring

As discussed in Section 5.0 of this preliminary determination, new Conditions 5.2.8.a and b require the facility to install, calibrate, maintain, and operate NOx and CO CEMS to continuously monitor NOx and CO emissions from each LNG vaporizer with ID Nos. V009 – V014. The facility is also allowed to use a PEMS instead of CEMS to continuously monitor NOx and CO emissions. If the facility chooses to use a CEMS, then new Condition 5.2.8.c requires the facility to perform daily calibration drift tests (assessments) and data accuracy assessments in accordance with Procedure 1 (Appendix F) of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants and 40 CFR Part 60. If the facility chooses to use a PEMS, then new Condition 5.2.8.d requires the facility to conduct a RATA on each PEMS between January 16 and March 15 of each year. This monitoring requirement is for determining whether the NOx emissions are in continuous compliance with the NSPS Subpart Db NOx emission limit specified in new Condition 3.3.8.b and whether the NOx and CO emissions are in continuous compliance with the NOx and CO BACT emission limits specified in new Conditions 3.3.9.a and b.

As discussed in Section 5.0 of this preliminary determination, new Condition 5.2.9.a requires the facility to continuously measure and record the quantity of natural gas, in cubic feet, burned in each LNG vaporizer with ID Nos. V009 – V014 during each day. This is an NSPS Subpart Db requirement.

As discussed in Section 5.0 of this preliminary determination, new Condition 5.2.9.b requires the facility to continuously measure and record the quantity of natural gas, in cubic feet, burned in Heated Vent Stack Heater B002. Data must be recorded for each calendar month. This is an NSPS Subpart Dc requirement.

Section 6.0: Other Record Keeping and Reporting Requirements

New Condition 6.1.7.a.ii defines an excess emission as any 30-day rolling average NOx emission rate, measured and recorded in accordance with new Condition 5.2.8, that is in excess of the limit in Condition 3.3.8.b (NSPS Subpart Db NOx emission limit) for any LNG Vaporizer with ID Nos. V009 – V014.

New Condition 6.1.7.b.iv defines an exceedance as any 3-hour rolling average NOx emission rate, measured and recorded in accordance with Condition 5.2.8, that is in excess of the limit in Condition 3.3.9.a (NOx BACT limit) for any LNG Vaporizer with ID Nos. V009 – V014.

New Condition 6.1.7.b.v defines an exceedance as any 3-hour rolling average CO emission rate, measured and recorded in accordance with Condition 5.2.8, that is in excess of the limit in Condition 3.3.9.b (CO BACT limit) for any LNG Vaporizer with ID Nos. V009 – V014.

New Condition 6.2.6 requires the facility to notify the Division of the startup date of each LNG vaporizer with ID Nos. V009 – V014 and Heated Vent Stack Heater No. 2 (ID No. B002).

New Conditions 6.2.7 and 6.2.8 require the facility to submit, within 360 days after the initial startup of the LNG vaporizers with ID Nos. V009 – V014, a PEMS plan to the Division for approval if the facility seeks to demonstrate compliance with the NSPS Subpart Db NOx, NOx BACT, and CO BACT emission limits through the use of a PEMS.

New Condition 6.2.9 requires the facility to record and maintain records of the amount of fuel combusted in each LNG vaporizer with ID Nos. V009 – V014 and Heated Vent Stack Heater No. 2 (ID No. B002), using the fuel consumption meters required by new Condition 5.2.9.

New Condition 6.2.10 includes the record keeping requirements specified in 40 CFR 60.49b(g) (NSPS Subpart Db). Data recorded in accordance with Items b and f must be used to verify continuous compliance with the NOx BACT limit. Data recorded in accordance with Items d and g must be used to verify continuous compliance with the CO BACT limit.

In order to avoid being subject to the NSPS Subpart Db PM or opacity limits in 40 CFR 60.43b, SO_2 performance test requirements specified in 40 CFR 60.45b, and SO_2 emission monitoring requirements specified in 40 CFR 60.47b, the facility must fire natural gas exclusively in LNG vaporizers with ID Nos. V009 – V014. Details of NSPS Subpart Db requirements have been discussed in Section 3.0 of this preliminary determination. In order to satisfy the requirements specified in 40 CFR 60.43b(h)(5), 60.45b(k), 60.46b(i), 60.47b(g), and 60.48b(j), the facility must submit a fuel supplier certification or a natural gas tariff for the fuel combusted in LNG vaporizers with ID Nos. V009 – V014.

Section 7.0: Other Specific Requirements

No conditions in Section 7.0 are being added, deleted or modified as part of this permit action.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Southern LNG Inc. Elba Island LNG Terminal
Savannah (Chatham County), Georgia

APPENDIX B

Southern LNG Inc. Elba Island LNG Terminal PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. TV-16697, dated April 6, 2006
2. A Letter and "Statement of Facts on Common Control" both dated July 26, 2006
3. Additional Information Package dated September 1, 2006 that Included an Updated Air Quality Modeling Analysis that Included NOx Secondary Emissions (from Vessels at Berth).
4. Additional Information Package dated October 31, 2006 that Included Vaporizer PM Emissions Documentation, an Indirect Emissions Inventory, an Air Toxics Modeling Update, and a Plume Visibility Analysis Update.

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review