Neptune LNG LLC

Minor Source Preconstruction Air Permit Application for a Liquefied Natural Gas (LNG) Deepwater Port

Neptune Project
Offshore Boston, Massachusetts

May 2006

Submitted by:

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List of Acronyms and Abbreviations

°C	degrees Celsius
°F	degrees Fahrenheit
µg	microgram(s)
Applicant	Neptune LNG LLC, the Applicant for the deepwater port license application
BACT	Best Available Control Technology
Btu	British thermal unit
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CMR	Code of Massachusetts Regulations
CO	carbon monoxide
CPA	Comprehensive Plan Approval
DEP	(Massachusetts) Department of Environmental Protection
DF	dual fuel
DWPA	Deepwater Port Act
E & E	Ecology & Environment, Inc.
EPA	United States Environmental Protection Agency
EPN POWER	Emission Point Name – Standby Power Generator
EPN SRVBLR	Emission Point Name – Shuttle Regasification Vessel Vaporization Boiler
ERC	Emission Reduction Credits
FGD	flue gas desulfurization
FGR	flue gas recirculation
g	gram(s)
GEP	Good Engineering Practice
H_2O	water
HAP	hazardous air pollutant
HHV	higher heating value
hr	hour(s)

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List of Acronyms and Abbreviations (Cont.)

HubLine^{SM}	Algonquin HubLine^{SM}
km	kilometer(s)
kW	kilowatt(s)
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	pound(s)
LNG	liquefied natural gas
m^3	cubic meter(s)
mg	milligram(s)
mmBtu	million British thermal units
MMS	Minerals Management Service
mmscf	million standard cubic feet
mmscfd	million standard cubic feet per day
N_2	nitrogen
NAAQS	National Ambient Air Quality Standards
NANSR	Nonattainment New Source Review
Neptune LNG LLC	the Applicant
Neptune	the proposed deepwater port
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
Nm^3	normal cubic meter
NO_2	nitrogen dioxide
NO_X	oxides of nitrogen
NSCR	non-selective catalytic reduction
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
O_3	ozone
OCD	Offshore and Coastal Dispersion (Model)
OCS	Outer Continental Shelf
Pb	lead
PCHE	printed circuit heat exchanger

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List of Acronyms and Abbreviations (Cont.)

PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
ppm	parts per million
ppmvd	parts per million, volumetric dry
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RMP	Risk Management Program
scf	standard cubic feet
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SRV	shuttle and regasification vessel
TO	thermal oxidizer
tpy	tons per year
UHC	unburned hydrocarbons
U.S.C.	United States Code
USCG	United States Coast Guard
VOC	volatile organic compounds
yr	year

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1

Introduction

Neptune LNG LLC (the Applicant), a Delaware limited liability company, is filing an application for a license pursuant to the Deepwater Port Act of 1974, as amended (the DWPA) and the United States Coast Guard's (USCG's) January 6, 2004, Temporary Interim Rules to construct, own, and operate a deepwater port. The proposed deepwater port, named *Neptune,* would be located in the federal waters of the Outer Continental Shelf (OCS), blocks NK 19-04 6525 and NK 19-04 6575, approximately 22 miles northeast of Boston, Massachusetts, in a water depth of approximately 250 feet.

Neptune would be capable of mooring liquefied natural gas (LNG) shuttle and regasification vessels (SRVs) with a capacity of approximately 140,000 cubic meters (m^3). Up to two SRVs would temporarily moor at the proposed deepwater port by means of a submerged unloading buoy system. Two separate buoys would allow natural gas to be delivered in a continuous flow, without interruption, by having a brief overlap between arriving and departing SRVs. The average annual throughput capacity would be approximately 500 million standard cubic feet per day (mmscfd), with an initial throughput of 400 mmscfd, and a peak capacity of approximately 750 mmscfd.

The SRVs would be equipped to store, transport, and vaporize LNG, and to odorize, meter, and send out natural gas by means of two 16-inch flexible risers and one 24-inch subsea flowline. The risers and flowline would lead to a proposed 24-inch gas transmission pipeline connecting the deepwater port to the existing 30-inch Algonquin HubLine^{SM} (HubLine^{SM}) located approximately 9 miles west of the proposed deepwater port location. The deepwater port will be designed, constructed, and operated in accordance with applicable codes and standards and will have an expected operating life of approximately 20 years.

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The source of LNG delivered to the deepwater port would be from the Applicant's affiliate companies' global portfolio of LNG supply at locations including the Caribbean, Africa, and the Middle East. Construction of the deepwater port components (including SRVs, unloading buoy system fabrication, and offshore construction) is expected to take 36 months. On-site construction activities in Massachusetts Bay would be initiated in mid-May 2009 and completed in late September 2009, assuming no weather delays. Start-up of commercial operations is expected in October 2009.

During the vaporization of LNG and send out of natural gas to the pipeline, up to two SRVs, each with a capacity of approximately 140,000 m^3, would temporarily moor at the proposed deepwater port by means of a submerged unloading buoy system. Two unloading buoys would moor each SRV on location throughout the unloading cycle by means of mooring lines and anchor points located on the seabed. Two unloading buoys would be utilized so that natural gas can be delivered in a continuous flow, without interruption, by having brief overlap between arriving and departing SRVs. As the first SRV finishes unloading, a second SRV (following its transit from an overseas loading point) would moor at the other unloading buoy. After vaporization of LNG and send out of natural gas, the first SRV would disconnect from the unloading buoy and proceed to an overseas loading point to reload. Meantime, a third SRV, already in transit to the deepwater port, would repeat the cycle.

For the vaporization process, each SRV would be equipped with two natural gas-fired boilers and two power generation engines. The power generation engines are dual fuel engines that would operate in the gas mode (with less than 1% distillate fuel oil) while moored at the deepwater port.

Summary of Changes to the Preconstruction Air Permit Application Submitted September 2005

This revised Preconstruction Air Permit Application is for minor source review of all pollutants in accordance with 310 Code of Massachusetts Regulation (CMR) 7.02. The Regulations for the Prevention of Significant Deterioration (PSD) and for Nonattainment New Source Review (NANSR) do not apply to the proposed project as revised. A previous permit application (dated September 2005) was submitted with the project subject to NANSR as a major source. However, for this revised permit application, the additional application of selective catalytic reduction (SCR) to the SRV boilers permits the project to request a facility oxides of nitrogen (NO_X) cap of 45 tons per year (tpy), thus making the project a minor source not subject to NANSR. This permit application is based on an annual average daily natural gas send-out capacity of approximately 500 mmscfd. One SRV would be capable of supplying the peak capacity of approximately 750 mmscfd. Since two SRVs may temporarily moor at the same time (up to a nine-hour overlap period between incoming/departing SRVs), maximum short term emissions and impacts are conservatively based on two carriers unloading simultaneously.

Peak equipment operating capacity has been redefined for this revised permit application based on additional project engineering detail. In the September 2005 permit application, the short-term emission rates for the project were based on two SRVs, each operating two engines and two

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boilers at maximum load. This operating condition was reevaluated and determined to be overly conservative; therefore, the maximum short-term emission rates for this revised application are based on one SRV operating two boilers and two engines at 90% load while the second SRV operates one engine and one boiler at 90% load.

The proposed facility NO_X cap of 45 tpy required a re-analysis of other criteria pollutant and HAP annual emission rates. On an annual basis, the facility could be operated under two different operating scenarios, thus a comparison of the annual emission rates of the other criteria pollutants and HAPs from the two scenarios was performed and the highest annual emission rate for each pollutant was selected for the facility potential to emit (see Section 4.1).

Additional changes to this revised preconstruction Air Permit Application include:

- A reconfiguration of the engines onboard each SRV. Previously, two nine-cylinder Wartsila 50DF engines were proposed; for this application two 12-cylinder Wartsila engines will be used during the regasification process; and

- Provision for use of a thermal oxidizer (TO) for short periods during initial SRV hook-up to the buoy. Emissions from the TO were evaluated and included in short-term and annual average emission rates for modeling purposes and included in the facility total emissions for each criteria pollutant.

Emission offsets will not be required for the project due to the minor source status. Therefore, the discussion regarding emission offsets contained in the September 2005 Preconstruction Air Permit Application has been removed from this revised application.

This Preconstruction Air Permit Application is organized as follows:

- Section 1 – Introduction;
- Section 2 – Project Overview;
- Section 3 – Regulatory Overview;
- Section 4 – Emissions Characterization;
- Section 5 –Best Available Control Technology (BACT) Analysis;
- Section 6 – Air Quality Impact Analysis;
- Appendix A – Emission Calculations;
- Appendix B – Manufacturer's Emission Data;

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- Appendix C – Air Permit Application Forms; and
- Appendix D – Air Dispersion Modeling Files.

The United States Environmental Protection Agency (EPA), Region 1 is the regulatory authority responsible for reviewing the air quality permit application and issuing the preconstruction air quality permit.

This document was prepared by Ecology & Environment, Inc. (E & E) under the authorization of, and in cooperation with, Neptune LNG LLC.

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Project Overview

2.1 Facility Location

The proposed deepwater port named *Neptune* would be located in the federal waters of the OCS blocks NK 19-04 6525 and NK 19-04 6575, approximately 22 miles northeast of Boston, Massachusetts, in a water depth of approximately 250 feet. The location is shown on Figure 2-1, an artist's rendering of the proposed deepwater port is shown on Figure 2-2, and a site plan of the proposed deepwater port is shown on Figure 2-3.

Since the proposed project would be located in federal waters, it is subject to federal air quality regulations established by the EPA under the provisions of the Clean Air Act. The proposed project is also subject to air quality regulations of the adjacent state of Massachusetts in accordance with Chapter 310, Sections 6.00 through 8.00 of the CMR.

An evaluation of projected annual emissions has been completed, and it was determined that the source does not exceed the nonattainment major source threshold for volatile organic compounds (VOCs) or NO_X. Therefore the proposed project is not subject to Massachusetts Regulation 310 CMR 7.00: Appendix A: "Emission Offsets and Nonattainment Review." Emissions of NO_X and VOCs are below thresholds for 310 CMR 7.00: Appendix A due to use of SCR on engines and boilers used in the vaporization process and due to use of oxidation catalyst on the engines. The proposed project is not subject to the Regulations for PSD since emissions are less than the PSD major source threshold for all pollutants, nor would the project exceed hazardous air pollutant major source thresholds. Section 5 presents the BACT analysis on a pollutant specific basis in accordance with 310 CMR 7.02. As a minor source of NO_X and other pollutants, the proposed project is not subject to the Title V Operating Permit Program. Application forms for this revised Minor Source Preconstruction Air Permit Application have been completed using EPA "Non-Major Source

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Preconstruction Air Quality Permit Application" forms. Completed application forms are contained in Appendix C.

2.2 Vaporization Process Description

Each SRV would be equipped with three vaporization (shell and tube heat exchanger) units with a total maximum send-out capacity of 750 mmscfd. Each unit would have a capacity to vaporize 250 mmscfd (or 210 tons per hour). Under normal operation, two units would be in service with a combined maximum send-out capacity of up to 500 mmscfd. A single SRV can be unloaded in six days. Sixty-four (64) ships per year would discharge at the deepwater port.

The vaporization system would be installed on the main deck in the forward part of the vessel, and would consist of three separate skid-mounted units that would contain the required pumps, motors, heat exchangers, and control systems to provide the required capacity. Each unit would be independent and could be disconnected for transportation to shore for maintenance and overhaul (if required).

LNG would be pumped from the cargo tanks to a common suction drum/re-condenser tank on deck. Heat is required to vaporize the LNG so that the gas can be transported to shore through submarine pipelines. The two basic choices are a closed-loop system and an open-loop system. In the closed loop system, boilers are used to produce steam; the steam heats a fluid in a closed loop that is circulated through heat exchangers to warm the LNG. In the open-loop system, seawater would be circulated through heat exchangers to warm the LNG. The closed-loop system would be required for proper operation in the northeast portion of the United States because of the low water temperatures during winter months. In addition, the closed-loop is less harmful to the marine environment. The *Neptune* vaporization system would be a closed loop and would use an intermediate media (water/glycol) to heat the LNG in the regasification units. Steam produced by the marine boilers is used as the heat source for the water/glycol. The water/glycol enters the LNG shell and tube heat exchanger at approximately 90 degrees Celsius (°C) and leaves at approximately 20°C after evaporating and warming the LNG. It is then pumped via a circulation pump and re-heated by steam produced in the marine boilers before it is returned to the shell and tube heat exchanger. A printed circuit heat exchanger (PCHE) is used to transfer heat from the marine boilers to the water/glycol fluid.

LNG at –160°C and approximately 5 bars in the SRV's tanks is pressurized in multi stage centrifugal pump(s) to a pressure up to 120 bars prior to entering the shell and tube heat exchanger. The LNG is then evaporated and heated to approximately 0°C. In the heat exchanger, LNG passes through tubes where it is evaporated/heated in the pipes by the water/glycol surrounding the pipes.

A separate low-pressure vaporization system would generate natural gas for use as supplemental fuel for the power generation engines. Normally, the power generation engines would run on

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2-1 Deepwater Port Location Diagram

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2-2 Artists Rendering of Deepwater Port

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2-3 Site Plan

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boil-off gas. Supplemental fuel (forced boil-off gas) would be used when there is insufficient boil-off gas available for the power generation engines. Insufficient boil-off gas may occur when LNG levels in the SRV tanks are low (e.g., near the end of the re-gasification period).

In summary, the emission-generating equipment that would be used for the vaporization process onboard each SRV would include:

- Two vaporization natural gas-fired marine boilers using boil-off gas, each with a heat input capacity of approximately 281 million British thermal units per hour (mmBtu/hr) at 90% load. The boilers would generate steam for the vaporization of LNG for unloading, and
- Two power generation engines. While at the unloading buoy, the low-pressure gas-diesel engines of the dual fuel (DF) type, would operate using either boil-off gas or forced vaporized gas (99%) with low sulfur distillate fuel oil (maximum sulfur content of 0.05% wt.) as pilot fuel (<1%). Distillate fuel oil (100%) would be used for startup. Each power generation engine has a capacity of 11,400 kilowatts (kW) but would be operated at no more than 90% load (10,260 kW).

A thermal oxidizer will also be onboard each vessel; however it is not used as part of the vaporization process. Specifics of the thermal oxidizer are discussed in the next section.

2.3 Emission Generating Equipment

Emission-generating equipment onboard each of the SRVs while the vessels are moored at the unloading buoy(s) would consist of:

- Two 281 mmBtu/hr (562 mmBtu/hr total at 90% load) natural gas-fired boilers;
- Two 11,400-kW dual fuel power generation engines operating in the gas mode (with less than 1% low sulfur distillate fuel oil); and
- One TO (208 mmBtu/hr) to oxidize excess boil off gas.

2.3.1 SRV Vaporization Boilers

As described in Section 2.2, each SRV would be equipped with two 281-mmBtu/hr (562 mmBtu/hr total at 90% load) natural gas-fired marine boilers. These boilers would only be used for LNG vaporization while moored.

Based on Aalborg Industries, Mission 120 (or equivalent) gas-fired marine boilers, the boilers would be equipped with low NO_X burners and SCR. The use of flue gas recirculation (FGR) as described in the previous air permit application will not be utilized. Emissions of NO_X, determined as the BACT, would be controlled to 10 parts per million (ppm; 21milligrams per normal cubic meter [mg/Nm^3]). Emissions of carbon monoxide (CO), determined as the BACT, would be controlled to 20 ppm. The pollutant specific BACT analysis for the vaporization boilers is presented in Section 5.2.

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2.3.2 Power Generation Engines

The two 12-cylinder Wartsila 50DF (or equivalent) power generation engines have a capacity of 11,400 kW each. These engines would be operated at all times during re-gasification. The engines also generate power for ship hoteling. While at the unloading buoy, the dual fuel engines would operate using either boil-off gas or forced vaporized gas (99%) with low sulfur distillate fuel oil (maximum sulfur content of 0.05% wt.) as pilot fuel (<1%). Distillate fuel oil (100%) would be used for startup.

The engines would be equipped with SCR technology and an oxidation catalyst to minimize emissions. The SCR would control NO_X emission to 0.2 grams per kilowatt hour [g/kWh], as determined to be BACT. The oxidation catalyst would control CO emissions to 0.17 g/kWh. The pollutant specific BACT analysis for the power generation engines is presented in Section 5.3.

2.3.2 Thermal Oxidizer

One TO will be installed on each SRV to combust excess boil off gas as a precautionary measure while the SRV is moored at the deepwater port. The SRV vaporization boilers and engines normally use all excess boil-off gas at send-out rates above approximately 160 mmscfd. However, for a short period upon initial arrival at the deepwater port and during periods of no gas send out or at low send-out rates, the boilers and engines may not use all excess boil-off gas. Any excess boil-off gas would be oxidized by the TO. Annual and short-term emissions from the TO are described in Section 4.2.1.3.

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Regulatory Overview

The proposed *Neptune* project, located in federal waters, is subject to federal air quality regulations established by the EPA under the provisions of the Clean Air Act. The proposed project is subject to air quality regulations of the adjacent state, Massachusetts, in accordance with Chapter 310, Sections 6.00 through 8.00 of the CMR.

For regulatory review purposes, emission sources associated with the proposed LNG deepwater port (for each SRV) would include the following:

- Two 281-mmBtu/hr (562 mmBtu/hr total) natural gas-fired boilers;
- Two 11,400-kW DF power generation engines operating in the gas mode; and
- One 208 mmBtu/hr TO.

Neptune LNG LLC will comply with applicable federal and state air quality control requirements. The following sections describe the applicable federal and state air quality control regulations associated with the operation of the proposed *Neptune* deepwater port.

3.1 Federal Air Quality Regulations

The Clean Air Act of 1970, 42 United States Code (U.S.C.) 7401 *et seq*. amended in 1977 and 1990 and 40 Code of Federal Regulations (CFR) Parts 50-99 are the basic federal statutes and regulations governing air pollution. The following federal requirements have been reviewed to determine their applicability to the proposed *Neptune* deepwater port.

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3.1.1 National Ambient Air Quality Standards (NAAQS)

Primary and secondary National Ambient Air Quality Standards (NAAQS) are established under 40 CFR Part 50 for six criteria pollutants: sulfur dioxide (SO_2), particulate matter having an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}) and particulate matter having an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$), nitrogen dioxide (NO_2), CO, ozone (O_3), and lead (Pb). The EPA established the primary ambient air quality standards with an adequate margin of safety to protect the public health. Secondary ambient air quality standards define the levels of air quality that the EPA judges necessary to protect public welfare from any known or anticipated adverse effects of a pollutant. Massachusetts has established ambient air quality standards equal to the NAAQS. The NAAQS and Massachusetts ambient air quality standards are presented in Table 3-1.

Table 3-1 National Ambient Air Quality Standards (NAAQS) and Massachusetts Ambient Air Quality Standards

Pollutant	Averaging Period	Primary Standard	Secondary Standard
Carbon Monoxide	8-Hour (A)	9 ppm (10 mg/m^3)	---
	1-Hour (A)	35 ppm (40 mg/m^3)	---
Nitrogen Dioxide	Annual (B)	0.053 ppm (100 µg/m^3)	Same as Primary
Particulate Matter ≤10 Micrometers (PM_{10})	Annual (B)	50 µg/ m^3	Same as Primary
	24-Hour (A)	150 µg/ m^3	Same as Primary
Particulate Matter ≤2.5 Micrometers ($PM_{2.5}$)	Annual (B)	15.0 µg/ m^3	Same as Primary
	24-Hour (C)	65 µg/ m^3	Same as Primary
Ozone	8-Hour	0.08 ppm	Same as Primary
	1-Hour (D)	0.12 ppm	Same as Primary
Sulfur Oxides (Sulfur Dioxide)	Annual (B)	0.03 ppm (80 µg/m^3)	---
	24-Hour (A)	0.14 ppm (365 µg/m^3)	---
	3-Hour (A)	---	0.5 ppm (1,300 µg/m^3)
Lead	Calendar Quarter	1.5 µg/ m^3	Same as Primary

Notes:

(A) Standard not to exceed more than once per year.

(B) Annual arithmetic mean.

(C) 98th percentile standard.

(D) The 1-hour ozone standard was revoked in June 2005.

Key:

mg/m^3 = milligrams per cubic meter.

µg/m^3 = micrograms per cubic meter.

ppm = part per million.

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An air quality impact analysis was conducted for the proposed *Neptune* project. The dispersion modeling analysis presented in Section 6 demonstrates that potential emissions from operation of the proposed deepwater port: (1) would be in compliance with the NAAQS and Massachusetts ambient air standards, and (2) have maximum impacts less than modeling significance levels for all pollutants modeled.

3.1.2 New Source Review (NSR)

Separate preconstruction review procedures have been established for projects that are proposed to be built in attainment areas versus nonattainment areas. The preconstruction review process for new or modified major sources located in attainment areas is called New Source Review (NSR), and may include a PSD review. This review process is intended to prevent new air emission sources from causing existing air quality to deteriorate beyond acceptable levels codified in the federal regulations.

The federal preconstruction review for a new or modified major source located in a nonattainment area is commonly called Nonattainment New Source Review (NANSR). NANSR only applies to major sources of the pollutants that are classified as nonattainment; therefore, a new facility could potentially undergo both types of review, depending on the emissions of the various pollutants and their respective attainment status.

3.1.2.1 Prevention of Significant Deterioration (PSD)

The emission threshold for “major stationary sources” varies under PSD according to the type of facility. As defined by 40 CFR Part 52.21(b)(1)(i), a facility is considered major under PSD if it emits or has the potential to emit 250 tpy or more of any criteria pollutant, or 100 tpy for specified source categories.

Fossil fuel boilers (or combinations thereof) with a heat input capacity greater than 250 mmBtu/hr are included as one of the 28 source categories having an applicability threshold for PSD review of 100 tpy. The proposed *Neptune* project would include two natural gas-fired steam boilers for the vaporization process with a total heat input capacity of 562 mmBtu/hr (for the two boilers combined). Therefore, the PSD applicability threshold for the proposed project is 100 tpy.

The general requirements for PSD approval are: (1) conduct a case-by-case BACT analysis on pollutant-specific basis demonstrating that emissions represent the application of BACT, (2) conduct an ambient air quality impact analysis demonstrating compliance with ambient air quality standards and PSD increments, (3) conduct additional impact analyses to assess impacts on soils, vegetation, and visibility, and (4) demonstrate that the source would not adversely impact a Class I area.

Class I areas are specifically designated as pristine wilderness areas. There are no Class I areas in Massachusetts. The nearest Class I areas to the project location are Great Gulf (New Hampshire), Lyle Brook (Vermont), and Presidential Range-Dry River (New Hampshire) Wilderness

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Areas. These Class I areas are under the jurisdiction of the U.S. Forest Service, and all are greater than 100 kilometers (km) from the project site.

As described in Section 4, potential emissions associated with the proposed deepwater port would be less than the PSD major source threshold of 100 tpy for each pollutant. Therefore, in accordance with 40 CFR Part 52.21, the proposed project is not subject to review under the PSD regulations.

3.1.2.2 Nonattainment New Source Review (NANSR)

The only nonattainment pollutant in Massachusetts is for ozone. Massachusetts is in attainment for all other criteria pollutants: NO_2, CO, SO_2, PM_{10} and $PM_{2.5}$, and Pb.

The entire state is designated as a serious nonattainment area based on the old 1-hour ozone standard. The 1-hour ozone standard was revoked on June 15, 2005, and the serious nonattainment area designation does not continue to apply. With respect to the new and more protective 8-hour ozone standard, the entire state of Massachusetts is classified as moderate nonattainment area for ozone. The moderate ozone nonattainment designation took effect on June 15, 2004.

The major source threshold for ozone nonattainment areas depends on the severity of nonattainment. For moderate ozone nonattainment areas, the federal major source threshold level for NO_X is 100 tpy. However, 310 CMR 7.00 has established a threshold of 50 tpy for major sources, therefore, 50 tpy is considered the appropriate major source threshold for NO_X for the determination of applicability to the NANSR regulations for this project. With regard to VOCs, Massachusetts is located within the Ozone Transport Region and the applicable threshold level for VOCs is also 50 tpy.

The general requirements for NANSR projects are: (1) conduct a control technology review and apply emission controls representing the LAER for the nonattainment pollutant, and (2) obtain emission offsets for the nonattainment pollutant from existing sources.

As described in Section 4, potential emissions associated with the proposed deepwater port would be less than the nonattainment major source threshold of 50 tpy for NO_X. Therefore, the proposed project is not subject to the NANSR for emissions of NO_X. The proposed project also is not subject to NANSR for VOC emissions since potential VOC emissions are less than the nonattainment major source threshold.

3.1.3 New Source Performance Standards

40 CFR Part 60 establishes New Source Performance Standards (NSPS) for specific emission sources. The following NSPS requirements were identified as potentially applicable to the specified sources at the proposed *Neptune* facility.

40 CFR Part 60, Subpart D "Standards of Performance for Fossil-Fuel-Fired Steam Generating Units." For gas-fired units, the NSPS establishes emission standards for NO_X and particulate matter. The applicable NSPS emission standard for NO_X is 0.20 pounds per million British thermal units (lb/mmBtu). The particulate matter emission standard, applicable to any

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fossil fuel, is 0.10 lb/mmBtu. The particulate matter NSPS includes an emission standard for opacity of no greater than 20% opacity except for one six-minute period per hour of no greater than 27% opacity.

The heat input capacity of each vaporization boiler would be 281 mmBtu/hr firing natural gas. Low NO_X burner technology and SCR would be utilized to control NO_X emissions to 0.01 lb/mmBtu. Particulate emissions from the natural gas-fired boilers are expected to be no more than 0.0075 lb/mmBtu. Emissions would comply with the particulate and opacity standards by firing clean burning natural gas that inherently produces minimal particulate emissions.

As allowed in the regulation, if it can be demonstrated during initial stack testing that emissions of NO_X are less than 70% of the applicable standard, then the installation of a continuous emissions monitoring system (CEMS) would not be required, Since the applicable standard is 0.20 lb/mmBtu and the estimated level of emissions is only 0.010 lb/mmBtu (or only 5% of the standard), the NSPS does not require a NO_X CEMS for the proposed boilers.

3.1.4 National Emissions Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) are established under 40 CFR Parts 61 and 63. The proposed project would not operate any process source type or emission source type regulated under Part 61. Therefore, the proposed project is not subject to the NESHAP regulations established under 40 CFR Part 61.

The Part 63 (and Part 61) NESHAP regulations apply only to major sources of hazardous air pollutant (HAP) emissions. A facility is a major source of HAP if potential emissions are greater than or equal to 10 tpy of any single HAP or greater than or equal to 25 tpy of total HAPs. As described in Section 4.3, potential emissions of HAPs from the proposed project are less than the major source thresholds. The highest potential emission rate of any single HAP is 3.26 tpy (for hexane), and total HAP emissions are 5.4 tpy. Therefore, the proposed project is not subject to the NESHAP regulations under 40 CFR Part 63.

In summary, the project would not be a major source of HAP emissions and is not subject to the NESHAP regulations established under 40 CFR Parts 61 and 63.

3.1.5 Risk Management Program

40 CFR Part 68, Chemical Accident Prevention Provisions, is a federal regulation designed to prevent the release of hazardous materials in the event of an accident and to minimize impacts when releases do occur. The regulation contains a list of substances and threshold quantities for determining applicability of the rule to a facility. If a facility stores, handles, or processes one or more substances on this list at a quantity equal to or greater than specified in the regulation, the facility must prepare and submit a risk management plan as part of its overall Risk Management Program (RMP). No substances on this list would be used in the quantities described, and therefore a risk management plan is not required for the proposed project.

3.2 State Air Quality Regulations

Massachusetts air quality and permitting requirements are codified in 310 CMR 6.00 to 8.00. They incorporate the federal program requirements listed in 40 CFR Parts 50-99, and establish plan approval procedures for all facilities that can emit pollutants to the ambient air.

All new facilities are required to obtain plan approval prior to initiating construction. Facilities can trigger additional review if emissions exceed the major source thresholds listed in 40 CFR §52.21(b)(1)(i), or 310 CMR Part 7.00. The proposed project, as revised to incorporate SCR to reduce NO_X in the vaporization boiler exhaust, would not exceed the threshold of 50 tpy for potential NO_X emissions in Appendix A of 310 CMR 7.00, therefore, the nonattainment major source requirements do not apply.

The remainder of this section provides the information necessary to demonstrate that the proposed *Neptune* LNG deepwater port would comply with the requirements in 310 CMR 6.00 through 8.00. The emissions from the proposed project would comply with applicable Massachusetts regulations. A summary discussion on compliance with each applicable rule is included below.

3.2.1 Ambient Air Quality Standards for the Commonwealth of Massachusetts - 310 CMR 6.00

Massachusetts ambient air quality standards contained in 310 CMR 6.00 are identical to the NAAQS per 40 CFR Part 50 as described previously. The NAAQS and Massachusetts ambient air quality standards are presented in Table 3-1.

The air quality dispersion modeling impact analysis for the proposed project is presented in Section 6. The air quality impact analysis demonstrates that the proposed project would be in compliance with the NAAQS and Massachusetts ambient air quality standards.

3.2.2 Nonattainment New Source Review and Emission Offsets - 310 CMR 7.00: Appendix A and Appendix B

The entire state of Massachusetts is classified as a nonattainment area for ozone. Emissions of NO_X and VOC are precursors to the pollutant ozone. Major sources of NO_X or VOC emissions are considered major for ozone. New major sources of NO_X or VOC located in Massachusetts are subject to the NANSR regulations in accordance with 310 CMR 7.00: Appendix A: “Emission Offsets and Nonattainment Review” and Appendix B: “Emission Banking, Trading, and Averaging.”

For moderate ozone nonattainment areas, the major source threshold level for NO_X is 50 tpy. With regard to VOCs, Massachusetts is located within the Ozone Transport Region and the applicable threshold level for VOC is 50 tpy. Potential emissions from the proposed project have been estimated at 45 tpy for NO_X, and approximately 33 tpy for VOCs. A cap of 45 tpy for annual NO_X emissions is proposed for the project. Since potential emissions of NO_X and VOC would not exceed the major source threshold, the project is considered a minor source and would not be subject to 310 CMR 7.00 Appendix A (nonattainment review).

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3.2.3 Plan Approval - 310 CMR 7.02

Massachusetts regulations for preconstruction approval for air emission sources are described under 310 CMR 7.02. In accordance with this state regulation, the proposed project would require a Comprehensive Plan Approval (CPA) application since each vaporization boiler would have a heat input capacity greater than the CPA threshold (40.0 mmBtu/hr).[1]

Through this preconstruction approval process with the EPA, the proposed project will:

- Utilize emission controls representing BACT for all pollutants;
- Demonstrate that effects from the project comply with Massachusetts and NAAQS;
- Comply with applicable emission limitations and provisions under 310 CMR 7.00; and
- Comply with the applicable provisions of the NSPS in accordance with 40 CFR Part 60, Subpart D for the vaporization boilers.

As previously described, the proposed project is not subject to review under the PSD regulations.

3.2.4 Operating Permit and Compliance Program - 310 CMR 7.00, Appendix C

The Title V Permit program, as described in 40 CFR Part 70, requires major sources of air emissions to obtain federal operating permits. In Massachusetts, the EPA has delegated authority to issue Title V operating permits to the Massachusetts Department of Environmental Protection (DEP). The Title V regulations for Massachusetts are described under 310 CMR 7.00: Appendix C: “Operating Permit and Compliance Program.”

The major source threshold levels for determining the need for a Title V operating permit are: 50 tpy of NO_X or VOC, 100 tpy of any other criteria air pollutant, 10 tpy of any individual HAP, or 25 tpy of any combination of HAPs. Potential emissions from the proposed project do not exceed any Title V major source threshold; therefore, a Title V Operating Permit is not required.

3.2.5 Particulate Emission Limitation for New Fossil Fuel Utilization Facilities - 310 CMR 7.02(8)(h)

Particulate emission limitations for new fossil fuel utilization facilities are established by Massachusetts Regulation 310 CMR 7.02(8)(h). The particulate emission limitations are 0.10 lb/mmBtu for units with a heat input capacity of 3 to 250 mmBtu/hr and 0.05 lb/mmBtu for units with heat input capacity of greater than 250 mmBtu/hr.

The vaporization boilers, power generation engines, and TO are subject to this regulation. Particulate emissions from the boilers (each greater than 250 mmBth/hr) are estimated at no more than 0.010 lb/mmBtu, and thus would comply with the applicable particulate emission limitation of 0.05 lb/mmBtu. Particulate emissions from the engines (each less than 250 mmBtu/hr) are estimated at no more than 0.047 lb/mmBtu, and thus would comply with the

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[1] CPA applications are also required for new reciprocating engines or gas turbines with a heat input capacity of 3.0 mmBtu/hr or greater.

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applicable particulate emission limitation of 0.10 lb/mmBtu. Particulate emissions from the TO (<250 mmBtu/hr) are estimated at no more than 0.008 lb/mmBtu, and thus would comply with the applicable particulate emission limitation of 0.10 lb/mmBtu.

3.2.6 Sulfur Content of Fuels - 310 CMR 7.05(1)

Massachusetts regulations limiting the sulfur content of fossil fuels, except natural gas, are contained in 310 CMR 7.05(1). This regulation establishes a sulfur content limit of 0.17 lb sulfur/mmBtu (equivalent to 0.3% sulfur content) for No. 2 (distillate) fuel oil. The power generation engines would be subject to this fuel sulfur limitation.

The power generation engines in the gas mode would use less than 1% low sulfur distillate fuel oil with a maximum sulfur content of 0.05% (wt.). Therefore, the project would comply with 310 CMR 7.05(1) for sulfur content and the utilization of distillate fuel oil.

The only other combustion emission source for the vaporization process would be natural gas-fired marine boilers. A TO would also be used to combust excess boil-off gas from the LNG cargo tanks. Natural gas vaporized from LNG contains minute quantities of sulfur. The boilers would burn only natural gas while at the buoy. There are no applicable federal or Massachusetts regulations limiting the sulfur content of natural gas.

3.2.7 Visible Emissions - 310 CMR 7.06

Regulations 310 CMR 7.06(1)(a), (b) and 7.06(3) establish general visible emission standards for stationary sources including marine vessels. Emissions of smoke would not have a shade, density, or appearance equal to or greater than No. 1 of the Ringelmann Scale (i.e., Chart) for a period in excess of six minutes during any one hour, provided that at no time would visible emissions be equal to or greater than No. 2 of the Chart. In addition, emissions of opacity, exclusive of uncombined water or smoke, would not exceed 20% opacity for a period in excess of two minutes during any one hour, provided that at no time would visible emissions exceed 40% opacity.

Visible emissions from the project would comply with 310 CMR 7.06 by using clean-burning natural gas for the boilers, power generation engines, and TO. In addition, low sulfur distillate fuel oil would be used in the power generation engines and good combustion practices would be employed through standard operating and maintenance procedures.

3.2.8 The Prevention and/or Abatement of Air Pollution Episode and Air Pollution Incident Emergencies – 310 CMR 8.00

The purpose of 310 CMR 8.00 is to prevent ambient air contaminant concentrations at any location in the Commonwealth of Massachusetts from reaching levels that would constitute significant harm, or imminent and substantial endangerment to the health of persons. The levels that constitute significant harm, or imminent and substantial endangerment, to the health of persons have been defined by the Administrator of the EPA.

Based upon DEP evaluation of such information relative to ambient air contaminant concentration levels, the criteria set forth in 310 CMR 8.03 and/or other substantive and germane informa-

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tion, the DEP Commissioner may declare an Air Pollution Incident Emergency, an Air Pollution Episode Alert, or an Air Pollution Episode Warning.

The *Neptune* LNG deepwater port project would monitor current alert, warning, and emergency status, and comply with Massachusetts requirements for prevention and abatement of such air pollution episodes.

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4

Emissions Characterization

This section provides a summary of criteria pollutant and hazardous air pollutant potential emission rates for the proposed *Neptune* LNG deepwater port.

4.1 Operating Scenarios

The facility would be comprised of two unloading buoys. While moored at the unloading buoys, vaporization and ship hoteling activities would be conducted onboard SRVs. At least three SRVs would be designed and built for this project. Each SRV would be equipped with two vaporization boilers for LNG vaporization, two dual-fuel power generation engines and one TO. Two boilers would satisfy the heating requirements of the maximum design LNG vaporization rate of 750 mmscfd.

For the facility-wide annual emissions evaluation, the proposed annual NO_X cap of 45 tpy would apply to the combined six boilers, six power generation engines and three TOs onboard the three SRVs while conducting vaporization activities at the unloading buoys.

During an operational year, the normal operating condition will consist of operation of only engines and boilers. NO_X emissions from the engines and boilers under the proposed cap will be limited to 45 tpy facility-wide. The thermal oxidizer is an emission source that will not be routinely operated. When the TO does operate however, it emits NOx and thus will reduce the total amount of LNG that can be regasified under the annual NOx cap.

As stated above, if the TO is used oxidize excess boil off gas additional emissions will be produced by the TO. NO_X emissions from the TO will be included under the facility NO_X cap of 45 tpy. In order to remain under the facility wide 45 tpy NO_X cap, slightly less operation of the power generation engines and boilers will occur compared to the “no TO” annual operation scenario.

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Facility-wide annual emissions of other pollutants (CO, SO_2, PM_{10}/$PM_{2.5}$, VOCs and HAPs), were selected by calculating annual facility emissions for two annual operating scenarios: (1) only engines and boilers operating or (2) engines, boilers and the TO operating. A comparison of emissions for each pollutant in these two scenarios was made and the highest annual emission was selected as the facility-wide emission total for that pollutant. Except for CO, the annual facility-wide emissions are highest for engines and boilers only operating (annual scenario 1). For CO, the combination of engines, boilers and TO produced the maximum annual emission level.

For evaluating short-term emission rates, there would be overlapping periods of two SRVs at the facility (up to nine hours of overlap); an arriving SRV would attach to the buoy and begin LNG vaporization while a departing SRV completes LNG vaporization and detaches from the buoy. In this situation, three short-term operating scenarios may occur:

- One SRV operates two boilers and two engines at 90% load while the second SRV operates one engine and one boiler at 90% load;
- One SRV operates two boilers and two engines at 90% load while the second SRV operates in a “low send-out” condition during which one engine and one boiler operate at reduced load and the TO treats small quantities of excess boil off gas; and
- One SRV operates two boilers and two engines at 90% load while the second SRV operates in a “no send-out” condition during which only the TO operates on the second SRV.

Maximum hourly emissions for each pollutant short-term averaging time (i.e., one, three, eight, and 24 hours) were determined by examining the short-term emission rates from each scenario and selecting the highest.

Potential annual emissions for the project are based on a facility cap of 45 tpy for NO_X. This cap accommodates the required facility operation to achieve the annual average daily natural gas vaporization rate of approximately 500 mmscfd through use of SCR on both the SRV vaporization boiler and engine emissions. The resulting maximum annual fuel use for the boilers is 3,061.9 mmscf/yr. The power generation engines maximum annual fuel use would be 628 mmscf/yr at an annual average gas send-out rate of approximately 500 mmscfd and including ship hoteling. Fuel use is no longer requested as a permit restriction.

Proposed capped facility-wide NO_X emissions are less than the major source threshold for NO_X applicable in a moderate ozone nonattainment area. Therefore, the proposed project is not a major source of NO_X emissions. All pollutant emissions are subject to BACT in accordance with 310 CMR 7.02. The emission control technology analysis for the vaporization boilers and power generation engines is presented in Section 5.

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4.2 Criteria Pollutant Emissions

The following section summarizes the methodology used to determine potential emissions of criteria pollutants from the proposed deepwater port.

4.2.1 Determination of Potential Emissions

4.2.1.1 SRV Vaporization Boilers

Each SRV would be equipped with two Aalborg Mission 120 (or equivalent) vaporization boilers, each rated at 281 mmBtu/hr (at 90% load). As described in Section 4.1, maximum hourly emissions are based on the highest emission rate determined by examining three potential short-term operating scenarios. Maximum annual emissions are based on the highest annual total for each pollutant determined by examining two potential annual operating scenarios.

Emissions information was obtained from a representative marine boiler supplier (see Appendix B for emissions information). Emissions of NO_X are based on 10 parts per million, volumetric dry (ppmvd) at 3% oxygen (O_2). This emission level will be achieved by low NO_X burner technology and SCR; see Appendix B). According to the representative manufacturer, emissions of CO are expected to be low, in the range of 10 to 20 ppm at full load (20 ppm has been used for emissions calculations). Based on the estimated exhaust characteristics, these concentrations correspond to approximately 0.012 lb/mmBtu for NO_X, and 0.015 lb/mmBtu for CO. Emissions for other pollutants (VOC, PM_{10}, and SO_2) are based on the appropriate AP-42 emission factor for natural gas-fired boilers, as adjusted for the project design energy content of natural gas.[2]

Appendix A contains additional information on the emissions calculation methodology. Operation of the SCR for NO_X emissions control on the boilers would result in ammonia emissions. Total ammonia emissions were calculated based on manufacturer supplied data on ammonia slip (see Appendix A). Ammonium sulfate particulate is produced when passing exhaust containing trace sulfur through an SCR unit. Therefore, the $PM_{10}/PM_{2.5}$ emission rates include an ammonium sulfate particulate component. A summary of the vaporization boilers potential criteria pollutant emissions is presented in Table 4-1. Annual emissions are shown for the two potential annual operating scenarios.

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[2] United States Environmental Protection Agency, 1988, Compilation of Air Pollutant Emission Factors, Section 1.4, Natural Gas Combustion, July 1998, AP-42, Fifth Edition, EPA, Washington, D.C.

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Table 4-1 Potential Criteria Pollutant and Ammonia Emissions from SRV Vaporization Boilers [(A)]

Pollutant	Emission Factor (lb/mmBtu)	Maximum Hourly Emissions (lb/hr/boiler)	Total Hourly Emissions (lb/hr) [(B)]	Total Annual Emissions w/TO (tpy) [(C)]	Total Annual Emissions w/o TO (tpy)[(E)]
Oxides of Nitrogen (NO_X)	0.012	3.36	10.08	19.1	22.2
Carbon monoxide (CO)	0.015	4.09	12.27	23.9	27.7
Volatile organic compounds (VOC)	0.005	1.41	4.23	8.0	9.2
Particulate matter (PM_{10} and $PM_{2.5}$)	0.007	1.98	5.94	11.3	13.0
Sulfur dioxide (SO_2)	0.0006	0.17	0.51	1.0	1.1
Ammonia (NH_3)[(D)]	0.0044	1.24	3.72	7.0	8.1

Notes:

[(A)] Emissions of $PM_{2.5}$ are assumed equal to PM_{10} emissions. Particulate matter emissions include ammonium sulfate formed across selective catalytic reduction (SCR) due to trace sulfur. Emissions of lead (Pb), a criteria pollutant, are addressed in the emission estimate for HAP as presented in Section 4.3.

[(B)] Total hourly emissions are based on three vaporization boilers at 90% load (281 mmBtu/hr per boiler).

[(C)] Total annual emissions are based on the proposed facility NO_X limit of 45 tpy and corresponding fuel use of 3,061.9 mmscf/yr for all vaporization boilers combined to achieve an annual average send out rate of approximately 500 mmscfd.

[(D)] Ammonia emissions are based on an emission factor of 0.0044 lb/mmBtu for an SCR ammonia slip of 10 ppm.

[(E)] Total annual emissions without TO operation are based on the proposed facility NOx limit of 45 tpy and corresponding fuel use of 3,545.7 mmscf/yr. Without TO operation, the gas send-out annual daily average will be slightly above 500 mmscfd, thus the boilers will operate slightly more than under the "with TO" scenario.

Key:

hr = Hour.
lb = Pounds.
mmBtu = Million British thermal units.
tpy = Tons per year.
w/ = with
w/o = without

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Example Emission Calculation Procedure (with TO operation):

CO Emissions (lb/hr/unit)

= (Emission Factor)(Unit Rating)*

= (0.015 lb/mmBtu)(281 mmBtu/hr)*

=4.09lb/hr per boiler, or 12.27 lb/hr maximum for two SRVs (two boilers for first SRV, one boiler on second SRV)

CO Emissions (tpy)

= (Annual fuel usage)(Fuel energy content)*(Emission Factor)/(2000 lb/ton)*

= (3,061.9 mmscf/yr) (1,041.4 mmBtu/mmscf)*(0.015 lb/mmBtu)/(2000 lb/ton)*

= 23.9 tpy

4.2.1.2 Power Generation Engines

As described in Section 4.1, maximum hourly emissions are based on three power generation engines at 90% load. Annual emissions from the power generation engines are based on an average annual gas send-out rate of approximately 500 mmscfd. Emissions from the engines include power generation for the vaporization process and ship hoteling.

Emissions of NO_X, CO, VOC, and PM_{10} for the power generation engines are based on information from a representative engine manufacturer (see Appendix B for emissions information from Wartsila for the 12L50DF engine). Emissions of SO_2 were calculated based on the use of low sulfur diesel with maximum sulfur content of 0.05% (by weight). Based on the annual facility NO_X cap of 45 tpy and an approximately 500 mmscfd gas send-out rate, the power generation engines would use approximately 628.2 mmscf/yr for all SRVs while at the buoys. Fuel oil combustion (<1% fuel oil would be used as a pilot fuel during normal power generation engine operations) would result in minute amounts of sulfur in the engine exhaust. Ammonium sulfate particulate is produced when passing exhaust containing sulfur through an SCR unit. Therefore, the $PM_{10}/PM_{2.5}$ emission rates include an ammonium sulfate particulate component. Potential criteria pollutant emissions for the power generation engines are shown in Table 4-2; emission calculations are included in Appendix A. Annual emissions are shown in Table 4-2 for the two potential annual operating scenarios.

Operation of the SCR for NO_X emissions control on the power generation engines would result in ammonia emissions. Total ammonia emissions were calculated based on manufacturer supplied data on ammonia slip (see Appendix A).

Example Emission Calculation Procedure (with TO operation):

CO Emissions (lb/hr)

= (Emission Factor)(engine rating)*

= (0.17 g/kWh)(10,260 kW)/(453.59 g/lb)*

= 3.85 lb/hr per power generation engine, or 11.55 lb/hr max. for two SRVs (three power generation engines total)

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CO Emissions (tpy)
= Annual fuel usage)(Fuel energy content) (Emission Factor)*(Engine Rating)/ (Fuel Input)/(2000 lb/ton)*
= (628.2 mmscf/yr) (1,041.4 mmBtu/mmscf)*((0.17 g/kWh)*(10,260 kW)/ (453.59 g/lb)/(73 mmBtu/hr)/(2000 lb/ton)*
= 17.23 tpy

Table 4-2 Potential Criteria Pollutant and Ammonia Emissions from the Power Generation Engines [(A)]

Pollutant	Emission Factor (g/kWh)	Maximum Hourly Emissions (lb/hr/engine)	Total Hourly Emissions (lb/hr) [(B)]	Total Annual Emissions w/TO (tpy) [(C)]	Total Annual Emissions w/o TO (tpy) [(E)]
Oxides of nitrogen (NO_X)	0.20	4.52	13.56	20.30	22.8
Carbon monoxide (CO)	0.17	3.85	11.55	17.23	19.5
Volatile organic compounds (VOC)	0.23	5.20	15.60	23.20	26.1
Particulate matter (PM_{10} and $PM_{2.5}$)	0.15	3.43	10.29	15.40	17.3
Sulfur dioxide (SO_2)	na	0.07	0.21	0.33	0.37
Ammonia (NH_3)[(D)]	na	0.78	2.34	3.6	4.0

Notes:

[(A)] Emissions of $PM_{2.5}$ are assumed equal to PM_{10} emissions. Particulate matter emissions include ammonium sulfate formed across selective catalytic reduction (SCR) due to trace sulfur. Emissions of lead (Pb) are addressed in the emission estimate for HAPs as presented in Section 4.3.

[(B)] Total hourly emissions are based on three power generation engines at 90% load (10,260 kW per power generation engine).

[(C)] Total annual emissions are based on the facility NO_X limit of 45 tpy and corresponding fuel use of 628.6 mmscf/yr for all power generation engines combined to achieve an annual average daily send out of 500 mmscfd.

[(D)] Ammonia emissions are based on an emission factor of 0.011 lb/mmBtu for an SCR ammonia slip of 10 ppm.

[(E)] Total annual emissions without TO operation are based on the proposed facility NOx limit of 45 tpy and corresponding fuel use of 3,545.7 mmscf/yr. Without TO operation, the gas send-out annual daily average will be slightly above 500 mmscfd, thus the engines will operate slightly more than under the "with TO" scenario.

Key:

g = Grams.
hr = Hour.
kWh = Kilowatt hour.
lb = Pounds.
na = Not applicable.
tpy = Tons per year.
w/ = with
w/o = without

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4.2.1.3 Thermal Oxidizer

Potential annual emissions from the TO are based on an estimated annual operation of the TO under no send-out and low send-out scenarios and are shown in Table 4-3. The no send-out period was conservatively estimated to occur for three hours during each of 64 SRV visits to the deepwater port. The low send-out period was conservatively estimated based on 535 operating hours per year.

Emissions of NO_X, CO, VOC, and PM_{10} for the TO is based on information from Leif Hoegh (see Appendix B for emissions information).

Table 4-3 Potential Criteria Pollutant Emissions from the Thermal Oxidizer

Pollutant	Emission Factor (lb/mmBtu)	Maximum Hourly Emissions (lb/hr)	Total Hourly Emissions (tpy) [B]	Total Emissions w/o TO (tpy)
No Send-Out Scenario				
Oxides of nitrogen (NO_X)	0.16	33.95	3.2	0
Carbon monoxide (CO)	0.24	50.04	4.8	0
Volatile organic compounds (VOC)	0.06	12.48	1.2	0
Particulate matter (PM_{10} and $PM_{2.5}$)[A]	0.008	1.66	0.16	0
Sulfur dioxide (SO_2)	0.00006	0.12	0.01	0
Ammonia (NH_3)	0	0 0	0	
Low Send-Out Scenario				
Oxides of nitrogen (NO_X)	0.16	13.36	2.4	0
Carbon monoxide (CO)	0.24	17.59	3.7	0
Volatile organic compounds (VOC)	0.06	7.34	0.9	0
Particulate matter (PM_{10} and $PM_{2.5}$)[A]	0.008	3.42	0.12	0
Sulfur dioxide (SO_2)	0.00006	0.12	0.01	0
Ammonia (NH_3)	0	0	0	0

Notes and Key on next page.

Notes:

[A] Emissions of $PM_{2.5}$ are assumed equal to PM_{10} emissions.

[B] Total annual emissions are based on a fuel use of 38.3 mmscf/yr for the no send-out scenario and 29.3 mmscf/yr for the low send-out scenario. A facility cap of 45 tpy is proposed for NO_X.

Key:

mmBtu = million British Thermal Units
hr = Hour.
lb = Pounds.
tpy = Tons per year.
w/ = with thermal oxidizer operation
w/o = without thermal oxidizer operation

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Example Emission Calculation (No Send-out condition):

CO Emissions (lb/hr)
= (Emission Factor)(heat input rating)*
= (0.2406 lb/mmBtu)(208 mmBtu/hr)*
= 50.04 lb/hr

CO Emissions (tpy)
= (Annual fuel usage)(Fuel energy content)* (Emission Factor)/(2000 lb/ton)*
= (38.3 mmscf/yr) (1,041.4 mmBtu/mmscf)*(0.24 lb/mmBtu)/(2000 lb/ton)*
= 4.8 tpy

4.2.2 Summary of Potential Emissions

Table 4-4 summarizes the potential emissions from all emission generating equipment. Total facility potential emissions were selected from the highest of either the facility total with TO operation or facility total without TO operation.

Table 4-4 Summary of Potential Annual Criteria Pollutant Emissions[(A)]

Unit	NO_X (tpy)	CO (tpy)	VOC (tpy)	$PM_{10}/PM_{2.5}$ (tpy)	SO_2 (tpy)	NH_3 (tpy)
SRV Vaporization Boilers w/TO operation	19.1	23.9	8.0	11.3	1.0	7.0
Power Generation Engines w/TO operation	20.3	17.3	23.2	15.4	0.3	3.6
TO operation - Low Send-out(B)	2.4	3.7	0.9	0.12	0.01	0
TO operation - No Send-out(C)	3.2	4.8	1.2	0.16	0.01	0
Facility Total w/TO operation	*45.0*	*49.7*	*33.3*	*26.98*	*1.32*	*10.6*
SRV Vaporization Boilers w/o TO operation	22.2	27.7	9.2	13.0	1.1	8.1
Power Generation Engines w/o TO operation	22.8	19.5	26.1	17.3	0.37	4.0
Facility Total w/o TO operation	*45.0*	*47.2*	*35.3*	*30.3*	*1.5*	*12.1*
TOTAL(D)	**45.0**	**49.7**	**35.3**	**30.3**	**1.5**	**12.1**

Notes:
Total may include data round-off from spreadsheet calculations.

(A) Emissions of $PM_{2.5}$ (particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers) are assumed equal to PM_{10} emissions. Particulate matter emissions for the SRV vaporization boilers and power generation engines include ammonium sulfate formed across SCR due to trace sulfur. Emissions of lead (Pb) are addressed in the emission estimate for HAPs as presented in Section 4.3.

(B) Includes emission from boil-off gas fired in the thermal oxidizer; 29.3 mmscf/yr fuel consumption. See Appendix A for heat input rates used in emission calculation.

(C) Includes emission from boil-off gas fired in the thermal oxidizer; 38.3 mmscf/yr fuel consumption. See Appendix A for heat input rate.

(D) Total annual PTE is the highest of either facility total w/TO operation or facility total w/o TO operation.

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Table 4-4 Summary of Potential Annual Criteria Pollutant Emissions(A)

Key:
CO = Carbon monoxide.
NO_X = Oxides of nitrogen.
PM_{10} = Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
SO_2 = Sulfur dioxide.
SRV = Shuttle regasification vessel.
tpy = Tons per year.
VOC = Volatile organic compounds.
w/ = with
w/o = without

4.3 Hazardous Air Pollutants

The following is a summary of HAP potential emissions from the emission generating equipment.

4.3.1 SRV Vaporization Boilers

HAP emissions from the SRV vaporization boilers were estimated based on available emission factors from AP-42 (Section 1.4, "Natural Gas Combustion").

Emission factors for HAPs are provided as lb/ mmscf based on a natural gas energy content of 1,020 Btu/standard cubic feet (scf). As suggested in AP-42, the emission factors were adjusted to the project design natural gas energy content of 1,041.4 Btu/scf (higher heating value [HHV]).

Each SRV vaporization boiler is estimated to have a maximum hourly natural gas usage rate of 0.270 mmscf/hr, based on a maximum heat input of 281 mmBtu/hr at 90% load (i.e., 281 mmBtu/hr / 1,041.4 Btu/scf). Maximum annual natural gas usage would be 3,545.7 mmscf/yr for all boilers combined under the "no TO" annual operating scenario.

HAP emissions from the SRV vaporization boilers are summarized in Table 4-5. Annual emissions are shown for the two potential annual operating scenarios.

Table 4-5 Potential HAP Emissions from SRV Vaporization Boilers

Pollutant	Emission Factor (lb/mmscf)	Maximum Hourly Emissions (lb/hr/boiler)	Total Hourly Emissions (lb/hr) (B)	Total Annual Emissions w/TO (tpy) (c)	Total Annual Emissions w/o TO (tpy) (D)
Organics					
2-Methylnaphthalene	2.45E-05	6.60E-06	1.98E-05	3.75E-05	4.35E-05
3-Methylchloranthrene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
7,12-Dimethylbenz(a)anthracene	1.63E-05	4.40E-06	1.32E-05	2.50E-05	2.90E-05
Acenaphthene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Acenaphthylene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Anthracene	2.45E-06	6.60E-07	1.98E-06	4.00E-06	4.50E-06
Benz(a)anthracene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06

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Table 4-5 Potential HAP Emissions from SRV Vaporization Boilers

Pollutant	Emission Factor (lb/mmscf)	Maximum Hourly Emissions (lb/hr/boiler)	Total Hourly Emissions (lb/hr) (B)	Total Annual Emissions w/TO (tpy) (c)	Total Annual Emissions w/o TO (tpy) (D)
Benzene	2.14E-03	5.77E-04	1.73E-03	3.28E-03	3.79E-03
Benzo(a)pyrene	1.23E-06	3.32E-07	9.96E-07	2.00E-06	2.00E-06
Benzo(b)fluoranthene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Benzo(g,h,i)perylene	1.23E-06	3.32E-07	9.96E-07	2.00E-06	2.00E-06
Benzo(k)fluoranthene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Chrysene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Dibenzo(a,h)anthracene	1.23E-06	3.32E-07	9.96E-07	2.00E-06	2.00E-06
Dichlorobenzene	1.23E-03	3.32E-04	9.96E-04	1.88E-03	2.18E-03
Fluoranthene	3.06E-06	8.27E-07	2.48E-06	4.50E-06	5.50E-06
Fluorene	2.86E-06	7.73E-07	2.32E-06	4.50E-06	5.00E-06
Formaldehyde	7.66E-02	2.07E-02	6.20E-02	1.17E-01	1.36E-01
Hexane	1.84E+00	4.97E-01	1.49E+00	2.82E+00	3.26E+00
Indeno(1,2,3-cd)pyrene	1.84E-06	4.97E-07	1.49E-06	3.00E-06	3.50E-06
Naphthalene	6.23E-04	1.68E-04	5.04E-04	9.54E-04	1.10E-03
Phenanathrene	1.74E-05	4.70E-06	1.41E-05	2.65E-05	3.10E-05
Pyrene	5.10E-06	1.38E-06	4.13E-06	8.00E-06	9.00E-06
Toluene	3.47E-03	9.37E-04	2.81E-03	5.31E-03	6.15E-03
Subtotal Organics	-	-	**1.56**	**2.96**	**3.4**
Metals					
Arsenic	2.04E-04	5.50E-05	1.65E-04	3.13E-04	3.62E-04
Beryllium	1.23E-05	3.32E-06	9.96E-06	1.90E-05	2.20E-05
Cadmium	1.12E-03	3.02E-04	9.07E-04	1.71E-03	1.99E-03
Chromium	1.43E-03	3.87E-04	1.16E-03	2.19E-03	2.54E-03
Cobalt	8.58E-05	2.32E-05	6.95E-05	1.32E-04	1.52E-04
Lead (A)	5.10E-04	1.38E-04	4.13E-04	7.81E-04	9.04E-04
Manganese	3.88E-04	1.05E-04	3.14E-04	5.94E-04	6.88E-04
Mercury	2.65E-04	7.17E-05	2.15E-04	4.06E-04	4.70E-04
Nickel	2.14E-03	5.77E-04	1.73E-03	3.28E-03	3.79E-03
Selenium	2.45E-05	6.60E-06	1.98E-05	3.75E-05	4.35E-05
Subtotal Metals	-	-	**0.005**	**0.01**	**0.01**
Total HAPS			**1.57**	**2.97**	**3.4**

Notes:

(A) Lead (Pb) a criteria pollutant.

(B) Total hourly emissions are based on three vaporization boilers at 90% load (281 mmBtu/hr per boiler).

(C) Total annual emissions are based on the proposed facility NO_X limit of 45 tpy and corresponding fuel use of 3,061.9 mmscf/yr for all vaporization boilers combined to achieve an annual average send out rate of 500 mmscfd.

(D) Total annual emissions without TO operation are based on the proposed facility NOx limit of 45 tpy and corresponding fuel use of 3,545.7 mmscf/yr. Without TO operation, the gas send-out annual daily average will be slightly above 500 mmscfd, thus the boilers will operate slightly more than under the “with TO” scenario.

Key:

HAP = Hazardous air pollutant.
hr = Hour.

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Table 4-5 Potential HAP Emissions from SRV Vaporization Boilers

Pollutant	Emission Factor (lb/mmscf)	Maximum Hourly Emissions (lb/hr/boiler)	Total Hourly Emissions (lb/hr) (B)	Total Annual Emissions w/TO (tpy) (c)	Total Annual Emissions w/o TO (tpy) (D)

lb = Pound.
Mmscf = Million standard cubic feet.
tpy = ton per year.
w/TO = with thermal oxidizer operation
w/o TO = without thermal oxidizer operation

Example Emission Calculation Procedure (with TO operation):

Maximum hourly Hexane emissions (lb/hr/unit)
= (Emission Factor)(Natural Gas flowrate)*
= $(1.84\ lb/10^6\ scf)*(0.27x10^6\ scf/hr)$
= 0.497 lb/hr per boiler, or 1.49 lb/hr maximum for two SRVs (three boilers)

Maximum annual Hexane emissions (tpy)
= (Emission Factor)(Natural Gas flowrate)*
= $(1.84\ lb/10^6\ scf)*(3{,}061.9x10^6\ scf/yr)/(2000\ lb/ton)$
= 2.82 tpy

4.3.2 Power Generation Engines

HAP emission factors were obtained from available uncontrolled emission factors in the U.S. EPA FIRE 6.25 database for SCC 20200402 Large Bore Dual Fuel Engines as shown in Table 4-5. For the power generation engines, vendors for the CO catalyst indicate that the catalyst would also provide a range of VOC reduction from 70% to 85% depending on the specie of VOC. Therefore, for the HAPs shown in the table, a uniform 70% reduction in HAPs was applied in estimating the HAP emission rates in Table 4-6. Annual emissions are shown in Table 4-6 for the two potential annual operating scenarios.

Table 4-6 Potential HAP Emissions from Power Generation Engines

Pollutants	Emission Factor (A) (lb/mmBtu)	HAP Emissions(B) Maximum Hourly Emission Rate (lb/hr)	Annual Emissions w/TO (tpy)(B)	Annual Emissions w/o TO (tpy)(B)
Speciated Organic Compounds				
Benzene	4.450E-03	0.292	0.44	0.49
Fluoranthene	3.730E-05	0.002	0.00	0.00
Formaldehyde	5.400E-03	0.355	0.53	0.60
Xylenes	1.300E-03	0.085	0.13	0.14

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Table 4-6 Potential HAP Emissions from Power Generation Engines

Pollutants	Emission Factor [(A)] (lb/mmBtu)	HAP Emissions[(B)] Maximum Hourly Emission Rate (lb/hr)	Annual Emissions w/TO (tpy)[(B)]	Annual Emissions w/o TO (tpy)[(B)]
Naphthalene	1.400E-03	0.092	0.14	0.15
Styrene	9.310E-06	0.001	0.00	0.00
Toluene	5.230E-03	0.344	0.51	0.58
TOTAL HAPs		**1.17**	**1.8**	**2.0**

Notes:

(A) Uncontrolled emission factors from U.S. EPA FIRE 6.25 database for SCC 20200402 Large Bore Dual Fuel Engines.

(B) Assumes HAP control level same as VOC control level, thus 70% reduction in HAP achieved from CO catalyst

Key:

HAP = Hazardous air pollutant.
Hr = Hour.
yr = Year.
lb = Pound.
mmBTU = Million British Thermal Unit.
Tpy = Ton per year

Example Calculation (with TO operation):

Toluene Emissions (lb/hr)

= (Uncontrolled Emission Factor)(Fuel usage)*(1-catalyst control)*
= (5.23E-03 lb/mmBtu)(219mmBtu/hr)*(1-0.7)*
= 0.344 lb/hr for two SRVs (three power generation engines total)

Toluene Emissions (tpy)

= [(Uncontrolled Emission Factor)(Fuel Heat Content)* (Annual fuel use)/(2000 lb/ton)*(1-catalyst control)*
= (5.23E-03 lb/mmBtu)(1,041.4 Btu/scf)*(628.2 mmscf/yr)/(2000 lb/ton)]*(1-0.7)*
= 0.51 tpy

4.3.3 Summary of HAP Emissions

Table 4-7 presents a summary of potential HAP emissions from all emissions-generating sources for both annual operating scenarios. Annual potential emissions are slightly higher for the facility operation without TO scenario due to slightly more operation of the engines and boilers than facility operation with TO operation. For both scenarios, potential emissions do not exceed the major source threshold levels for HAPs for any single HAP (10 tpy) or any combination of HAPs (25 tpy).

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Table 4-7 Summary of Potential HAP Emissions

Unit	Organics (tpy)	Metals (tpy)	TOTAL (tpy)
SRV Vaporization Boilers w/TO operation	2.96	0.01	**2.97**
Power Generation Engines w/TO operation	1.8	-	**1.8**
Facility Total w/TO operation	**4.76**	**0.01**	**4.8**
SRV Vaporization Boilers w/o TO operation	3.4	0.01	**3.4**
Power Generation Engines w/o TO operation	2.0	-	**2.0**
Facility Total w/o TO operation	**5.4**	**0.01**	**5.4**
TOTAL HAP(A)	**5.4**	**0.01**	**5.4**

(A) Total annual PTE for HAPs is the highest of facility total w/TO operation and facility total w/o TO operation.

Key:
HAP = Hazardous air pollutant.
LNG = Liquefied natural gas.
tpy = Tons per year.

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5

Best Available Control Technology (BACT) Analysis

This section presents the BACT analysis for the proposed vaporization boilers and power generation engines.

5.1 Introduction

The proposed project would be a minor source of NO_X emissions. Emission controls for all pollutants will be addressed based on the determination of the BACT on a pollutant specific basis for each source type and size.

5.1.1 Background

The intent of the BACT evaluation is to identify the best technological solution allowing for energy, environmental, economic, and other considerations. Using a top-down evaluation method provides for ranking of available control alternatives in descending order of emission control effectiveness. Top-down BACT evaluations on a pollutant-specific basis for the SRV vaporization boilers and power generation engines are presented below.

If the source is subject to NSPS, the minimum control efficiency to be considered as BACT must result in an emission rate more stringent than or equal to the NSPS emission limit. The SRV vaporization boilers are subject to 40 CFR Part 60, Subpart D and would comply with the emission limits therein.

5.1.2 BACT Methodology

The BACT determinations presented below are based on the top-down approach developed by the EPA. This approach, which is described in the EPA's *New Source Review Workshop Manual* (October 1990), includes the following:

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1. Identify all available control alternatives;
2. Evaluate the technical feasibility of each control alternative and eliminate technically infeasible alternatives;
3. Rank the remaining control alternatives by control effectiveness;
4. Evaluate the most effective control alternative with regard to energy, environmental, and economic impacts. Eliminate control alternatives that are infeasible. Continue the process until the alternative under consideration cannot be eliminated; and
5. Select as BACT the most effective alternative not eliminated in step 4.

Identification of possible control technology options is generally accomplished through a review of EPA's RBLC. Additional sources of possible control technology options include state BACT clearinghouses, recent permit decisions for similar projects, and recent developments in emissions control technology applications.

5.2 BACT for SRV Vaporization Boilers

Among the proposed fleet of SRVs, two vaporization boilers rated at 281 mmBtu/hr (at 90% load) would be onboard each SRV. Up to three vaporization boilers may be in service at one time when two SRVs are buoyed at once. Maximum annual fuel use in the SRV vaporization boilers will occur for the "no TO" operation scenario described in section 4.1. The SRV vaporization boilers are proposed to burn natural gas only.

5.2.1 BACT for Oxides of Nitrogen

NO_X is formed during the combustion of natural gas principally by the oxidation of fuel-bound nitrogen ("fuel NO_X"), and by the dissociation of nitrogen in the combustion zone at elevated temperatures ("thermal NO_X"). The primary mechanism for NO_X formation for natural gas combustion is thermal NO_X. Most thermal NO_X is formed in high-temperature flame pockets where the peak-temperature fuel/air interface occurs. A second mechanism of formation, fuel NO_X, occurs from the reaction of fuel-bound nitrogen with oxygen in the combustion air. Fuel NO_X is not considered a significant component of NO_X formation for natural gas combustion because this fuel typically has negligible amounts of chemically bound fuel nitrogen.

5.2.1.1 Best Available Control Alternatives

Available control alternatives for NO_X emissions from large natural gas-fired marine boilers consist of low NO_X burners, flue gas recirculation, combustion control with standard burners, SCR, and ultra-low NO_X burners. However, no control technology determinations were identified in the RBLC or other database for ship marine boilers.

Low NO_X burner technology, flue gas recirculation, combustion control with standard burners, and SCR technology are each considered technically feasible for this project. Ultra-low NO_X burner technology is a relatively new technology with limited development and application, and used primarily on boilers smaller than the project boilers. The vaporization boilers would be

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custom designed for the project. For application to the project, an ultra-low NO_X burner would have to be developed and proven. Without such commercial development, ultra-low NO_X burner technology is not considered technically feasible for this application. The technical feasibility of the remaining control alternatives are evaluated below.

5.2.1.2 Selective Catalytic Reduction (SCR) with Low NO_X Burners

SCR systems would reduce NO_X emissions by injecting ammonia (NH_3) or urea into the exhaust gas stream upstream of a catalyst. NO_X, NH_3, and O_2 react in the SCR to form nitrogen (N_2) and water (H_2O). Reduction is accomplished through the following reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

The NH_3 is injected into the flue gas upstream of the catalyst at the appropriate temperature to react with the NO_X. The SCR catalyst has both upper and lower temperature bounds for successful operation. SCR systems require the exhaust gases be within a typical temperature range of approximately 500 degrees Fahrenheit (°F) to 800°F for optimum reduction of NO_X.

Additional environmental impacts of SCR operation would include ammonia emissions and the disposal of spent catalyst. Ammonia that does not react with NO_X would pass through the catalyst system and be emitted to the atmosphere (ammonia slip). Spent catalyst may be classified as a hazardous waste and thus require special handling and disposal procedures.

The next most effective control alternative for NO_X is low NO_X burner technology. As previously described, combustion controls for natural gas-fired boilers focus on reducing thermal NO_X formation. Low NO_X burners are designed to reduce the flame temperature, which suppresses thermal NO_X formation. This is accomplished by operating at low excess oxygen concentrations and staging the combustion to control the mixing of combustion air and fuel to create a diffused flame. The diffused flame results in reduced combustion-zone temperatures, thereby lowering the reaction rate that produces thermal NO_X.

In some cases, emissions of CO and VOC may increase when using low NO_X burner technology, in comparison to units without these combustion controls. However, any such increase is not expected to result in adverse emissions or impacts.

From research collected for this analysis, it has been determined that there is only experience with low NO_X burners optimized for marine boilers when in oil-burning mode, which has little to no effect on NO_X emissions when in gas-burning mode (Hamworthy Combustion has delivered such burners on other marine boiler applications). In response to reduce emissions, Aalborg has specified the MISSION-D 120 boiler with low NO_X burner technology and SCR to achieve an emission of 10 ppm NO_X maximum. This level would be achieved by using an oversized boiler box downsized to the desired heat input rate. This results in lower internal temperatures and lower generation of NO_X emissions.

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Application of SCR to boiler emissions to reduce NO_X is the most effective NO_X reduction technique available. In order to reduce facility NO_X emissions to less than major nonattainment NSR levels, SCR will be used on boiler exhaust in combination with low NO_X burners in the boiler.

5.2.1.3 NO_X BACT Determination

The use of low NO_X burners in combination with SCR limiting NO_X emissions to 0.012 lb/mmBtu is determined to be BACT for the vaporization boilers. Ammonia slip emissions from operation of the SCR would not exceed 10 ppm.

5.2.2 BACT for Carbon Monoxide

Production of CO emissions results from incomplete combustion of carbon in the fuel. Carbon monoxide is produced when there is insufficient residence time at high temperatures to complete the final step in oxidation of hydrocarbons in the fuel. Maximum oxidation of CO to CO_2 would be achieved through maintaining sufficient temperature, residence time, and oxygen supply to the combustion process.

5.2.2.1 Available Control Alternatives

Methods to control carbon monoxide emissions from boilers include combustion controls wherein CO formation would be suppressed, as well as exhaust gas control by catalytic oxidation. Both control alternatives are considered technically feasible for this application. The top control alternative is an oxidation catalyst system.

No control technology determinations for CO were identified in the RBLC or other database for ship boilers.

5.2.2.2 Oxidation Catalyst

Oxidation catalyst systems operate by converting CO in the presence of oxygen to carbon dioxide and water vapor. Oxidation catalysts operate over a wide range of exhaust temperatures, including the exhaust temperatures expected from the vaporization boilers, therefore, use of a CO catalyst is technically feasible.

Economic Feasibility

An economic feasibility analysis was performed to apply an oxidation catalyst system to the SRV vaporization boilers. Capital and annual cost were estimated based on procedures contained in the EPA Air Pollution Control Cost Manual. The costs presented in Table 5-1 are for three oxidation catalyst systems, one for each SRV (i.e., one oxidation catalyst system serving two vaporization boilers on each SRV).

The equipment cost for the oxidation catalyst system is based on a budgetary estimate obtained from the international ship builder (Leif Hoegh & Co.) for a similar size gas-fired marine boiler. Direct and indirect installation costs were estimated based on factors of the purchased equipment cost, based on guidance contained in the EPA Air Pollution Control Cost Manual.

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As shown on Table 5-1, the total capital cost to install oxidation catalyst systems on the vaporization boilers for the three SRVs would be approximately $834,000.

Annual costs include direct and indirect annual costs. Direct annual costs include costs for catalyst replacement. Indirect annual cost for capital recovery is based on a 7% interest rate over a 15-year period. As shown in Table 5-1, the total annual cost for oxidation catalyst on three SRVs would be approximately $291,000.

Table 5-1 CO Cost Effectiveness for Oxidation Catalyst Applied to the Vaporization Boilers (total costs for three SRVs)*

Capital Cost		
Equipment Cost		
Oxidation Catalyst System Equipment	$156,000 per system, budgetary estimate (A)	$468,000.
	Equipment Cost	*$468,000.*
Taxes and Freight	(0.10) x (equipment costs)	$46,800.
	Total Purchased Equipment Cost (PEC)	*$514,800.*
Direct Installation Cost	(0.24)(B) x (PEC)	$123,552.
Indirect Installation Cost	(0.28)(C) x (PEC)	$144,144.
Contingency	(0.10) x (PEC)	$51,480.
	Total Capital Cost (TCC)	**$833,976**
Annual Cost		
Direct Annual Cost		
Catalyst Replacement	$78,000 per system, budgetary estimate (A) (CRF, 5 yrs, 7% int.)	$57,070.
	Total Direct Annual Cost	*$57,070.*
Indirect Annual Cost		
Taxes, Insurance, Administration	(0.04) x (PEC)	$142,559.
Capital Recovery	15 yrs, 7% int.	$91,566.
	Total Indirect Annual Cost	*$234,125.*
	Total Annual Cost	**$291,195.**
Cost Effectiveness		
CO Potential Emissions without oxidation catalyst (20 ppmvd at 3% O_2 at 27.7 tpy.		27.7 tpy
CO Potential Emissions with oxidation catalyst (4 ppmvd @ 3% O_2at 5.5 tpy)		5.5 tpy
CO Emissions Reduced		22.2 tpy
	Cost Effectiveness ($/ton CO reduced)	**$13,117.**

Notes:

* Costs presented in Table 5-1 are for three oxidation catalyst systems, one for each SRV. Each oxidation catalyst system would serve two vaporization boilers.

(A) Budgetary estimates from Lief Hoegh & Co for a similar size natural gas-fired marine boiler.

(B) Direct installation cost includes: foundations/supports (0.08), handling/erection (0.14), insulation (0.01), and painting (0.01).

(C) Indirect installation cost includes: engineering (0.10), construction/field expenses (0.05), contractors fees (0.10) startup (0.02), and performance test (0.01).

Reference for cost procedure: EPA Air Pollution Control Cost Manual, EPA/452/B-02/001.

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CO catalysts can reduce CO in the exhaust stream in the range of 80% to 90% reduction. The cost effectiveness determination shown in Table 5-1 is based on reducing CO emissions from the proposed level of 20 ppmvd at 3% O_2 to 4 ppm (80% control). As presented in Table 5-1, the cost is determined to be high at approximately $13,100/ton CO reduced. For a 90% CO reduction, the cost is still determined to be high at approximately $11,700/ton CO reduced. This cost is well above the threshold of cost effectiveness for CO of approximately $2,000 per ton of CO removed. Therefore, an oxidation catalyst system is eliminated from further review in this BACT analysis based on economic considerations.

5.2.2.3 Combustion Control and CO BACT Determination

The use of combustion control, the next most effective control method, is determined to be BACT for CO for the vaporization boilers. Based on emission information from a representative boiler manufacturer and the ship builder Leif Hoegh & Co., the estimated CO BACT emission rate for this application is 0.015 lb/mmBtu.

5.2.3 BACT for Volatile Organic Compounds

Unburned hydrocarbons (UHC) are emitted as a result of incomplete combustion of fuel. The volatile components of the unburned hydrocarbons are organic compounds that participate in atmospheric photochemical reactions. This excludes methane, ethane, and other compounds that have negligible photochemical reactivity. Natural gas is comprised primarily of methane, which is a non-volatile organic compound. VOC emissions are minimized by combustion practices that promote combustion efficiency.

Alternatives to control VOC emissions from natural gas-fired boilers consist of combustion control and/or an oxidation catalyst. Both control alternatives are technically feasible. An oxidation catalyst system (in combination with combustion control) is the top control alternative. However, the use of an oxidation catalyst would require a supplemental heating system to raise the fuel gas temperature significantly higher than for CO oxidation, for optimum reduction of VOCs. As with CO, an oxidation catalyst to reduce VOC emissions would not be cost effective for this application. The only viable alternative to control VOC emissions from a natural gas-fired boiler is combustion control. Maintaining efficient combustion is considered representative of BACT to minimize VOC emissions from the proposed vaporization boilers.

An estimate of VOC emissions from the boiler manufacturer was not available. Emissions of VOC in this application are represented as 0.005 lb/mmBtu based on the AP-42 emission factor for natural gas external combustion sources.

5.2.4 BACT for Particulate Matter

Particulate matter emissions from the combustion of natural gas in boilers occur primarily from carryover of noncombustible trace constituents in the fuel and the combustion air. Emissions are dependent on the fuel combusted and its ash content. For higher ash content fuels, such as coal, flue gas emission control systems (e.g., fabric filter systems [baghouses], electrostatic precipita-

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tors, and mechanical collectors) are typically employed to collect and reduce particulate matter emissions.

The use of natural gas is the top alternative to control particulate matter emissions from external combustion sources. The ash content of natural gas is very low, resulting in inherently low emissions of particulate matter, assuming proper combustion control is maintained. The combustion of natural gas precludes the use of flue gas particulate control systems. All particulate matter emitted from natural gas combustion are expected to be PM_{10}; it is assumed that the $PM_{2.5}$ emission rate is equal to the PM_{10} emission rate.

The proposed vaporization boilers would use the top alternative (natural gas fuel) to control particulate matter emissions. Emissions of PM_{10} and $PM_{2.5}$ for this application are estimated at 0.01 lb/mmBtu based on the AP-42 emission factor for natural gas-fired boilers.

5.2.5 BACT for Sulfur Dioxide

Emissions of SO_2 from fuel combustion result from the oxidation of sulfur compounds present in the fuel. Therefore, potential emissions of SO_2 depend on the fuel sulfur content. High sulfur content fuels like coal and residual oil typically use flue gas desulfurization (FGD) systems to control SO_2 emissions. The use of natural gas is the top alternative for the control of SO_2 emissions from fuel combustion sources. Natural gas contains only trace amounts of naturally occurring sulfur compounds and mercaptan that is added as an odorant for leak detection and safety purposes. Typically, LNG does not contain sulfur compounds.

Representing BACT, the proposed vaporization boilers would use the top alternative (natural gas fuel) to control SO_2 emissions. Emissions of SO_2 from the boilers are estimated at 0.0006 lb/mmBtu.

5.2.6 BACT for Hazardous Air Pollutants

Natural gas fired boilers are not significant sources of HAP. Potential emissions of HAP from the gas-fired boilers are well under the applicable major source thresholds. In this case, the only practical method for control of HAP, aside from natural gas firing, is combustion control consistent with the control for CO and VOC. For this application, BACT for HAP and the vaporization boilers is determined to be natural gas-firing and combustion control.

5.2.7 SRV Vaporization Boilers BACT Summary

In summary, a BACT analysis has been conducted for the proposed natural gas-fired SRV vaporization boilers. The BACT analysis was conducted on a pollutant specific basis in accordance with EPA guidelines. The BACT determinations for the boilers are as follows:

- Low NO_X burner technology in combination with SCR for the control of NO_X emissions achieving 0.012 lb/mmBtu. This method of emission control provides BACT for the vaporization boilers used in a marine application.

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- Combustion control for the control of CO and VOC emissions achieving 0.015 lb/mmBtu for CO, and 0.005 lb/mmBtu for VOC.

- Natural gas firing for the control of particulate matter (PM_{10} and $PM_{2.5}$) and SO_2 emissions, achieving 0.01 lb/mmBTU and 0.0006 lb/mmBTU, respectively.

- Combustion control for the control of HAP emissions.

5.3 BACT for Power Generation Engines

Two power generation engines would be installed on each ship to supply power for the vaporization process and ship hoteling. Each engine would have a generating capacity of 11,400 kW. During vaporization operations at the facility, the dual-fuel power generation engines would utilize natural gas with a small amount (less than 1%) distillate fuel oil (maximum 0.05% S) as a pilot fuel. As a general practice, the engines would not be operated above 90% of maximum load (10,260 kW). NO_X emissions from the engines would be included in the 45 tpy facility NO_X cap.

5.3.1 BACT for Nitrogen Oxides

Available control technologies for the control of NO_X emissions from reciprocating engines include combustion control, water injection, non-selective catalytic reduction (NSCR), and SCR technology. NSCR technology applies to natural gas rich-burn reciprocating engines where significant concentrations of oxygen are not present. For this reason, NSCR (controlling NO_X, CO, and VOC emissions simultaneously) is not applicable to this application.

SCR systems available from a variety of suppliers reduce NO_X emissions by injecting ammonia or urea into the exhaust gas stream upstream of a catalyst. NO_X, ammonia (NH_3), and O_2 react in the SCR to form N_2 and H_2O. Reduction is accomplished through the following reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

The NH_3 is injected into the flue gas upstream of the catalyst at the appropriate temperature to react with the NO_X. The SCR catalyst has both upper and lower temperature bounds for successful operation. SCR systems require the exhaust gases be within a typical temperature range of approximately 500°F to 800°F for optimum reduction of NO_X. The exhaust gas temperature from the power generation engines would be approximately 750ºF; therefore, the exhaust gas temperature is in the proper range for SCR operation.

For this application, the proposed power generation engines would achieve 0.2 g/kWh by using SCR to control NO_X emissions (see e-mail dated June 10, 2005 in Appendix B for manufacturer's data). Ammonia slip emissions from operation of the SCR would not exceed 10 ppm.

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5.3.2 BACT for Carbon Monoxide

Oxidation catalysts are commonly used on engines to achieve control of CO emissions. CO catalysts can also reduce VOC and HAP emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and H_2O as the gas stream passes through the catalyst bed.

As with SCR, a CO oxidation catalyst removes pollutants from the engine exhaust gas rather than limiting pollutant formation at the source. Unlike SCR, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation of CO to CO_2 occurs spontaneously and utilizes the excess oxygen present in the engine exhaust (typically 15%). The activation energy required for the CO to CO_2 reaction to proceed is lowered in the presence of the catalyst. Optimum operating temperatures for oxidation catalysts generally fall into the range of 700°F to 1100°F. Below 700°F, CO conversion efficiency falls off rapidly. Above 1200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. Operation at part load or during start-up/shut-down would result in less than optimum temperatures and reduced control efficiency.

For the proposed project, a CO oxidation catalyst would be applied to the power generation engines on each SRV, to reduce CO emissions to 0.165 g/kWh. As a secondary benefit, the oxidation catalyst would also reduce VOC emissions.

5.3.3 BACT for Volatile Organic Compounds

Alternatives to control VOC emissions from the power generation engines consist of combustion control and an oxidation catalyst. Both control alternatives are technically feasible. An oxidation catalyst is the top control alternative. The oxidation catalyst described above for CO emission control would also reduce VOC emissions from 0.5 g/kWh to 0.15 g/kWh.

5.3.4 BACT for Particulate Matter

As described for the LNG vaporization boilers in Section 5.2.4, the use of natural gas is the top alternative to control particulate matter emissions from fuel combustion sources. The ash content of natural gas is very low, resulting in inherently low emissions of particulate matter, assuming proper combustion control is maintained. The combustion of natural gas makes the use of flue gas particulate control systems unnecessary. All particulate matter emitted from natural gas combustion are expected to be PM_{10}; it is assumed that the $PM_{2.5}$ emission rate is equal to the PM_{10} emission rate.

The proposed power generation engines would use 99+% natural gas fuel and <1% distillate oil fuel during vaporization operations, thus they would use the top alternative to control particulate matter emissions. Due to the small amount of sulfur in the exhaust resulting from combustion of distillate oil and the use of SCR, ammonium sulfate may form. The emission rates for PM_{10} and $PM_{2.5}$ have been adjusted to account for this effect. Emissions of PM_{10} and $PM_{2.5}$ for this appli-

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cation are estimated at 0.05 lb/mmBtu based on the Manufacturer supplied emission data (see Appendix A for emission calculation methods and Appendix B for manufacturer's data).

5.3.5 BACT for Sulfur Dioxide

As discussed in Section 5.2.5, emissions of SO_2 from fuel combustion result from the oxidation of sulfur compounds present in the fuel. The use of natural gas is the top alternative for the control of SO_2 emissions from fuel combustion sources. Natural gas contains only trace amounts of naturally occurring sulfur compounds and mercaptan that is added as an odorant for leak detection and safety purposes. Typically, LNG does not contain sulfur compounds.

Representing BACT, the proposed dual-fuel power generation engines would use >99% natural gas, and therefore utilize the top alternative to (natural gas fuel) control SO_2 emissions. Low sulfur distillate fuel oil will be utilized as pilot fuel for the dual-fuel engines in the gas mode. The sulfur content of distillate fuel oil will not exceed 0.05% (by weight). Emissions of SO_2 from the power generation engines are estimated at 0.001 lb/mmBtu.

5.3.6 BACT for Hazardous Air Pollutants

Since the power generation engines would burn 99% natural gas during vaporization operations, they would not be a significant source of HAP. Potential emissions of HAP from the power generation engines would be well under the applicable major source thresholds. The oxidation catalyst described above for CO emission control would result in some reduction of HAP emissions. As a conservative estimate, it was assumed that the oxidation catalyst would result in a 70% reduction in HAP emissions.

5.3.7 Power Generation Engines BACT Conclusions

In summary, a BACT analysis has been conducted for the proposed power generation engines. This analysis was conducted on a pollutant-specific basis in accordance with EPA guidelines. The BACT determinations for the engines are as follows:

- SCR to control NO_X emissions to 0.2 g/kWh. Operation of the SCR may result in ammonia slip emissions of no more than 10 ppm;

- Oxidation catalyst to control CO emissions to 0.165g/KWh, VOC emissions to 0.15g/kWh, and reduce HAP emissions; and

- The dual-fuel engines would operate in the gas mode with less than 1% distillate fuel oil to minimize SO_2 and particulate matter emissions. The distillate fuel oil would have a maximum sulfur content of 0.05% (wt.).

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6

Air Quality Impact Analysis

6.1 Modeling Approach

6.1.1 Model Selection

Atmospheric modeling was performed in accordance with the procedures found in the EPA document *Guideline on Air Quality Models* (revised; EPA-450-2-78-027R, original issue July 1986). The Minerals Management Service (MMS) Offshore and Coastal Dispersion (OCD) model version 5 was used to determine maximum predicted ambient air concentrations for all criteria pollutants to be emitted from the *Neptune* LNG deepwater port. (Model input/output for each OCD model run is provided in Appendix D.)

6.1.2 National Ambient Air Quality Standards (NAAQS) Analysis

The purpose of the NAAQS analysis is to demonstrate that emissions of criteria pollutants would not cause or contribute to an exceedance of the NAAQS. The criteria pollutants evaluated are CO, SO_2, NO_2, PM_{10}, and $PM_{2.5}$.

An impact determination was conducted to estimate whether the proposed sources could have a significant effect on existing air quality – that is, equal or exceed a NAAQS *de minimis* threshold level (or "modeling significance level"). Table 6-1 shows the NAAQS concentrations for each averaging period and the corresponding *de minimis* values. The predicted maximum concentration at or beyond the 500-meter exclusion zone for each pollutant and each averaging time were compared with the appropriate NAAQS *de minimis* threshold level.

As discussed in Section 6.4, all modeling results were less than the NAAQS modeling significance levels. Therefore, by definition, the proposed sources require no further modeling analysis (i.e., cumulative air quality analysis) and would not cause or contribute to a violation of the ambient air quality standards.

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Table 6-1 National Ambient Air Quality Standards (NAAQS) and Ambient Significance Levels

Pollutant	Averaging Period	NAAQS Primary (µg/m^3)	NAAQS Secondary (µg/m^3)	Significance Level (µg/m^3)
Sulfur Dioxide (SO_2)	3-Hour	-	1300	25
	24-Hour	365	-	5
	Annual	80	-	1
Particulate Matter ≤10 micrometers (PM_{10})	24-Hour	150	150	5
	Annual	50	50	1
Nitrogen Dioxide (NO_2)	Annual	100	100	1
Carbon Monoxide (CO)	1-Hour	40,000		2,000
	8-Hour	10,000		500

Key:
µg/m^3 = Micrograms per cubic meter.

6.2 Input Data Requirements

6.2.1 Meteorology

Meteorological data for the OCD model consists of both overland and overwater data with hourly records for each year modeled. Data files were processed for the most recent five year period of 2000-2004.

Overland data consisted of surface data obtained from Boston Logan Airport (station ID 72509) and upper air data obtained from Portland, ME (station ID 54762). Although there is an upper air station located at Chatham, MA, due to the location of Chatham these observations are more representative of overwater conditions; therefore, the Portland site was deemed more appropriate for overland use.

Overwater data were obtained from buoy no. 44013 located 16 nm east of Boston. Since mixing height is a required parameter for OCD modeling, and the buoy data does not contain mixing height data, the mixing heights were determined from the upper air measurements taken at the Chatham, MA station.

Since the raw data files did not contain 100% of the hourly records, it was necessary to fill in missing data. The procedures used included a combination of persistence and interpolation and followed the guidance given in the document *Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models*, Dennis Atkinson and Russell F. Lee, July 7, 1992.

6.2.2 Receptors

To ensure that the maximum ambient impact was located, a series of two polar grids was used. As a matter of conservatism, although up to two SRVs may be at buoy at a given time, all emission sources were co-located. This serves to overestimate the predicted ambient impact, yet provides a convenient method to position receptors relative to the source location.

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The first grid was placed to determine impacts in the near vicinity of the LNG deepwater port. Receptors were placed from 500 meters (exclusion zone) to 2 km away in all directions. These receptors were spaced 50 meters apart, on 36 radials (i.e., 10-degrees between radials) extending from the project location. This provided a total of 1,080 receptors. These receptors are depicted on Figure 6-1. To insure the maximum concentration was found for the 24-hour averaging period for $PM_{10}/PM_{2.5}$, a closer spaced grid consisting of receptors spaced 25 meters apart from 50 meters to 1,000 meters was used.

In addition, another polar grid was placed to determine impacts up to the Massachusetts shoreline, about 25 km away. In this case receptors were placed from 500 meters (exclusion zone) to 25 km away in all directions. These receptors were spaced 1,000 meters apart, on 36 radials (i.e., 10-degrees between radials) extending from the project location. This provided a total of 936 additional receptors. These receptors are also depicted on Figure 6-1.

In addition to the receptor locations, terrain elevations were used as allowed in the OCD model. For receptors located on water, an elevation of zero was used. For receptors on land, the elevation was determined based on interpolation of values obtained from United States Geological Survey (USGS) quadrangle elevation contours. (The actual elevation assigned to any given receptor can be found in any of the model input files.) All receptors were input as discrete receptors (as opposed to automatically generated polar grids).

6.2.3 Building Downwash and Good Engineering Practice

Building wake effects may have a significant effect on the concentration of pollutants near the stack. Building wake effects are flow lines that cause plumes to be forced down to the ground much sooner than they would if the building were not there.

Section 123 of the Clean Air Act Amendments requires the EPA to promulgate regulations to assure that the control of any air pollutant under an applicable State Implementation Plan was not affected by: 1) stack heights that exceed Good Engineering Practice (GEP), or 2) any other dispersion technique. The EPA provides specific guidance for determining GEP stack height and for determining whether building downwash would occur in the *Guidance for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations;* EPA-450-4-80-023R, June, 1985).

GEP is defined as “the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes that may be created by the source itself, or nearby structures, or nearby terrain obstacles.” The GEP definition is based on the observed phenomena of atmospheric flow in the immediate vicinity of a structure. It identifies the minimum stack height at which significant adverse aerodynamics (downwash) caused by nearby structures are avoided.

The OCD model contains a building downwash algorithm; however, it is not as sophisticated as the algorithm provided in the Industrial Source Complex model and does not include direction-specific building parameters. As implemented within the OCD model, only one building height and width is used for each source.

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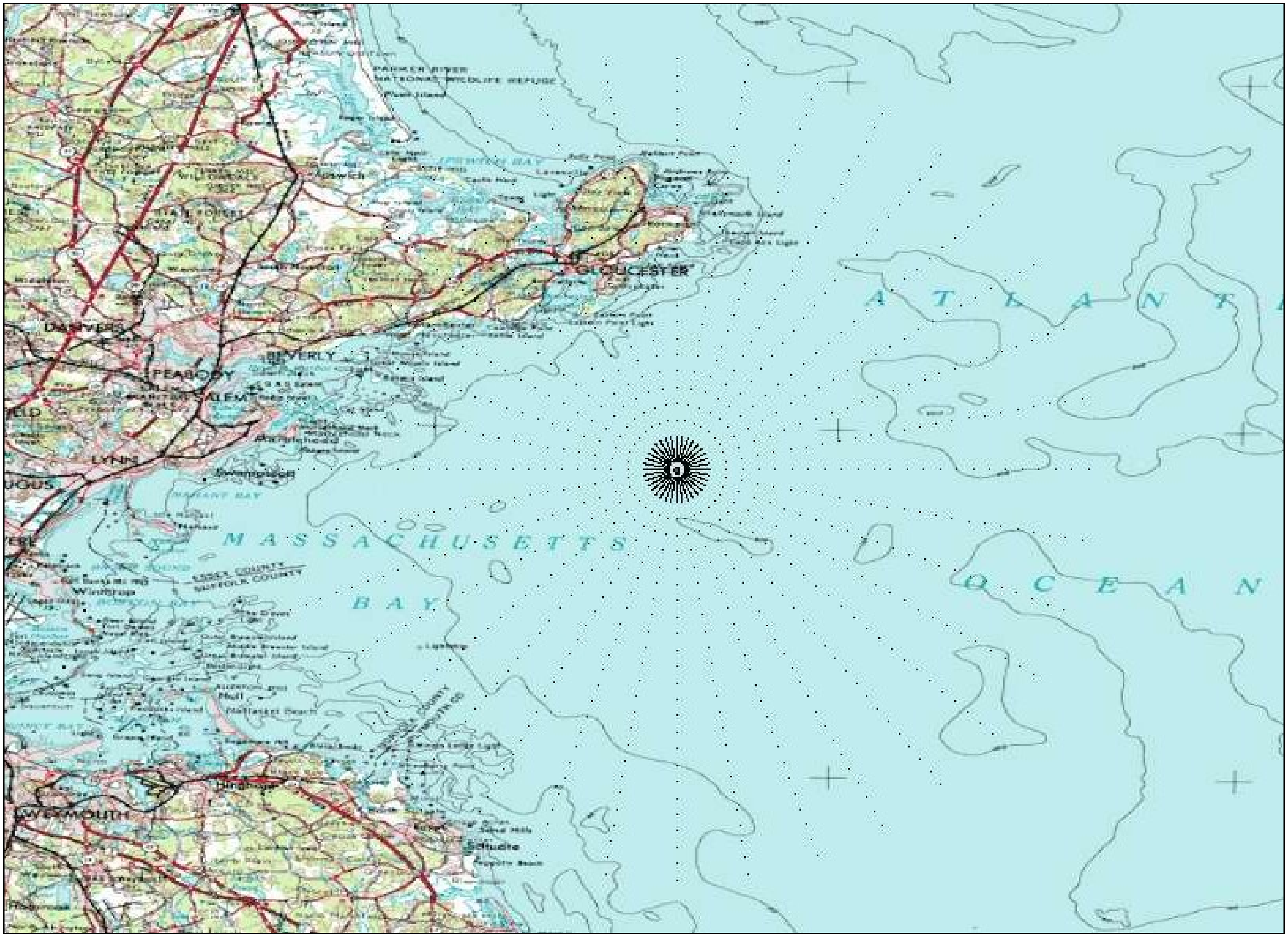

Figure 6-1 Modeling Receptor Domain

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Since the SRVs would be approximately 125 feet (38 meters) high (height of the highest structure on the SRV), 918 feet long, and 141 feet wide, a building height of 125 feet (38 meters) was used for all sources as input for the OCD downwash algorithm. Since the SRVs would be allowed to rotate around the mooring point, and would face into the wind, the width of the SRV of 141 feet (43 meters), rather than its length, was used as the cross-wind dimension for all sources.

6.3 Source Inventory

6.3.1 Facility Sources Evaluated in Modeling

Emissions from the SRV vaporization boilers, power generation engines and the TO were included in the modeling. Table 6-2 shows the annual emission rates of the SRV emission sources that were included in the modeling analysis; Table 6-3 shows the short-term emission rates. The Emission Point Name (EPN) SRVBLR refers to the SRV vaporization boiler, the EPN POWER refers to the power generation engines and TO refers to the thermal oxidizer.

Each SRV would have two boilers firing natural gas while at buoy. Since up to two SRVs may be unloading at a given time (during overlapping periods of arriving/departing vessels), short-term emissions (i.e., one-hour, three-hour, eight-hour, and 24-hour averaging periods) from two SRVs, as described in Section 4.1, were evaluated. Similar to the vaporization boilers, for purposes of short-term modeling (i.e., one-hour, three-hour, eight-hour, and 24-hour averaging periods) it was necessary to explicitly model a second SRV at buoy. Operation scenarios for short-term emission rates are described in Section 4.1. The TO would be used during no gas send-out or low gas send-out conditions. After the arriving SRV connects to the buoy, operation of the TO for a period of approximately three hours may be needed while the SRV prepares to discharge vaporized LNG. During this time, boil-off gas will continue to be generated. Since the engines and boilers on-board the SRV may not be able to consume all boil-off gas generated, the excess will be burned in the TO.

6.3.2 Short-term Emission Rates

The maximum hourly emission rate in pounds per hour (lb/hr) used for short term air pollutant averaging periods may be affected by the short term operating configuration of the port. Hourly emissions in pounds per hour (lb/hr) for three short-term operating scenarios were analyzed to determine the maximum hourly emission rate for the facility for use in modeling pollutants with short-term (i.e., less than 24 hours) averaging periods. Possible operating scenarios included:

- One SRV operating at maximum send-out rate (90% load on two engines and two boilers) and the second SRV operating the TO only (no send-out condition);
- One SRV operating at maximum send-out rate (90% load on two engines and two boilers) and the second SRV operating in low send-out mode (reduced load on engines and boilers compared to normal send-out conditions and use of the TO at a rate less than the no send-out condition); and

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- One SRV operating at maximum send-out rate (90% load on two engines and two boilers) and the second SRV operating one engine and one boiler at 90% load. The TO is not used.

The first scenario results in the maximum hourly emission rate for modeling carbon monoxide over the 1-hour and 8-hour averaging periods. Maximum hourly emissions in pounds per hour for other pollutant's short term emission analysis (SO_2 and $PM_{10}/PM_{2.5}$) were modeled using the third scenario. The second scenario did not result in a maximum hourly emission rate for any pollutant or averaging time.

These short-term emission scenarios identify the worst-case conditions when two SRVs may overlap at the port such as during overlapping periods of arriving/departing SRVs.

6.3.3 Emission Rates for Annual Average Period

The NO_X emission rate for each source for the annual average period was calculated by determining the contribution of each source under the facility 45-tpy permit limitation on annual NO_X emissions for the annual scenarios described in Section 4.1 (i.e. with and without operation of the TO during the year). The resulting fuel consumption for each source type (i.e., boiler, engines, and TO) corresponding to the annual NO_X emission was used to determine fuel consumption for each source; other pollutants' annual emission rates were then based on the resulting fuel consumption. Annual emission rates selected for annual average period modeling are based on the highest annual emission total from the two annual operating scenarios (i.e. with and without TO operation). The "without TO" annual scenario resulted in the highest annual emissions for $PM_{10}/PM_{2.5}$ and SO_2 (facility-wide NO_X will be capped at 45 tpy therefore the annual total is the same for both scenarios).

Table 6-2 Modeling Emission Rates – Annual Average Period

	Annual Emission Rates[A]					
	Nitrogen Oxides (NO_X)		Particulate Matter ($PM_{10}/PM_{2.5}$)		Sulfur Dioxide (SO_2)	
Source	**tpy**	**g/sec**	**tpy**	**g/sec**	**tpy**	**g/sec**
SRVBLR	22.2	0.638	13.0	0.373	1.1	0.032
POWER	22.8	0.656	17.3	0.497	0.37	0.011
TO	0	0	0	0	0	0
Total	**45.0**	**1.294**	**30.3**	**0.87**	**1.47**	**0.043**

Notes:

(A) Annual tpy and annual average g/sec emission rates are for two buoys combined; emission rates reflect the highest annual rate selected from two annual operating scenarios (i.e. with or without TO operation). $PM_{10}/PM_{2.5}$ emission rates for SRVBLR and POWER include ammonium sulfate formed across SCR due to trace amount of sulfur in exhaust.

Key:

g/sec = Grams per second.
lb/hr = Pounds per hour.
NA = Not applicable.
POWER = Power generation engines.
SRVBLR = Shuttle regasification vessel vaporization boiler
tpy = Tons per year.

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Table 6-3 Modeling Emission Rates – Short-term Average Period

	Maximum Short-term Emission Rates									
	CO		CO		Particulate Matter ($PM_{10}/PM_{2.5}$)		Sulfur Dioxide (SO_2)		Sulfur Dioxide (SO_2)	
	8-Hour		1-Hour		24-Hour		3-Hour		24-Hour	
Source	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec
SRVBLR + POWER(A)	23.82	3.001	23.82	3.001	16.23	2.045	0.72	0.091	0.72	0.091
Low Send-out(B)	17.59	2.216	17.59	2.216	3.42	0.431	0.12	0.015	0.12	0.015
No Send-out(C)	18.77	2.365	50.04	6.305	1.66	0.209	0.12	0.015	0.12	0.015
Maximum of Above(d)	23.82	3.001	50.04	6.305	16.23	2.045	0.72	0.091	0.72	0.091

Notes:

(A) Emissions from both buoys combined.

(B) Emissions from one buoy only. Consists of emissions from engines and boilers at low load and TO and low use.

(C) Emissions from one buoy only. Consists of TO emissions only. CO 8-hour rate assumes 3 hours operating at CO 1-hour emission rate, then 0 emissions for 5 hours.

(D) Maximum emission rate used in short term modeling at buoy 1; second highest emission rate used at buoy 2.

Key:

g/sec = Grams per second.
lb/hr = Pounds per hour.
= Not applicable.
POWER = Power generation engines.
SRVBLR = Shuttle regasification vessel vaporization boiler
NA tpy = Tons per year.

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6.3.4 Stack Parameters

Table 6-4 includes stack parameters for all sources being modeled for the annual average period analysis. Table 6-5 shows stack parameters for all sources modeled for short term averaging periods. For modeling CO at the 1 hour average period, the SRVs were modeled with one SRV operating two boilers and two engines at 90% load while the second SRV operates only the TO, based on the maximum 1-hour emission rate analysis discussed in section 6.3.

Table 6-4 Modeling Stack Parameters – Annual Average Period

	Stack Parameters							
	Height		Diameter		Velocity		Temp.	
Source	feet	meters	feet	meters	feet per second	meters per second	ºF	K
SRVBLR1	164	50	4.27	1.30	50.30	15.33	633	607.2
POWER1	164	50	3.94	1.20	92.10	28.07	756	675.6
TO	164	50	11.81	3.60	86.40	26.33	842	723.3

Key:

°F = Degrees Fahrenheit.
K = Kelvin.
POWER = Power generation engines.
SRVBLR = Shuttle regasification vessel vaporization boiler.
TO =Thermal Oxidizer

Table 6-5 Modeling Stack Parameters – Short Term Average Period

	Stack Parameters							
	Height		Diameter		Velocity		Temp.	
Source	feet	meters	feet	meters	feet per second	meters per second	ºF	K
SRV at Buoy 1– no send out condition (CO 1 hour modeling)								
SRVBLR1	164	50	4.27	1.30	0	0	na	na
POWER1	164	50	3.94	1.20	0	0	na	na
TO	164	50	11.81	3.60	86.40	26.33	842	723.3
SRV at Buoy 2 at 90% Load (per engine and boiler) – no TO operation								
SRVBLR1	164	50	4.27	1.30	50.30	15.33	633	607.2
POWER1	164	50	3.94	1.20	92.10	28.07	756	675.6
TO	164	50	11.81	3.60	0	0	na	na

Key:

°F = Degrees Fahrenheit.
K = Kelvin.
POWER = Power generation engines.
SRVBLR = Shuttle regasification vessel vaporization boiler.
TO = Thermal Oxidizer

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6.4 Model Results

Table 6-6 shows the results of the modeling runs. The maximum ambient pollutant concentration from the receptor grid is used for comparison to the NAAQS *de minimis* threshold levels.

Since maximum ambient impacts for all pollutants are shown to be below the modeling significance levels, no additional modeling was required. By definition, the proposed emissions would not cause or contribute to exceedance of the NAAQS for any pollutant.

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Table 6-6 NAAQS De Minimis Analysis

		Maximum Concentration by Year ($\mu g/m^3$)							
Pollutant	**Averaging Period**	**2000**	**2001**	**2002**	**2003**	**2004**	**Overall Max. Con. ($\mu g/m^3$)**	**De minimis ($\mu g/m^3$)**	**Exceeds De minimis?**
CO	1-Hr	37.01	30.04	31.24	26.38	28.61	37.01	2000	No
CO	8-Hr	5.38	6.47	7.00	5.94	6.45	7.00	500	No
NO_2	Annual	0.09	0.11	0.09	0.09	0.08	0.11	1	No
PM_{10}	Annual	0.06	0.07	0.06	0.06	0.05	0.07	1	No
PM_{10}	24-Hr	3.01	2.33	2.97	2.79	2.77	3.01	5	No
SO_2	Annual	0.00	0.00	0.00	0.00	0.00	0.00	1	No
SO_2	3-Hr	0.53	0.45	0.65	0.51	0.48	0.65	25	No
SO_2	24-Hr	0.17	0.12	0.16	0.15	0.14	0.17	5	No

Key:

$\mu g/m^3$ = Micrograms per cubic meter.
CO = Carbon monoxide.
Hr = Hour.
NO_2 = Nitrogen dioxide.
PM_{10} = Particulate matter (10 microns or less)
$PM_{2.5}$ = Particulate matter (2.5 microns or less)
SO_2 = Sulfur dioxide.

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A

Emission Calculations

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B

Manufacturer's Emission Data

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C

Air Permit Application Forms

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D

Air Dispersion Modeling Files

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Air dispersion modeling files on CD in pocket.

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