JORDAN COVE ENERGY PROJECT, L.P.
LNG Terminal

Type B State New Source Review Application

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SLR

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ACRONYMS

ACDP	Air Contaminant Discharge Permit
ARM	Ambient Ratio Method
AQRV	Air Quality Related Value
BOG	Boil-Off Gas
BPIPPRM	Building Profile Input Program
Btu/scf	British Thermal Unit per Standard Cubic Feet
°C	Degrees Celsius
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CT	Combustion Turbine
DFDE	Duel-Fuel Diesel-Electric
Dth/d	Dekatherm Per Day
EPA	Environmental Protection Agency
°F	Degrees Fahrenheit
ft	Feet
FLM	Federal Land Managers
g/hp-hr	Grams per Horsepower-Hour
g/kW-hr	Grams per Kilowatt-Hour
GEP	Good Engineering Practice
GHG	Greenhouse Gas
gr/100 scf	Grain per 100 Standard Cubic Feet
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HAPs	Hazardous Air Pollutants
HHV	Higher Heating Value
hp	Horsepower
hr	Hour
HRSG	Heat Recovery Steam Generator

ACRONYMS (CONTINUED)

JCEP	Jordan Cove Energy Project, L.P.
JCLNG	Jordan Cove LNG Terminal
K	Kelvin
KBJ	Kiewit, Black & Veatch, and JGC
kg	Kilogram
km	Kilometer
kPa	Kilopascals
Lb	Pound
lb/MWh	Pound per Megawatt-hour
LHV	Lower Heating Value
LNB	Low NO_X Burners
LNG	Liquefied Natural Gas
LNGC	LNG Carrier
m	Meter
m^3	Cubic meter
µg	Microgram
$µg/m^3$	Micrograms per cubic meter
MERPs	Modeled Emission Rates for Precursors
MMBtu	Million British Thermal Units
MMCF	Million Cubic Feet
MMscf/d	Million Standard Cubic Feet per Day
MOF	Material Offloading Facility
MPGF	Multi-Point Ground Flare
mtpa	Million Tonnes Per Annum
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NAD	North American Datum
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMHC	Non-Methane Hydrocarbon
NO	Nitric Oxide
NO_2	Nitrogen Dioxide

ACRONYMS (CONTINUED)

NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
OAR	Oregon Administrative Rules
OCIMF	Oil Companies International Marine Forum
ODEQ	Oregon Department of Environmental Quality
OLM	Ozone Limiting Method
PCGP	Pacific Connector Gas Pipeline
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10-microns in diameter
$PM_{2.5}$	Particulate Matter less than 2.5-microns in diameter
ppm	Parts Per Million
ppmv	Parts Per Million By Volume
ppmvd	Parts Per Million By Volume, Dry
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PVMRM	Plume Volume Molar Ratio Method
RICE	Reciprocating Internal Combustion Engine
SCF	Standard Cubic Feet
SCR	Selective Catalytic Reduction
sec	Seconds
SER	Significant Emission Rate
SILs	Significant Impact Levels
SMR	Single Mixed Refrigerant
SO_2	Sulfur Dioxide
SORSC	Southwest Oregon Regional Security Center
ST	Steam Turbine
STG	Steam Turbine Generator
SU/SD	Startup and Shutdown
TEGF	Totally Enclosed Ground Flare

ACRONYMS (CONTINUED)

TO	Thermal Oxidizer
tpy	Tons Per Year
USCG	United States Coast Guard
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids
yr	Year

1. INTRODUCTION

Jordan Cove Energy Project, L.P. (JCEP) is submitting a Type B State New Source Review (NSR) application for approval to construct and operate the Jordan Cove liquefied natural gas (LNG) Terminal (JCLNG) near Coos Bay, Oregon. JCEP obtained approval for construction and operation of the terminal under Standard Air Contaminant Discharge Permit (ACDP) No. 06-0118-ST-01 on June 16, 2015. Since that approval, several changes were made to the facility design to optimize energy use and lower the environmental impacts. This permit application is being submitted to obtain a Standard ACDP to reflect the final facility equipment and emissions.

JCLNG will be a LNG export terminal and will consist of facilities to receive, liquefy, store, and load the refrigerated fuel onto LNG carriers (LNGC). JCEP has designed the LNG Terminal to receive a maximum of 1,200,000 dekatherms per day (dth/d) of natural gas and produce a maximum of 7.8 million tonnes per annum (mtpa) of LNG for export.

The project site is 199 acres located on the bay side of the North Spit of Coos Bay, between Coos Bay Navigation Channel Miles 7.0 and 8.0. The site consists of two areas located on either side of Roseburg Forest Products and connected by a utility corridor. The liquefaction facility, LNG storage tanks, and berth will be located at Ingram Yard to the west of Roseburg Forest Products. The South Dunes part of the site will contain administrative buildings and temporary workforce housing. JCLNG will include five turbine-driven refrigeration compressors, gas conditioning equipment, a thermal oxidizer, an auxiliary boiler, emergency fire water pumps, black start engine generators, backup engine generators, a marine flare, a warm flare, and a cold flare.

The LNG Terminal site is located in Coos County, Oregon, which is in attainment or unclassified for all pollutants. The proposed Jordan Cove LNG Project has the potential to emit nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), particulate matter less than 10 micrometers (PM_{10}), particulate matter less than 2.5 micrometers ($PM_{2.5}$), and sulfuric acid mist (H_2SO_4) above Oregon Significant Emission Rates (SERs) but below the Prevention of Significant Deterioration (PSD) threshold of 250 tons per year (tpy).[1] JCEP is submitting an application for approval in accordance with Oregon Administrative Rule (OAR) 340-224-0270 for these pollutants, which includes a Type B State NSR air quality impact analysis for CO, SO_2, PM_{10}, $PM_{2.5}$, and NO_X. This report provides a description of the proposed facility, emission calculations, regulatory applicability, and the air quality impact analysis.

[1] 340-224-0010(2)(b)(A)

2. PROJECT DESCRIPTION

Jordan Cove Energy Project, L.P. is proposing to construct and operate an LNG export terminal in Coos Bay, Oregon. The LNG Terminal will turn natural gas into its liquid form via refrigeration to approximately -260 degrees Fahrenheit (°F). The Jordan Cove terminal includes an access channel from the Coos Bay navigation channel, a marine slip with one LNG carrier berth, an emergency lay berth, four tug boat berths, a loading platform and transfer piping, two LNG storage tanks, five liquefaction trains, one gas conditioning train, several support buildings, and the Southwest Oregon Regional Security Center (SORSC).

In coordination with federal and state agencies and in consultation with the public, plans for both the terminal and natural gas pipeline route have been optimized to avoid or minimize potential impacts and increase efficiency.

The project will include the following emitting equipment:

- Five aero-derivative gas turbines (with waste heat recovery);
- Thermal oxidizer;
- Auxiliary boiler;
- Fire-water pumps;
- Black start generators;
- Backup generators;
- A multi-point ground flare (warm and cold flares); and
- A totally enclosed ground flare (marine flare).

The general location of the proposed LNG Terminal is shown on Figure 1. Also, Figure 1 includes a general layout of the surrounding area and identifies the names of various geographic areas related to the project.

The LNG Terminal will receive natural gas from the Pacific Connector Gas Pipeline (PCGP), process the gas, liquefy the gas into LNG, store the LNG, and load the LNG onto ocean-going LNG carriers at its marine berth. The main operational components of the LNG Terminal are shown on Figure 2 (Plot Plan of the LNG Terminal) and include a connection to the Pipeline metering station, gas inlet facilities, a gas conditioning plant, an access and utility corridor, liquefaction facilities (including five liquefaction trains), two full-containment LNG storage tanks, an LNG loading line, LNG loading facilities, a marine slip, and an access channel for LNG carriers.

JCEP currently anticipates that construction for the Project would begin in the first half of 2019, with a target in-service date in the first half of 2024. Planned construction milestones are:

- Q1 2019 - Q4 2019 – Purchasing combustion equipment
- Q3 2019 - Q4 2019 – Release combustion equipment for manufacturing
- Q3 2019 – Mobilize to site and break ground
- Q3 2021 - Q2 2023 – Pre-Commissioning
- Q4 2022 – Introduce natural gas to site

- Q3 2022 - Q4 2023 – Commissioning
- Q2 2023 – LNG Tank Cooldown
- Q4 2023 – Plant Completion/Operations Begin

2.1 PROPOSED PROJECT

2.1.1 PROCESS DESCRIPTION

2.1.1.1 Gas Inlet and Conditioning

Pipeline quality feed gas will be supplied to the LNG Terminal via the 36-inch-diameter PCGP natural gas transmission pipeline routed from Malin, Oregon to a metering skid located on the South Dunes Site. Inlet pipeline metering facilities consist of a pipeline pig receiver, inlet filter/separator, and a flow meter. Additionally, a feed inlet heater will provide heating of the high pressure feed gas on cold days to prevent formation of natural gas hydrates resulting from Joule-Thomson cooling when gas pressure is let down by the pressure reduction unit. The feed inlet heater uses low pressure steam to warm the gas.

The feed gas from the pipeline will be treated before the gas enters the liquefaction trains. A Gas Conditioning train, in a 1 x 100 percent configuration, will include a system for mercury removal via sulfur impregnated activated carbon, carbon dioxide (CO_2) and acid gas removal via an amine system, and dehydration via a molecular sieve adsorbent system.

Mercury is removed via adsorption onto sulfur-impregnated activated carbon beds, in a 3 x 33 percent configuration, in order to prevent cold box corrosion during gas liquefaction and to minimize the exposure of other equipment and vent streams to mercury contamination. The mercury removal beds will reduce the amount of mercury in the treated pipeline gas down to less than 0.01 micrograms per Normal cubic meter ($\mu g/Nm^3$). Spent catalyst from the mercury removal vessels will be removed periodically and sent off-site for disposal at a licensed hazardous waste management contractor.

Acid gas removal involves a closed-loop system that circulates a promoted methyldiethanolamine solution to absorb CO_2 and sulfur species from the feed gas. The process reduces the feed gas CO_2 concentration from a maximum of 2 percent on a molar basis to less than 50 parts per million on a volumetric basis (ppmv). The CO_2 removed from the feed gas is to be vented to the atmosphere, but the vent stream must first be treated for co-absorbed contaminants. To limit emissions, absorbed hydrogen sulfide (H_2S) and other sulfur species in the vent stream will be thermally oxidized after passing through the sulfur scavenger unit. Co-absorbed hydrocarbons, including benzene, toluene, ethylbenzene, and xylenes, will also be combusted and destroyed in the thermal oxidizer at greater than 99.9 percent destruction efficiency.

The dehydration system is located immediately downstream of the acid gas removal system and employs four molecular sieve adsorption beds. The water removal system will reduce water in the treated feed gas to less than 0.1 ppmv. At any time, two beds will be in adsorption mode, one bed will be in regeneration/cooling mode, and the remaining bed will be on stand-by. Regeneration of a bed involves passing dehydrated heated feed gas through it, in an up-flow direction, which drives the adsorbed water out of the bed. This water-saturated regeneration gas is then cooled to condense and remove the water, which is collected and recycled back into the acid gas removal system. This regeneration gas is then compressed and recycled upstream of the dehydration units. The regenerated bed will then be cooled by non-heated dehydrated feed gas until a low enough temperature is achieved to place it back into adsorption service.

2.1.1.2 Natural Gas Liquefaction

Liquefaction Trains

The LNG Terminal includes five liquefaction trains utilizing the Black & Veatch proprietary PRICO® LNG technology to produce a maximum of 7.8 mtpa (1,077 MMscf/d [million standard cubic feet per day]) of LNG production net, after deduction for Boil-Off Gas (BOG) generation. Each liquefaction train will have an anticipated maximum annual capacity of 1.56 mtpa (215.5 MMscf/d). The nominal annual capacity may be less than this value due to annual ambient temperature variation, planned non-major facility maintenance outages, unplanned facility outages, and the expected degradation of the combustion gas turbines. The PRICO® LNG technology utilizes a single mixed refrigerant (SMR) circuit with a two-stage compressor and a brazed aluminum refrigerant exchanger.

The dry treated gas from the gas conditioning train is divided equally among the five liquefaction trains. In each liquefaction train, the dry treated gas stream flows into a refrigerant exchanger where it is pre-cooled and condensed into liquid by cooling it to approximately -260 °F via heat transfer with the mixed refrigerant. The refrigeration cycle is a closed-loop process that utilizes a single-body, two-stage refrigerant compressor. For each liquefaction train, an aero-derivative combustion turbine directly provides the power to drive the refrigerant compressor. Turbine exhaust-gas waste heat recovery steam generators (HRSGs) maximize the overall thermal efficiency of the LNG Terminal.

Heavies Removal

Heavy hydrocarbons, or “heavies” (generally referred to as C5+ components), will be removed from the feed gas before the final liquefaction step in order to meet the LNG specification and prevent possible freezing in the brazed aluminum refrigerant exchanger at subcooled temperatures. The system will be designed to remove the most likely-to-freeze components—benzene and octane—to less than 1 ppmv while recovering as much of the C4 and lighter molecules as economically as possible into the gas going to the final liquefaction step. The total volume of heavies removed across the range of feed compositions is not enough to produce economically viable natural gas liquids product for sale or export; however, it will be blended into the fuel gas stream, so no tankage or disposal logistics need to be considered.

Refrigerant Makeup

For many technologies, refrigerant losses occur from the closed-loop refrigeration loops primarily due to normal compressor seal leakage. However, the Black & Veatch patented seal gas recovery system will be utilized to minimize the refrigerant losses to flare by returning the normal leakage to the refrigerant compressor suction. Even with seal gas recovery, the refrigeration loop components must be replenished periodically to normal operation inventory levels. The hydrocarbons that provide make-up to the SMR circuit used in the liquefaction trains cannot be generated on-site (with the exception of methane, which comes from the treated feed gas) and will be delivered to the LNG Terminal and stored in pressurized vessels for intermittent makeup to the SMR circuit.

LNG Storage and Containment

The LNG will be stored in two full-containment insulated LNG storage tanks, each of which is designed for a working capacity of 160,000 cubic meters (m^3) (42,232,000 gallons) of LNG. Each tank will have a primary 9 percent nickel inner tank and a secondary concrete outer containment wall with a steel vapor barrier. The LNG storage tanks will have top connections only with piping that will permit top and bottom loading. Top loading operation will be done via a spray device/splash plate in order to obtain flashing and mixing of the LNG as it combines with LNG inventory. The bottom loading operation will be achieved via a standpipe to ensure effective mixing. The separated flash vapor combines with vapors from tank displacement and heat leak and flows to the boil-off gas compressors for use as fuel.

LNG is pumped to the marine berth and into an LNG carrier at a normal loading rate of 12,000 m^3/hr. An LNG transfer line will connect the shore-based storage system with the LNG loading system. A smaller recirculation, “keep cool” line is provided from the LNG storage tank area to the marine berth in order to maintain the LNG transfer piping at cryogenic temperatures to avoid excessive boil-off losses and potential damage from thermal cycling between carrier arrivals.

Marine Facilities

The LNG Terminal will include a single-use marine slip dedicated to supporting LNG exports. The east side of the slip will be utilized for the LNG carrier loading berth and LNG loading facilities. Berths for tugboats and security vessels will be located on the north side of the slip. An emergency lay berth will be provided on the west side of the slip to allow for berthing a temporarily disabled LNG carrier in an emergency. This berth will have no product loading facility, but it will comply with and be designed to meet all of the safety and security standards of the Oil Companies International Marine Forum (OCIMF) and the United States Coast Guard (USCG).

The LNG carrier loading berth will be capable of accommodating LNG carriers with a cargo capacity range of 89,000 m^3 to 217,000 m^3.

Vessel Transit

LNG carriers would access the LNG Terminal through a waterway for LNG marine traffic, which is defined by the USCG for the Project as extending from the outer limits of the U.S. territorial waters 12 nautical miles off the coast of Oregon, and up the existing Federal Navigation Channel about 7.5 miles to the LNG Terminal.

The total average LNG carrier port time is estimated to be approximately 36 hours, assuming there are no delays caused by natural environmental conditions. This estimate includes the transit time from the Pilot boarding to arrival at the LNG loading berth to the Pilot drop-off at departure, time of mooring, unmooring and cast off, the bulk LNG loading time of approximately 15 hours (using the 12,000 m^3/hr loading rate), and the 8 hours of time waiting for the next available high tide cycle needed for safe departure transit of the Federal Navigation Channel.

Vapor Handling System

BOG is primarily generated from the LNG storage and loading system and consists of flash gas from the LNG product stream entering the LNG flash drum, vapors from the heat leak into the LNG storage tanks, piping and pump systems, vapor displaced as the LNG storage tanks are filled, and vapor return from the LNG carrier during LNG loading. The BOG will be consumed as fuel. Two BOG compressor trains are included to compress the vapor from LNG storage tank pressure to fuel gas pressure. The centrifugal compressors have electric motors and dry gas seals.

The mode of operation of the liquefaction plant when not loading an LNG carrier is known as "holding mode." The mode of operation during LNG carrier loading is known as "loading mode." One BOG compression train will be operating continuously to handle holding mode BOG volumes; the second will be needed only during loading mode or during an off-design condition that results in increased BOG generation.

During normal operation, fuel gas will be supplied from BOG and vaporized heavy hydrocarbon streams and supplemented with gas from the inlet pipeline upstream of the gas conditioning train. After mixture in the high-pressure fuel gas mixing drum, this high-pressure fuel gas stream primarily feeds the combustion gas turbines to drive the refrigerant compressors. Some high-pressure fuel gas is let down from the high-pressure fuel gas header to the low-pressure fuel gas knockout drum before going to other smaller consumers, such as the thermal oxidizer, duct burners, and flare pilots. Normally, a small amount of makeup to the high-pressure fuel from the pipeline feed gas is required to meet demands; if the BOG/heavies mixture results in excess fuel for the demand, it can be recycled upstream of the amine unit and re-liquefied.

Instrument Air

Instrument air will be provided through compression and drying packages. Air will be compressed in 1 x 100 percent centrifugal compressors. There will be one additional compressor with the ability to provide essential instrument air duty. Air will be dried in 2 x 100 percent air dryer packages, with each package containing four air dryers designed for full, continuous operation. During operations, one dryer will be in adsorption mode while the other dryer regenerates. Instrument air will be used for pneumatic control of automated instrumentation, utility air, and supply for nitrogen generation.

Flare, Relief, and Blowdown System

Flare systems are a necessary safety feature of all LNG export facilities. The LNG Terminal will have three separate flare systems for pressure relief plant-protection conditions: one for warm (wet) reliefs; one for cold, cryogenic (dry) reliefs; and one for low-pressure cryogenic reliefs from the LNG storage tanks and marine loading system. The “warm” relief loads are separated to ensure that wet fluids cannot freeze in the header if there was a cryogenic relieving event. The “cold” and “marine” relief loads are separated to ensure that the relief of near-atmospheric pressure vapors is not affected by back-pressure in the header if an unrelated release were to occur. The warm and cold flares will both be within a multi-point ground flare field surrounded by radiation fencing, while the marine flare will be a cylindrical totally enclosed ground flare. Small pilots with electronic ignition are provided on each flare.

The flare system will be used only during plant-protection situations, maintenance activities, cases of purging and gassing-up an LNG carrier, and initial commissioning/start-up.

Electrical Systems

JCEP plans to obtain limited power from the regional electric grid for the SORSC and temporary construction activities. With the exception of the SORSC, the LNG Terminal facilities will be islanded (with black-start capability) and will not have the means, infrastructure, or need to import or export power during operations. The total power requirements for the LNG Terminal are 39.2 MW (holding mode) and 49.5 MW (loading mode).

Electrical power will be via two 30 MW steam turbine generators (STGs) and one spare 30 MW STG. The steam is efficiently generated by HRSGs using exhaust from the refrigerant compressor combustion turbine drivers. A black-start auxiliary boiler will be used to generate steam for power when gas turbines are not in operation. In addition, there are 2 x 100 percent standby diesel generators for the LNG facility and one for the SORSC. The facility will not be connected to the local grid and will not import or export power.

2.1.2 PROPOSED EQUIPMENT

Final vendors have not been selected for the LNG Terminal equipment. Equipment parameters and specifications presented in this application are based on design needs of the project and preliminary quotes obtained from vendors, where available.

The proposed project will include five combustion turbine-driven refrigeration compressors with duct burners operating in combined-cycle mode with a HRSG. Steam will be used to generate power for the facility in STGs. All power produced by the STGs will be used on site. Steam from the HRSGs will be used as a heat transfer fluid for process heating.

The project will also involve installation of combustion and post-combustion emission controls. The aero-derivative turbines will use dry low NO_X burners (LNBs) and selective catalytic reduction (SCR) systems with aqueous ammonia injection to control NO_X emissions and oxidation catalysts to control emissions of CO and VOC.

The operating parameters for the turbines and duct burners are presented in Table 2-1. During startup of the facility, the turbines will be fueled by pipeline natural gas. During routine facility operations the turbines will be fueled by BOG from the LNG vapor system, supplemented by pipeline natural gas. Fuel specifications for pipeline gas and BOG differ slightly but do not affect emissions substantially.

The turbines are expected to operate full time with the exception of maintenance downtime. One startup and shutdown per month per turbine is expected. Duct burner firing is dependent on the power needs of the facility given the ambient temperature. Per year, 4,000 hours of duct burner firing per turbine is anticipated. The turbines have inlet air preheating to 42 °F during cold weather. A chiller provides inlet air cooling for the turbines during warmer weather.

Table 2-1. Combined Cycle Turbine Model Parameters for JCEP

Parameter(1)	Aero-derivative Turbine
Mechanical Power Output (MW)	55.6
Maximum CT Heat Input – HHV (MMBtu/hr)	504.4
Maximum Duct Burner Heat Input – HHV (MMBtu/hr)	19.7
Maximum Total Heat Input – HHV (MMBtu/hr)	524.1

(1) 100 percent load at 42 degrees Fahrenheit ambient dry bulb temperature

In addition, the JCLNG will include a 296.2 MMBtu/hr natural gas-fired auxiliary boiler for startup of the liquefaction trains. The boiler may also be used to provide supplemental steam if more than two liquefaction turbines are offline. The auxiliary boiler will be equipped with SCR for NO_X control and an oxidation catalyst for CO and VOC control. The boiler will be used extensively during facility commissioning but is expected to operate only 10 percent of the year after facility startup. The operating parameters for the auxiliary boiler are presented in Table 2-2.

Table 2-2. Description of Auxiliary Boiler

Parameter	Auxiliary Boiler
Manufacturer/Model	TBD
Fuel	Natural Gas
Sulfur Content	1 gr/100 scf
Maximum Fuel Consumption	296.2 MMBtu/hr HHV
Operating Hours	876 hrs/yr

A thermal oxidizer will combust the gases exhausted from the acid gas removal system to destroy reduced sulfurs and co-absorbed hydrocarbons. The oxidizer will also combust flash gases and supplemental fuel gas. The single oxidizer will operate full time. Acid gas removal exhaust will be vented during any maintenance downtime. The operating parameters for the thermal oxidizer are presented in Table 2-3.

Table 2-3. Description of Thermal Oxidizer

Parameter	Thermal Oxidizer
Manufacturer/Model	TBD
Process Feeds	Acid Gas, Flash Gas, Natural Gas assist
Maximum Process Mass Input	238,142 lb/hr
Maximum Process Heat Input	110 MMBtu/hr

JCLNG will include three 700 hp diesel-fired fire water pump engines and two 1,073 hp diesel-fired backup generators to provide emergency back-up power for the SORSC and two 4,376 hp diesel-fired black-start generators for the LNG Terminal. Operation of the fire water pumps and backup generators, other than for emergency purposes, will be limited to reliability testing and maintenance. The two diesel-fired black-start generators will be used to power the auxiliary boiler; the backup air compressor; control building essential loads; miscellaneous electrical loads for enclosures and buildings; and miscellaneous process loads during initial startup of the facility and in the event of a facility-wide power outage. A summary of the operating parameters for the diesel-fired engines is provided in Table 2-4 below.

Table 2-4. Description of Diesel-Fired Engines

Parameter	Fire Water Booster Pumps	Backup Generators	Black-Start Generators
Manufacturer/Model	Caterpillar/C18	Caterpillar/C27	Caterpillar/C175
Number of Units	3	2	2
Engine Tier	Tier 3	Tier 2	Tier 2
Fuel	Diesel	Diesel	Diesel
Fuel Sulfur Content	15 ppm	15 ppm	15 ppm
Maximum Fuel Consumption	35.9 gal/hr	57.3 gal/hr	219 gal/hr

There will be three separate flare systems: one for warm (wet) reliefs; one for cold, cryogenic (dry) reliefs; and one marine flare for low-pressure cryogenic relief. The low-pressure cryogenic relief totally enclosed ground flare (TEGF) will be located at the southwest side of the LNG tank area. The warm and cold flare systems have been combined into one multi-point ground flare which will be located in the northwest corner of the facility. A summary of the operating parameters for the flares is provided in Table 2-5 below.

Table 2-5. Description of Flares

Parameter	MPGF	TEGF
Manufacturer/Model	TBD	TBD
Description	Warm and cold flares	Marine flare
Fuel Sulfur Content	1 grain/100 scf	1 grain/100 scf
Number of Pilots	28 pilots	6 pilots
Pilot Fuel Consumption – LHV	1.82 MMBtu/hr	0.39 MMBtu/hr
Purge Gas Fuel Consumption – LHV	0.31 MMBtu/hr	0.35 MMBtu/hr

2.1.3 APPLICATION FORMS

The ODEQ application forms for the project and equipment described above are included in Appendix A. Specification sheets (or pertinent portions of vendor quotes) and equipment performance data have been included as attachments to each form where available.

2.2 SITE LOCATION

The proposed site of the LNG Terminal is located in the coastal, western region of the State (Section 5, Township (T.) 25 South (S.), Range (R.) 13 West (W.), shown on Coos County Assessor's map as tax lots 100/200/300) on the bay side of the North Spit, about 7.5 miles up the existing Federal Navigation Channel, approximately 1,000 feet north of the city limit of North Bend, in Coos County, Oregon. An area map indicating the location of the proposed terminal is shown in Figure 3. The area map shows the site property relative to predominant geographical features such as the bay, roads, and surrounding dunes. Typically, and due to the functional requirements of the facility, the facility will be at or above 46 feet above sea level. Exceptions include the LNG tanks and water-dependent facilities such as the marine terminal and Material Offloading Facility (MOF).

2.3 EMISSIONS

Emissions attributable to the LNG Terminal are generated from natural gas combustion in the combustion turbines (CTs), natural gas combustion in the HRSG duct burners, natural gas combustion in the auxiliary boiler, combustion of the gas conditioning train acid gas stream in the thermal oxidizer, and diesel combustion in the fire water pumps, backup generator, and black start generators. Routine pilot and purge gas combustion will result in emissions from the MPGF and the TEGF; both of those units will also have emissions during upset or other condition flaring events. Fugitive emissions of natural gas (or BOG) and refrigerants will result from components and fittings throughout the LNG Terminal.

Emissions from the five CTs are exhausted via the HRSG stacks. The heating value of the turbine fuel gas is assumed to be 952 Btu/scf (standard cubic feet) HHV, based on a fuel specification provided by the terminal design engineering firm (a Kiewit, Black & Veatch, and JGC joint venture, "KBJ"), incorporating a mix of pipeline natural gas with BOG.

Emission factors for the CTs were provided by KBJ for several operation loads and ambient temperatures. Annual potential emissions for each CT are estimated from maximum hourly emissions at 100% load with 4,000 hours per year of duct burner firing and an ambient temperature of 42 °F. The turbines will have inlet air pre-heating to a minimum of 42 °F, and the highest emissions occur at the lowest inlet temperature.

Emissions are based on the proposed emission limits with control using SCR for NO_X, oxidation catalysts for CO and VOC, and good combustion practices for particulate matter species. A maximum fuel sulfur content of 1 grain per 100 standard cubic feet (gr/100 scf) of natural gas is used to estimate emissions of SO_2 and oxidation rates. H_2SO_4 emissions are based on oxidation rates provided by KBJ (SO_2 to SO_3 based on the turbine type, post-combustion configuration and control, and 100% conversion of SO_3 to H_2SO_4). SO_2 emission rates do not take oxidation into account and are conservative. A two percent by volume oxidation rate of SO_2 in the CT is assumed, with zero oxidation in the duct burner. A 20 percent oxidation rate is expected to occur in the CO catalyst and a three percent oxidation rate is expected for the SCR. Ammonia slip is calculated at 5 ppmvd for a maximum emission rate of 3.47 lb/hr at 42 °F.

Turbine startup and shutdown emissions are calculated for 12 startups and 12 shutdowns for each turbine per year. The liquefaction trains will operate continuously with the exception of maintenance downtime. Low load turbine operations are not expected except during short startup and shutdown periods.

Emission estimates for PM_{10} and $PM_{2.5}$ include the ammonium sulfates created downstream of the SCR (again assuming all SO_3 is converted to H_2SO_4). Hazardous air pollutant (HAP) emissions are based on AP-42 Section 1.4 (September 1999) for duct burner and Section 3.1 (April 2000) for combustion turbine emission factors.

Criteria pollutant emissions from the auxiliary boiler are calculated using manufacturer's emission factors and information from KBJ. SO_2 emissions are based on natural gas sulfur content of 1 gr/100 scf. 44 percent by volume conversion of SO_3 to H_2SO_4 is assumed. PM and HAP emissions are calculated using factors from AP-42 Section 1.4, July 1998. The boiler will have SCR and an oxidation catalyst to control NO_X and CO/VOC, respectively.

The gas conditioning unit produces an acid gas process stream which is routed to the thermal oxidizer for destruction. Emissions are calculated using manufacturer's emission rate information. The VOC and greenhouse gas (GHG) emission estimates also include 350 hours per year of venting to account for maintenance downtime. HAP emissions are calculated using factors from AP-42 Section 1.4, July 1998.

For the fire water pump engines, the backup generators, and the black start generators, $PM/PM_{10}/PM_{2.5}$, CO, NO_X, and VOC emission factors are based on the emission rates provided by the manufacturer. Mass balance with a diesel fuel sulfur content of 0.0015 percent by weight (15 ppm) is used to estimate SO_2 emissions for all diesel engines. AP-42 Section 3.1 and Section 3.4, October 1996, emission factors are used to estimate HAP emissions for all diesel engines.

For the MPGF and the TEGF, emissions are calculated for full time firing of pilot gas and purge gas.

The flare events which will occur are unplanned and have unknown gas volumes, with one exception. When an LNGC arrives following a dry dock overhaul period, the hull will be too warm to load LNG, and the carrier must be 'conditioned' prior to loading. The conditioning process is typically called "Gas-up" and "Cool Down." During "Gas Up," the ship vapor within the hull is replaced by vaporized LNG (methane), and the inert gases are displaced. At this stage the tanks are full of methane at ambient temperature. During "Cool Down" LNG is sprayed into the tanks by spray heads which vaporizes and cools the tank. When tank temperatures reach -220 °F, the tanks are ready for bulk loading.

At the LNG Terminal, the "Gas Up" displaced hull vapors will be routed to the TEGF for combustion. When the gas contains less than 50 ppmv CO_2 it will be routed to the fuel gas system. The emission calculations include up to 3 ships a year requiring "Gas Up." During the "Cool Down" procedure, all vapors will be sent to the fuel gas system.

Fugitive emissions of natural gas, BOG, and refrigerants will result from the components and fittings throughout the facility. Fugitive emission estimates of VOC, GHGs, and HAPs have been estimated for equipment leaks using component counts and emission factors from the EPA Protocol for Equipment Leak Emission Estimates, November 1995. LNG Tank fugitive emissions were provided in the May 2013 PSD Air Permit Application for the JCEP; those emission estimates have been included.

One ton per year of aggregate insignificant emissions is included for each criteria pollutant, and 0.7 tons per year of aggregate insignificant emissions of H_2SO_4 is included.

The potential emissions are summarized in Table 2-6 below. Detailed emission rate calculations are provided in Appendix B.

Table 2-6. JCLNG Potential Emission Rates (tons/yr)

Unit	NO_X	CO	SO_2	VOC	$PM/PM_{10}/PM_{2.5}$	H_2SO_4	NH_3	Lead	$CO_2(e)$	HAPs(1)
Turbines	81.99	97.82	35.19	32.72	112.26	23.61	75.4	--	1,292,706	5.06
Turbine Startup/ Shutdown	0.23	0.73	4.4E-03	0.10	0.11	--	--	--	188	6.2E-04
Gas Conditioning (TO)	63.25	38.5	19.84	1.08	3.85	--	--	2.5E-04	622,154	0.96
Auxiliary Boiler	0.96	1.16	0.36	0.67	1.30	2.4E-01	0.87	6.3E-05	15,193	0.24
Fire Water Pumps	1.59	0.8	2.1E-03	4.5E-02	9.0E-02	1.6E-04	--	2.1E-05	241	3.6E-03
Emergency Generators	3.33	0.28	2.5E-03	0.04	0.04	1.9E-04	--	2.4E-05	278	4.1E-03
Black Start Generators	1.49	0.21	8.8E-03	0.09	0.05	6.8E-04	--	8.6E-05	1,002	1.5E-02
Flares (MPGF and TEGF)	0.86	3.9	3.9E-02	8.31	0.38	3.0E-03	--	7.6E-06	2,177	4.3E-02

Unit	NO_X	CO	SO_2	VOC	PM/PM_{10}/ $PM_{2.5}$	H_2SO_4	NH_3	Lead	CO_2(e)	HAPs[(1)]
Gas Up (TEGF)	2.09	9.5	0.16	17.53	1.12	1.3E-02	--	2.1E-05	4,351	3.8E-02
Fugitives	--	--	--	7.98	--	--	--	--	13,116	1.77
Aggregate Insignificant	1.0	1.0	1.0	1.0	1.0	0.7	--	--	--	--
Total Emissions	**156.8**	**153.9**	**56.6**	**69.5**	**120.2**	**24.6**	**76.3**	**4.8E-04**	**1,951,406**	**8.1**

Note: '--' = not applicable.
(1) Maximum single HAP is n-hexane at 3.29 tpy.

2.4 PROPOSED PLANT SITE EMISSION LIMITS

Based on the proposed installation of the equipment described in this application, the Plant Site Emission Limits (PSELs) presented in Table 2-7 are requested.

Table 2-7. Proposed PSELs for JCLNG (tons/yr)

Pollutant	Proposed PSELs
PM	121
PM_{10}	121
$PM_{2.5}$	121
SO_2	57
NO_X	157
CO	154
VOC	70
H_2SO_4	25
GHG	1,951,410

3. REGULATORY APPLICABILITY

This section describes the applicable regulations triggered by the proposed project. The applicability determination conducted in this analysis is pursuant to the Oregon NSR regulations, National Emissions Standards for Hazardous Air Pollutants (NESHAP), and New Source Performance Standards (NSPS).

3.1 NEW SOURCE REVIEW APPLICABILITY

The JCLNG must be evaluated in relation to Oregon's NSR program. The Coos Bay area is designated as "attainment" or is unclassified for all criteria pollutants. JCLNG was permitted as a Prevention of Significant Deterioration (PSD) source under ACDP No. 06-0118-ST-01 in 2015. The facility has not yet been constructed and the design has changed. The planned facility and equipment must then be re-evaluated under the NSR and PSD requirements of OAR 340, Division 224 to determine whether it will be a federal major source in order to determine whether Oregon's PSD program has been triggered and, if so, for what pollutants.[2]

A "federal major source" is a source with the potential to emit 100 tons per year or more of any individual regulated pollutant (excluding greenhouse gases and hazardous air pollutants) if that source is in one of the designated source categories or 250 tons per year or more if it is not.[3] The JCLNG (i.e., the source) is no longer within one of the designated source categories which have a PSD threshold of 100 tons per year. The design no longer includes a power plant. The fossil fuel fired auxiliary boiler does have a capacity in excess of 250 MMBtu/hr heat input. The auxiliary boiler potential to emit will not, however, exceed 100 tons per year, meaning the boiler is not a federal major source.[4]

Because LNG terminals are not within any of the 28 listed source categories in OAR 340-200-0020(66), the JCLNG emissions must be compared to the 250-tpy threshold to determine whether the project constitutes a federal major source. The potential to emit is compared to the PSD threshold for each regulated pollutant except GHG and HAPs in Table 3-1.

Table 3-1. Oregon PSD Applicability (tons/yr)

Pollutant	Potential to Emit	PSD Federal Major Source Threshold	PSEL Requested in Excess of PSD Threshold?
PM	120	250	No
PM_{10}	120	250	No
$PM_{2.5}$	120	250	No
SO_2	57	250	No
NO_X	157	250	No
CO	154	250	No
VOC	70	250	No

[2] OAR 340-224-0070. It is important to note that the term "federal major source" should not be taken to imply that the federal PSD rules apply to the JCEP. Rather "federal major source" is a defined term of art under the Oregon New Source Review program.
[3] OAR 340-200-0020(66)
[4] Refer to the Dispersion Modeling Protocol included in Appendix D for additional analysis of the boiler applicability.

As shown in Table 3-1, the potential to emit of the plant as a whole will be less than 250 tpy for each for each regulated pollutant. As neither the facility as a whole nor the fossil fuel fired boiler qualifies as a federal major source, the JCLNG is not subject to Major NSR/PSD program requirements.

The project must then be assessed for applicability under State NSR requirements per OAR 340-224-0010(2)(b)(A). The requested PSELs are compared to the significant emission rates for each regulated pollutant in Table 3-2.

Table 3-2. Oregon State NSR Applicability (tons/yr)

Pollutant	Requested PSEL	Significant Emission Rate	PSEL Requested in Excess of SER?
PM	120	25	**Yes**
PM_{10}	120	15	**Yes**
$PM_{2.5}$	120	10	**Yes**
SO_2	57	40	**Yes**
NO_X	157	40	**Yes**
CO	154	100	**Yes**
VOC	70	40	**Yes**
H_2SO_4	25	7	**Yes**
Lead	0	0.6	No
GHG	1,951,406	75,000	NA

The project is subject to State NSR requirements because emissions of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, SO_2, VOC, and H_2SO_4 will each exceed the significant emission rates, as identified in Table 3-2. GHG emissions will exceed the SER, but GHGs are not subject to State NSR.

State NSR projects are categorized as Type A or Type B actions. Construction of projects located in attainment areas are categorized as Type B State NSR actions. JCLNG will be located in an attainment area and construction of the LNG Terminal will be a Type B State NSR action.

As a result, this application is prepared in accordance with OAR 340-224-0270, "State New Source Review Requirements for Sources in Attainment or Unclassified Areas" for the proposed emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, VOC, and H_2SO_4.

3.2 AMBIENT AIR QUALITY ANALYSIS

JCEP must provide an air quality impacts analysis for the proposed project in accordance with OAR 340-225-0050(1) and (2) and 340-225-0060 for each pollutant other than GHGs for which emissions will exceed the SER.[5] The JCLNG potential emissions of CO, SO_2, VOC, PM_{10}, $PM_{2.5}$, PM, NO_X, and H_2SO_4 exceed the netting basis of zero by more than the SERs; therefore, an air quality impact analysis is required for CO, SO_2, PM_{10}, $PM_{2.5}$, and NO_X. No air quality impact analysis is required for H_2SO_4 as no

[5] OAR 340-224-0270(1)(a)

National Ambient Air Quality Standard (NAAQS) or PSD Increment has been established in relation to this pollutant.

A dispersion modeling analysis is conducted to demonstrate that impacts from PM_{10}, $PM_{2.5}$, NO_X, SO_2, and CO emissions from the JCLNG comply with the NAAQS and PSD Increments as they apply to Class I and Class II areas. The analyses are provided in Section 4 and Section 5 of this report.

In addition, for increases of direct $PM_{2.5}$ or $PM_{2.5}$ precursors greater than the SER, an analysis of $PM_{2.5}$ air quality impacts based on the emission increases must be performed.[6]

Draft EPA guidance on addressing secondary formation of ozone was used to develop a project-specific evaluation of the potential impacts from project VOC and NO_X emissions. Following this guidance, it was determined that significant ozone concentrations will not be generated from the project. Further discussion of the ozone precursor analysis may be found in Section 4.7.3.

3.2.1 AIR QUALITY MAINTENANCE AREAS

The owner or operator of any source subject to OAR 340-224-0270 that significantly affects air quality in a designated nonattainment or maintenance area must meet the requirements of net air quality benefit in OAR 340-224-510 and 340-224-0520 for ozone areas and OAR 340-224-510 and 340-224-0540 for other designated areas.[7] The JCLNG is located greater than 100 km from all designated nonattainment and maintenance areas, including the Grants Pass particulate and CO maintenance area, the Eugene-Springfield CO area, and the Salem ozone and CO maintenance area.

3.3 NEW SOURCE PERFORMANCE STANDARDS

NSPS are established under 40 CFR Part 60 and adopted by reference in OAR 340-238-0060. The following NSPS are applicable to the proposed project.

3.3.1 NSPS SUBPART KKKK

The combustion turbines are subject to 40 CFR 60 Subpart KKKK, *Standards of Performance for Stationary Combustion Turbines*, because they are stationary combustion turbines with a heat input capacity greater than 10 MMBtu/hr and will commence construction after February 18, 2005. Pursuant to 40 CFR 60.4305, the turbines, HRSGs, and duct burners are exempt from the requirements of Subparts GG, Da, Db, and Dc.

Subpart KKKK regulates emissions of SO_2 and NO_X. Based on the source type and heat input, the NO_X emission limit for the JCEP turbines is 25 ppm at 15% O_2 or 1.2 lb/MW-hr of useful output. The heat content of the natural gas/BOG mixture meets the definition of 'natural gas' in Subpart KKKK. JCLNG will use a continuous emission monitoring system (CEMS) in accordance with §60.4335(b) and 60.4345 to demonstrate continuous compliance with the NO_X emissions limit for each unit.

[6] OAR 340-224-0270(1)(b)
[7] OAR 340-224-0070(4)

The SO_2 emission limit of 0.90 pounds per megawatt-hour (lb/MWh) gross output is based on an emission factor of 0.06 lb/MMBtu-heat input (or 20 gr/100 scf). JCLNG will maintain a natural gas tariff sheet to demonstrate that the fuel burned by each affected facility contains a total sulfur content of 20 gr/100 scf, or less, in accordance with §60.4365(a). The fuel gas fired in the turbines will often have a lower sulfur content than the incoming pipeline natural gas because the BOG has had sulfur compounds removed.

3.3.2 NSPS SUBPART Db

The proposed 296 MMBtu/hr auxiliary boiler is subject to 40 CFR 60 Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, because it is a steam generating unit with a design capacity greater than 100 MMBtu/hr heat input that will commence construction after June 19, 1984. Units firing only gaseous fuel with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in §60.42b(k)(1). In addition, PM standards do not apply to units combusting only natural gas. Per §60.44b(l)(1), the auxiliary boiler will be subject to the emission standard of 0.20 lb/MMBtu heat input determined on a 30-day rolling average basis.

The projected boiler operating hours result in a 10 percent annual capacity factor estimate. The annual capacity factor is calculated on annual actual operating hours. Because there may be years when auxiliary boiler operations exceed 876 hours per year, JCEP does not want to take a federally enforceable limit on the annual capacity factor. A NO_X CEMS will be required to monitor NO_X emissions.

Refer to Table 3-3 for a summary of NSPS Subpart Db emission limits applicable to the auxiliary boiler. Refer to Appendix C for a more detailed compliance summary and the supporting calculations.

Table 3-3. Emission Standards for Auxiliary Boilers

Boiler Category	Annual Capacity Factor	NO_X lb/MMBtu	PM lb/MMBtu	SO_2 lb/MMBtu
Natural gas-fired, > 250 MMBtu/hr	10%	0.20	Exempt	Exempt

3.3.3 NSPS SUBPART IIII

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, applies to all of the proposed diesel-fired engines. The 700 hp fire pump engines are subject to the emission limits of Table 4 in Subpart IIII, and JCLNG must comply with the emission standards shown in Table 3-4. The proposed engines are rated to meet Tier 3 standards.

Table 3-4. Emission Standards for Stationary Fire Pump Diesel Engines

Maximum Engine Power	Model Year	NMHC + NO_X g/kW-hr (g/hp-hr)	PM g/kW-hr (g/hp-hr)
450≤KW≤560 (600≤HP≤750)	2009 +	4.0 (3.0)	0.20 (0.15)

The 1,214 hp emergency backup generator engines have a displacement of 2.25 liters per cylinder and must comply with the certification emission standards for new non-road compression ignition engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants because the engines will be newer than the 2007 model year. The engines must be certified for Tier 2 standards and operation will be limited according to 40 CFR 60.4211(f). The engines must comply with the emission standards shown in Table 3-5.

Table 3-5. Emission Standards for Stationary Emergency Diesel Engines

Maximum Engine Power	Model Year	$NMHC + NO_X$ g/kW-hr (g/hp-hr)	CO g/kW-hr (g/hp-hr)	PM g/kW-hr (g/hp-hr)
kW ≥ 560 (hp ≥ 750)	2007 +	6.4 (4.8))	3.5 (2.6)	0.2 (0.15)

The 4,376 hp black start engines will serve the dual function of providing power for turbine startup and providing power to supply the plant's critical essential services during loss of on-site generation, resulting from turbine trips offline. The facility, including instrument air and safety mechanisms, is islanded from the power grid and the black start generators serve an emergency response function. The engines have a displacement of 5.29 liters per cylinder and must comply with the certification emission standards for new non-road compression ignition engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants because the engines will be newer than the 2007 model year. The engines must be certified for Tier 2 standards and operation will be limited according to 40 CFR 60.4211(f). The applicable emission standards are shown in Table 3-6.

Table 3-6. Emission Standards for Stationary Emergency Diesel Engines

Maximum Engine Power	Model Year	$NMHC + NO_X$ g/kW-hr (g/hp-hr)	CO g/kW-hr (g/hp-hr)	PM g/kW-hr (g/hp-hr)
kW ≥ 560 (hp ≥ 750)	2007 +	6.4 (4.8))	3.5 (2.6)	0.2 (0.15)

In order to demonstrate compliance with the NSPS, JCEP will purchase engines certified by the manufacturer and operate and maintain all diesel engines according to the manufacturer's instructions. Pursuant to §60.4207, JCEP will only burn ultra-low-sulfur fuel (15 ppm sulfur) in the diesel-fired engines. A non-resettable hour meter will also be installed for the fire pump engines, emergency backup generator units, and black start units. Initial notification is not required by this subpart.

3.3.4 NSPS SUBPART Kb

40 CFR 60, Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984*, applies to storage vessels greater than 75 cubic meters that are used to store volatile organic liquids (VOL), which is an organic liquid that can emit VOC into the atmosphere. Methane is not considered a VOC due to its limited photochemical reactivity. LNG typically includes more than just methane, specifically propane and butane, which are considered VOCs. However, Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters, storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). The maximum true vapor pressure is the

equilibrium partial pressure exerted by the VOCs in the stored VOL. The vapor pressure of propane (and butane) is below 3.5 kPa at the storage temperature. As such, 40 CFR 60 Subpart Kb is not applicable to the LNG storage tanks at JCLNG.

3.3.5 NSPS SUBPART OOOOa

40 CFR 60, Subpart OOOOa, *Standards of Performance for Crude Oil and Natural Gas Production Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015*, applies to certain equipment within the crude oil and natural gas source category that are constructed, modified, or reconstructed after September 18, 2015. Subpart OOOOa has superceded, in date, the NSPS, Subpart OOOO, which was found to be applicable to certain operations at JCLNG in ACDP 06-0118.

Subpart OOOOa must be examined for applicability. Each affected facility equipment type must be considered. The applicability findings are as follows.

- JCLNG will not include any well affected facilities.
- JCLNG will not include any centrifugal or reciprocating compressor affected facilities. Centrifugal compressors will be used to move BOG through the fuel gas system, but the compressors will have dry seals.
- JCLNG does not meet the definition of natural gas processing plant (gas plant) in Subpart OOOOa. Consequently, pneumatic controllers will not be affected sources. In addition, the process unit equipment associated with the liquefied natural gas unit is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a because it is not located at an onshore natural gas processing plant site.
- JCLNG will not operate a sweetening unit because the pipeline natural gas being treated in the gas conditioning unit is not sour gas.
- JCLNG will not include any affected source VOC storage tanks. The LNG storage tanks will not contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and fugitive VOC emissions will be less than 6 tons per year.
- JCLNG will not include any pneumatic pumps.
- JCLNG does meet the definition of compressor station in Subpart OOOOa. Consequently, JCLNG will not have a fugitive component affected source.

JCLNG will not be subject to any NSPS Subpart OOOOa requirements.

3.4 NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS

NESHAPs have been established in 40 CFR Parts 61 and 63 to control the emissions of HAPs. NESHAP regulations establish emission standards or work practices for specific types of equipment located at a HAP major source. A HAP major source is a facility with a potential to emit 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs. The JCLNG will not be a Major Source of HAPs. Potential emissions are below the 10 tpy single HAP and 25 tpy total HAPs thresholds. Thus, JCLNG qualifies as an "area source" under the following NESHAP rules.

The following NESHAPs were reviewed for applicability to the proposed project.

3.4.1 40 CFR 63, SUBPART JJJJJJ

The proposed 296.2 MMBtu/hr auxiliary boiler is exempt from 40 CFR 63 Subpart JJJJJJ, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources,* because it is a gas-fired boiler.

3.4.2 40 CFR 63, SUBPART ZZZZ

Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* (RICE), applies to all of the proposed diesel-fired engines. However, a new diesel engine meeting the criteria in paragraphs 40 CFR 63.6590 (c)(1) through (7) of Subpart ZZZZ meets the requirements of the subpart by meeting the requirements of 40 CFR 60 Subpart IIII for compression ignition engines. Each of the proposed diesel engines will meet the criteria of 40 CFR 63.6590(c)(1), so no further requirements apply for any of the engines under the NESHAP.

3.5 TITLE V

JCLNG will be a major source of air pollutants because the facility will have the potential to emit over 100 tpy or more of NO_X, CO, and $PM/PM_{10}/PM_{2.5}$. JCEP will be required by OAR 340, Division 218 to obtain a Title V Operating Permit from ODEQ. The complete application to obtain the Oregon Title V Operating Permit must be submitted within 12 months after commencing operation (initial startup).[8]

3.6 CONTINUOUS EMISSIONS MONITORING

JCEP will install CEMS to record the exhaust concentration of NO_X and CO from all five combustion turbines. These CEMS will be used to demonstrate compliance with the NSPS standards and to provide accurate measurement of actual emissions from each turbine for PSEL compliance demonstration on a rolling 12-month basis. Because the turbines are subject to NSPS Subpart KKKK, the CEMS will comply with the performance evaluations for the monitoring systems detailed in 40 CFR 60. Although Subpart KKKK provides alternative provisions for use of Part 75 CEMS methods, JCEP is not subject to Acid Rain requirements and use of the Part 75 alternative methods is not proposed.

JCEP will also install a NO_X CEMS on the auxiliary boiler to meet the monitoring requirements of NSPS Subpart Db. The auxiliary boiler CEMS will also be installed and operated following Part 60 methods.

[8] 340-218-0040(1)(a)(B)

4. CLASS II AMBIENT AIR QUALITY ANALYSIS

This section summarizes the dispersion modeling used to demonstrate compliance with the applicable NAAQS and Class II PSD Increments. A dispersion modeling analysis was conducted to demonstrate compliance with the applicable air quality standards for all criteria pollutants subject to State NSR review. The results of the analysis, summarized below, indicate that the project will be in compliance with all applicable Class II air quality standards.

The modeling analysis summarized herein is based on the approved modeling protocol[9], except for the following clarifications or revisions:

- Clarification - the meteorological data were not processed with the adjust_u* option;
- Clarification - the moisture selection by month was based on data collected at the Southwest Oregon Regional Airport following EPA guidance; and
- Revision - the receptor grid was extended out to 50 km in the north, east, and south directions to capture all potential significant impacts (to the west lies the Pacific Ocean).

A full discussion of the modeling methodology, including model versions, meteorology, land use, receptor grid setup, and downwash analyses, is provided in the approved modeling protocol (the Protocol), attached as Appendix D. Summaries of model inputs are provided in Appendix E. All modeling files used in support of this analysis are provided in Appendix F.

4.1 EQUIPMENT LIST

JCLNG emission units include the following equipment:

- Five (5) combined-cycle natural gas turbines with duct burners;
- One (1) auxiliary boiler;
- Three (3) liquefaction area fire pumps;
- Four (4) emergency generators;
- One (1) thermal oxidizer;
- One (1) multipoint (warm and cold) ground flares; and
- One (1) totally enclosed (marine) ground flare.

LNG carrier emissions are not part of the stationary source, but LNGC emissions and downwash are included in the cumulative source analysis as competing sources.

4.2 SITE LAYOUT

The effect of plume downwash due to airflow around project-related buildings and structures was considered for all stationary point sources.[10] As shown in Figure 4, large buildings and structures near

[9] The modeling protocol was approved, with edits, by ODEQ on July 15, 2017. Email from Phil Allen (ODEQ) to Jason Reed (SLR).

[10] For the totally enclosed (marine) ground flare, downwash effects were considered from other surrounding structures, but not the flare enclosure itself.

the stationary sources were entered in to the current version of the EPA-approved Building Profile Input Program (BPIPPRM Version 04274). BPIPPRM produced direction-specific downwash parameters for direct input into AERMOD and also the Good Engineering Practice (GEP) stack height for each stack. All stacks are below their calculated GEP-stack height.

The facility design also includes the use of vapor dispersion walls along the fenceline of the LNG Terminal for safety purposes. The vapor dispersion walls will range from 20 feet to 80 feet above grade. Although BPIPRM was not designed or tested for a structure with these height-to-width ratios, a sensitivity analysis was conducted to quantify the potential impact of these features on air quality concentrations. Based on the site layout and the height of the vapor dispersion walls, only the fire-water pumps would be affected by the inclusion of the walls in the development of downwash coefficients using BPIPRM. When input into AERMOD, the design-value air quality concentrations for all averaging periods are virtually identical when the vapor dispersion walls are included.

4.3 SOURCE PARAMETERS

All emissions from the combined-cycle turbines, auxiliary boiler, fire pumps, emergency generators, and thermal oxidizer will be released from vertical, unobstructed stacks. One of the three flares, the total enclosed ground flare, is also treated as a vertical stack. The other two flares are warm and cold flare lines in a combined multi-point ground flare, which were modeled as an area source. The source locations and elevations are shown in Table 4-1.

Table 4-1. Source Locations

Source ID	Description	UTM-x (m)(1)	UTM-y (m)(1)	Stack Elevation (m)
Turb1(2), Turb1SU(3)	Combined Cycle Turbine	397644.9	4809333.4	14.0
Turb2(2), Turb2SU(3)	Combined Cycle Turbine	397643.0	4809401.2	14.0
Turb3(2), Turb3SU(3)	Combined Cycle Turbine	397641.2	4809469.0	14.0
Turb4(2), Turb4SU(3)	Combined Cycle Turbine	397639.3	4809536.8	14.0
Turb5(2), Turb5SU(3)	Combined Cycle Turbine	397637.5	4809604.6	14.0
ThermOx	Thermal Oxidizer	397465.0	4809694.7	14.0
AuxBoil	Auxiliary Boiler	397385.3	4809623.5	14.0
FP1	Fire Pump	397823.0	4809674.7	15.8
FP2	Fire Pump	397830.3	4809674.9	15.8
FP3	Fire Pump	397835.5	4809675.1	15.8
Gen1	Backup Generator	399631.0	4809864.4	19.8
Gen2	Backup Generator	399627.0	4809864.2	19.8
BSGen1	Black Start Generator	397297.1	4809620.9	14.0

Source ID	Description	UTM-x (m)[(1)]	UTM-y (m)[(1)]	Stack Elevation (m)
BSGen2	Black Start Generator	397289.4	4809620.7	14.0
MFlare	Marine Flare	397361.3	4809303.0	14.0
GFlare	Ground Flare	397253.6	4809794.1	14.0

(1) UTM zone 10, NAD 83 horizontal datum.
(2) These turbine sources are for normal operation (i.e., no startups or shutdowns) for the entire operating period.
(3) These turbine sources indicate a scenario where startup and shutdown emissions are included from the source. For the 1, 3, 8, and 24-hour averaging periods, either one startup or one shutdown is included in the period, depending on which of the events produced the worst emissions for each pollutant. For the annual averaging periods, these sources include 12 startups and 12 shutdowns per year.

The source release parameters are listed in Table 4-2 for the point sources and Table 4-3 for the multi-point ground flare.

Table 4-2. Stack Parameters for JCLNG Point Sources[(1)]

Source ID	Description	Release Height (ft)	Exit Temperature (°F)	Exit velocity (ft/s)	Stack Diameter (ft)
Turb1, Turb1SU	Combined Cycle Turbine	119.1	242.8	71.0	10.0
Turb2, Turb2SU	Combined Cycle Turbine	119.1	242.8	71.0	10.0
Turb3, Turb3SU	Combined Cycle Turbine	119.1	242.8	71.0	10.0
Turb4, Turb4SU	Combined Cycle Turbine	119.1	242.8	71.0	10.0
Turb5, Turb5SU	Combined Cycle Turbine	119.1	242.8	71.0	10.0
ThermOx	Thermal Oxidizer	131.2	1600.0	41.7	9.5
AuxBoil	Auxiliary Boiler	100.0	330.0	48.7	6.0
FP1	Fire Pump	18.0	948.3	193.0	0.7
FP2	Fire Pump	18.0	948.3	193.0	0.7
FP3	Fire Pump	18.0	948.3	193.0	0.7
Gen1	Backup Generator	13.1	952.5	287.0	0.7
Gen2	Backup Generator	13.1	952.5	287.0	0.7
BSGen1	Black Start Generator	18.0	873.6	177.0	1.7

Source ID	Description	Release Height (ft)	Exit Temperature (°F)	Exit velocity (ft/s)	Stack Diameter (ft)
BSGen2	Black Start Generator	18.0	873.6	177.0	1.7
MFlare	Marine Flare	100.1	1831.7	29.7	45.0

(1) The stack parameters were input into the model using the metric units. English units are shown here for ease of comparison with the supplied vendor data in Appendix A.

Table 4-3. Parameters for JCLNG Area Source[(1)]

Source ID	Description	Release Height (ft)	East-West Dimension (ft)	North-South Dimension (ft)	Initital Vertical Dimension of Plume(ft)
GFlare	MPGF	85.0	259	227	39.5

(1) The parameters were input into the model using the metric units. English units are shown here for ease of comparison with the supplied vendor data in Appendix A.

4.4 OPERATING SCENARIOS

The potential operating scenarios for the turbines include normal operation and startup and shutdown (SU/SD). The support equipment is held constant for both turbine scenarios. The scenarios will include the following:

- Normal operation – where the turbine operates in normal mode for the entire period (short-term).
- SU/SD mode – where the turbine undergoes a startup or shutdown for a portion of the period (i.e., 9-10 minutes) and operates in normal mode for the remainder of the period (short-term).

The annual emissions scenario includes the total emissions from the expected number of startups and shutdowns plus normal operation for the remainder of the year.

4.5 BACKGROUND CONCENTRATIONS

The use of ambient background concentrations is an important aspect to air quality analyses as they represent the effects from existing sources, which directly influences the attainment status with respect to ambient standards. For the NAAQS analysis, background concentrations represent non-modeled sources and are added to the modeled impacts of the proposed project and any nearby industrial sources to assess the potential cumulative impacts.

Ambient background concentrations for this project were obtained from the Northwest AIRQUEST database hosted by Washington State University. Northwest AIRQUEST maintains a database of criteria pollutant design values based on monitoring data and archived CMAQ modeling runs for the 2009-2011 period. The database of design values exists for 12 km by 12 km grid cells covering the states of Idaho, Oregon, and Washington. For the modeling demonstration, the values were obtained from the grid cell representative of the proposed facility location (latitude 43.434°, longitude -124.524°).

Background concentrations can also be used to assess the available headroom between existing conditions and the ambient standards in order to justify the use the SILs.[11] If that headroom is less than the SIL, then project contributions less than the SIL may not be sufficient to demonstrate that the standards will be protected. A list of background concentrations, NAAQS, the difference between the background and NAAQS (i.e. "headroom"), and SILs are shown in Table 4-4. In all cases, the difference between the NAAQS and background concentration is at least 10 times the level of the SIL. This table demonstrates that the difference between the background concentrations and NAAQS is adequate to demonstrate that use of the SIL will not threaten compliance with the NAAQS in the project area.

Table 4-4. Analysis of Headroom Between NAAQS and Background Air Quality (µg/m^3)

Pollutant/ Averaging Period	Background Concentration	NAAQS	Difference	SIL
NO_2 1-hr	16	188	172	8
NO_2 Annual	1.9	100	98.1	1
CO 1-hr	755	40,000	39,245	2,000
CO 8-hr	591	10,000	9,409	500
$PM_{2.5}$ 24-hr	9.9	35	25.1	1.2
$PM_{2.5}$ Annual	6.7	12	5.3	0.3
PM_{10} 24-hr	35.0	150	115.0	1.0
PM_{10} Annual	N/A(1)	N/A(1)	N/A(1)	0.2(1)
SO_2 1-hr	3.1	196	192.9	8
SO_2 3-hr	2.9	1,300	1,297.1	25
SO_2 24-hr	2.9	260	259.1	5
SO_2 Annual	1.1	52	50.9	1

(1) There is no current Oregon standard or NAAQS for PM_{10} at the annual averaging period; however, there is still a SIL per OAR 340-200-0010(163).

4.6 SIGNIFICANCE ANALYSIS

Using the source inputs summarized in previous sections and inputs and methodology described in the approved modeling protocol (Appendix D), the maximum project impacts from either operating scenario are shown in Table 4-5 and maximum concentration contour plots are provided in Figures 5 through 16. Table 4-5 also lists SILs and monitoring *de minimis* levels for comparison to the project modeled concentrations.

The maximum predicted 1-hr CO concentration and the maximum predicted 8-hr CO concentration both occur on the western facility fenceline. As shown in Figures 5 and 6 and Table 4-5 below, predicted concentrations of CO do not exceed the SIL for either the 1-hr averaging period or the 8-hr averaging period. Therefore, no further analysis is required of CO for either averaging period.

For the SIL analysis, the NO to NO_2 conversion ratio has been conservatively assumed to be 100 percent. The maximum predicted 1-hr NO_2 concentration is located on the western facility fenceline, while the

11 OAR 340-225-0050(1)(b)(A)

maximum predicted annual NO_2 concentration is located on the South Dunes fenceline. As shown in Figures 7 and 8 and Table 4-5 below, predicted concentrations of NO_2 exceed the SIL for the 1-hr averaging period and the annual averaging period. Therefore, full impact analysis for NO_2 is required for the 1-hr averaging period and annual averaging period.

The maximum predicted 1-hr SO_2 concentration is located in hilly terrain approximately 8 km south of the facility. The maximum predicted 3-hr SO_2 concentration is located on the southern facility fenceline. The maximum predicted 24-hr concentration is located about 1 km northwest of the facility. The maximum predicted annual concentration is located on the western facility fenceline. As shown in Figures 9 to 12 and Table 4-5 below, predicted concentrations of SO_2 exceed the SIL for the 1-hr averaging period but do not exceed the SIL for the 3-hr, 24-hr, and annual averaging periods. Therefore full impact analysis for SO_2 is required for the 1-hr averaging period, but no further analysis is required for the 3-hr, 24-hr, and annual averaging periods.

The maximum predicted concentrations for $PM_{2.5}$ and PM_{10} for the 24-hr averaging period occurs just west of the facility. The maximum predicted concentrations for $PM_{2.5}$ and PM_{10} for the annual averaging period occur on the western facility fenceline. As shown in Figures 13 to 16 and Table 4-5 below, for both species of particulate matter and both the 24-hr and annual averaging periods, the predicted concentrations of particulate matter exceed the SILs. Therefore, full impact analysis of both $PM_{2.5}$ and PM_{10} for the 24-hr and annual averaging periods will be required. [12]

Table 4-5. Significance Analysis Results

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)	SIL (µg/m^3)
$NO_2$$^{(1)}$	Annual	3.4	1
	1-hr	50.5	8
$PM_{2.5}$	Annual	1.1	0.3
	24-hr	8.1	1.2
PM_{10}	Annual	1.1	0.2
	24-hr	8.1	1
SO_2	Annual	0.3	1
	24-hr	2.5	5
	3-hr	5.7	25
	1-hr	11.5	8
CO	8-hr	16.2	500
	1-hr	108.0	2,000

(1) Assumes 100% NO_X to NO_2 conversion.

[12] It is noted that there are currently no state or federal ambient air quality standards for annual PM_{10}; however, an annual Class II increment is still present.

4.7 FULL IMPACT ANALYSIS

The proposed project emissions are shown to have maximum ambient concentrations that exceed the SILs for PM_{10} at the 24-hr and annual averaging periods, $PM_{2.5}$ at the 24-hr and annual averaging periods, SO_2 at the 1-hr averaging period, and NO_2 at the 1-hr and annual averaging periods. Therefore, a Full Impact Analysis is conducted for these seven combinations of pollutants and averaging periods. The same project emission and operating scenarios from the significance analysis are combined with LNG carrier emissions and nearby, competing sources that were provided by ODEQ. Only receptors where the predicted concentration, for each pollutant and averaging time, was greater than the SIL are considered in the Full Impact Analysis.[13]

4.7.1 COMPETING SOURCES

ODEQ provided a list of competing sources on August 5, 2017 for NO_2, $PM_{2.5}$, PM_{10}, and SO_2.[14] All provided sources are included in the full impact analysis as provided by ODEQ. A list of those sources and emission rates are included in Appendix E. The information provided by ODEQ includes the actual emissions for calendar year 2016, as well as the allowable, potential to emit for each source. The allowable, potential to emit values are used in the competing source analysis. Tons per year emission rates provided by ODEQ were converted to grams per second rates for input into AERMOD[15], and stack parameters provided in English units were converted to metric units before AERMOD input.

The fleet of LNG vessels expected to call at the JCEP terminal consists of both vessels that have boiler/steam turbine-driven (ST) propulsion systems, as well as vessels powered by duel-fuel diesel-electric (DFDE) propulsion. Further, each type of vessel may be operated on either natural gas or fuel oil. For the DFDE ships, however, operation on oil versus operation on natural gas was confined to different activities during the ship's call. Therefore, three vessel emissions scenarios were created in order to determine worst-case air emissions calculations and associated air quality impacts:

- ST carriers operating on oil;
- ST carriers operating on natural gas; and
- DFDE carriers.

JCEP expects up to 120 LNG vessel calls per year. For the purposes of the modeling, in each of the three scenarios, it is assumed that all of the 120 vessel calls will be of ships of the same propulsion and fuel type.

The LNG vessel call activities can be divided into several scenarios and operating periods per visit. These activity times are not dependent on the ship or fuel type. Emission rates for different activities during the carrier's call were developed from the emission factors shown in Appendix G and the amount of power expected to be consumed during that particular activity. As the emission factors are in a g/kW-hr basis, and the power will vary depending on activity, the emission rates (on a mass per unit time basis) will vary depending on the activity in which the ship is engaged.

[13] OAR 340-225-0050(1)(a) and (b).
[14] Further discussions between ODEQ and SLR on August 30, 2017 about larger significant impact areas confirmed no additional offsite sources needed to be included.
[15] Assuming 8,760 hours of operation.

If a ship is engaged in a particular activity for the full averaging period, than the full mass per unit time rate was used for modeling of that activity. If a ship is engaged for the activity for a portion of the averaging period, then the mass per unit time emission factor was weighted by the proportion of the activity time to the time of the averaging period. For example, for an activity that takes four hours, the full mass per unit time emission rate calculated was used for 1-hour averaging periods (as the activity time is longer than that averaging period), but one-sixth of the full mass per unit time emission rate was used for 24-hour averaging periods (as the four hours of activity time is one-sixth of the averaging period).

In addition to the activities at, and in, the immediate vicinity of the terminal, the emissions of the carrier's transit of the channel and near-shore open water were considered by setting up 68 surrogate sources[16] along the geographic track of arriving and departing ships. The transit emission rates were used for these surrogate sources, with the emissions divided equally over the 68 surrogate sources.

In addition to the 120 LNG vessels, three tugboats will also be deployed in operation at the JCEP LNG Terminal. The worst-case scenario resulting in the highest emissions involves use of one tugboat while the carrier is berthed. Because the tugboat will be maneuvering around the ship during the worst case scenario, the tugboat is represented as a series of four surrogate sources in the channel adjacent to the ship dock, with one-quarter of the total tugboat emissions assigned to each surrogate source. The tugboat emissions, location of surrogate sources, and stack parameters are shown in Appendix G. The effects of plume downwash were also considered for the marine carriers and support vessels in the multisource modeling.

4.7.2 NO_2 FORMATION

The modeling analysis used the first two tiers in the approach described in the latest EPA guidance:

1. The first Tier will assume a full, 100% conversion of NO_X to NO_2.
2. If needed, the second tier will utilize the ambient ratio method (ARM2) method implemented and documented per EPA guidance.
3. If needed, the third tier will utilize the Ozone Limiting Method (OLM) or Plume Volume Molar Ratio Method (PVMRM) implemented and documented per EPA guidance.

The significant impact analysis utilized the first tier and the NAAQS and increment analysis utilized the second tier, ARM2.

4.7.3 OZONE AND $PM_{2.5}$ SECONDARY FORMATION

The draft EPA guidance on addressing secondary formation of $PM_{2.5}$ and ozone was used to develop a project-specific evaluation of the potential impacts from project VOC, SO_2, and NO_X emissions.[17,18] The

[16] The surrogate sources are the discrete locations where the carrier emissions are modeled to represent the movement of the ship along the channel.

[17] Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, December 2016.

project emissions were compared to the information provided in the EPA guidance for Modeled Emission Rates for Precursors (MERPs). This EPA guidance is based on a suite of photochemical modeling runs across the continental U.S. designed to assess secondary ozone and $PM_{2.5}$ formation from various, hypothetical sources. These runs were used to establish modeled responses to precursor emissions, which can be used to determine:

- Emission thresholds below which insignificant secondary formation is expected to occur
- Secondarily-formed downwind concentrations of ammonium sulfate, ammonium nitrate, or ozone from emitted precursors.

The first step of the guidance is to compare Project emissions to the emission thresholds. Since the Project emits more than one precursor pollutant, an additional calculation is needed to account for the combined effect of the precursors. This is accomplished by adding ratios (project emissions divided by an emission threshold) for each precursor together. If the combined ratios of the precursors are greater than one, then significant secondary formation is possible and needs to be quantified.

The second use of the guidance allows for quantification of the secondary formation. Because the EPA modeling was for a limited number of sources, several inputs were varied by EPA to obtain more robust model responses. The inputs that were varied include stack height and parameters, precursor emission levels, and inherently based on the source's location, regional emissions, and geophysical characteristics (i.e., climate, terrain, proximity to other large sources or cities). For the pollutants in which the quantification of secondary effects is required, Appendix A of the EPA guidance was reviewed to find a source-impact relationship that is representative of the Project. Representativeness was determined by stack parameters, emission levels, local/regional emissions, and geophysical environment.

Table 4-6 compares the lowest (most conservative) ozone emission threshold values for NO_X and VOCs in the Western U.S to Project emissions. Because both NO_X and VOC are emitted, the combined effect is accounted for, as shown in Table 4-6. Following the draft EPA guidance, since the sum of the combined ratios (project emissions/emission threshold value) for each precursor is less than a value of 1, significant ozone concentrations will not be generated from the Project.

Table 4-6. Summary of MERPs Analysis for Ozone

Precursor	Project Emissions (tpy)	8-hr O3 MERP (tpy)[(1)]	Ratio of Project Emissions to Daily Ozone MERP	Sum of Ratios
NO_X	155.0	184	0.84	0.91
VOC	72.5	1,049	0.07	

(1) These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

[18]Distribution of the EPA's modeling data used to develop illustrative examples in the draft Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, February, 2017.

A similar analysis for daily and annual $PM_{2.5}$ is shown in Tables 4-7 and 4-8, respectively. The approach for secondary $PM_{2.5}$ formation from NO_X and SO_2 emissions is the same as ozone, but $PM_{2.5}$ also needs to include direct $PM_{2.5}$ impacts as modeled in AERMOD.[19] As shown in Tables 4-7 and 4-8, insignificant secondary formation is expected to occur for both daily and annual $PM_{2.5}$. However, because Project direct $PM_{2.5}$ impacts (i.e., modeled in AERMOD) are above the significant impact level (see Table 4-5), then the reported $PM_{2.5}$ will include the expected secondary formation using representative modeled responses in Appendix A of the EPA guidance as discussed further below.

While the lowest (most conservative) emission thresholds are useful for screening project emissions, they are not necessarily representative of potential secondary formation due to project emissions. For instance, the sources with the lowest (most conservative) SO_2 and NO_X emission thresholds are in interior California, which is not representative of the climatology or source environment of the proposed project. Furthermore, both of these sources were modeled with 'low' source heights (release height of 1 m), which is not representative of Project sources.

The summarized modeling results for 24-hour average concentrations of secondary formation for precursor SO_2 and NO_X in Appendix A of the MERP guidance was further reviewed. The data were sorted to only include:

- Sources located in Oregon or Washington (considered to be more representative of climate at the Project site);
- Precursor emissions of 500 tpy (similar in magnitude to Project emissions, yet conservative); and
- And 'high' stack heights (similar to Project sources).

The results of this analysis are summarized in Table 4-9. Taking the two highest modeled responses, 0.15 $\mu g/m^3$ and 0.24 $\mu g/m^3$ for NO_X and SO_2, respectively, the combined potential secondary formation from Project emissions is 0.39 $\mu g/m^3$. This concentration is added to the modeled result for direct $PM_{2.5}$ on a 24-hour basis to represent the additional concentration from $PM_{2.5}$ formation. For conservatism, this 24-hour secondary formation will also be added to annual $PM_{2.5}$ impacts.

Table 4-7. Summary of MERPs Analysis for Daily $PM_{2.5}$

Precursor	Project Emissions (tpy)	Daily $PM_{2.5}$ MERP (tpy)(1)	Ratio of Project Emissions to Daily $PM_{2.5}$ MERP	Sum of Ratios
Direct $PM_{2.5}$	AERMOD results > SIL			0.34
NO_X	155.0	1,075	0.14	
SO_2	40.2	210	0.19	

(1) These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

[19] Total $PM_{2.5}$ is the sum of direct $PM_{2.5}$ plus secondary $PM_{2.5}$. Direct $PM_{2.5}$ emissions and downwind impacts are modeled in AERMOD. The secondary formation of Project NO_X and SO_2 emissions into $PM_{2.5}$ is crux of the MERPs guidance.

Table 4-8. Summary of MERPs Analysis for Annual $PM_{2.5}$

Precursor	Project Emissions (tpy)	Annual $PM_{2.5}$ MERP (tpy)(1)	Ratio of Project Emissions to Annual $PM_{2.5}$ MERP	Sum of Ratios
Direct $PM_{2.5}$	AERMOD results > SIL			0.07
NO_X	155.0	2,289	0.05	
SO_2	40.2	3,184	0.02	

(1) These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

Table 4-9. Summary of Modeled Responses for Representative Sources

Precursor	Area	Emissions (tpy)	Height	Source	FIPs	State	County	Modeled Response ($\mu g/m^3$)
NO_X	**WUS**	**500**	**H**	**18**	**41049**	**Oregon**	**Morrow**	**0.15**
NO_X	WUS	500	H	22	53057	Washington	Skagit	0.05
NO_X	WUS	500	H	23	53039	Washington	Klickitat	0.03
SO_2	**WUS**	**500**	**H**	**23**	**53039**	**Washington**	**Klickitat**	**0.24**
SO_2	WUS	500	H	18	41049	Oregon	Morrow	0.19
SO_2	WUS	500	H	22	53057	Washington	Skagit	0.08

4.7.4 NAAQS ANALYSIS

The NAAQS analysis takes into consideration a representative background concentration in addition to emissions from competing sources and the proposed project to determine compliance. Results of the NAAQS analysis for the seven pollutants and averaging periods that were above their respective SILs are shown in Figures 17 through 22 and Table 4-10 below. As shown, the total predicted concentration from the proposed and competing sources plus background concentration is below the NAAQS for all pollutants and averaging periods.

Table 4-10. NAAQS Analysis Results

Pollutant	Averaging Period	Modeled Concentration(1) ($\mu g/m^3$)	Secondary Formation ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2(2)	1-hour	132.3	--	16.0	148.3	188.0
	Annual	4.1	--	1.9	6.0	100.0
PM_{10}(3)	24-hour	9.3	--	35.0	44.3	150.0
	Annual	1.4	--	n/a	1.4	n/a
$PM_{2.5}$(4)	24-hour	6.9	0.4	9.9	17.2	35.0
	Annual	1.3	0.4	6.7	8.4	12.0
SO_2	1-hour	30.1	--	3.1	33.2	196.0

(1) Modeled concentrations are as follows. These are in some cases conservative as compared to the NAAQS, as several NAAQS standards allow use of three-year average values, while the presented results are based on results from the single worst year.
  a. The modeled 1-hour NO_2 concentration is the highest result for the 98th percentile of 1-hour daily maximum concentrations for any of the five given years.
  b. The modeled annual NO_2 is the maximum concentration at any receptor.
  c. The modeled 24-hour PM_{10} concentration is the highest second high result for any of the five given years.
  d. The modeled 24-hour $PM_{2.5}$ concentration is the highest result for the 98th percentile of 1-hour daily maximum concentrations for any of the five given years.
  e. The modeled annual $PM_{2.5}$ concentration is the maximum concentration at any receptor.
  f. The modeled 1-hour SO_2 concentration is the the highest result for the 99th percentile of 1-hour daily maximum concentrations for any of the five given years.

(2) The reported NO_2 modeled concentration is based on the ARM2 method in AERMOD.
(3) PM_{10} has a Class II SIL defined in OAR 340, but no associated NAAQS.
(4) As described in Section 4.7.3.

4.7.5 CLASS II PSD INCREMENT ANALYSIS

Results of the Class II PSD Increment analysis for NO_2, PM_{10}, and $PM_{2.5}$ are provided in Figures 23 through 27 and Table 4-11 below. The 1-hr NO_2 and SO_2 pollutants/averaging periods do not have an applicable increment, so an increment analysis was not performed for those pollutants. As shown, the total predicted concentration is below the Class II PSD Increment standard for all pollutants and both averaging periods.

Table 4-11. Class II PSD Increment Results ($\mu g/m^3$)

Pollutant	Averaging Period	Modeled Concentration(1) ($\mu g/m^3$)	Secondary Formation ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
NO_2	Annual	4.1	--	4.1	25.0
PM_{10}	24-hour	9.3	--	9.3	30.0
	Annual	1.4	--	1.4	17.0
$PM_{2.5}$(2)	24-hour	7.9	0.4	8.3	9.0
	Annual	1.3	0.4	1.7	4.0

(1) Maximum second highest 24-hour concentration in the modeled year. Maximum annual average concentration.
(2) As described in Section 4.7.3.

5. CLASS I AMBIENT AIR QUALITY ANALYSIS

In addition to the Class II air quality analysis discussed in Section 4 above, a Class I screening air quality and regional haze analysis was also performed for relevant areas within 200 km of the project site. There are five federal Class I areas within that radius, managed by either the National Park Service or the Forest Service. The modeling analysis summarized herein is based on the approved modeling protocol and the project inputs detailed in Section 4.

5.1 CLASS I PSD SIGNIFICANCE ANALYSIS

An assessment of project impacts in comparison to the Class I significant impact level for the Class I PSD increments was run using with the same model and inputs as described in Section 4. If results for all years at these 50 km receptors for a particular Class I area were below the SIL for a particular pollutant and averaging period, then it was presumed the concentrations would be below the SIL for that pollutant and averaging period at the more distant Class I area (110 km to 178 km) as well, and no further analysis was conducted in these cases.

Receptors were placed at a distance of 50 km from the project (the farthest distance for which AERMOD is approved) in arcs that were located to capture plume impacts in the direction of each Class I area. The elevations of the receptors were based on the actual elevation of each receptor location as determined by AERMAP and standard NED data. Receptors were also placed at the potential plume height to ensure the maximum potential impacts were captured. Results from the screening modeling are compared to the Class I SILs defined in the OAR, which are listed in Table 5-1, below. For Project impacts that are above the Class I SILs, a screening analysis was conducted to determine the impacts on the Class I areas within 200 km of the proposed facility.

Further analysis was conducted if results at 50 km associated with a particular pollutant, averaging period, and Class I area were above the SIL. In these cases, the concentrations from each year and receptor were averaged over the five years, and the receptor on the 50 km ring with the highest five-year average concentration was chosen. A receptor was then placed at the 1 km distance along the ray ranging from the center of the proposed facility to the 50 km receptor with the highest average concentration. AERMOD was run at this 1 km receptor for each of the five years, and the average of the five years was taken. As such, five-year averages at both 1 km and 50 km were obtained. Use of the five-year average at 50 km was chosen based on an assumption that steady-state, deterministic results at that distance are conservative, particularly for longer time periods. The use of the five-year average at 1 km, rather than the single highest value obtained from any year, was a conservative choice so as not to allow a particularly high value to create a sharp and rapid decay function and corresponding lower result at the farther Class 1 areas.

An exponential decay function was then calculated to fit the results at 1 km and 50 km. The exponential decay function was used as the concentrations will decrease faster than they would under a linear relationship as distance increases from the facility, and the concentrations cannot go below zero (a limit for development of a mathematical extrapolation of concentration versus distance). The faster-than-linear decrease occurs because rather than existing in one dimension, air may move in three different dimensions as distance increases from the facility. In addition, sinks such as deposition would reduce the ambient air concentrations of the pollutant as well. The rate of decay depends on the relative difference between the 1 and 50 km values; higher values at 1 km and lower values at 50 km produce a more rapid rate of decay. Hence the use of the average value rather than the highest value at 1 km is conservative because it lowers the rate of modeled decay, resulting in a higher pollutant concentration at the Class I area distances (110 to 178 km away).

Curve parameters were determined for each pollutant, averaging period, and Class I area for which there was a modeled result at 50 km measured above the SIL, and the parameters were used to determine a concentration at the distance to the boundary of the Class I areas. It is shown that for all cases, the concentrations obtained through the curve fitting and extrapolation analysis are below the Class I SILs at the distance to the Class I areas. Class I analysis results for each area are summarized in Appendix H. Table 5-1 shows the results of the highest concentrations from all Class I areas. The results demonstrate the LNG Terminal emissions will below the Class I SILs and the project is not expected to contribute to Increment or NAAQS impacts in those locations.

Table 5-1. Class I Results and Significant Impact Levels (μg/m^3)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area Boundary	Class I SILs(1)
SO_2	3-hr	1.33	0.24	1.0
	24-hr	0.35	0.023	0.2
	Annual	0.012	N/A	0.1
NO_2	Annual	0.032	N/A	0.1
PM_{10}	24-hr	0.854	0.061	0.3
	Annual	0.026	N/A	0.2
$PM_{2.5}$	24-hr	0.854	0.061	0.07
	Annual	0.026	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

5.2 CLASS I AQRV ANALYSIS

An air quality related values (AQRV) analysis is not required for a Type B State NSR project but is part of other regulatory requirements for the Project.[20] Therefore, for consistency and informational purposes, a Q/D calculation for regional haze and deposition was used to screen for AQRVs.[21] The screening analysis was based on distance from the source to the Class I area and the annualized daily emissions of AQRV-impacting pollutants. If the Q/D analysis results are less than or equal to the screening factor of 10, then FLM agencies do not require any further Class I AQRV impact analyses from those sources.

[20] The 2017 FERC guidance recommends Class I analyses for those projects within 100 km of a Class I area, subject to PSD permitting requirements, or for projects in which comments are expected.

[21] U.S. Forest Service – Air Quality Program, National Park Service – Air Resources Division, U.S. Fish and Wildlife Service – Air Quality Branch, *Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG)- Revised*, Section 3.2. October 2010.

A detailed calculation of the Q value along with the resultant Q/D values (all less than 10) is provided in Appendix H. Also provided are concurrences from the National Park Service and US Forest Service that no additional AQRV analyses are warranted.

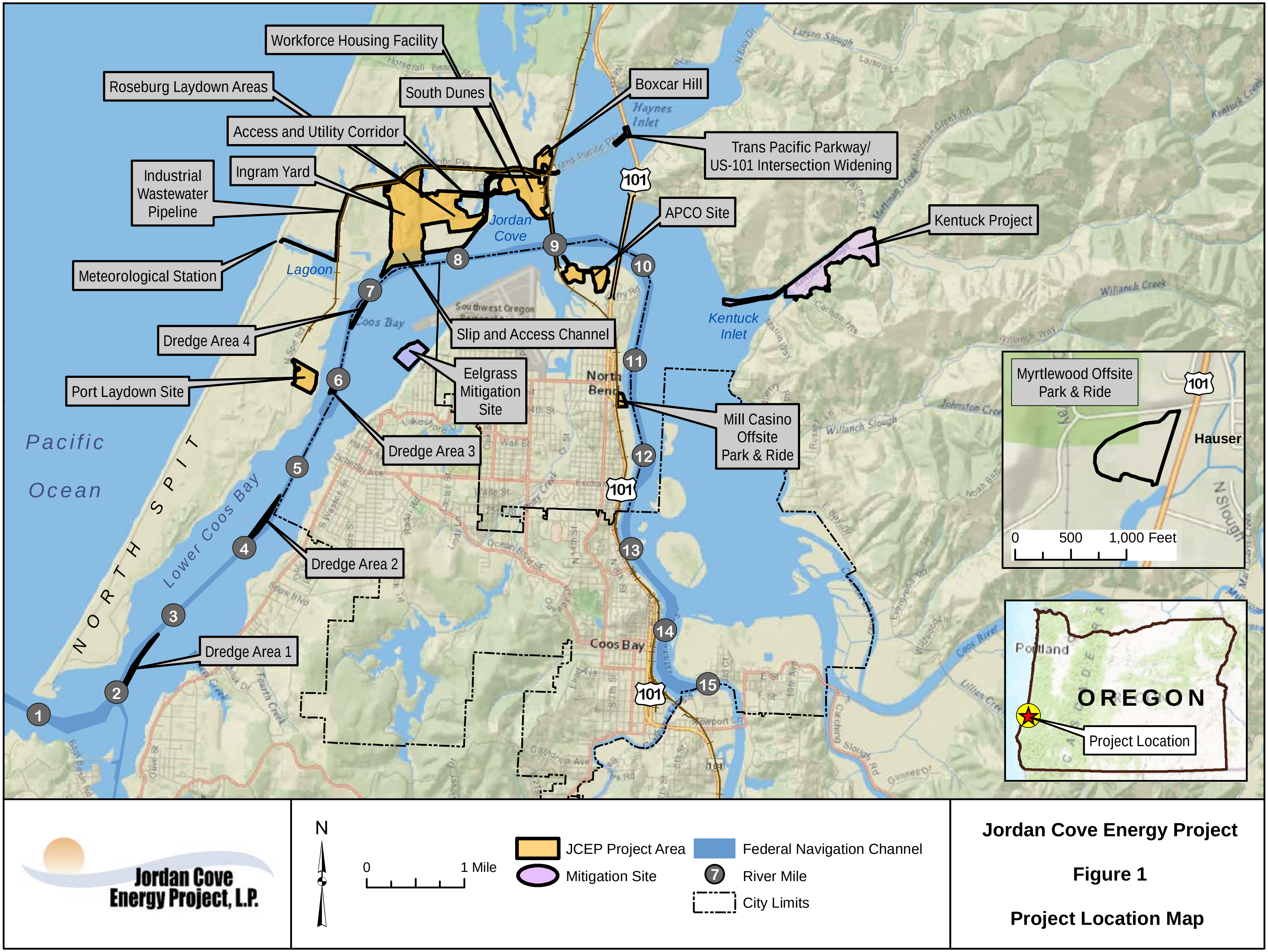
6. REFERENCES

Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program, December 2016.

US Environmental Protection Agency, AP-42, Fifth Edition *Compilation of Air Pollutant Emission Factors, Volume I, Stationary Point and Area Sources,* January 1995 (with updates to chapters).

U.S. Forest Service – Air Quality Program, National Park Service – Air Resources Division, U.S. Fish and Wildlife Service – Air Quality Branch*, Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG)- Revised*, Section 3.2. October 2010.

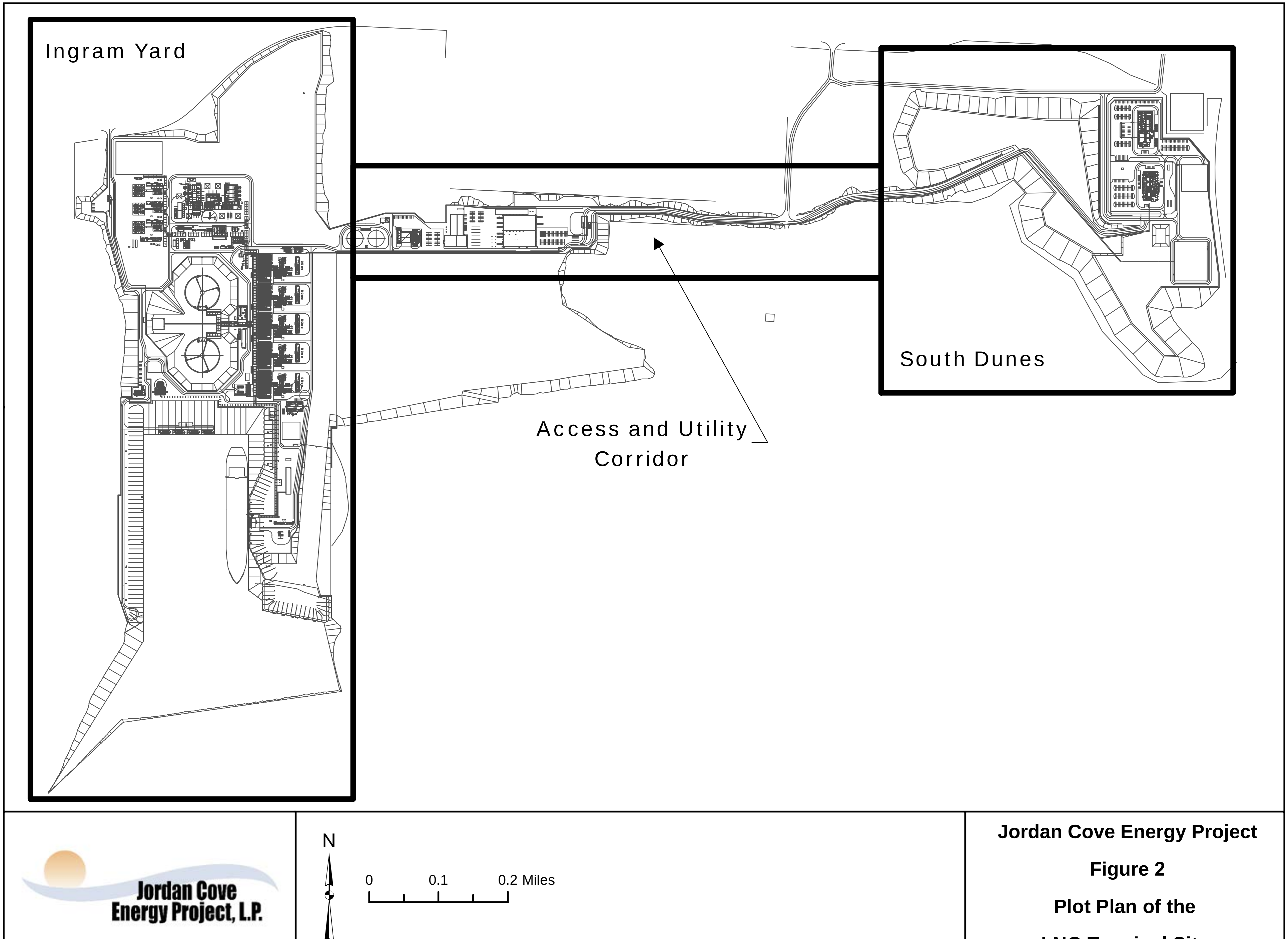
FIGURES



Jordan Cove Energy Project

Figure 1

Project Location Map

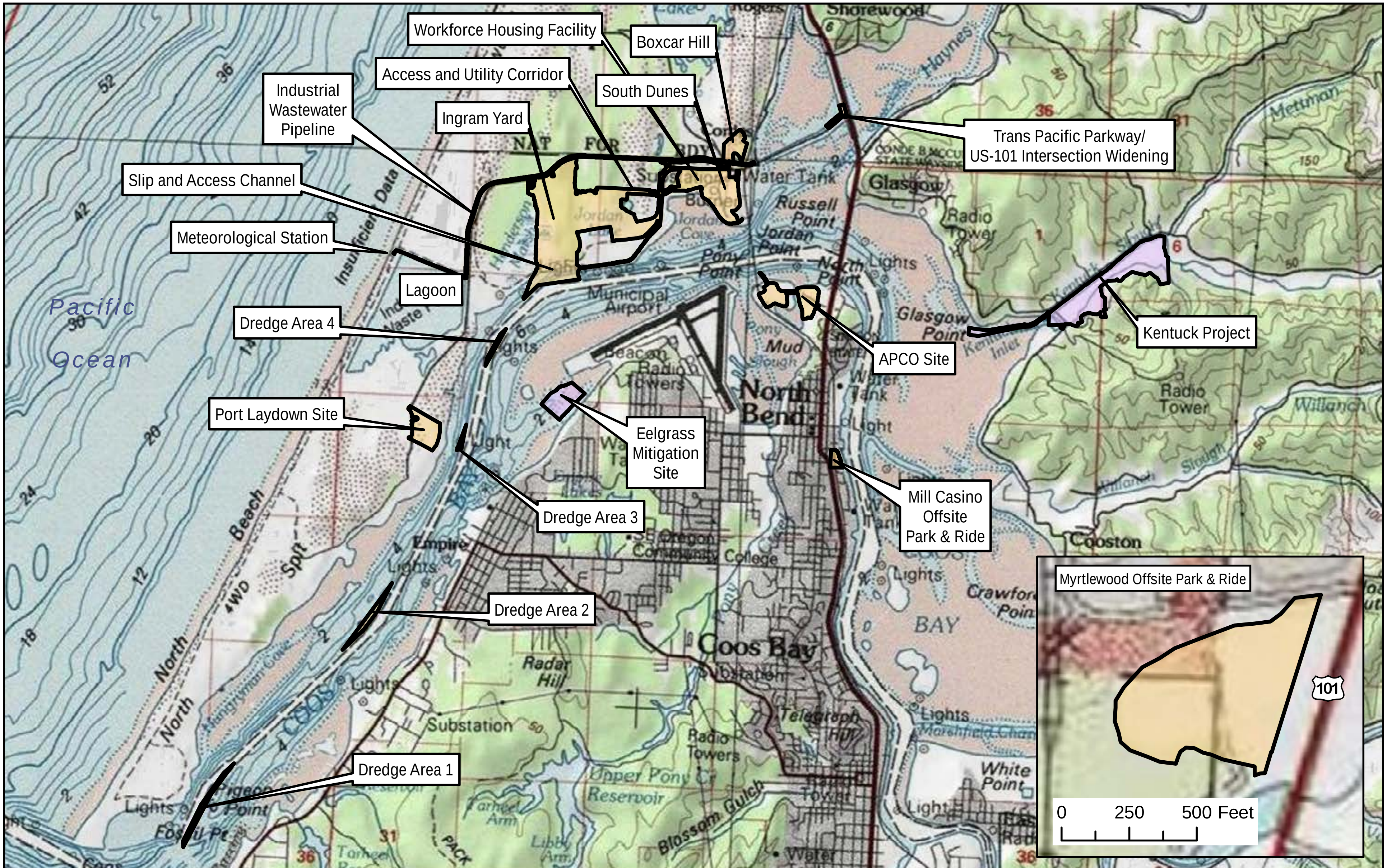


Jordan Cove Energy Project

Figure 2

Plot Plan of the

LNG Terminal Site



Jordan Cove Energy Project, L.P.

N

0 0.5 1 Mile

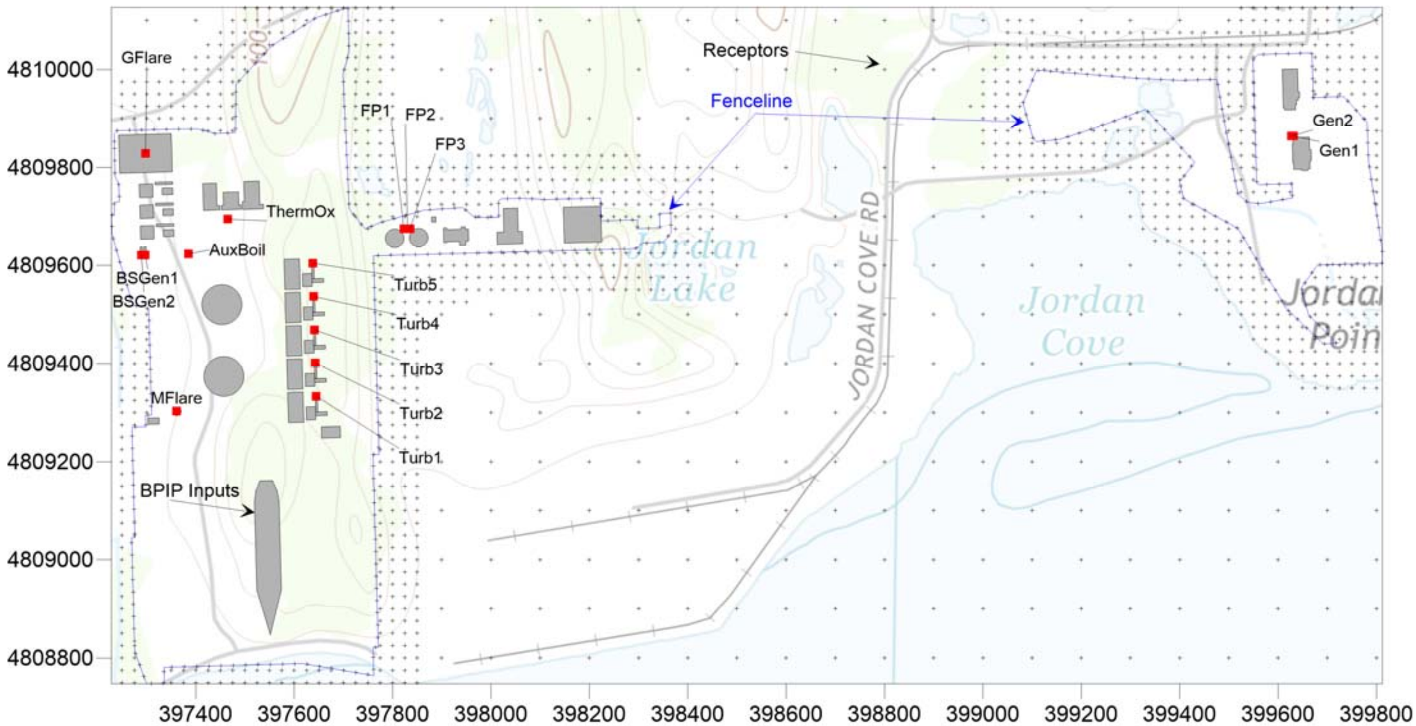
JCEP Project Area

Mitigation Site

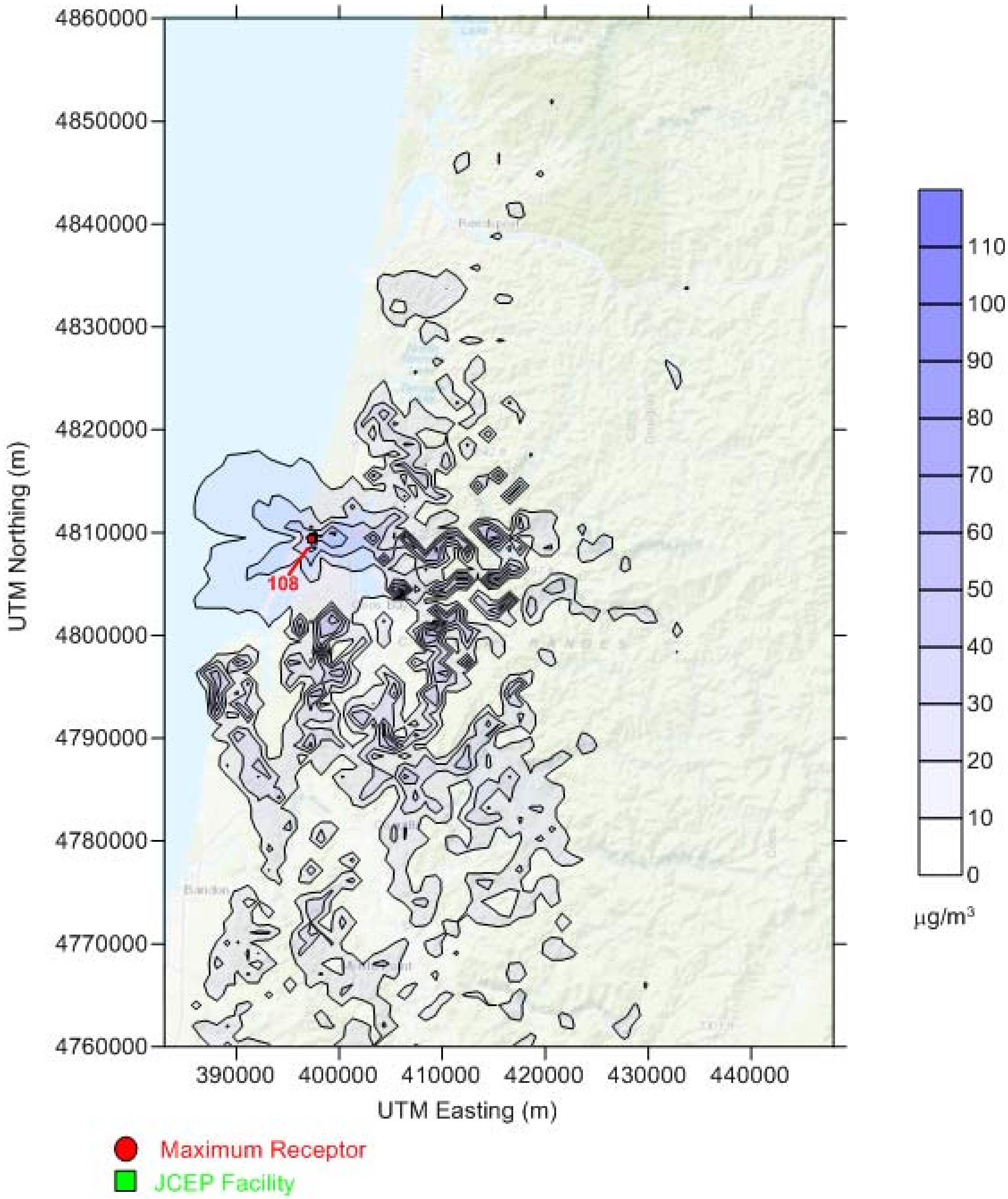
Jordan Cove Energy Project

Figure 3

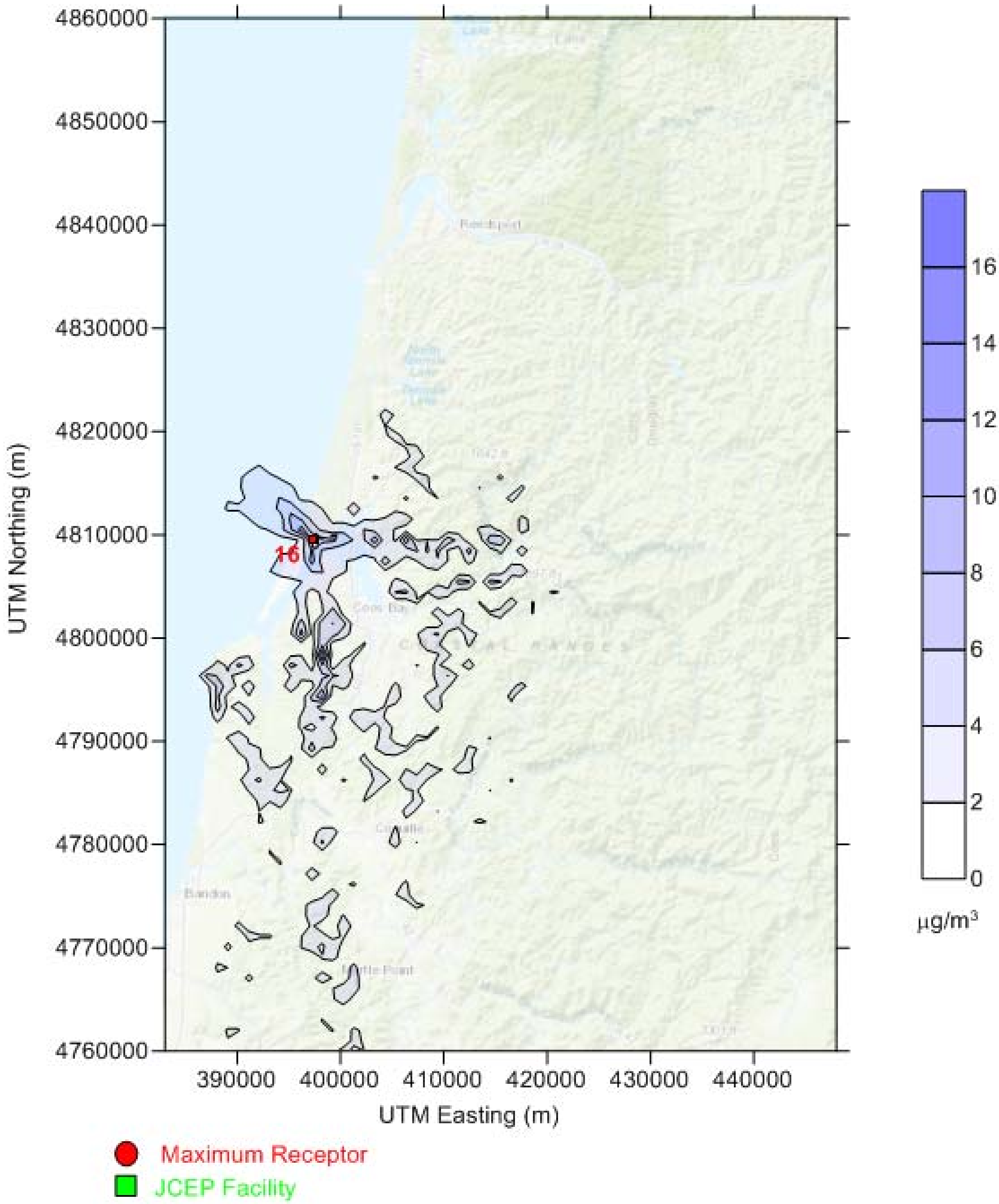
USGS Topographic Map of the Project Site



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
Drawing MODELED SITE LAYOUT		
Date	September 2017	Fig. No.
Project No.	108.01593.00001	**4**



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
Drawing CO 1-HOUR SIGNIFICANCE ANALYSIS		
Date	September 2017	Fig. No.
Project No.	108.01593.00001	**5**



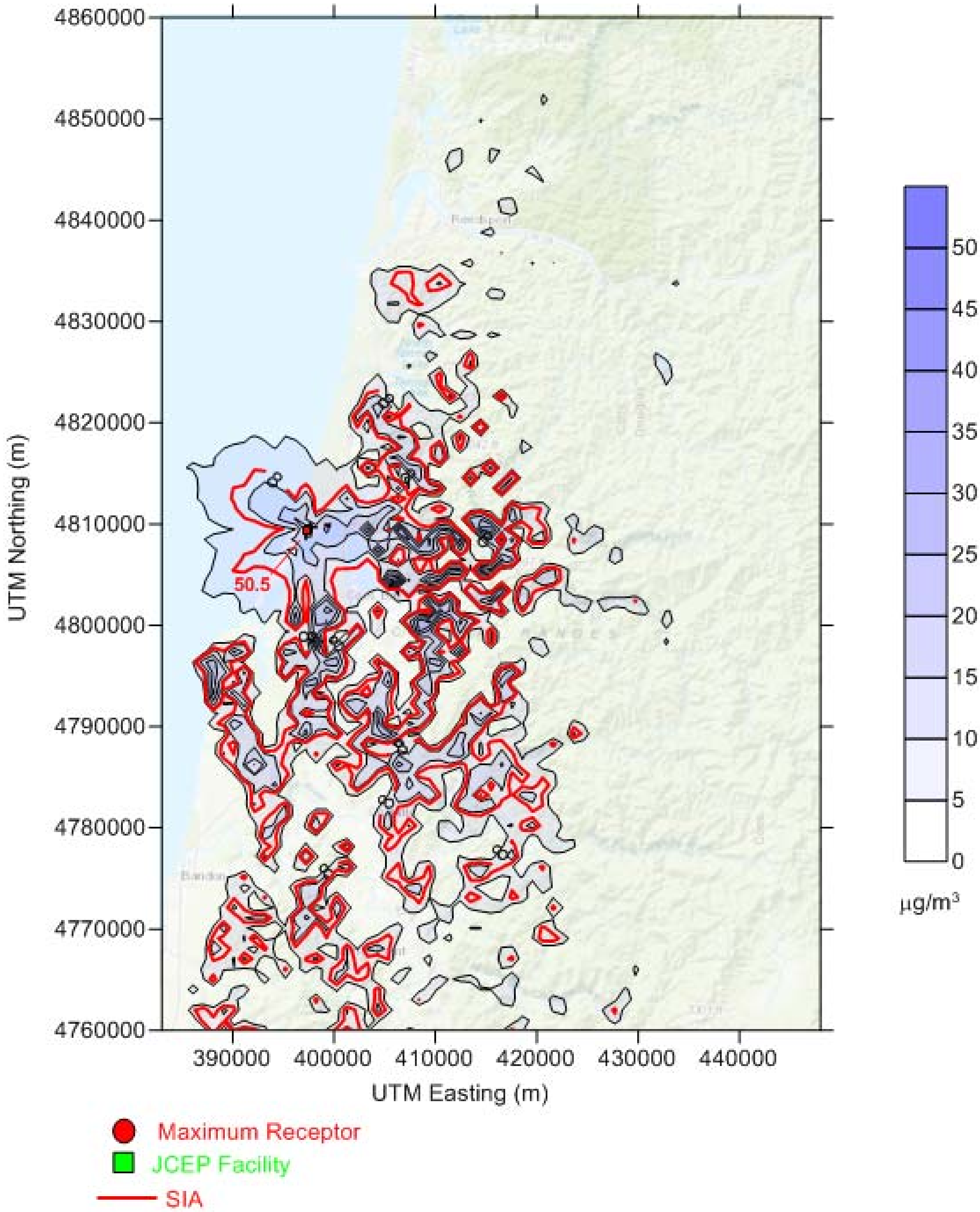
Report

JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

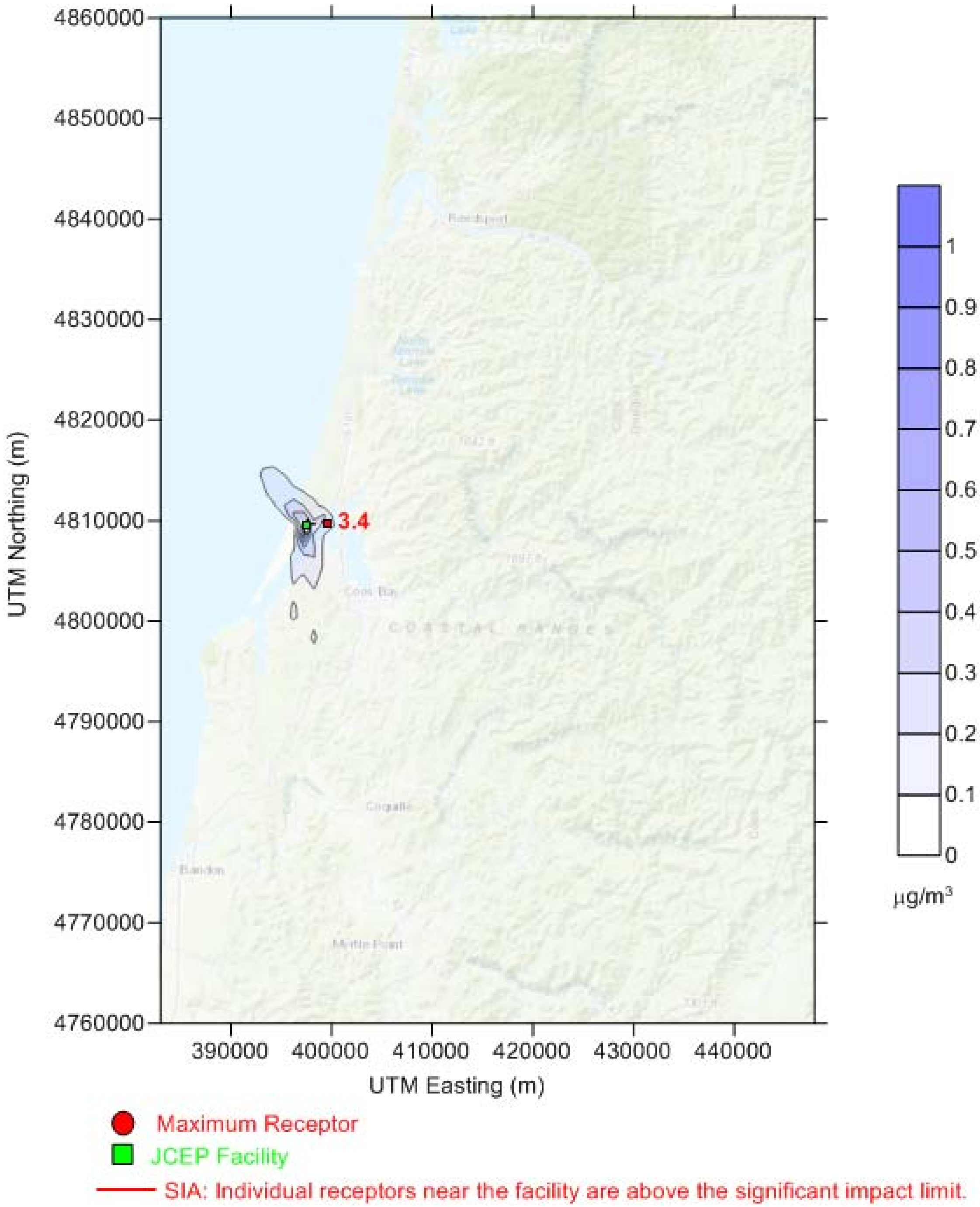
Drawing

CO 8-HOUR SIGNIFICANCE ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	6



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240	
Drawing NO_2 1-HOUR SIGNIFICANCE ANALYSIS	
Date September 2017	Fig. No.
Project No. 108.01593.00001	**7**



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240	
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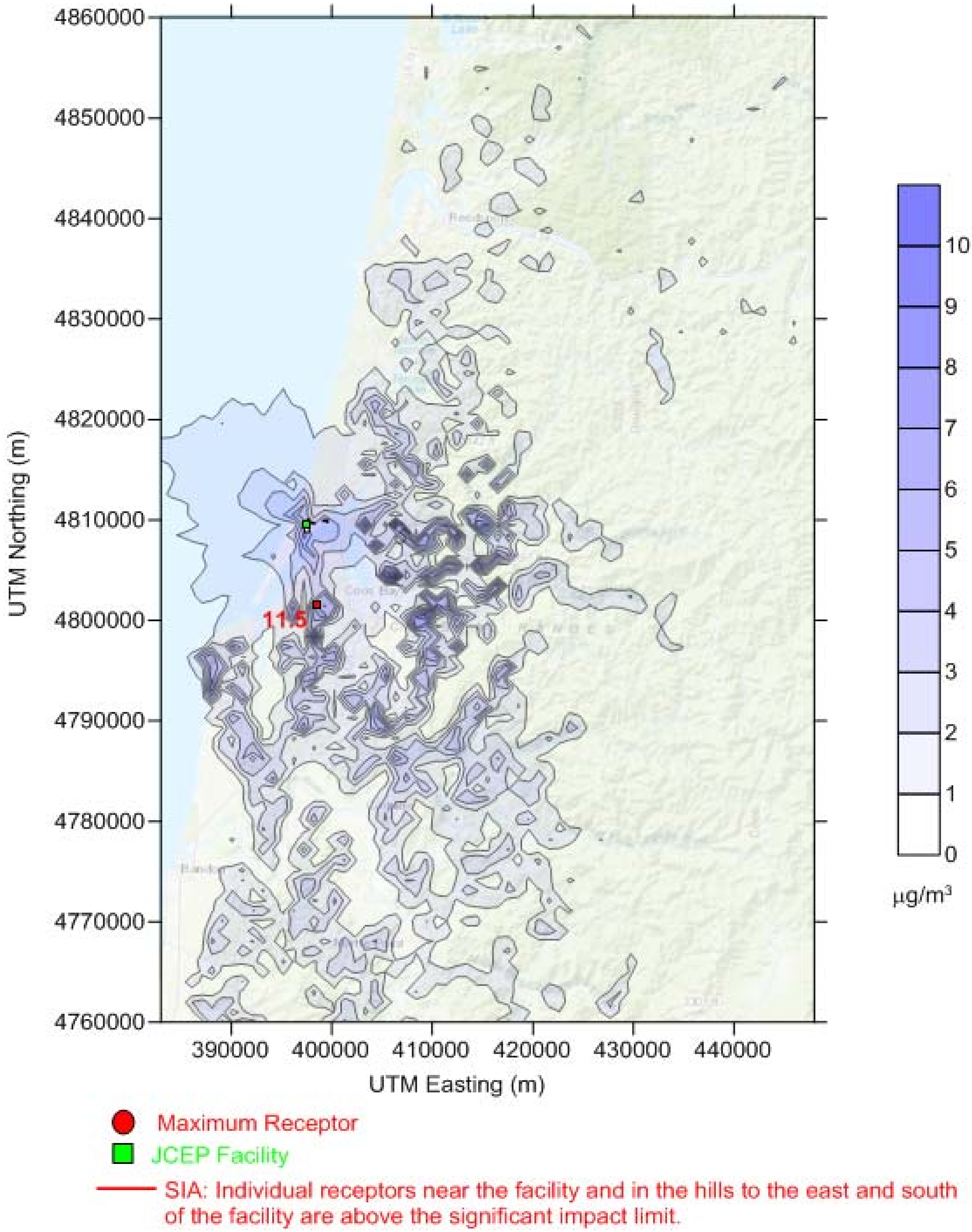
Date September 2017	Fig. No.
Project No. 108.01593.00001	**8**



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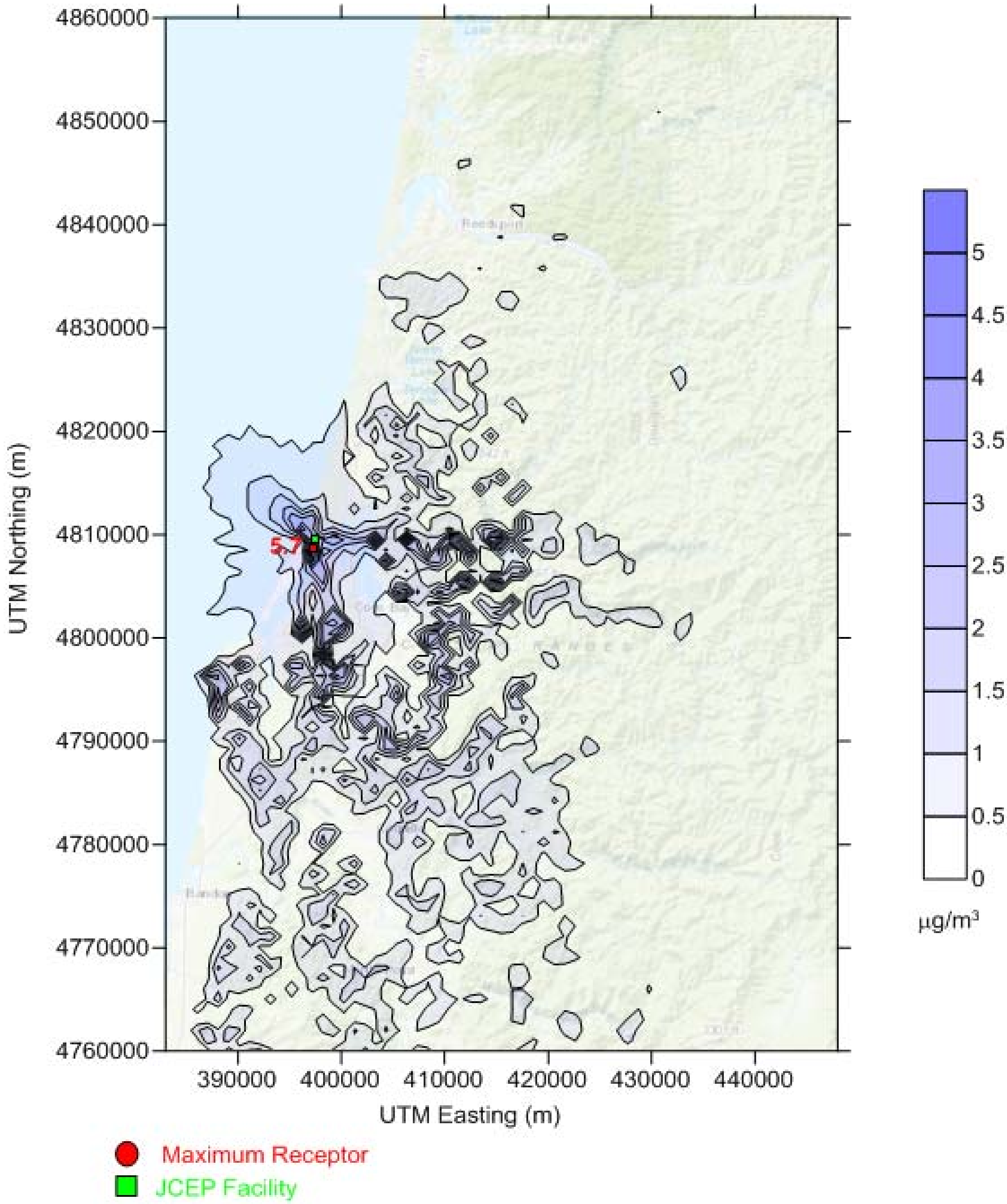
JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
Drawing SO_2 1-HOUR SIGNIFICANCE ANALYSIS		
Date	September 2017	Fig. No.
Project No.	108.01593.00001	9



Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing
SO_2 3-HOUR SIGNIFICANCE ANALYSIS

Date	September 2017	Fig. No.
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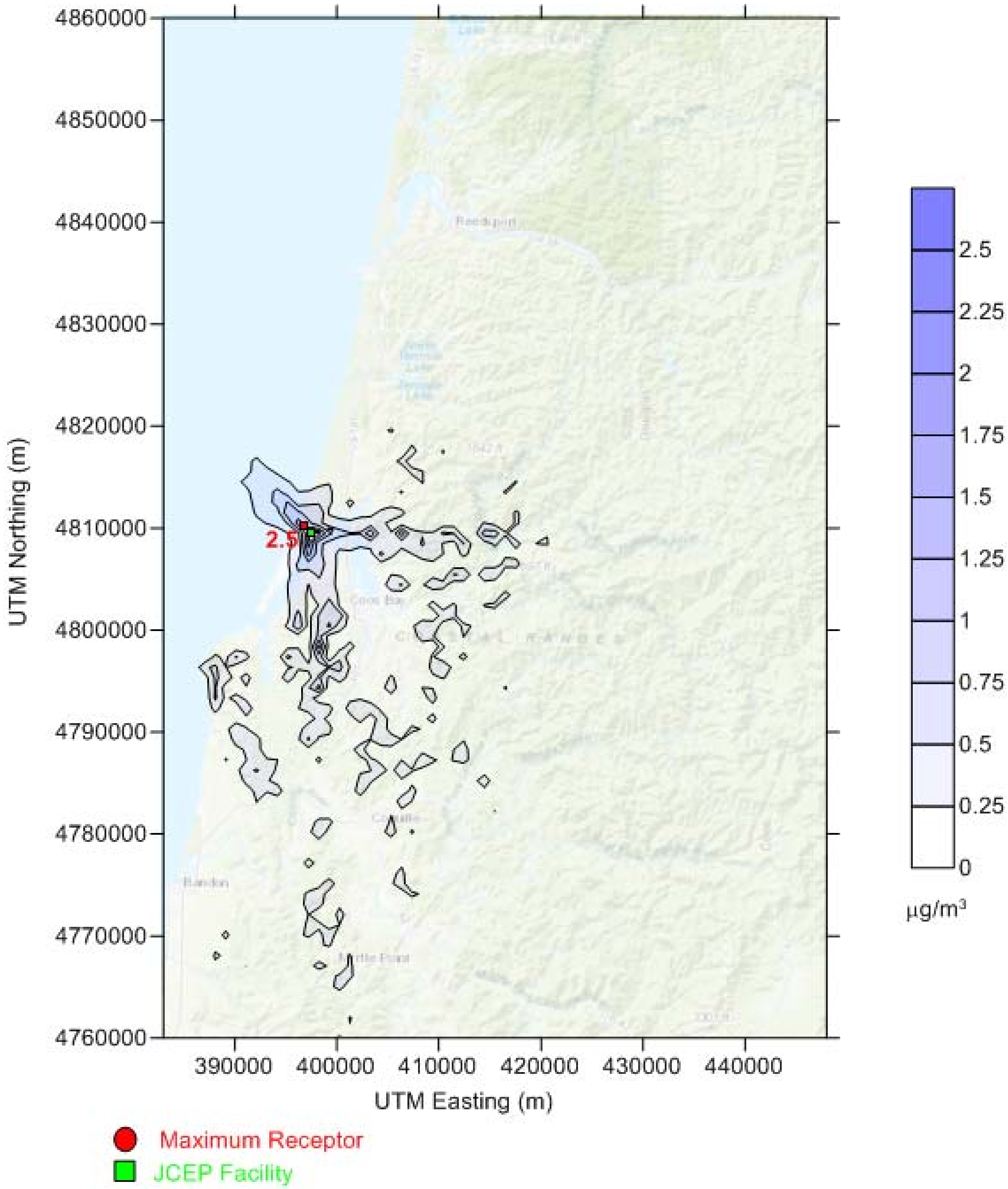

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JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
Drawing		
SO_2 24-HOUR SIGNIFICANCE ANALYSIS		
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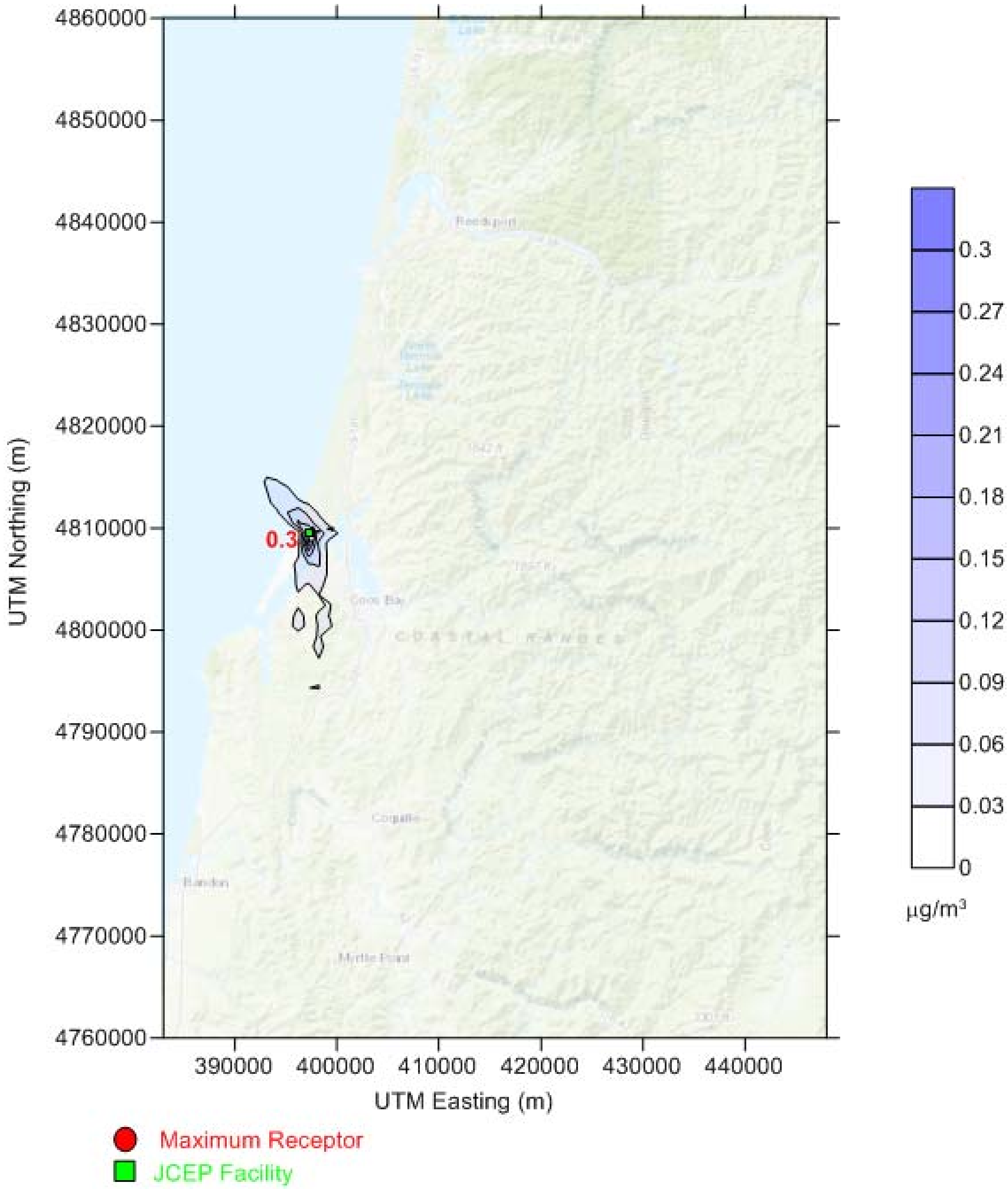
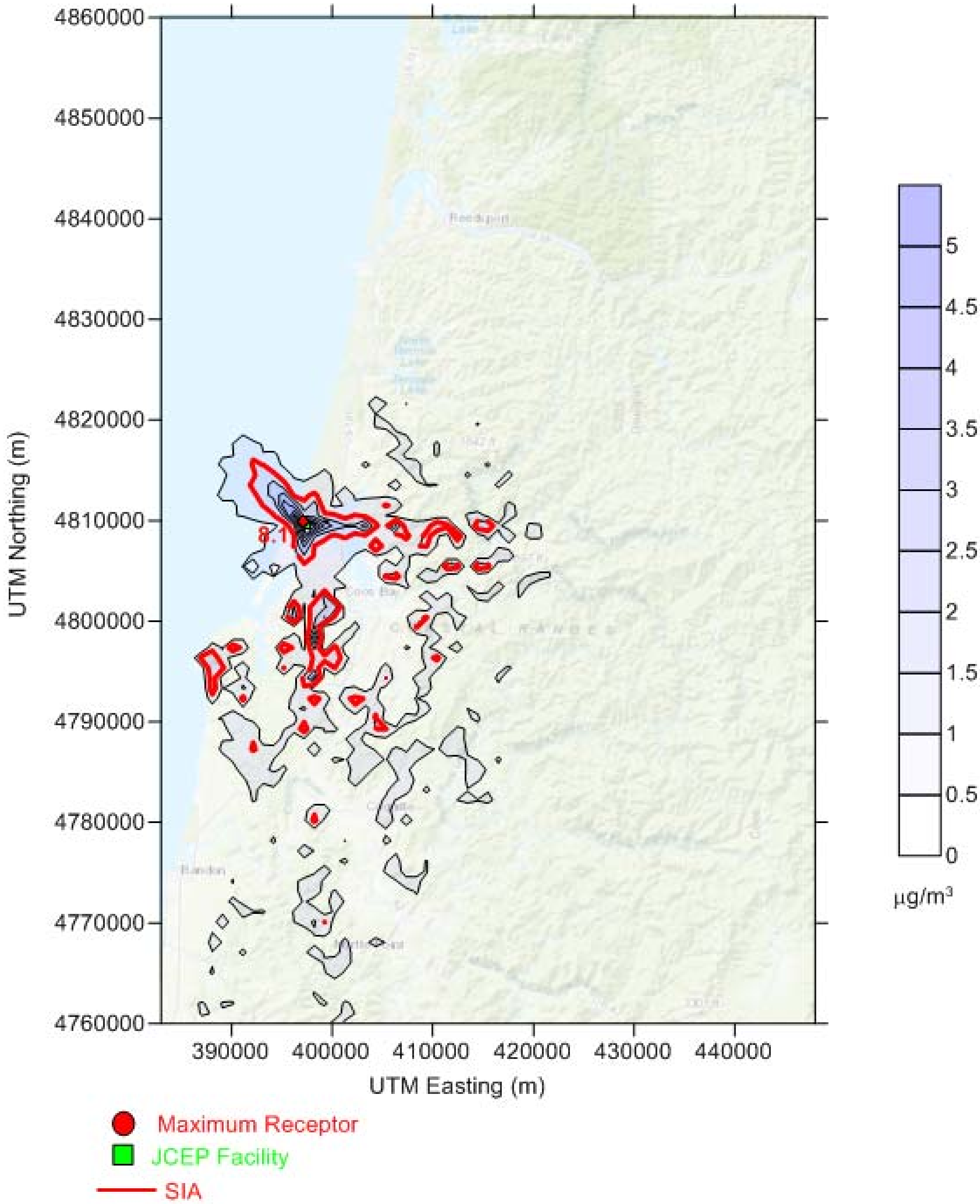


Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing
SO_2 ANNUAL SIGNIFICANCE ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	**12**



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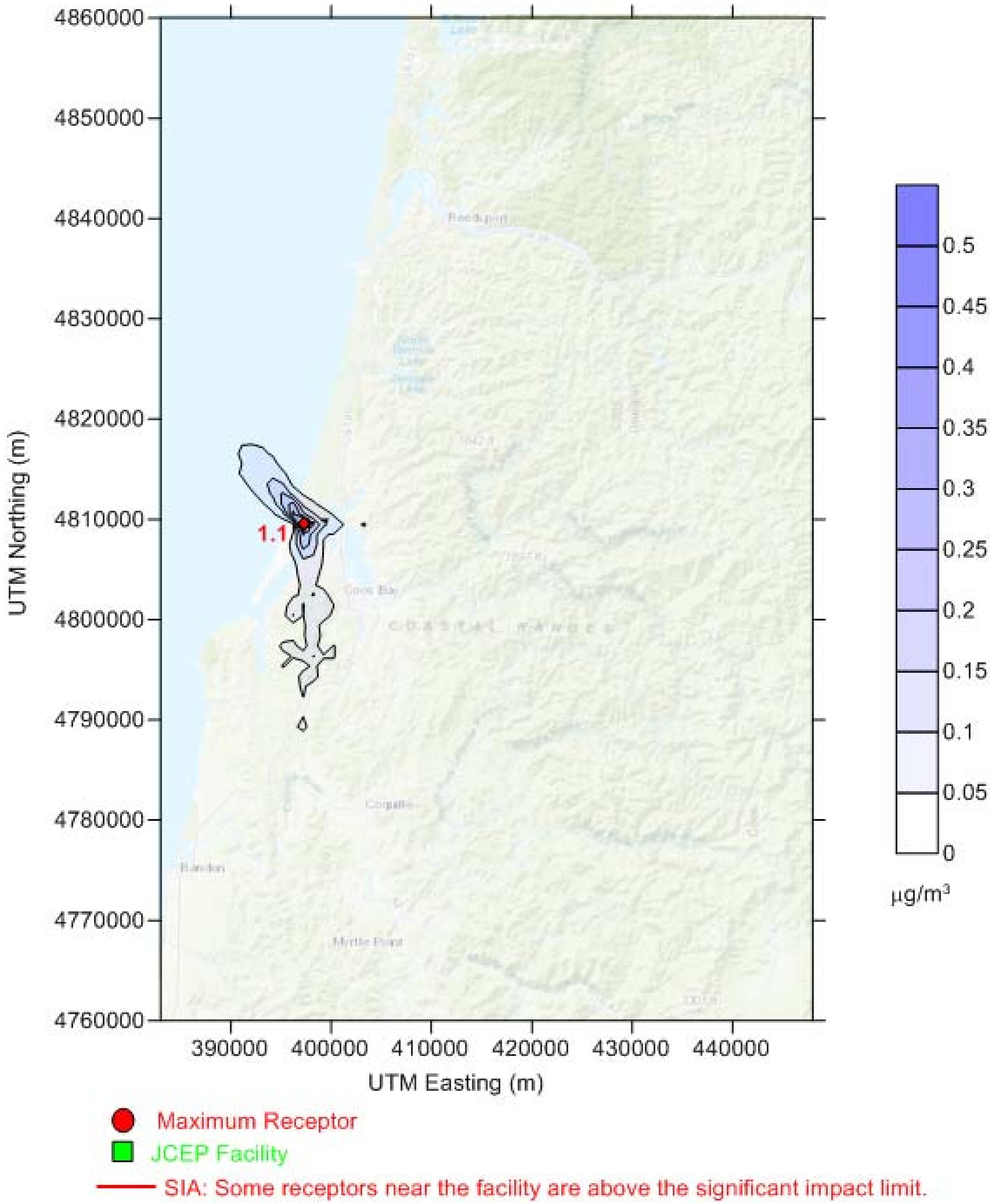
Date	September 2017	Fig. No. **13**
Project No.	108.01593.00001	



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
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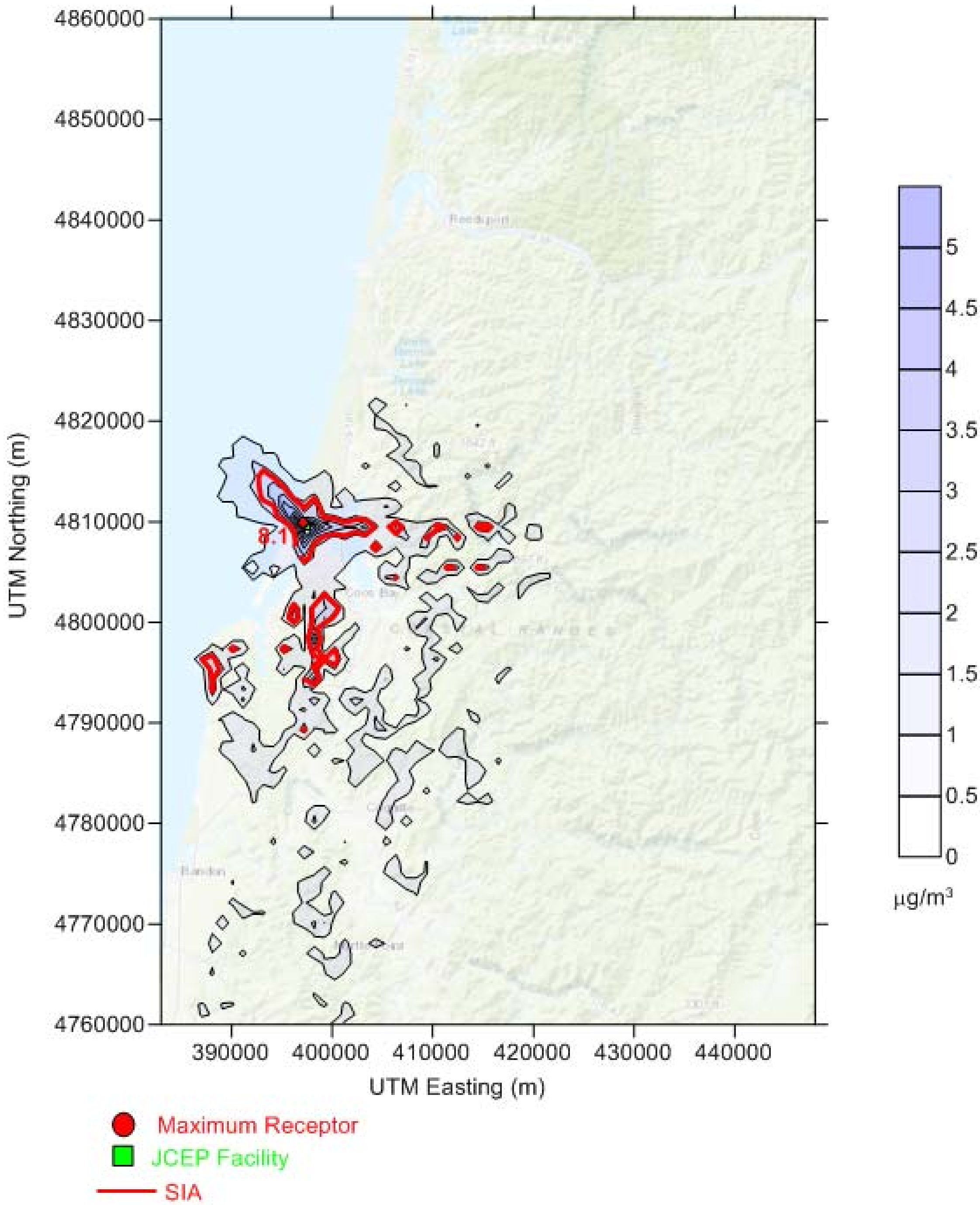

Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
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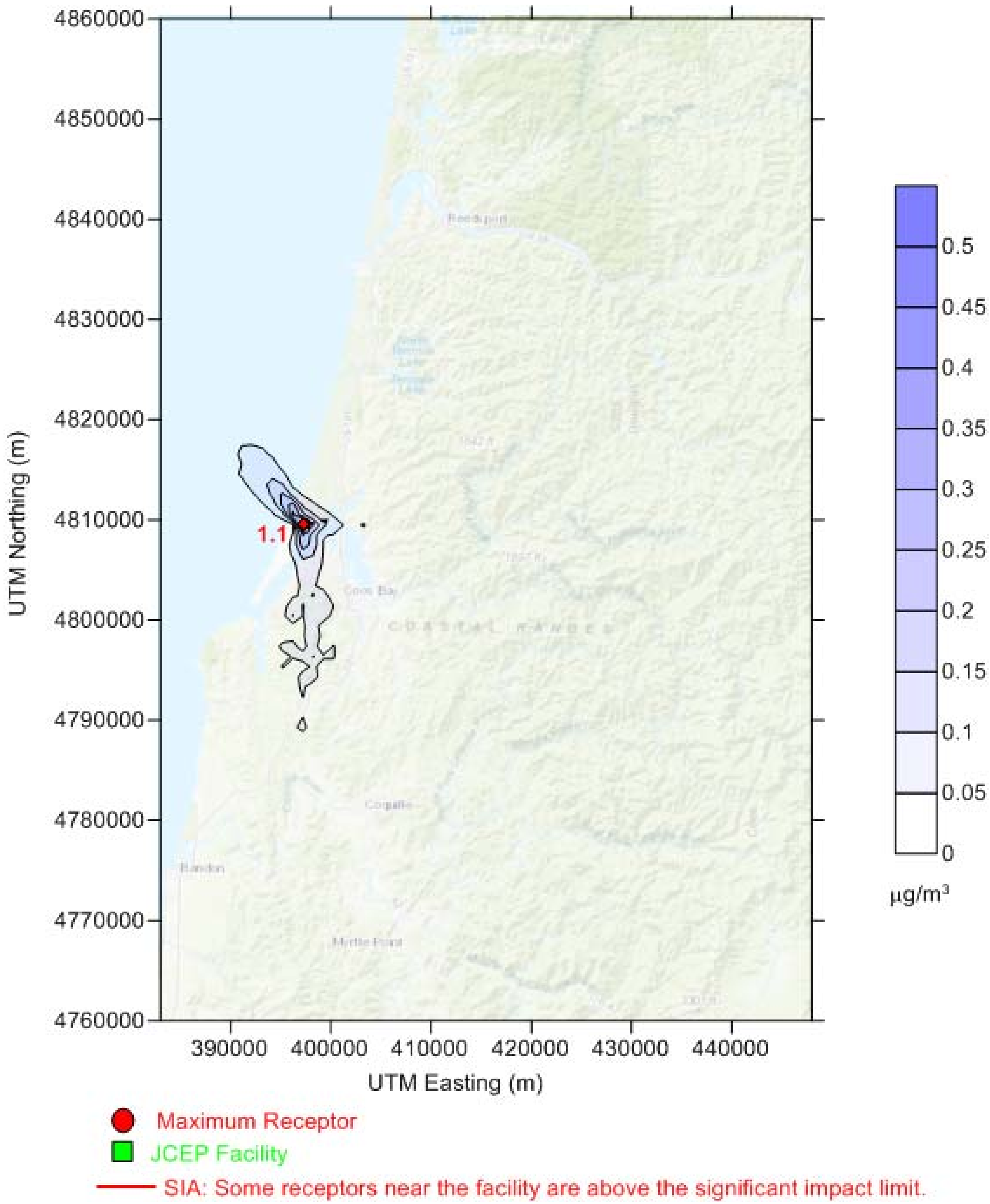
Drawing
$PM_{2.5}$ 24-HOUR SIGNIFICANCE ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	15



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
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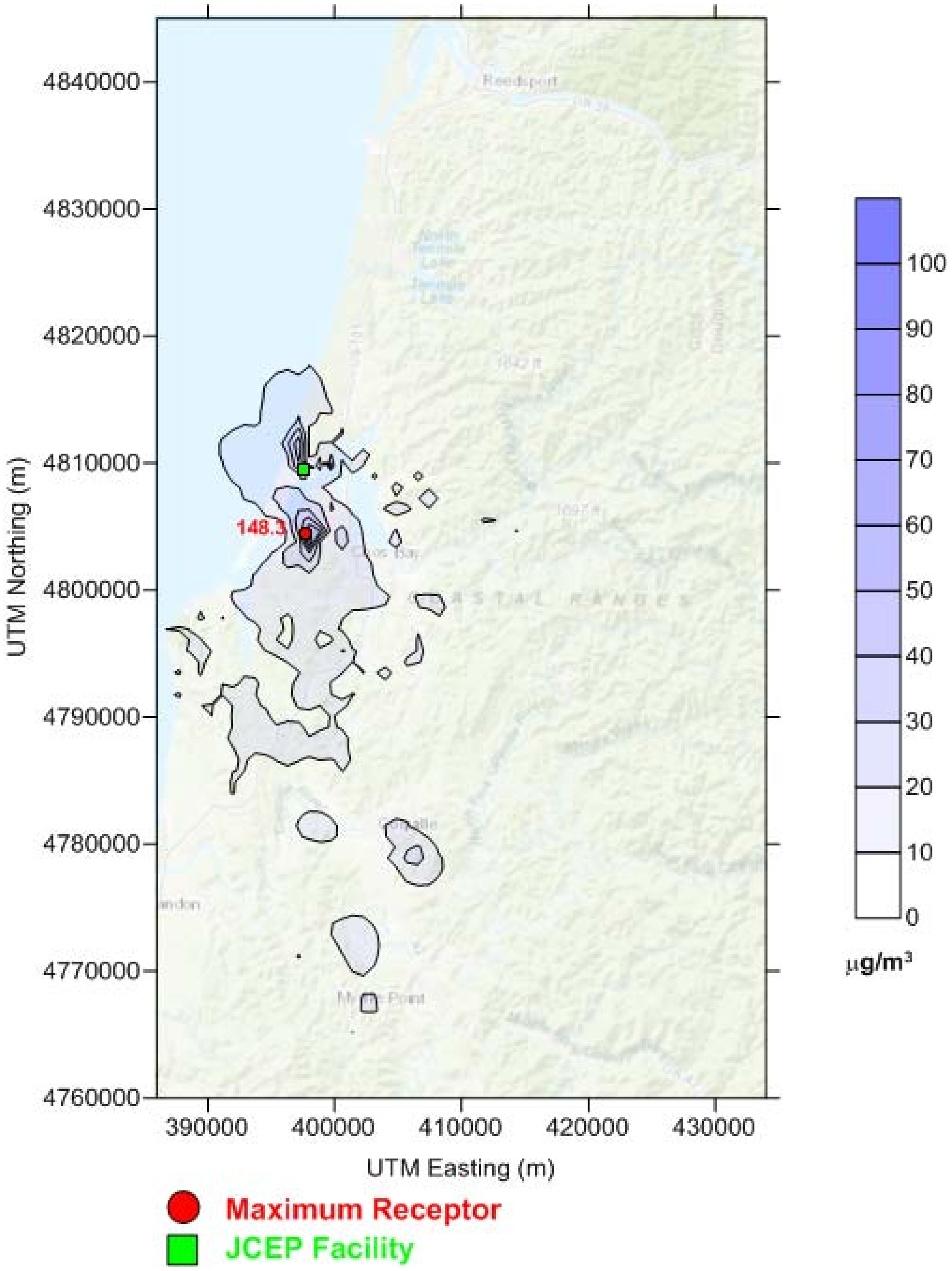
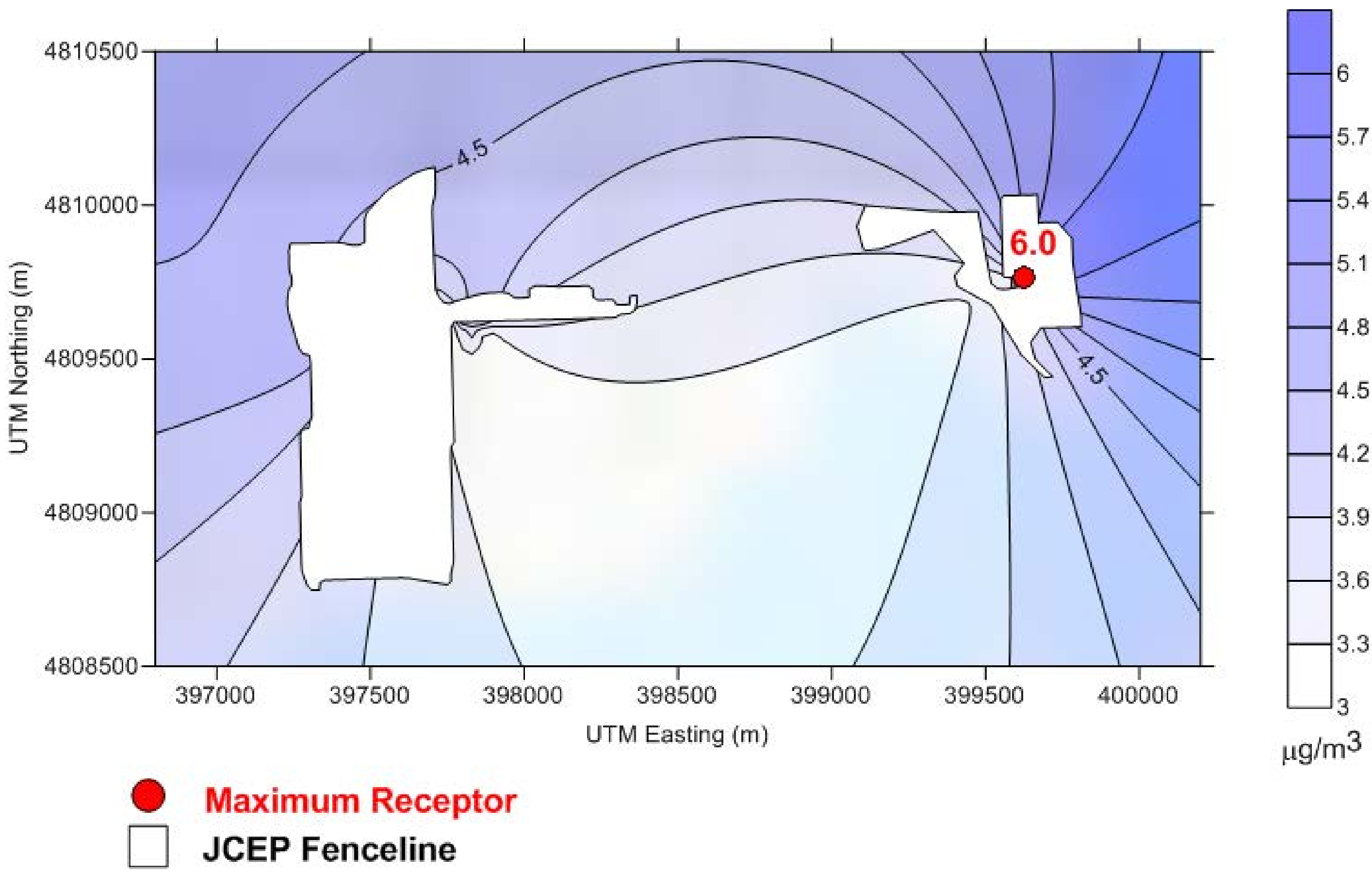
Date	September 2017	Fig. No. **16**
Project No.	108.01593.00001	



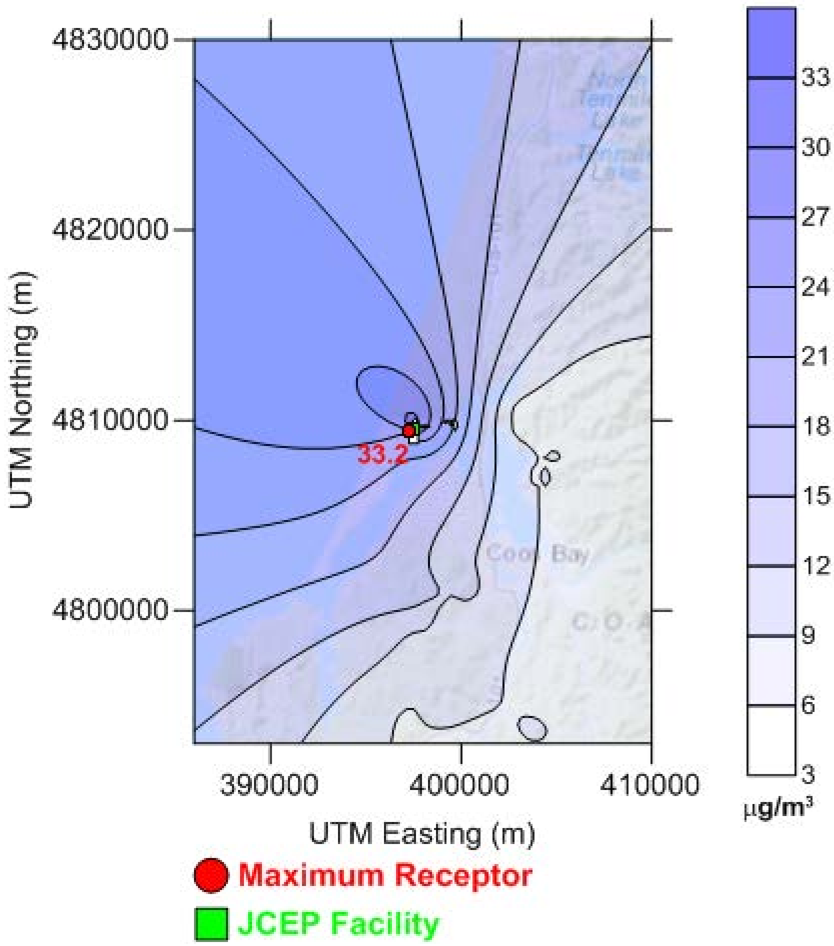
Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240	
Drawing NO_2 1-HOUR NAAQS ANALYSIS	
Date September 2017	Fig. No.
Project No. 108.01593.00001	**17**



Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing
NO_2 ANNUAL NAAQS ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	**18**



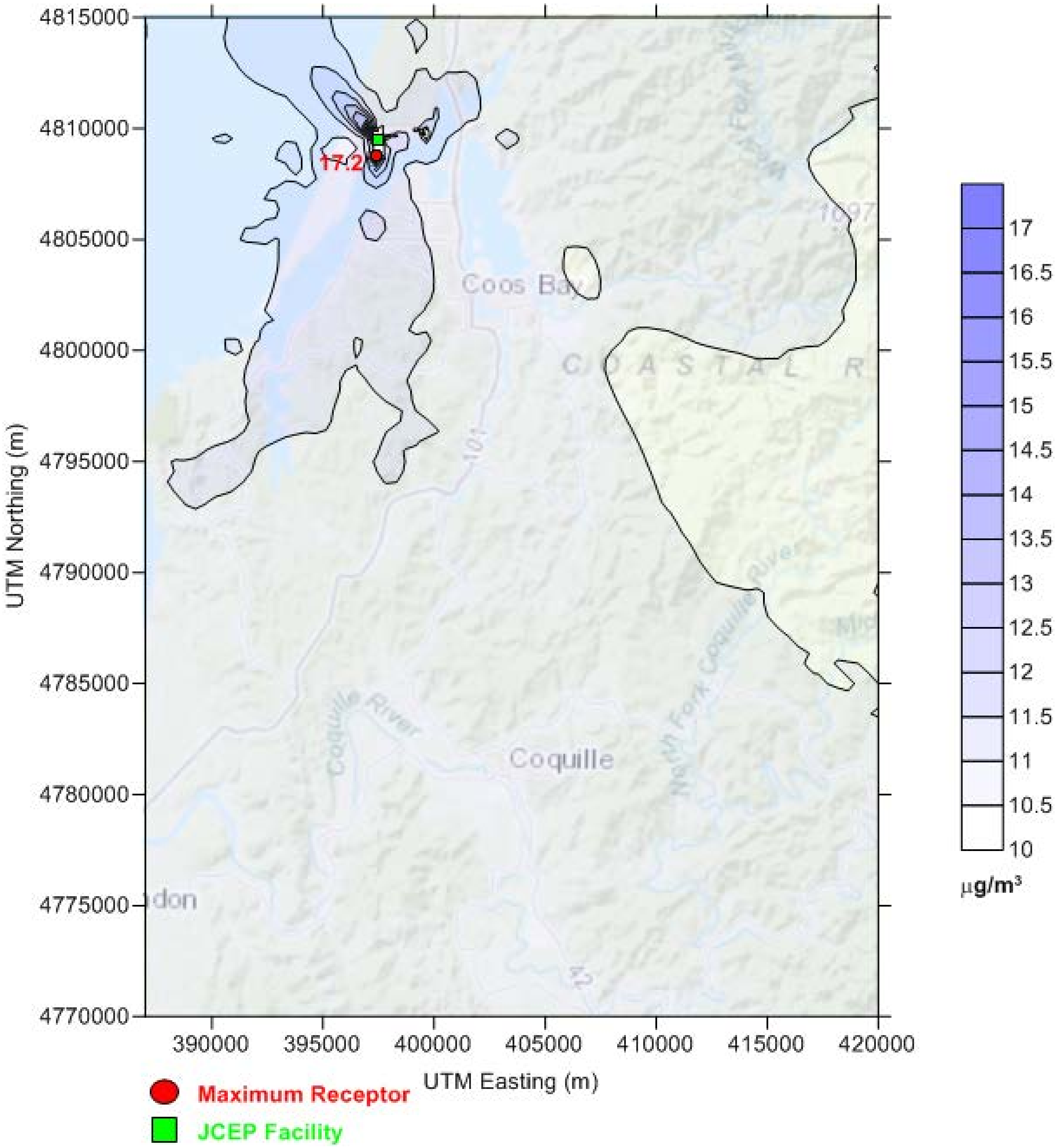
Report

JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing

SO_2 1-HOUR NAAQS ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	**19**



Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing
$PM_{2.5}$ 24-HOUR NAAQS ANALYSIS

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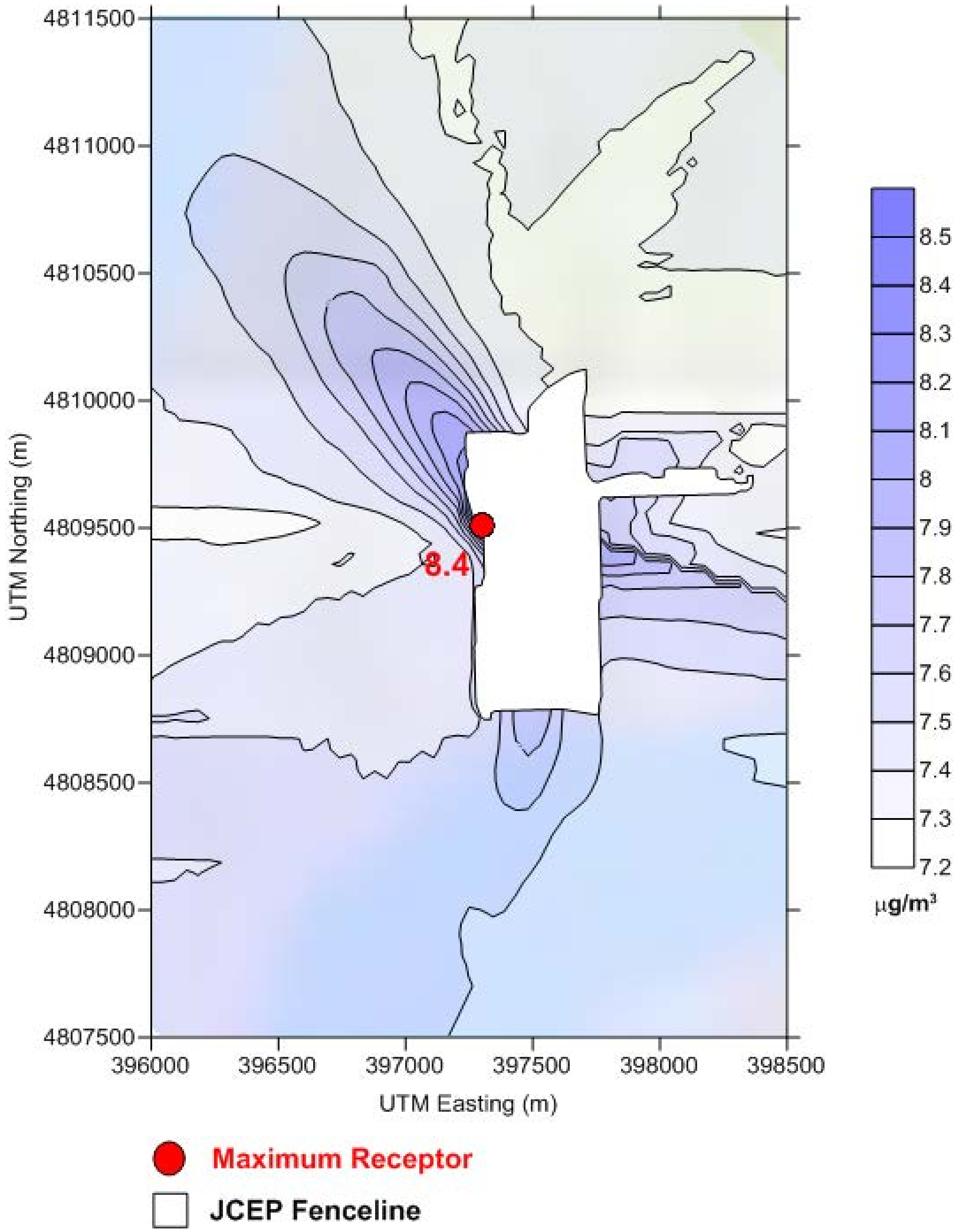

Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
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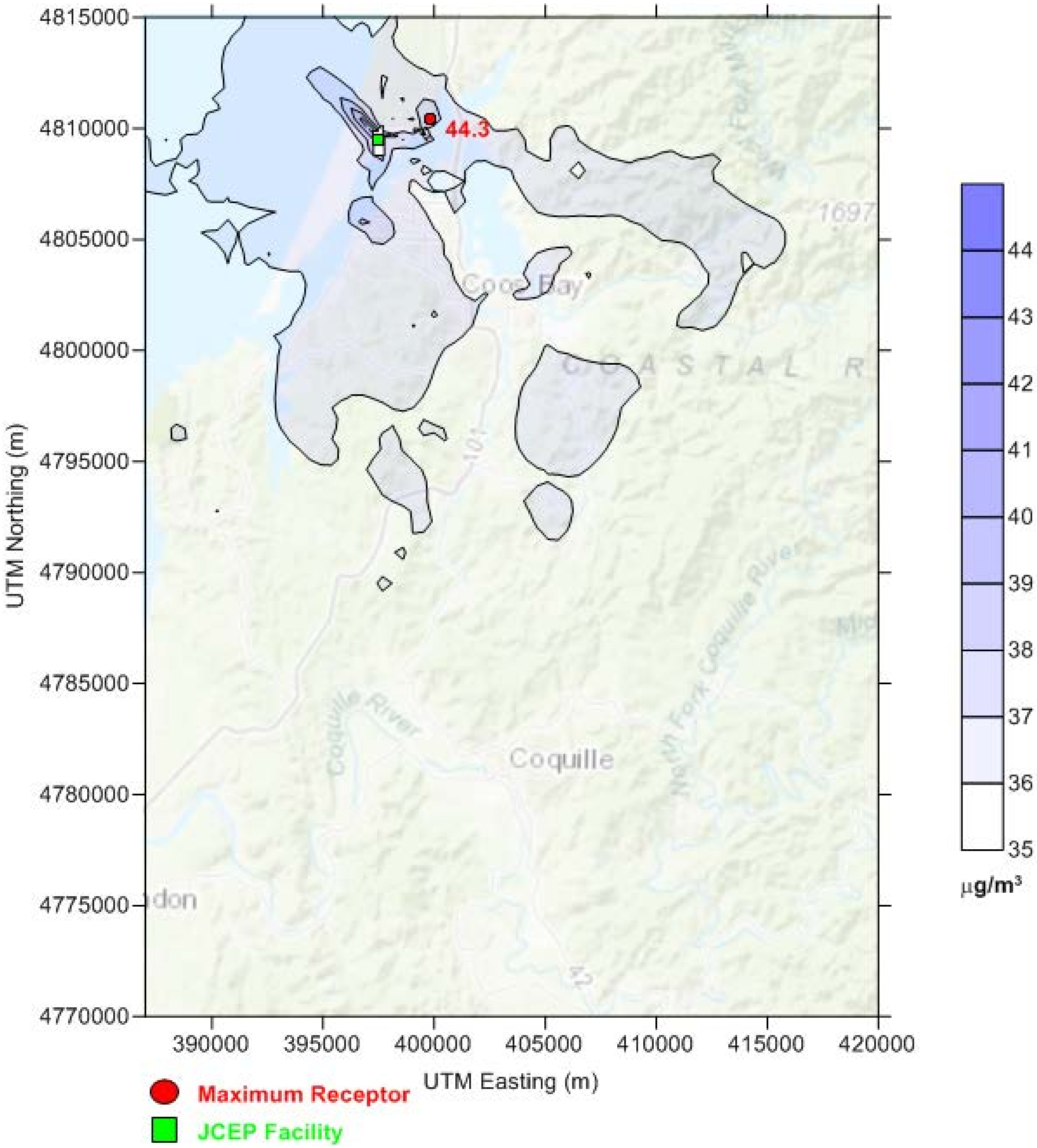


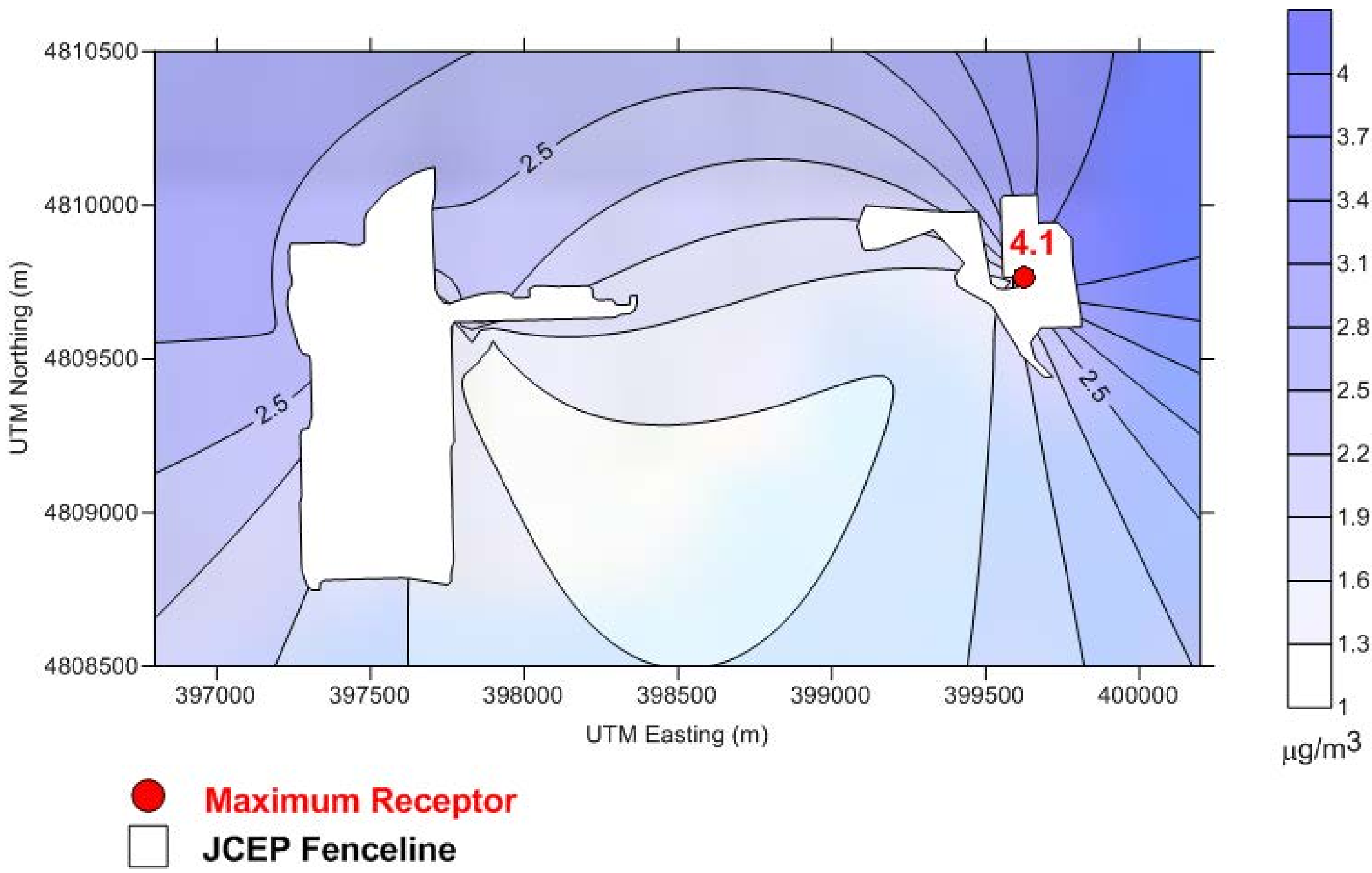
Report

JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing

PM_{10} 24-HOUR NAAQS ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	**22**



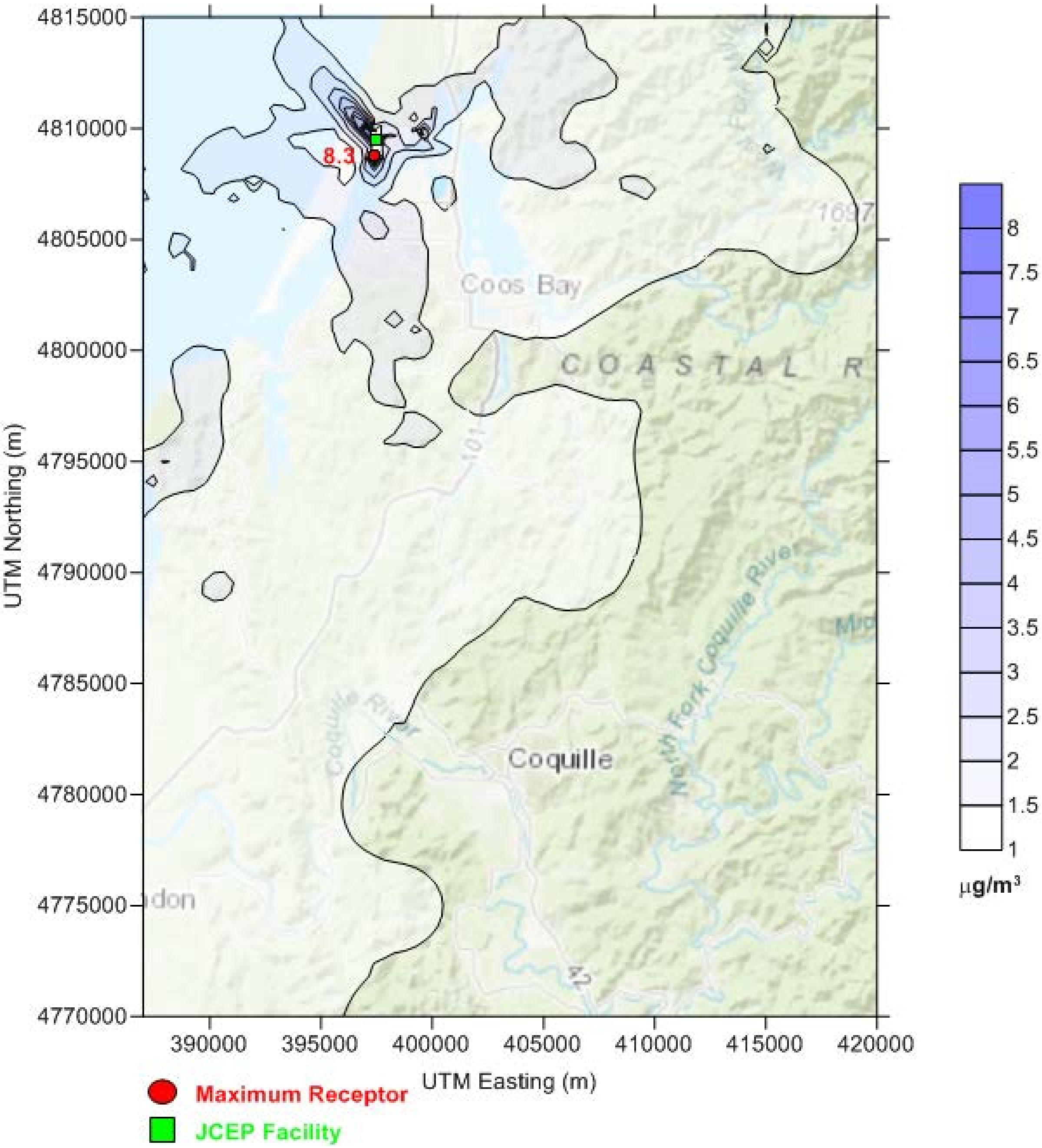
Report

JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing

NO_2 ANNUAL INCREMENT ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	**23**



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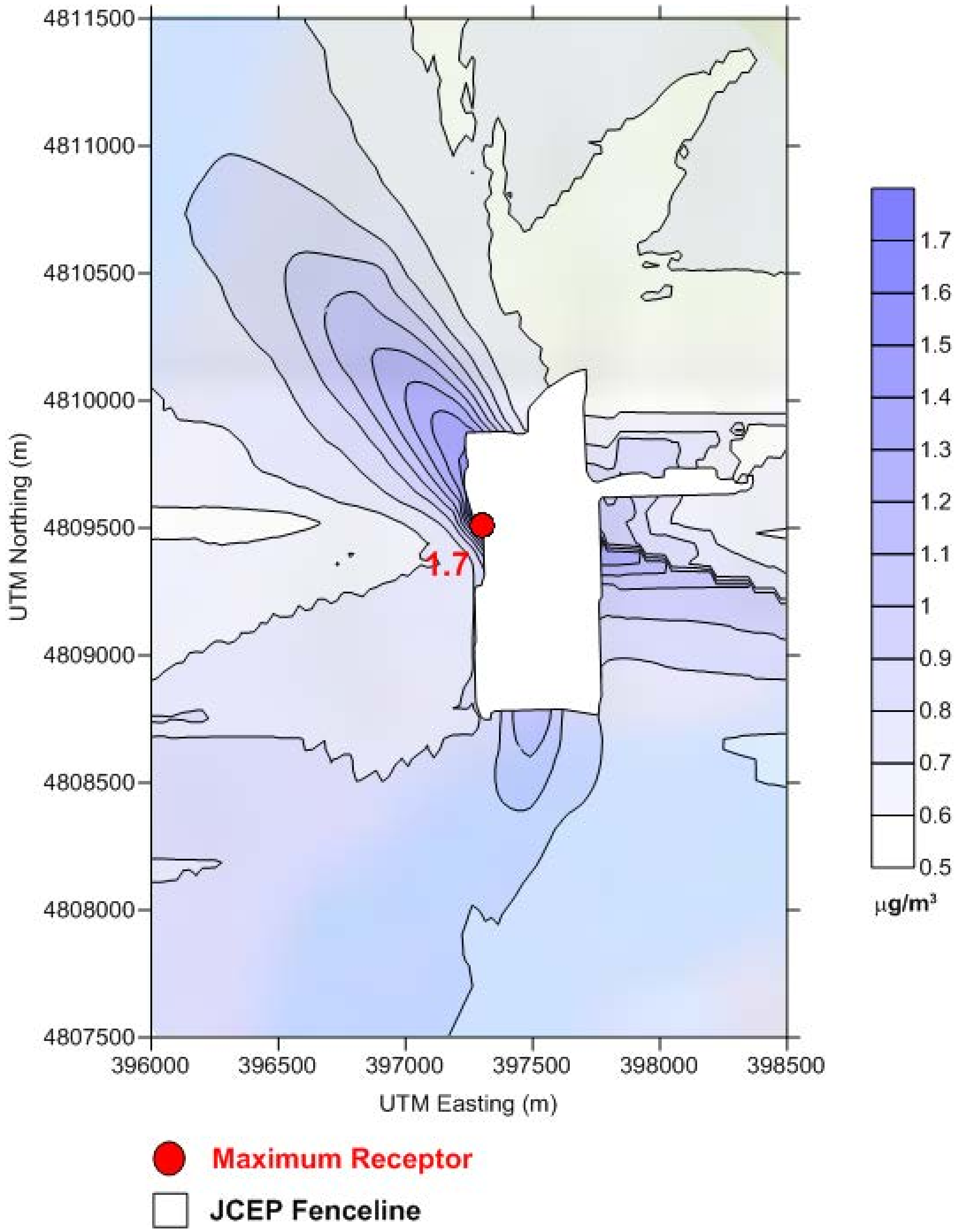
Drawing $PM_{2.5}$ 24-HOUR INCREMENT ANALYSIS	
Date September 2017	Fig. No.
Project No. 108.01593.00001	**24**



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240		
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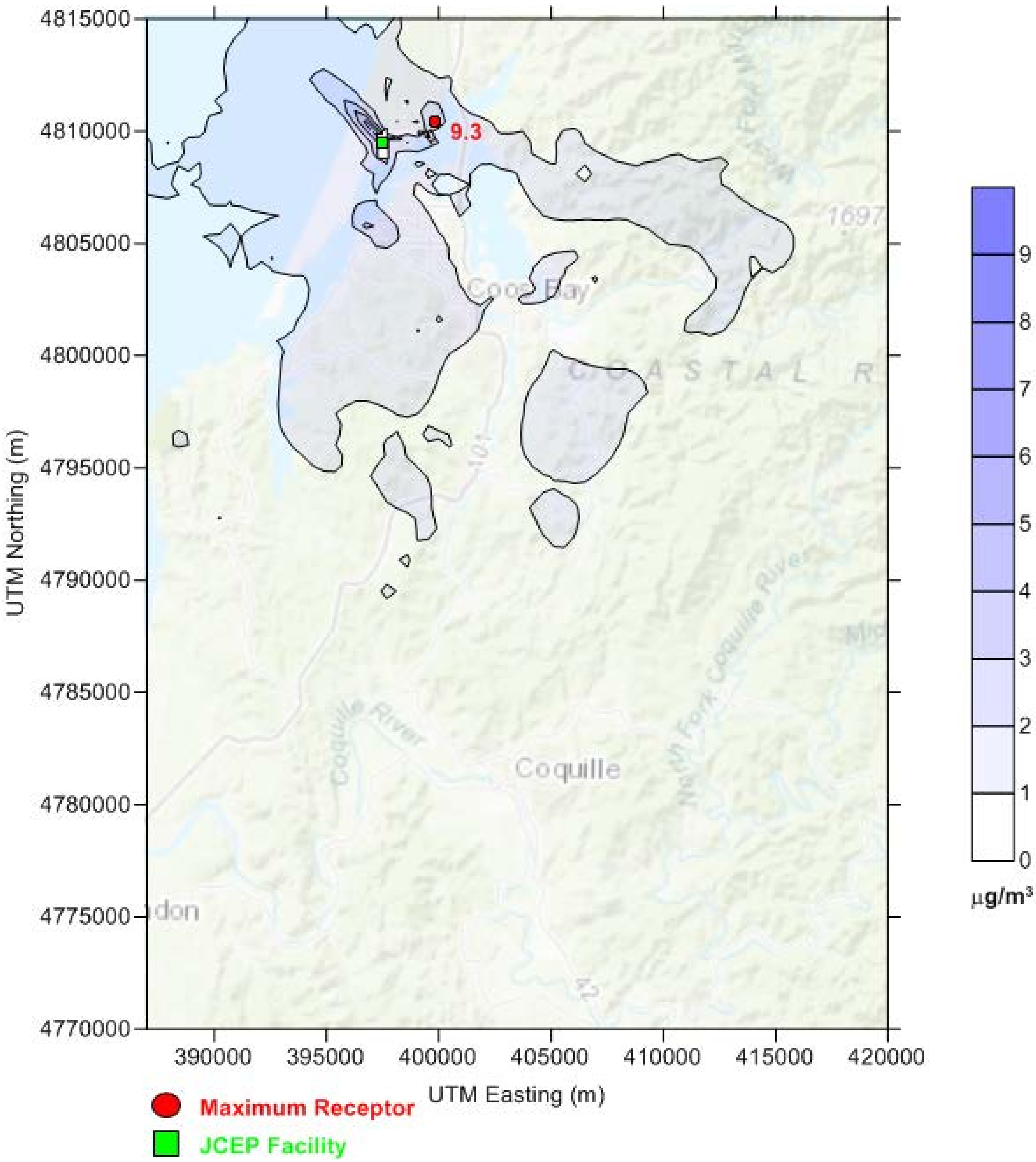
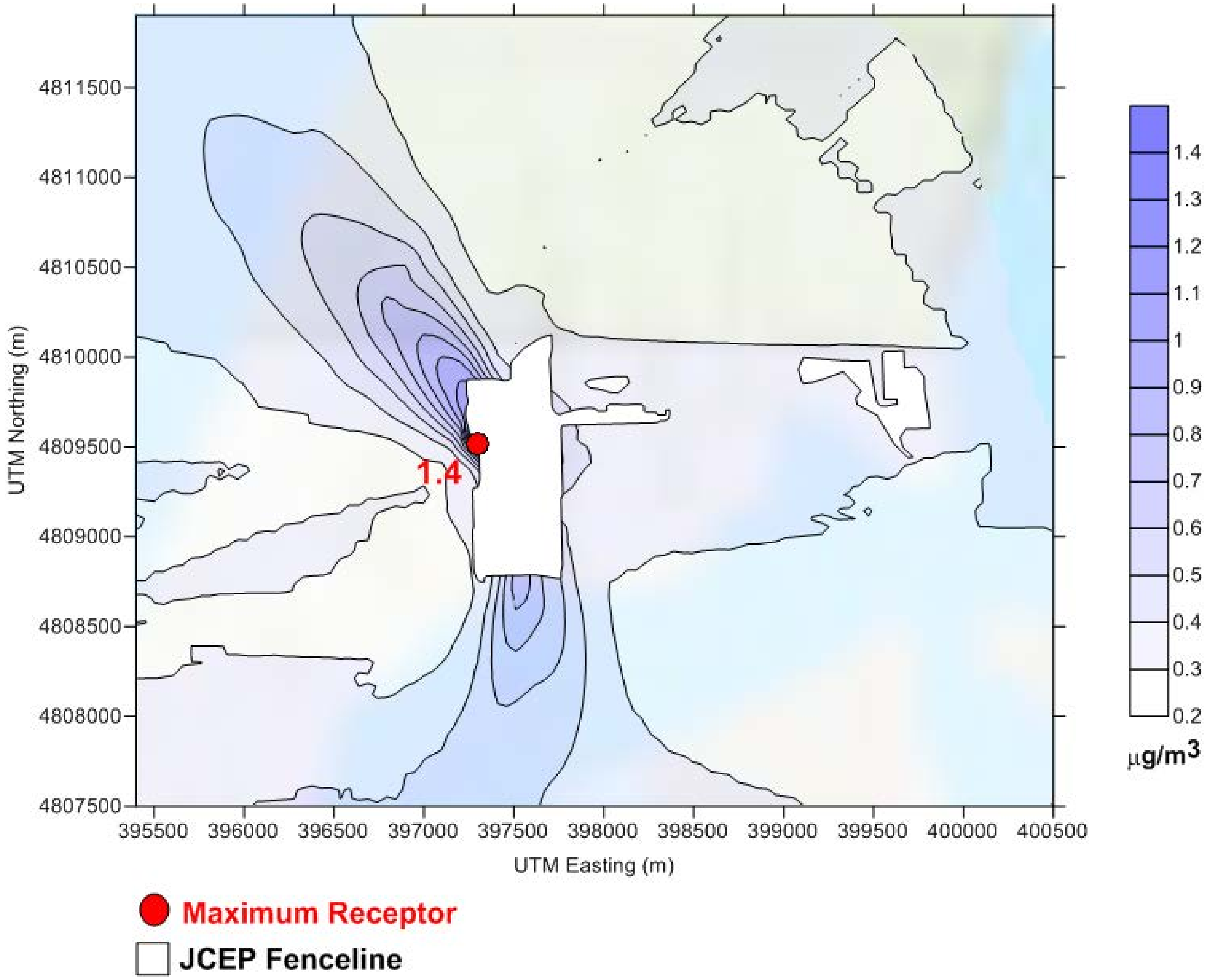
Project No.	108.01593.00001	



Report
JORDAN COVE LNG TERMINAL
JORDAN COVE ENERGY PROJECT, LP
125 CENTRAL AVENUE, SUITE 380
COOS BAY, OREGON 97240

Drawing
PM_{10} 24-HOUR INCREMENT ANALYSIS

Date	September 2017	Fig. No.
Project No.	108.01593.00001	26



Report JORDAN COVE LNG TERMINAL JORDAN COVE ENERGY PROJECT, LP 125 CENTRAL AVENUE, SUITE 380 COOS BAY, OREGON 97240	
Drawing PM_{10} ANNUAL INCREMENT ANALYSIS	
Date September 2017	Fig. No.
Project No. 108.01593.00001	**27**

APPENDIX A

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY PERMIT APPLICATION FORMS

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

JCEP Index to DEQ Forms and Emission Unit Identification

DEQ Form	Description	Emission Unit ID	Control Device IDs	Attachment(s)
AQ101wr	Administrative Information			
AQ102	Facility Description			Plot Plans and Figures A-1, A-2, A-3
AQ210, AQ307 (2)	Turbine	EU1.CT	CD.SCR1, CD.OC1	Turbine Emission Scenarios from Manufacturer
	Turbine	EU2.CT	CD.SCR2, CD.OC2	
	Turbine	EU3.CT	CD.SCR3, CD.OC3	
	Turbine	EU4.CT	CD.SCR4, CD.OC4	
	Turbine	EU5.CT	CD.SCR5, CD.OC5	
AQ208, AQ307 (2)	Auxiliary Boiler	EU6.AB	CD.SCR6, CD.OC6	
AQ210	Fire Pump Engines	EU7.FP		Engine Specification
AQ210	Black Start Generators	EU8.BSG		Engine Specification
AQ210	Emergency Generators	EU9.EG		Engine Specification
AQ230, AQ307	Gas Conditioning	EU10.GC	CD.TO	TO Specification
AQ230	Multi Point Ground Flare	EU11.MPGF		
AQ230	Marine Flare	EU12.MF		
--	Fugitive Emissions	EU13.FUG		
--	Aggregate Insignificant	EU14.AI		
AQ402	PSEL Detail Sheet			
AQ403	HAP Detail Sheet			
AQ404	Categorically Insignificant Activities			
LUCS	Land Use Compatibility Statement			

Print Form

State of Oregon Department of Environmental Quality

ADMINISTRATIVE INFORMATION

FORM AQ101
ANSWER SHEET

FOR DEQ USE ONLY	
Permit Number:	Type of Application:
Application No:	RNW ☐ MOD ☐ NEW ☐ EXT ☐
Date Received :	
Regional Office:	Check No. Amount $

1. Company	**2. Facility Location**
Legal Name: Jordan Cove Energy Project, L.P.	Name: JCEP LNG Terminal Project
Mailing Address: 125 W. Central Avenue, Suite 250	Street Address: Jordan Cove Road
City, State, Zip Code: Coos Bay, OR 97240	City, County, Zip Code: Unincorporated Coos County, OR
Number of employees (corporate):	Number of employees (facility):
3. Facilty Contact Person	**4. Industrial Classification Code(s)**
Name: Rose Haddon	Primary SIC and NAICS: SIC 4922; NAICS 486210
Title: Director, Regulatory Affairs	Secondary SIC and NAICS:
Telephone number: 713-400-2834	**5. Other DEQ Permits**
Fax. number:	
e-mail address: rose.haddon@jordancovelng.com	

6. Permit Action:

- ☐ New Simple ACDP
- ☐ New Construction ACDP
- ☒ New Standard ACDP
- ☐ New Standard ACDP (PSD/NSR)
- ☐ Renewal of an existing permit without changes (include form AQ403 for Standard ACDPs)
- ☐ Renewal of an existing permit with changes (include form AQ403 for Standard ACDPs)
- ☐ Revision (or Modification) to an existing permit application

7. Signature

I hereby apply for permission to discharge air contaminants in the State of Oregon, as stated or described in this application, and certify that the information contained in this application and the schedules and exhibits appended hereto, are true and correct to the best of my knowledge and belief.

Elizabeth Spomer	President and CEO
Name of official (Printed or Typed)	Title of official and phone number
Signature of official	Date

FEE INFORMATION

(Make the check payable to DEQ)

Note: The initial application fees and annual fees specified below (OAR 340-216-8020, Table 2, Parts 1 and 2) are only required for initial permit applications. These fees are not required for an application to renew or modify an existing permit. The appropriate specific activity fee(s) specified below (OAR 340-216-8020, Table 2, Part 3) applies to permit modifications or may be in addition to initial permit application fees.

OAR 340-216-8020, Table 2, Part 1 – INITIAL PERMITTING APPLICATION FEES:		
Short Term Activity ACDP	☐	$3,600.00
Basic ACDP	☐	$144.00
Assignment to General ACDP	☐	$1,440.00
Simple ACDP	☐	$7,200.00
Construction ACDP	☐	$11,520.00
Standard ACDP	☒	$14,400.00
Standard ACDP (Major NSR or Type A State NSR)	☐	$50,400.00
OAR 340-216-8020, TABLE 2, PART 2 - ANNUAL FEES:		
Simple ACDP – Low Fee Class	☐	$2,304.00
Simple ACDP – High Fee Class	☐	$4,608.00
Standard ACDP	☒	$9,216.00
OAR 340-216-8020, TABLE 2, PART 3 - SPECIFIC ACTIVITY FEES:		
Non-Technical Permit Modification	☐	$432.00
Basic Technical Permit Modification	☐	$432.00
Simple Technical Permit Modification	☐	$1,440.00
Moderate Technical Permit Modification	☐	$7,200.00
Complex Technical Permit Modification	☐	$14,400.00
Major NSR or type A State NSR Permit Modification	☐	$50,400.00
Modeling review (outside Major NSR or Type A State NSR)	☒	$7,200.00
Public Hearing at Source's Request	☐	$2,880.00
State MACT Determination	☐	$7,200.00
TOTAL FEES		**$ 30,816.00**

SUBMIT TWO COPIES OF THE COMPLETED APPLICATION TO:

New or Modified Permits (include fees):	**Permit Renewals (no fees):**
Oregon Department of Environmental Quality Business Office 811 SW Sixth Avenue Portland, OR 97204-1390	Oregon Department of Environmental Quality Air Quality Program, Western Region Office 4026 Fairview Industrial Drive Salem, Oregon 97302

ADMINISTRATIVE INFORMATION

CONTACT LIST

1. **Company Information:**

Legal Name:	Other company name (if different than legal name):
Jordan Cove Energy Project, L.P.	JCEP LNG Terminal Project

2. **Site Contact Person**: *(A person who deals with DEQ staff about equipment problems.)*

Name:	Telephone number:
Rose Haddon	
Title:	**E-mail address:**
Director, Regulatory Affairs	rose.haddon@jordancovelng.com

3. **Facility Contact Person:** *(If other than the site contact person, a person involved with all environmental issues at the facility although they may be housed at a different site.)*

Name:	Telephone number:
Rose Haddon	
Title:	**E-mail address:**
Director, Regulatory Affairs	rose.haddon@jordancovelng.com

4. **Mailing Contact Person:** *(If other than the site contact person, a person to whom the company would like all agency communications directed.)*

Name:	Telephone number:
Rose Haddon	
Title:	**E-mail address:**
Director, Regulatory Affairs	rose.haddon@jordancovelng.com

5. **Invoice Contact Person**: *(If other than the site contact person, a valid contact information to which invoices and communications related to resolving invoice questions can be directed.)*

Name:	Telephone number:
Rose Haddon	
Title:	**E-mail address:**
Director, Regulatory Affairs	rose.haddon@jordancovelng.com

State of Oregon Department of Environmental Quality

Facility Name: JCEP LNG Terminal Project Permit Number: ______________

1. Description of facility and processes:

Jordan Cove Energy Project, L.P. (JCEP) is proposing to construct and operate a natural gas liquefaction and export facility (LNG Terminal or Project), located on the bay side of the North Spit of Coos Bay, Oregon. Natural gas will be delivered to the LNG Terminal via the proposed Pacific Connector Gas Pipeline (PCGP), which will connect the Project with existing interstate natural gas pipeline systems.

Natural gas received at the LNG Terminal will be cooled into liquid form at - 260 degrees F and stored in two 160,000 cubic meter full-containment LNG storage tanks. The Project facilities would have the capability to export up to 7.8 million tonnes per annum (MTPA) via LNG carriers.

The Project will consistent of the following facilities:
• A pipeline gas conditioning facility consisting of one feed gas cleaning and dehydration train with a combined natural gas throughput of approximately 1.19 billion standard cubic feet per day (Bscf/d);
• A thermal oxidizer to combust the acid gases produced by the gas conditioning unit;
• Five natural gas liquefaction trains, each with the export capacity of 1.56 MTPA;
• Five turbine-driven compressors with waste heat recovery;
• A refrigerant storage and resupply system;
• An Aerial Cooling System (Fin-Fan);
• An LNG storage system consisting of two full-containment LNG storage tanks, each with a net capacity of 160,000 m3 (42,232,000 gallons), and each equipped with three fully submerged LNG in-tank pumps sized for approximately 11,600 gallons per minute (gpm) each;
• An LNG transfer line consisting of one approximately 2,500-foot-long, 36-inch-diameter line that would connect the shore based storage system with the LNG loading system;
• An LNG carrier cargo loading system designed to load LNG at a rate of 10,000 m3 per hour (m3/hr) with a peak capacity of 12,000 m3/hr, consisting of three 16-inch loading arms and one 16-inch vapor return arm;
• A protected LNG carrier loading berth constructed on an Open Cell® technology sheet pile slip wall and capable of accommodating LNG carriers with a range of capacities;
• A boil off gas (BOG) recovery system used to control the pressure in the LNG storage tanks;
• Electrical, nitrogen, fuel gas, lighting, instrument/plant air and service water facility systems;
• An emergency relief system (a marine flare and warm and cold ground flares);
• An LNG spill containment system, a fire water system and various other hazard detection, control, and prevention systems; and
• Utilities, buildings and support facilities.

2. Attach plot plan. Please see Figures 1, 2, and 3 as well as attached plot plans.

3. Attach process flow diagram. Please see attached Figures A-1, A-2, and A-3.

4. Attach a city map or drawing showing the facility location. Please see Figure 1.

WIND ROSE - ANNUAL
NORTH BEND MUNICIPAL AIRPORT
(PERCENT OF TIME)

NOTES:
1. FOR LNG PLANT PLOT PLAN, SEE DRAWING 189980-0000-FG2001.
2. FOR SOUTH DUNES PLOT PLAN, SEE DRAWING 189980-0000-FG2002.

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Jordan Cove LNG℠

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0	03/APR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH	0	03/APR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH

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SIGNED
DATE REG NO.

DRAWN HHS DATE ECB
CHECKED DATE 04/MAY/16

JORDAN COVE LNG PROJECT
OVERALL PLOT PLAN

PROJECT DRAWING NUMBER 189980-0000-FG2000 REV 1
JCLNG NUMBER J1-000-TEC-PLT-KBJ-51000-01 REV 1

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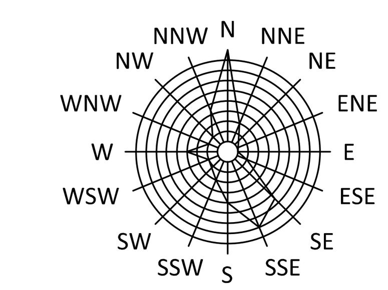
PUBLIC

ITEM	FACILITIES LEGEND
1	FEED GAS HEADER
2	GAS CONDITIONING TRAIN
3	PROPERTY BOUNDARY
4	LNG LIQUEFACTION TRAIN #1 THROUGH #5
5	LNG EXPANDER (WITH SHELTER)
6	LNG FLASH DRUM
7	LNG RUNDOWN PUMPS (WITH SHELTER)
8	LNG STORAGE TANK
9	LNG TANK PUMPS
10	LNG LOADING PLATFORM
11	REFRIGERANT MAKE-UP
12	LP/HP BOG COMPRESSORS (WITH SHELTER)
13	COLD FLARE KO DRUM
14	MULTI POINT GROUND FLARE KO DRUM
15	NOT USED
16	MULTI POINT GROUND FLARE
17	ENCLOSED GROUND FLARE - MARINE
18	BOP AUXILIARY POWER STG
19	BOP AUXILIARY POWER STG CONTROL ENCLOSURE
20	AUXILIARY BOILER
21	DEAERATOR / BFW PUMPS
22	NOT USED
23	PLANT / INSTRUMENT AIR PACKAGES
24	NITROGEN GENERATION PACKAGE
25	LIQUED N2 STORAGE / VAPORIZATION
26	AMMONIA STORAGE TANKS AND PUMPS
27	AMINE STORAGE
28	LNG DRAINAGE CHANNEL
29	PROCESS AREA LNG IMPOUND BASIN
30	MARINE AREA LNG IMPOUND BASIN
31	FREE FIELD SEISMOMETER SHELTER
32	TRANSFORMERS
33	CONSTRUCTION LAYDOWN AREA
34	DIESEL STORAGE
35	FIREWATER STORAGE TANKS
36	LNG TANK ACCESS ROAD
37	PLANT SECURITY FENCE
38	RETAINING WALL
39	BACKUP GENERATOR
40	PIPERACK
41	IMPERMEABLE VAPOR BARRIER
42	RO PRODUCT TANK
43	CONST. MARINE OFF-LOADING FACILITIES AREA (CONST. MOF)
44	DEMIN WATER STORAGE TANK
45	WASTEWATER TREATMENT PACKAGE PLANT
46	LAYDOWN AREA
47	DUMP CONDENSER
48	BURIED STORM WATER INFILTRATION CHAMBER
49	BOG VFD ENCLOSURE
50	PERMEABLE VAPOR BARRIER
51	TSUNAMI WALL (ELEVATION VARIES TO SUIT THE DESIGN TSUNAMI)
52	METEOROLOGICAL MAST LOCATED WEST OF THE SITE NEAR INDUSTRIAL WASTEWATER LAGOON

ITEM	FACILITIES LEGEND
A	MAIN GUARD HOUSE / SECURITY BUILDING
B	TUG FACILITY BUILDING
C	PLANT WAREHOUSE
D	MAINTENANCE BUILDING
E	OPERATIONS BUILDING (INCLUDES CONTROL ROOM)
F	WATER TREATMENT BUILDING
G	FACILITY FIREWATER PUMPS WITH BUILDING
H	LUBE OIL, PAINT AND COMPRESSED GAS STORAGE
J	FACILITY AUX POWERHOUSE ENCLOSURE
K	POWERHOUSE ENCLOSURE
L	FIREWATER VALVE HOUSE
M	SECONDARY ENTRANCE SECURITY GATE/TERMINAL GUARD BUILDING
N	MARINE POWERHOUSE ENCLOSURE
P	FIRE DEPARTMENT
Q	GC TRAIN 1 POWERHOUSE ENCLOSURE
R	CEMS BUILDING (HRSG PKG)
S	INSPECTION STATION SHELTER
T	MARINE AREA GUARD HOUSE
U	TUG BOAT BERTH



WIND ROSE - ANNUAL
NORTH BEND MUNICIPAL AIRPORT
(PERCENT OF TIME)

NOTES:

1. ELEVATIONS NOTED ARE NAVD88.

LEGEND:

- SECURITY FENCE
- DEMARCATION FENCE
- PROPERTY BOUNDARY
- ASPHALT PAVED ROADS AND PARKING
- GRAVEL ROADS AND PARKING
- IMPERMEABLE VAPOR BARRIER WITH SECURITY
- PERMEABLE VAPOR BARRIER

300' 150' 0 300' 600'
1"=300'

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0	03/APR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH

NO	DATE	KBJ REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
1	30/AUG/17	ISSUED FOR FERC FILING	HHS	HHS	-	JME	SPH
0	03/APR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH

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SIGNED

DATE REG NO.

DESIGNER HHS
DRAWN ECB
CHECKED
DATE 03/FEB/16

JORDAN COVE LNG PROJECT

LIQUEFACTION PLOT PLAN

PROJECT 189980-0000 DRAWING NUMBER FG2001 REV 1

JCLNG NUMBER J1-000-TEC-PLT-KBJ-51001-01 REV 1

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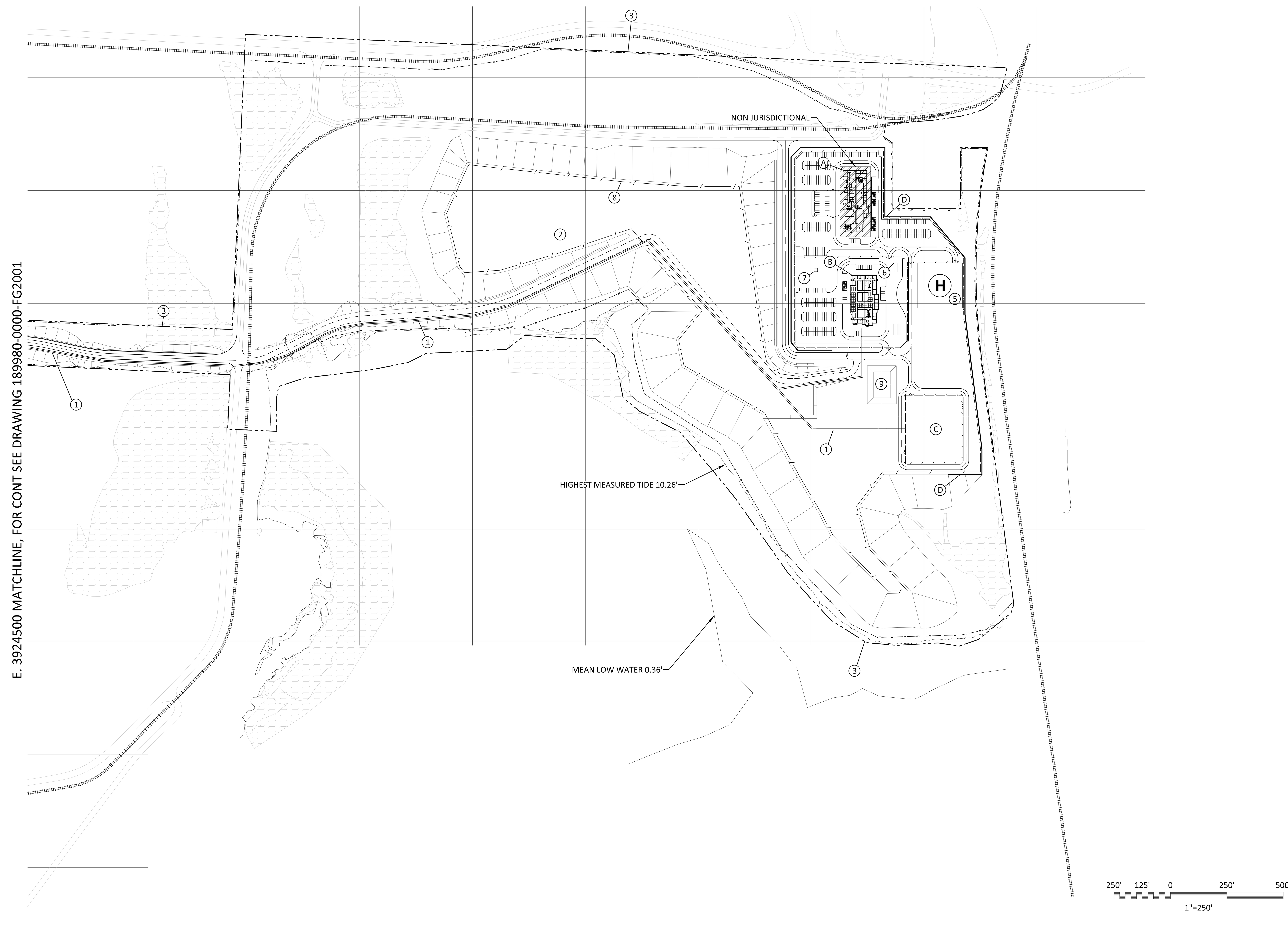
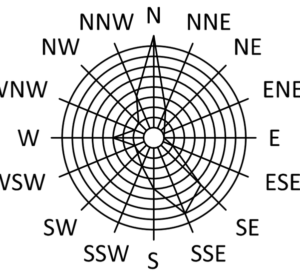
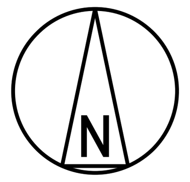


ITEM	FACILITIES LEGEND
A	SORSC BUILDING
B	ADMINISTRATION BUILDING
C	GAS METERING STATION
D	RETAINING WALL

ITEM	FACILITIES LEGEND
1	ACCESS AND UTILITY CORIDOR (SEE NOTE 3)
2	TEMPORARY CONSTRUCTION FACILITIES
3	PROPERTY BOUNDARY
4	PG&E SWITCHYARD EASEMENT
5	HELI-PAD
6	WASTEWATER TREATMENT PACKAGE PLANT
7	COMMUNICATIONS TOWER
8	PLANT SECURITY FENCE
9	VEGETATED INFILTRATION BASIN



WIND ROSE - ANNUAL
NORTH BEND MUNICIPAL AIRPORT
(PERCENT OF TIME)



NOTES:

1. ELEVATIONS NOTED ARE NAVD88.
2. FOR OVERALL PLOT PLAN, SEE DRAWING 189980-0000-FG2000.
3. THE ACCESS AND UTILITY CORRIDOR CONTAINS THE FOLLOWING BURIED LINES. CORRIDOR WILL BE ROUTED ON JCLNG LAND.
   * FEED GAS LINE
   * FIRE WATER SUPPLY TO ADMIN AND SORSC BUILDINGS
   * POWER TO ADMIN BUILDING
   * IT AND SECURITY TO ADMIN AND SORSC BUILDINGS
   * CONTROL CABLING FROM METERING STATION

LEGEND:

SECURITY FENCE

DEMARCATION FENCE

ASPHALT PAVED ROADS AND PARKING

GRAVEL ROADS AND PARKING

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0	03/MAR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH	0	03/APR/17	ISSUED FOR FERC DRAFT FILING	HHS	HHS	-	EAH	SPH

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DATE REG NO.

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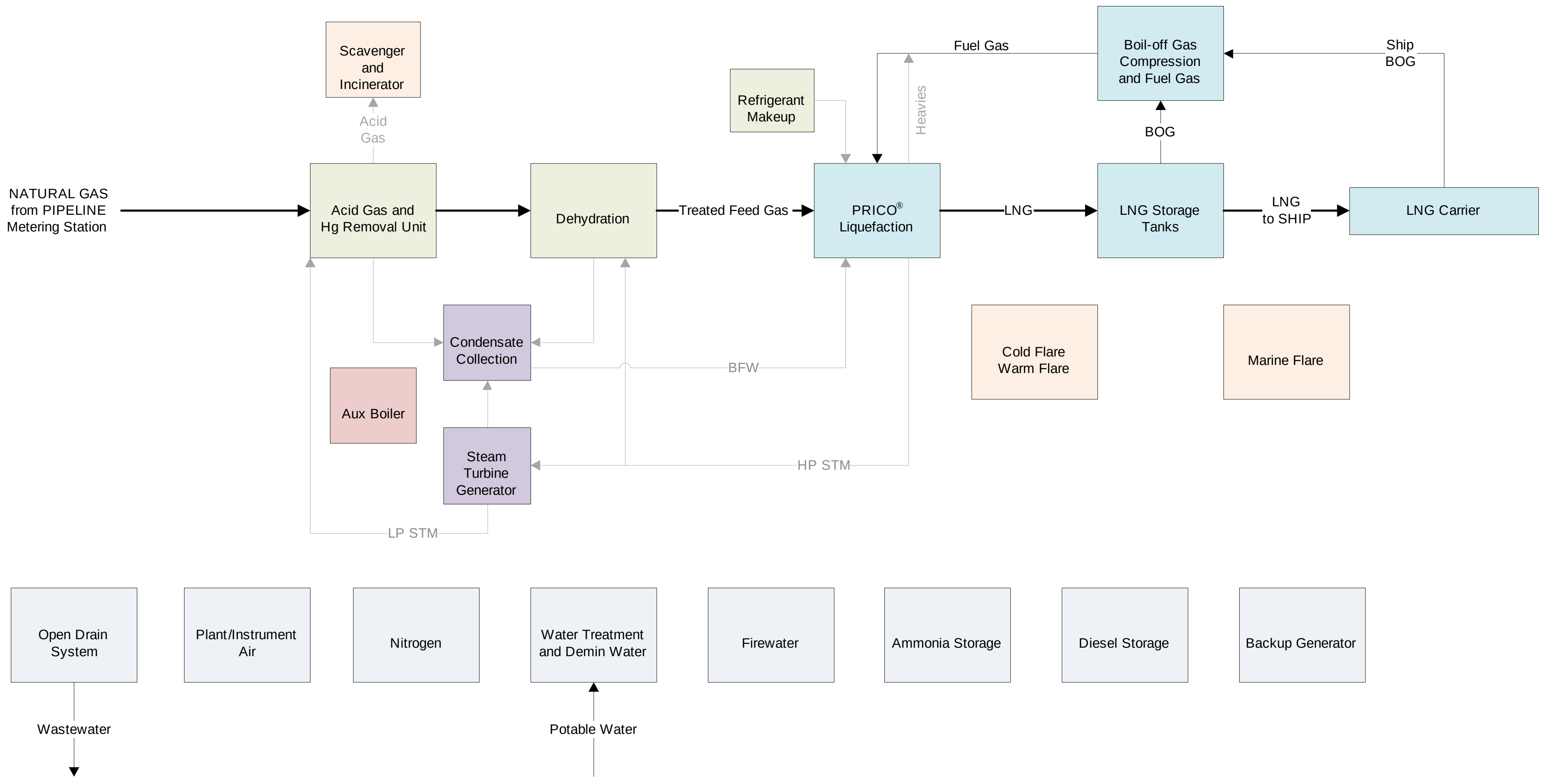
CHECKED	DATE 04/MAY/16

JORDAN COVE LNG PROJECT

SOUTH DUNES PLOT PLAN

PROJECT	DRAWING NUMBER	REV
189980-0000-FG2002		1
JCLNG NUMBER		REV
J1-000-TEC-PLT-KBJ-51002-01		1

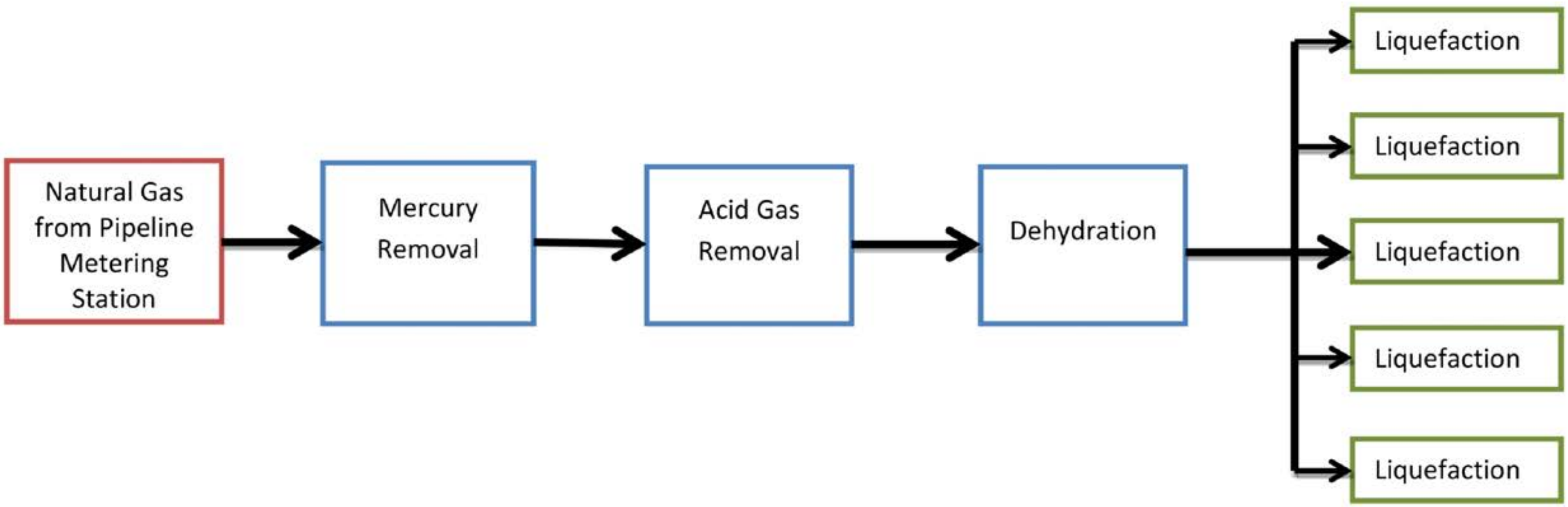


Jordan Cove Energy Project, L.P.

Jordan Cove Energy Project

Figure A-1

Block Flow Diagram

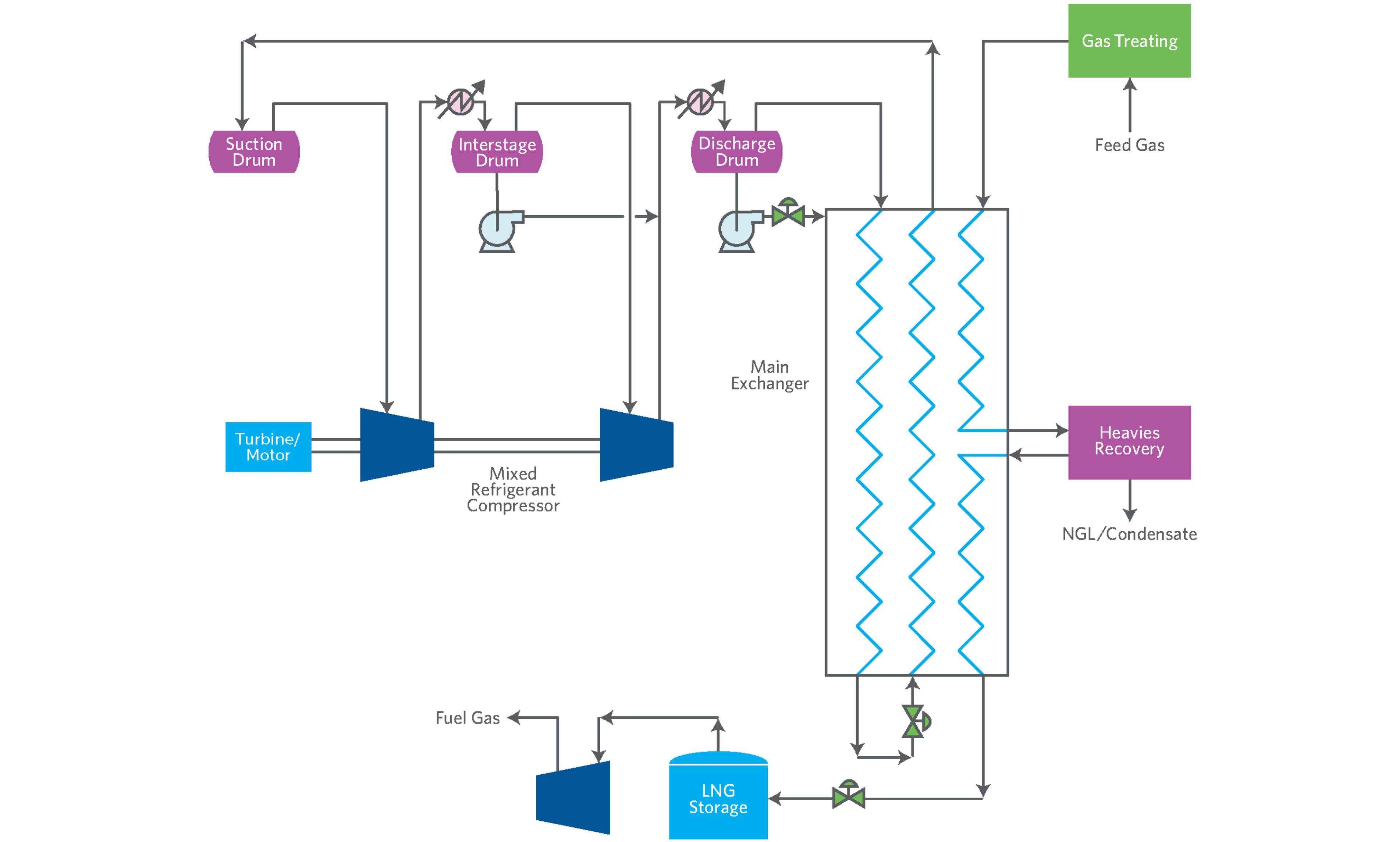


Jordan Cove Energy Project, L.P.

Jordan Cove Energy Project

Figure A-2

Gas Conditioning Train



Jordan Cove Energy Project, L.P.

Jordan Cove Energy Project

Figure A-3

PRICO LNG Process

State of Oregon Department of Environmental Quality

Facility Name: JCEP LNG Terminal Project   Permit Number:

Engine Information

1.	Device ID Number	EUs 1.CT through 5.CT (Turbines)
2.	Existing or future?	Future
3.	Date construction commenced	January 2019
4.	Date installed/completed	April 2022 (1.CT) - July 2022 (5.CT)
5.	Special controls (if applicable)	No
6.	Manufacturer	General Electric
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	504.4 turbine, 19.7 duct burner
9.	Control device(s) (yes/no)	Yes
	If yes, enter the identification number(s)	CD.SCR1-5, CD.OC1-5
10.	Description of device:	

Natural gas/ boil off gas- fired, combined cycle General Electric LM6000PF+ turbines to drive refrigeration compressors for five liquefaction trains. Each turbine is equipped with a duct burner and operates in combined cycle mode with a heat recovery steam generator.

Operating Schedule

11.	Projected maximum hours/day	24
12.	Projected maximum hours/year	8,760

Fuel Information

13. Fuel usage:	a. Type	b. Hourly usage	c. Annual usage
Primary	Natural Gas/ BOG	0.530 MMscf/hr	4,641 MMscf
Back-up			
Other			

Stack Information

14.	Exit height (ft)	119
15.	Exit diameter (ft)	10
16.	Design flowrate (dscf/min)	

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)	Yes	recorder? (y/n)	Yes
engine load (y/n)	Yes	recorder? (y/n)	Yes
other (specify)	CEMS	recorder? (y/n)	Yes

State of Oregon Department of Environmental Quality

MISCELLANEOUS
CONTROL DEVICE INFORMATION

FORM AQ307
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project

Permit Number:

1.	Control Device ID	CD.SCR1 through CD.SCR5 (Selective Catalytic Reduction)
2.	Process/Device(s) Controlled	EUs 1.CT through 5.CT (combined-cycle turbines)
3.	Year installed	2022
4.	Manufacturer/Model No.	
5.	Control Efficiency (%)	NOx reduction- 92.0 %wt
6.	Design inlet gas flow rate (acfm)	790,170 acfm
7.	Design parameter(s)	Exhaust gas flow rate and NOx concentration
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the control device	

Each combined cycle liquefaction turbine has an SCR system on the HRSG exhaust to reduce emissions of NOx.

State of Oregon Department of Environmental Quality

MISCELLANEOUS
CONTROL DEVICE INFORMATION

FORM AQ307
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project Permit Number:

1.	Control Device ID	CD.OC1 through CD.OC5 (Oxidation Catalyst)
2.	Process/Device(s) Controlled	EUs 1.CT through 5.CT (combined-cycle turbines)
3.	Year installed	2022
4.	Manufacturer/Model No.	
5.	Control Efficiency (%)	CO reduction- 84.6%wt VOC reduction- 30.0%wt
6.	Design inlet gas flow rate (acfm)	790,170 acfm (CTG exhaust gas flow)
7.	Design parameter(s)	Exhaust flow rate and CO concentration
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the control device	
	Each combined cycle liquefaction turbine has an oxidation catalyst on the HRSG exhaust to reduce emissions of CO and VOC.	

JORDAN COVE
Turbine Stack Parameters

CASE NUMBER	1	2	5	6	7	8	13	14	15
Ambient Dry Bulb Temperature, ° F	42.0	42.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0
CTG Manufacturer	OEM	OEM	OEM	OEM	OEM	OEM	OEM	OEM	OEM
CTG Model	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+	GE LM6000PF+
CTG Combustor Type	0	0	0	0	0	0	0	0	0
CTG Load, percent of base load	BASE	BASE	50.0	75.0	BASE	BASE	50.0	75.0	BASE
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Inlet Air Cooling Type	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller
CTG Inlet Air Cooling Status, On/Off	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
Duct Burner Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
HRSG Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired
Post Combustion NOx Emissions Control	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Post Combustion CO Emissions Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Number Shutdowns/cold start events per year (per train)	12	12	12	12	12	12	12	12	12
Fuel Composition (Ultimate Analysis by Weight)									
Ar, % wt.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C, % wt.	65.87	65.87	68.20	68.20	68.20	68.20	68.20	68.20	68.20
H2, % wt.	22.09	22.09	22.67	22.67	22.67	22.67	22.67	22.67	22.67
N2, % wt.	12.02	12.02	8.60	8.60	8.60	8.60	8.60	8.60	8.60
O2, % wt.	0.01	0.01	0.29	0.29	0.29	0.29	0.29	0.29	0.29
S, % wt.	0.00329	0.00329	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333
Total, % wt.	100.00	100.00	99.76	99.76	99.76	99.76	99.76	99.76	99.76
Fuel Sulfur Content (grains/100 standard cubic feet)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel LHV, Btu/lb	18,911	18,911	19,359	19,359	19,359	19,359	19,359	19,359	19,359
Fuel HHV, Btu/lb	21,012	21,012	21,500	21,500	21,500	21,500	21,500	21,500	21,500
COMBUSTION TURBINE PERFORMANCE									
CTG Load Level, percent of base load	BASE	BASE	50.0	75.0	BASE	BASE	50.0	75.0	BASE
Gross CTG Output, kW	55,607	55,607	25,794	38,692	51,589	51,589	22,189	33,283	44,378
Gross CTG Heat Rate, Btu/kWh (LHV)	8,164	8,164	11,426	9,209	8,318	8,318	12,221	9,716	8,670
Gross CTG Heat Rate, Btu/kWh (HHV)	9,071	9,071	12,689	10,227	9,238	9,238	13,572	10,790	9,629
CTG Heat Input, MBtu/h (LHV)	454.0	454.0	294.7	356.3	429.1	429.1	271.2	323.4	384.7
CTG Heat Input, MBtu/h (HHV)	504.4	504.4	327.3	395.7	476.6	476.6	301.2	359.1	427.3
HRSG DUCT BURNERS									
Duct Burner Heat Input, MBtu/h (LHV)	17.7	0.0	0.0	0.0	0.0	7.8	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	19.7	0.0	0.0	0.0	0.0	8.7	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	936	0	0	0	0	403	0	0	0
STACK PARAMETERS									
Stack Height (ft)	119	119	119	119	119	119	119	119	119
Exhaust Temperature (F)	242.8	242.8	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Exhaust Velocity (ft/s)	71	71	60	73	85	85	55	66	76
Stack Diameter (ft)	10	10	10	10	10	10	10	10	10
Stack Orientation	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical	Vertical
Stack Capped?	No	No	No	No	No	No	No	No	No
Hours/Year (Each CT)	8760	8760	8760	8760	8760	8760	8760	8760	8760
Hours/Year (Duct Firing for each CT)	4000	N/A	N/A	N/A	N/A	4000	N/A	N/A	N/A
STACK EMISSIONS									
NOx (lb/hr)	3.8	3.7	2.4	2.9	3.5	3.5	2.2	2.6	3.1
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	2.3	2.2	2.1	2.1	2.2	2.2	2.2	2.2	2.2
CO (lb/hr)	4.6	4.4	2.8	3.4	4.1	4.2	2.6	3.1	3.6
CO, ppmvd (dry, 15% O2)	4.0	4.0	3.8	3.8	3.8	3.9	3.8	3.8	3.8
CO, ppmvd (dry)	4.6	4.4	4.1	4.1	4.2	4.4	4.2	4.2	4.3
VOC (lb/hr)	1.7	1.3	0.9	1.1	1.3	1.4	0.8	1.0	1.1
VOC, ppmvd (dry, 15% O2)	2.5	2.1	2.1	2.1	2.1	2.3	2.1	2.1	2.1
VOC, ppmvd (dry)	2.9	2.3	2.2	2.2	2.3	2.6	2.3	2.3	2.4
PM (lb/hr)	5.4	4.9	4.0	4.1	4.2	4.7	4.0	4.0	4.1
PM_{10} (lb/hr)	5.4	4.9	4.0	4.1	4.2	4.7	4.0	4.0	4.1
$PM_{2.5}$ (lb/hr)	5.4	4.9	4.0	4.1	4.2	4.7	4.0	4.0	4.1
SO_2 (lb/hr)	1.64	1.58	1.01	1.22	1.48	1.5	0.93	1.11	1.32
H_2SO_4 (lb/hr)	0.50	0.48	0.37	0.45	0.54	0.73	0.34	0.41	0.48
CO_2 (lb/hr)	60,218	57,958	38,037	46,009	55,406	56,412	35,013	41,735	49,658
CO_2e (lb/hr)	61,393	59,093	38,775	46,901	56,482	57,490	35,689	42,535	50,609

PROJECT NAME: JORDAN COVE LNG

PROJECT NUMBER: 189920 | REVISION: 4 | DATE: 11-JUL-2016

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Ambient Dry Bulb Temperature, ° F	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Configuration	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC	CC
CTG Manufacturer	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Model	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+	LM6000PF+
CTG Combustor Type	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN	DLN
CTG Load, percent of base load	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Inlet Air Cooling Type	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller	Chiller
CTG Inlet Air Cooling Status, On/Off	OFF	OFF	OFF	OFF	ON	ON	ON	ON	OFF	OFF	OFF	OFF	ON	ON	ON	ON
Duct Burner Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
HRSG Duct Firing	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Post Combustion NOx Emissions Control	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR	SCR
Post Combustion CO Emissions Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
AMBIENT CONDITIONS																
Ambient Dry Bulb Temperature, ° F	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Ambient Relative Humidity, %	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Atmospheric Pressure, psia	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696	14.696
COMBUSTION TURBINE PERFORMANCE																
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, percent	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CTG Compressor Inlet Dry Bulb Temperature, ° F	64.0	64.0	64.0	64.0	45.0	45.0	45.0	45.0	95.0	95.0	95.0	95.0	73.0	73.0	73.0	73.0
CTG Compressor Inlet Relative Humidity, percent	70.3	70.3	70.3	70.3	100.0	100.0	100.0	100.0	71.9	71.9	71.9	71.9	100.0	100.0	100.0	100.0
Inlet Loss, in. H2O	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Exhaust Loss, in. H2O	17.3	18.8	20.4	20.4	17.6	19.1	20.9	20.9	16.8	18.0	19.3	19.3	17.2	18.5	20.1	20.1
CTG Load Level, percent of base load	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0	50.0	75.0	100.0	100.0
Gross CTG Output, kW	25,794	38,692	51,589	51,589	27,581	41,371	55,162	55,162	22,189	33,283	44,378	44,378	24,672	37,008	49,343	49,343
Gross CTG Heat Rate, Btu/kWh (LHV)	11,426	9,209	8,318	8,318	10,999	9,001	8,165	8,165	12,221	9,716	8,670	8,670	11,656	9,199	8,420	8,420
Gross CTG Heat Rate, Btu/kWh (HHV)	12,689	10,227	9,238	9,238	12,216	9,996	9,069	9,069	13,572	10,790	9,629	9,629	12,945	10,217	9,352	9,352
CTG Heat Input, MBtu/h (LHV)	294.7	356.3	429.1	429.1	303.4	372.4	450.4	450.4	271.2	323.4	384.7	384.7	287.6	340.5	415.5	415.5
CTG Heat Input, MBtu/h (HHV)	327.3	395.7	476.6	476.6	336.9	413.6	500.2	500.2	301.2	359.1	427.3	427.3	319.4	378.1	461.4	461.4
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CTG Exhaust Flow, lb/h	754,596	912,888	1,057,932	1,057,932	790,200	953,028	1,108,152	1,108,152	680,868	816,948	944,100	944,100	732,384	884,808	1,024,200	1,024,200
CTG Exhaust Temperature, ° F	1,438	1,406	1,411	1,411	1,410	1,389	1,393	1,393	1,488	1,448	1,444	1,444	1,453	1,417	1,420	1,420
COMBUSTION TURBINE FUEL																
Total CTG Fuel Flow, lb/h	15,220	18,410	22,170	22,170	15,670	19,240	23,270	23,270	14,010	16,700	19,870	19,870	14,860	17,590	21,460	21,460
CTG Fuel Temperature, ° F	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
CTG Fuel LHV, Btu/lb	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359
CTG Fuel HHV, Btu/lb	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500
HHV/LHV Ratio	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106	1.1106
CTG Fuel Composition (Ultimate Analysis by Weight)																
Ar, % wt.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C, % wt.	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20
H2, % wt.	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67
N2, % wt.	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60
O2, % wt.	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
S, % wt.	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333
Total, % wt.	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76
Fuel Sulfur Content (grains/100 standard cubic feet)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fuel Sulfur Content, ppm	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
COMBUSTION TURBINE EXHAUST																
CTG EXHAUST ANALYSIS (VOLUME BASIS - WET)																
Ar, % vol.	0.93	0.93	0.93	0.93	0.94	0.94	0.94	0.94	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92
CO2, % vol.	3.25	3.25	3.38	3.38	3.20	3.26	3.39	3.39	3.29	3.27	3.36	3.36	3.26	3.19	3.36	3.36
H2O, % vol.	7.83	7.82	8.07	8.07	7.33	7.44	7.70	7.70	10.41	10.37	10.55	10.55	9.12	9.00	9.33	9.33
N2, % vol.	74.47	74.47	74.38	74.38	74.82	74.78	74.68	74.68	72.48	72.50	72.43	72.43	73.46	73.51	73.38	73.38
O2, % vol.	13.52	13.52	13.24	13.24	13.71	13.58	13.30	13.30	12.91	12.96	12.75	12.75	13.24	13.38	13.01	13.01
SO2, (after SO2 oxidation), % vol.	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006	0.00006
SO3, (after SO2 oxidation), % vol.	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total, % vol.	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular Wt, lb/mol	28.40	28.40	28.39	28.39	28.45	28.45	28.43	28.43	28.12	28.13	28.11	28.11	28.26	28.27	28.25	28.25
Specific Volume, ft^3/lb	46.78	45.83	45.80	45.80	45.98	45.31	45.25	45.25	48.54	47.43	47.19	47.19	47.40	46.36	46.29	46.29
Specific Volume, scf/lb	13.36	13.36	13.36	13.36	13.33	13.34	13.34	13.34	13.49	13.49	13.49	13.49	13.42	13.42	13.43	13.43
Exhaust Gas Flow, acfm	588,333	697,294	807,555	807,555	605,557	719,695	835,731	835,731	550,822	645,797	742,535	742,535	578,583	683,662	790,170	790,170
Exhaust Gas Flow, scfm	168,023	203,270	235,566	235,566	175,556	211,890	246,379	246,379	153,082	183,677	212,265	212,265	163,810	197,902	229,250	229,250
CTG NOX EMISSIONS (WITHOUT POST COMBUSTION EMISSIONS CONTROL)																
NOx Massflow Added to Match CTG Manufacturer's NOx Emissi	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NOx, ppmvd (dry, 15% O2)	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, ppmvd (dry)	26.4	26.4	27.5	27.5	25.9	26.4	27.5	27.5	27.4	27.3	28.1	28.1	26.8	26.2	27.7	27.7
NOx, ppmvw (wet)	24.3	24.3	25.3	25.3	24.0	24.4	25.4	25.4	24.6	24.4	25.1	25.1	24.4	23.9	25.1	25.1
NOx, lb/h as NO2	29.7	36.0	43.3	43.3	30.6	37.6	45.5	45.5	27.4	32.6	38.8	38.8	29.0	34.4	41.9	41.9
NOx, lb/MBtu (LHV) as NO2	0.1009	0.1010	0.1010	0.1010	0.1010	0.1010	0.1010	0.1010	0.1010	0.1009	0.1009	0.1009	0.1010	0.1010	0.1010	0.1010
NOx, lb/MBtu (HHV) as NO2	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909
CTG CO EMISSIONS (WITHOUT POST COMBUSTION EMISSIONS CONTROL)																
CO Massflow Added to Match CTG Manufacturer's CO Emissions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO, ppmvd (dry, 15% O2)	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CO, ppmvd (dry)	26.4	26.4	27.5	27.5	25.9	26.4	27.5	27.5	27.4	27.3	28.1	28.1	26.8	26.2	27.7	27.7
CO, ppmvw (wet)	24.3	24.3	25.3	25.3	24.0	24.4	25.4	25.4	24.6	24.4	25.1	25.1	24.4	23.9	25.1	25.1
CO, lb/h	18.1	21.9	26.4	26.4	18.6	22.9	27.7	27.7	16.7	19.9	23.6	23.6	17.7	20.9	25.5	25.5
CO, lb/MBtu (LHV)	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615
CO, lb/MBtu (HHV)	0.0553	0.0554	0.0554	0.0554	0.0553	0.0554	0.0554	0.0554	0.0554	0.0553	0.0553	0.0553	0.0554	0.0554	0.0553	0.0553
CTG SO2 EMISSIONS (WITHOUT THE EFFECTS OF SO2 OXIDATION)																
SO2, ppmvd (dry, 15% O2)	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
SO2, ppmvd (dry)	0.65	0.65	0.67	0.67	0.63	0.64	0.67	0.67	0.67	0.67	0.69	0.69	0.66	0.64	0.68	0.68
SO2, ppmvw (wet)	0.60	0.59	0.62	0.62	0.59	0.60	0.62	0.62	0.60	0.60	0.61	0.61	0.60	0.58	0.61	0.61
SO2, lb/h	1.01	1.22	1.48	1.48	1.04	1.28	1.55	1.55	0.93	1.11	1.32	1.32	0.99	1.17	1.43	1.43
SO2, lb/MBtu (LHV)	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034
SO2, lb/MBtu (HHV)	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
CTG SO2 EMISSIONS (WITH THE EFFECTS OF SO2 OXIDATION, WITHOUT POST COMBUSTION EMISSIONS CONTROL)																
Assumed SO2 oxidation rate in CTG, vol%	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
SO2, ppmvd (dry, 15% O2)	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
SO2, ppmvd (dry)	0.63	0.63	0.66	0.66	0.62	0.63	0.66	0.66	0.66	0.65	0.67	0.67	0.64	0.63	0.66	0.66
SO2, ppmvw (wet)	0.58	0.58	0.61	0.61	0.57	0.58	0.61	0.61	0.59	0.59	0.60	0.60	0.58	0.57	0.60	0.60
SO2, lb/h	0.99	1.20	1.45	1.45	1.02	1.25	1.52	1.52	0.91	1.09	1.30	1.30	0.97	1.15	1.40	1.40
SO2, lb/MBtu (LHV)	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034
SO2, lb/MBtu (HHV)	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030
CTG VOC EMISSIONS (WITHOUT POST COMBUSTION EMISSIONS CONTROL)																
VOC Massflow Added to Match CTG Manufacturer's VOC Emissi	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VOC percentage of UHC	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
VOC, ppmvd (dry, 15% O2)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
VOC, ppmvd (dry)	3.2	3.2	3.3	3.3	3.1	3.2	3.3	3.3	3.3	3.3	3.4	3.4	3.2	3.1	3.3	3.3
VOC, ppmvw (wet)	2.9	2.9	3.0	3.0	2.9	2.9	3.0	3.0	3.0	2.9	3.0	3.0	2.9	2.9	3.0	3.0
VOC, lb/h as CH4	1.2	1.5	1.8	1.8	1.3	1.6	1.9	1.9	1.1	1.4	1.6	1.6	1.2	1.4	1.8	1.8
VOC, lb/MBtu as CH4 (LHV)	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042
VOC, lb/MBtu as CH4 (HHV)	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038
CTG CO2 EMISSIONS																
CO2, lb/h	38,037	46,009	55,406	55,406	39,161	48,083	58,155	58,155	35,013	41,735	49,658	49,658	37,137	43,960	53,631	53,631
CO2, lb/MBtu (LHV)	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
CO2, lb/MBtu (HHV)	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116
CTG PARTICULATE EMISSIONS (WITHOUT THE EFFECTS OF SO2 OXIDATION)																
PARTICULATE EMISSIONS - FRONT HALF CATCH ONLY																
Particulate, lb/h	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Particulate, lb/MBtu (LHV)	0.0059	0.0049	0.0041	0.0041	0.0058	0.0047	0.0039	0.0039	0.0064	0.0054	0.0045	0.0045	0.0061	0.0051	0.0042	0.0042
Particulate, lb/MBtu (HHV)	0.0053	0.0044	0.0037	0.0037	0.0052	0.0042	0.0035	0.0035	0.0058	0.0049	0.0041	0.0041	0.0055	0.0046	0.0038	0.0038
PARTICULATE EMISSIONS - FRONT AND BACK HALF CATCH																
Particulate, lb/h	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Particulate, lb/MBtu (LHV)	0.0119	0.0098	0.0081	0.0081	0.0115	0.0094	0.0078	0.0078	0.0129	0.0108	0.0091	0.0091	0.0122	0.0103	0.0084	0.0084
Particulate, lb/MBtu (HHV)	0.0107	0.0088	0.0073	0.0073	0.0104	0.0085	0.0070	0.0070	0.0116	0.0097	0.0082	0.0082	0.0109	0.0092	0.0076	0.0076
CTG PM10 EMISSIONS (WITHOUT THE EFFECTS OF SO2 OXIDATION)																
PM10 EMISSIONS - FRONT HALF CATCH ONLY																
PM10, lb/h	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
PM10, lb/MBtu (LHV)	0.0059	0.0049	0.0041	0.0041	0.0058	0.0047	0.0039	0.0039	0.0064	0.0054	0.0045	0.0045	0.0061	0.0051	0.0042	0.0042
PM10, lb/MBtu (HHV)	0.0053	0.0044	0.0037	0.0037	0.0052	0.0042	0.0035	0.0035	0.0058	0.0049	0.0041	0.0041	0.0055	0.0046	0.0038	0.0038
PM10 EMISSIONS - FRONT AND BACK HALF CATCH																
PM10, lb/h	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
PM10, lb/MBtu (LHV)	0.0119	0.0098	0.0081	0.0081	0.0115	0.0094	0.0078	0.0078	0.0129	0.0108	0.0091	0.0091	0.0122	0.0103	0.0084	0.0084
PM10, lb/MBtu (HHV)	0.0107	0.0088	0.0073	0.0073	0.0104	0.0085	0.0070	0.0070	0.0116	0.0097	0.0082	0.0082	0.0109	0.0092	0.0076	0.0076
CTG PM2.5 EMISSIONS (WITHOUT THE EFFECTS OF SO2 OXIDATION)																
PM2.5 EMISSIONS - FRONT HALF CATCH ONLY																
PM2.5, lb/h	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
PM2.5, lb/MBtu (LHV)	0.0059	0.0049	0.0041	0.0041	0.0058	0.0047	0.0039	0.0039	0.0064	0.0054	0.0045	0.0045	0.0061	0.0051	0.0042	0.0042
PM2.5, lb/MBtu (HHV)	0.0053	0.0044	0.0037	0.0037	0.0052	0.0042	0.0035	0.0035	0.0058	0.0049	0.0041	0.0041	0.0055	0.0046	0.0038	0.0038
PM2.5 EMISSIONS - FRONT AND BACK HALF CATCH																
PM2.5, lb/h	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
PM2.5, lb/MBtu (LHV)	0.0119	0.0098	0.0081	0.0081	0.0115	0.0094	0.0078	0.0078	0.0129	0.0108	0.0091	0.0091	0.0122	0.0103	0.0084	0.0084
PM2.5, lb/MBtu (HHV)	0.0107	0.0088	0.0073	0.0073	0.0104	0.0085	0.0070	0.0070	0.0116	0.0097	0.0082	0.0082	0.0109	0.0092	0.0076	0.0076

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
HRSG DUCT BURNERS																
DUCT BURNER FUEL																
Duct Burner Heat Input, MBtu/h (LHV)	0.0	0.0	0.0	7.8	0.0	0.0	0.0	18.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8
Duct Burner Heat Input, MBtu/h (HHV)	0.0	0.0	0.0	8.7	0.0	0.0	0.0	20.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1
Total Duct Burner Fuel Flow, lb/h	0	0	0	403	0	0	0	973	0	0	0	0	0	0	0	144
Duct Burner Fuel LHV, Btu/lb	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359	19,359
Duct Burner Fuel HHV, Btu/lb	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500	21,500
Duct Burner Fuel Composition (Ultimate Analysis by Weight)																
Ar, % wt.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C, % wt.	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20	68.20
H2, % wt.	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67	22.67
N2, % wt.	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60	8.60
O2, % wt.	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
S, % wt.	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333	0.00333
Total, % wt.	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76	99.76
Fuel Sulfur Content (grains/100 standard cubic feet)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
DUCT BURNER EMISSIONS																
Duct Burner NOx, lb/MBtu (HHV)	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800
Duct Burner CO, lb/MBtu (HHV)	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240
Duct Burner Particulate, lb/MBtu (HHV) (front half catch only)	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100
Duct Burner Particulate, lb/MBtu (HHV) (front and back half ca	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240
Duct Burner PM2.5, lb/MBtu (HHV) (front half catch only)	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100
Duct Burner PM2.5, lb/MBtu (HHV) (front and back half catch)	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240	0.0240
Assumed SO2 oxidation rate in Duct Burner, vol%	0.0	0.0	0.0	10.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidatior	0.0000	0.0000	0.0000	0.0241	0.0000	0.0000	0.0000	0.0582	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0086
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidatior	0.0000	0.0000	0.0000	0.0033	0.0000	0.0000	0.0000	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0012
Duct Burner NOx, lb/h	0.00	0.00	0.00	0.69	0.00	0.00	0.00	1.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25
Duct Burner CO, lb/h	0.00	0.00	0.00	0.87	0.00	0.00	0.00	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31
Duct Burner VOC (as CH4), lb/h	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07
Duct Burner Particulate, lb/h (front half catch only)	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner Particulate, lb/h (front and back half catch)	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Duct Burner PM10, lb/h (front half catch only)	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner PM10, lb/h (front and back half catch)	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Duct Burner PM2.5, lb/h (front half catch only)	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Duct Burner PM2.5, lb/h (front and back half catch)	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
STACK EMISSIONS																
STACK EXHAUST ANALYSIS (VOLUME BASIS - WET)																
Ar, % vol.	0.93	0.93	0.93	0.93	0.94	0.94	0.94	0.93	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92
CO2, % vol.	3.25	3.25	3.38	3.44	3.20	3.26	3.39	3.53	3.29	3.27	3.36	3.36	3.26	3.19	3.36	3.38
H2O, % vol.	7.83	7.82	8.07	8.19	7.33	7.44	7.70	7.96	10.41	10.37	10.55	10.55	9.12	9.00	9.33	9.37
N2, % vol.	74.47	74.47	74.38	74.33	74.82	74.78	74.68	74.58	72.48	72.50	72.43	72.43	73.46	73.51	73.38	73.37
O2, % vol.	13.52	13.52	13.24	13.11	13.71	13.58	13.30	13.00	12.91	12.96	12.75	12.75	13.24	13.38	13.01	12.96
SO2, (after SO2 oxidation), % vol.	0.00005	0.00005	0.00005	0.00004	0.00004	0.00005	0.00005	0.00004	0.00005	0.00005	0.00005	0.00005	0.00005	0.00004	0.00005	0.00004
SO3, (after SO2 oxidation), % vol.	0.00001	0.00001	0.00001	0.00002	0.00001	0.00001	0.00001	0.00002	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00002
Total, % vol.	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Stack Exit Temperature, ° F	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
Stack Diameter, ft (estimated)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Stack Flow, lb/h	754,560	912,844	1,057,879	1,058,281	790,163	952,982	1,108,096	1,109,067	680,835	816,908	944,053	944,053	732,348	884,766	1,024,149	1,024,292
Stack Flow, scfm	168,023	203,270	235,566	235,832	175,556	211,890	246,379	246,780	153,082	183,677	212,265	212,265	163,810	197,902	229,250	229,282
Stack Flow, acfm	284,357	344,007	398,840	399,169	297,247	358,656	417,219	417,770	259,184	310,849	359,387	359,387	277,329	335,047	388,001	388,226
Stack Exit Velocity, ft/s	60	73	85	85	63	76	89	89	55	66	76	76	59	71	82	82
STACK NOX EMISSIONS WITHOUT THE EFFECTS OF SELECTIVE CATALYTIC REDUCTION (SCR) †																
NOx, ppmvd (dry, 15% O2)	25.0	25.0	25.0	24.9	25.0	25.0	25.0	24.9	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
NOx, ppmvd (dry)	26.4	26.4	27.5	28.0	25.9	26.4	27.5	28.5	27.4	27.3	28.1	28.1	26.8	26.2	27.7	27.9
NOx, ppmvw (wet)	24.3	24.3	25.3	25.7	24.0	24.4	25.4	26.3	24.6	24.4	25.1	25.1	24.4	23.9	25.1	25.3
NOx, lb/h as NO2	29.7	36.0	43.3	44.0	30.6	37.6	45.5	47.2	27.4	32.6	38.8	38.8	29.0	34.4	41.9	42.2
NOx, lb/MBtu (LHV) as NO2	0.1009	0.1010	0.1010	0.1008	0.1010	0.1010	0.1010	0.1005	0.1010	0.1009	0.1009	0.1009	0.1010	0.1010	0.1010	0.1009
NOx, lb/MBtu (HHV) as NO2	0.0909	0.0909	0.0909	0.0907	0.0909	0.0909	0.0909	0.0905	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0909	0.0908

† Note: includes NOx massflow added to match CTG manufacturer estimate and duct burner NOx.

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
STACK NOX EMISSIONS WITH THE EFFECTS OF SELECTIVE CATALYTIC REDUCTION (SCR) †																
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	2.1	2.1	2.2	2.2	2.1	2.1	2.2	2.3	2.2	2.2	2.2	2.2	2.1	2.1	2.2	2.2
NOx, ppmvw (wet)	1.9	1.9	2.0	2.1	1.9	2.0	2.0	2.1	2.0	2.0	2.0	2.0	1.9	1.9	2.0	2.0
NOx, lb/h as NO2	2.4	2.9	3.5	3.5	2.5	3.0	3.6	3.8	2.2	2.6	3.1	3.1	2.3	2.8	3.4	3.4
NOx, lb/MBtu (LHV) as NO2	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081
NOx, lb/MBtu (HHV) as NO2	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SCR NH3 slip, ppmvd (dry, 15% O2)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
SCR NH3 slip, lb/h	2.20	2.66	3.21	3.27	2.27	2.78	3.37	3.51	2.03	2.42	2.88	2.88	2.15	2.55	3.11	3.13
† Note: includes NOx massflow added to match CTG manufacturer estimate and duct burner NOx.																
STACK CO EMISSIONS WITHOUT THE EFFECTS OF CATALYTIC REDUCTION (CO CATALYST) †																
CO, ppmvd (dry, 15% O2)	25.0	25.0	25.0	25.4	25.0	25.0	25.0	25.8	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.1
CO, ppmvd (dry)	26.4	26.4	27.5	28.4	25.9	26.4	27.5	29.6	27.4	27.3	28.1	28.1	26.8	26.2	27.7	28.1
CO, ppmvw (wet)	24.3	24.3	25.3	26.1	24.0	24.4	25.4	27.2	24.6	24.4	25.1	25.1	24.4	23.9	25.1	25.4
CO, lb/h	18.1	21.9	26.4	27.2	18.6	22.9	27.7	29.8	16.7	19.9	23.6	23.6	17.7	20.9	25.5	25.8
CO, lb/MBtu (LHV)	0.0615	0.0615	0.0615	0.0624	0.0615	0.0615	0.0615	0.0635	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0615	0.0618
CO, lb/MBtu (HHV)	0.0553	0.0554	0.0554	0.0561	0.0553	0.0554	0.0554	0.0571	0.0554	0.0553	0.0553	0.0553	0.0554	0.0554	0.0553	0.0556
† Note: includes CO massflow added to match CTG manufacturer estimate and duct burner CO.																
STACK CO EMISSIONS WITH THE EFFECTS OF CATALYTIC REDUCTION (CO CATALYST) †																
CO, ppmvd (dry, 15% O2)	3.8	3.8	3.8	3.9	3.8	3.8	3.8	4.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.9
CO, ppmvd (dry)	4.1	4.1	4.2	4.4	4.0	4.1	4.2	4.6	4.2	4.2	4.3	4.3	4.1	4.0	4.3	4.3
CO, ppmvw (wet)	3.7	3.7	3.9	4.0	3.7	3.8	3.9	4.2	3.8	3.8	3.9	3.9	3.8	3.7	3.9	3.9
CO, lb/h	2.8	3.4	4.1	4.2	2.9	3.5	4.3	4.6	2.6	3.1	3.6	3.6	2.7	3.2	3.9	4.0
CO, lb/MBtu (LHV)	0.0095	0.0095	0.0095	0.0096	0.0095	0.0095	0.0095	0.0098	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
CO, lb/MBtu (HHV)	0.0085	0.0085	0.0085	0.0086	0.0085	0.0085	0.0085	0.0088	0.0085	0.0085	0.0085	0.0085	0.0085	0.0085	0.0085	0.0086
† Note: includes CO massflow added to match CTG manufacturer estimate and duct burner CO.																
STACK SO2 EMISSIONS WITHOUT THE EFFECTS OF SO2 OXIDATION †																
SO2, ppmvd (dry, 15% O2)	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
SO2, ppmvd (dry)	0.65	0.65	0.67	0.68	0.63	0.64	0.67	0.70	0.67	0.67	0.69	0.69	0.66	0.64	0.68	0.68
SO2, ppmvw (wet)	0.60	0.59	0.62	0.63	0.59	0.60	0.62	0.65	0.60	0.60	0.61	0.61	0.60	0.58	0.61	0.62
SO2, lb/h	1.01	1.22	1.48	1.50	1.04	1.28	1.55	1.61	0.93	1.11	1.32	1.32	0.99	1.17	1.43	1.44
SO2, lb/MBtu (LHV)	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034
SO2, lb/MBtu (HHV)	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031	0.0031
† Note: SO2 from CTG and and duct burner SO2.																
STACK SO2 EMISSIONS WITH THE EFFECTS OF SO2 OXIDATION †																
Assumed SO2 oxidation rate in CO Catalyst, vol%	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Assumed SO2 oxidation rate in SCR, vol%	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
SO2, ppmvd (dry, 15% O2)	0.46	0.46	0.46	0.42	0.46	0.46	0.46	0.42	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.42
SO2, ppmvd (dry)	0.49	0.49	0.51	0.47	0.48	0.49	0.51	0.48	0.51	0.51	0.52	0.52	0.50	0.49	0.52	0.47
SO2, ppmvw (wet)	0.45	0.45	0.47	0.43	0.45	0.45	0.47	0.44	0.46	0.45	0.47	0.47	0.45	0.44	0.47	0.42
SO2, lb/h	0.77	0.93	1.12	1.03	0.79	0.97	1.18	1.10	0.71	0.85	1.01	1.01	0.75	0.89	1.09	0.98
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0026	0.0026	0.0026	0.0024	0.0026	0.0026	0.0026	0.0024	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0024
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0024	0.0024	0.0024	0.0021	0.0024	0.0024	0.0024	0.0021	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0021
† Note: Also includes assumed SO2 oxidation rate in CTG.																
STACK VOC EMISSIONS WITHOUT THE EFFECT OF OXIDATION IN CO CATALYST †																

BLACK & VEATCH

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
VOC, ppmvd (dry, 15% O2)	3.0	3.0	3.0	3.3	3.0	3.0	3.0	3.6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.1
VOC, ppmvd (dry)	3.2	3.2	3.3	3.7	3.1	3.2	3.3	4.2	3.3	3.3	3.4	3.4	3.2	3.1	3.3	3.5
VOC, ppmvw (wet)	2.9	2.9	3.0	3.4	2.9	2.9	3.0	3.8	3.0	2.9	3.0	3.0	2.9	2.9	3.0	3.1
VOC, lb/h as CH4	1.2	1.5	1.8	2.0	1.3	1.6	1.9	2.4	1.1	1.4	1.6	1.6	1.2	1.4	1.8	1.8
VOC, lb/MBtu (LHV) as CH4	0.0042	0.0042	0.0042	0.0046	0.0042	0.0042	0.0042	0.0051	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0042	0.0044
VOC, lb/MBtu (HHV) as CH4	0.0038	0.0038	0.0038	0.0042	0.0038	0.0038	0.0038	0.0046	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0039
† Note: includes VOC massflow added to match CTG manufacturer estimate and duct burner VOC.																
STACK VOC EMISSIONS WITH THE EFFECTS OF CATALYTIC REDUCTION (CO CATALYST) †																
VOC, ppmvd (dry, 15% O2)	2.1	2.1	2.1	2.3	2.1	2.1	2.1	2.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2
VOC, ppmvd (dry)	2.2	2.2	2.3	2.6	2.2	2.2	2.3	2.9	2.3	2.3	2.4	2.4	2.3	2.2	2.3	2.4
VOC, ppmvw (wet)	2.0	2.0	2.1	2.4	2.0	2.0	2.1	2.7	2.1	2.1	2.1	2.1	2.0	2.0	2.1	2.2
VOC, lb/h as CH4	0.9	1.1	1.3	1.4	0.9	1.1	1.3	1.7	0.8	1.0	1.1	1.1	0.9	1.0	1.2	1.3
VOC, lb/MBtu (LHV) as CH4	0.0030	0.0030	0.0030	0.0032	0.0030	0.0030	0.0030	0.0036	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0031
VOC, lb/MBtu (HHV) as CH4	0.0027	0.0027	0.0027	0.0029	0.0027	0.0027	0.0027	0.0032	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0028
† Note: includes VOC massflow added to match CTG manufacturer estimate and duct burner VOC.																
STACK CO2 EMISSIONS †																
CO2, lb/h	38,037	46,009	55,406	56,412	39,161	48,083	58,155	60,585	35,013	41,735	49,658	49,658	37,137	43,960	53,631	53,991
CO2, lb/MBtu (LHV)	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129	129
CO2, lb/MBtu (HHV)	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116
† Note: includes CO2 emissions from CTG and duct burner.																
PARTICULATE WITH THE EFFECTS OF SO2 OXIDATION [INCLUDES MAX. (NH4)2-(SO4)] †																
PARTICULATE EMISSIONS - FRONT HALF CATCH ONLY																
Particulate, lb/h	2.2	2.4	2.5	2.8	2.3	2.4	2.5	3.0	2.2	2.3	2.4	2.4	2.2	2.3	2.5	2.7
Particulate, lb/MBtu (LHV) (incl. duct burner fuel)	0.0076	0.0066	0.0058	0.0064	0.0075	0.0064	0.0056	0.0064	0.0081	0.0071	0.0062	0.0062	0.0078	0.0068	0.0059	0.0065
Particulate, lb/MBtu (HHV) (incl. duct burner fuel)	0.0069	0.0059	0.0052	0.0058	0.0067	0.0058	0.0050	0.0058	0.0073	0.0064	0.0056	0.0056	0.0070	0.0062	0.0053	0.0058
PARTICULATE EMISSIONS - FRONT AND BACK HALF CATCH																
Particulate, lb/h	4.0	4.1	4.2	4.7	4.0	4.1	4.3	5.0	4.0	4.0	4.1	4.1	4.0	4.1	4.2	4.5
Particulate, lb/MBtu (LHV) (incl. duct burner fuel)	0.0136	0.0115	0.0098	0.0107	0.0132	0.0111	0.0095	0.0108	0.0146	0.0125	0.0108	0.0108	0.0139	0.0120	0.0101	0.0108
Particulate, lb/MBtu (HHV) (incl. duct burner fuel)	0.0122	0.0104	0.0089	0.0096	0.0119	0.0100	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097
† Note: PM based on CTG manufacturer estimate and includes duct burner PM, and (NH4)2(SO4) as front half catch (assuming 100% conversion from SO3 to (NH4)2(SO4)).																
PM10 WITH THE EFFECTS OF SO2 OXIDATION [INCLUDES MAX. (NH4)2-(SO4)] †																
PM10 EMISSIONS - FRONT HALF CATCH ONLY																
PM10, lb/h	2.2	2.4	2.5	2.8	2.3	2.4	2.5	3.0	2.2	2.3	2.4	2.4	2.2	2.3	2.5	2.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0076	0.0066	0.0058	0.0064	0.0075	0.0064	0.0056	0.0064	0.0081	0.0071	0.0062	0.0062	0.0078	0.0068	0.0059	0.0065
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0069	0.0059	0.0052	0.0058	0.0067	0.0058	0.0050	0.0058	0.0073	0.0064	0.0056	0.0056	0.0070	0.0062	0.0053	0.0058
PM10 EMISSIONS - FRONT AND BACK HALF CATCH																
PM10, lb/h	4.0	4.1	4.2	4.7	4.0	4.1	4.3	5.0	4.0	4.0	4.1	4.1	4.0	4.1	4.2	4.5
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0136	0.0115	0.0098	0.0107	0.0132	0.0111	0.0095	0.0108	0.0146	0.0125	0.0108	0.0108	0.0139	0.0120	0.0101	0.0108
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0122	0.0104	0.0089	0.0096	0.0119	0.0100	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097

CASE NUMBER	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
† Note: PM10 based on CTG manufacturer estimate and includes duct burner PM10, and (NH4)2(SO4) as front half catch (assuming 100% conversion from SO3 to (NH4)2(SO4)).																
PM2.5 WITH THE EFFECTS OF SO2 OXIDATION [INCLUDES MAX. (NH4)2-(SO4)] †																
PM2.5 EMISSIONS - FRONT HALF CATCH ONLY																
PM2.5, lb/h	2.2	2.4	2.5	2.8	2.3	2.4	2.5	3.0	2.2	2.3	2.4	2.4	2.2	2.3	2.5	2.7
PM2.5, lb/MBtu (LHV) (incl. duct burner fuel)	0.0076	0.0066	0.0058	0.0064	0.0075	0.0064	0.0056	0.0064	0.0081	0.0071	0.0062	0.0062	0.0078	0.0068	0.0059	0.0065
PM2.5, lb/MBtu (HHV) (incl. duct burner fuel)	0.0069	0.0059	0.0052	0.0058	0.0067	0.0058	0.0050	0.0058	0.0073	0.0064	0.0056	0.0056	0.0070	0.0062	0.0053	0.0058
PM2.5 EMISSIONS - FRONT AND BACK HALF CATCH																
PM2.5, lb/h	4.0	4.1	4.2	4.7	4.0	4.1	4.3	5.0	4.0	4.0	4.1	4.1	4.0	4.1	4.2	4.5
PM2.5, lb/MBtu (LHV) (incl. duct burner fuel)	0.0136	0.0115	0.0098	0.0107	0.0132	0.0111	0.0095	0.0108	0.0146	0.0125	0.0108	0.0108	0.0139	0.0120	0.0101	0.0108
PM2.5, lb/MBtu (HHV) (incl. duct burner fuel)	0.0122	0.0104	0.0089	0.0096	0.0119	0.0100	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097
† Note: PM2.5 based on CTG manufacturer estimate and includes duct burner PM2.5, and (NH4)2(SO4) as front half catch (assuming 100% conversion from SO3 to (NH4)2(SO4)).																
TOTAL EFFECTS OF SO2 OXIDATION																
Total SO2 to SO3 conversion rate, %vol	24.0	24.0	24.0	31.5	24.0	24.0	24.0	31.5	24.0	24.0	24.0	24.0	24.0	24.0	24.0	31.5
Total Amount of SO2 converted to SO3, lb/h	0.24	0.29	0.35	0.47	0.25	0.31	0.37	0.51	0.22	0.27	0.32	0.32	0.24	0.28	0.34	0.45
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming	0.50	0.61	0.73	0.98	0.52	0.63	0.76	1.05	0.46	0.55	0.65	0.65	0.49	0.58	0.71	0.94
Maximum Stack Sulfur Mist [H2SO4] (assuming 100% conversi	0.37	0.45	0.54	0.73	0.38	0.47	0.57	0.78	0.34	0.41	0.48	0.48	0.36	0.43	0.52	0.69
POST COMBUSTION EMISSIONS CONTROL EQUIPMENT																
CATALYTIC CONVERSION IN CO CATALYST																
CO removed in CO Catalyst, %wt	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6	84.6
CO removed in CO Catalyst, lb/h	15.3	18.5	22.3	23.1	15.8	19.4	23.4	25.2	14.1	16.8	20.0	20.0	15.0	17.7	21.6	21.9
VOC removed in CO Catalyst, %wt	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
VOC removed in CO Catalyst, lb/h	0.4	0.5	0.5	0.6	0.4	0.5	0.6	0.7	0.3	0.4	0.5	0.5	0.4	0.4	0.5	0.5
SELECTIVE CATALYTIC REDUCTION (SCR)																
NOx Removed in SCR, %wt	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
NOx removed in SCR, lb/h	27.4	33.1	39.9	40.5	28.2	34.6	41.8	43.4	25.2	30.0	35.7	35.7	26.7	31.6	38.6	38.8
Ammonia Slip, lb/h	2.2	2.7	3.2	3.3	2.3	2.8	3.4	3.5	2.0	2.4	2.9	2.9	2.2	2.5	3.1	3.1
NH3 Reagent Type	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)	Aqueous (19%)
Assumed stoichiometric ratio for NH3 consumption	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Total NH3 Reagent Consumption, lb/h	86	104	126	128	89	109	132	137	79	95	113	113	84	100	122	122

DEQ State of Oregon Department of Environmental Quality

BOILERS

FORM AQ208
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project   Permit Number:

1. Boiler Information:

Boiler identification	EU6.AB (Aux Boiler)			
Manufacturer	Rentech			
Date manufactured (month/year)				
Date construction commenced (month/year)	January 2019			
Date installed (month/year)	October 2021			
Rated design heat input capacity (million Btu per hour)	296.2			
Rated steam production capacity (pounds per hour)	200,000			
Primary fuel type	Natural Gas			
Max. fuel quantity used per hour (include units)	289,100 scf/hr			
Max. fuel quantity used per year (include units)	253.3MMscf/yr			
If oil is used, sulfur content (% by wt.)				
Secondary fuel type	None			
Max. fuel quantity used per hour (include units)				
Max. fuel quantity used per year (include units)				
If oil is used, sulfur content (% by wt.)				
Stack identification	AuxBoil			
Stack height (feet)	100 ft			
Stack gas flow rate at maximum load (dscf/minute)				
Control device(s) identification from AQ300	CD.SCR6, CD.OC6			
Continuous monitoring systems	Yes			

2. Describe how the boilers(s) is operated. (Refer to instructions for guidance)

Auxiliary boiler will be used to produce steam for liquefaction train startup. Emission controls include SCR and a CO catalyst.

State of Oregon Department of Environmental Quality

MISCELLANEOUS CONTROL DEVICE INFORMATION | **FORM AQ307 ANSWER SHEET**

Facility Name: JCEP LNG Terminal Project

Permit Number:

1.	Control Device ID	CD.SCR6 (Selective Catalytic Reduction)
2.	Process/Device(s) Controlled	EU6.AB (Auxiliary Boiler)
3.	Year installed	2021
4.	Manufacturer/Model No.	
5.	Control Efficiency (%)	NOx reduction- 94.0 %wt
6.	Design inlet gas flow rate (acfm)	51,215 acfm
7.	Design parameter(s)	Exhaust gas flow rate and NOx concentration
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the control device	
	The auxiliary boiler has an SCR system to reduce emissions of NOx.	

State of Oregon Department of Environmental Quality

MISCELLANEOUS CONTROL DEVICE INFORMATION

FORM AQ307 ANSWER SHEET

Facility Name: JCEP LNG Terminal Project

Permit Number:

1.	Control Device ID	CD.OC6 (Oxidation Catalyst)
2.	Process/Device(s) Controlled	EU6.AB (Auxiliary Boiler)
3.	Year installed	2021
4.	Manufacturer/Model No.	
5.	Control Efficiency (%)	CO reduction- 92%wt
6.	Design inlet gas flow rate (acfm)	51,215 acfm
7.	Design parameter(s)	Exhaust flow rate and CO concentration
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the control device	

The auxiliary boiler has an oxidation catalyst to reduce emissions of CO.

Boilers

D-Type

RENTECH

Proposal To:

BLACK & VEATCH

For:

Jordan Cove LNG℠

Auxiliary Boiler 189980.67.6150 - Located in Coos Bay, OR
Rentech Proposal No.: DFB-DTB-4983-CY-16-R0

Boilers for people who know and care

TO: Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

July 8, 2016

Attn: Venkoba Sah Pawar Narayana Sah, P.E

Based upon the request for an auxiliary boiler to be installed in the Jordan Cove LNG facility, located in Coos Bay, Oregon, RENTECH is pleased to furnish our proposal for:

ONE (1) 200,000 LB/HR, FULLY ASSEMBLED, "D-STYLE", Watertube BOILER, with BURNER, ECONOMIZER, FAN, SELECTIVE CATALYTIC REDUCTION, STACK, TRIM, and LADDERS & PLATFORMS to be designed and built in accordance with the requirements of Section I of the ASME Boiler and Pressure Vessel Code and described in the following pages.

Page No.

RENTECH is offering a ***completely custom boiler*** system, based on the specification provided.

Thank you for your interest in doing business with **RENTECH BOILER SYSTEMS, INC.** We look forward to providing a prompt response to all of your questions, attention to all details, and a top quality boiler. Please don't hesitate to contact me if you have any questions.

Sincerely,

Clayton Young

Rentech Boiler Systems, Inc.
cmyoung@rentechboilers.com
(325) 794-5631

Cc: Jez Vaughn - B&V
Don Skaggs - B&V
Jeff Meyer - John C. Hayes & Associates, Inc.

PROPOSAL SUMMARY

With over 500 boilers installed in 25 different countries it is no wonder that more than ever people who need steam are turning to ***RENTECH Boiler Systems, Inc***. Each RENTECH boiler is custom designed by our engineers and built by a team of our experienced employees to perform efficiently and safely in its unique application. We offer excellent technical solutions to the unique needs of our customers for steam with a focus on custom design and service, competitive prices, and ***reliable delivery schedules***. You will benefit from the years of combined experience of our employees in the boiler industry.

1. **Reliability and Availability**: We understand that these boilers will form a critical part of the steam system for the facility and that reliability is key. **This reliability is evident in RENTECH's 5-year parts and labor warranty covering the design and workmanship of the boiler pressure parts.**

2. **Life Expectancy:** Rentech understands that users are looking for the best possible quality and craftsmanship. This translates directly into an extended life expectancy of the installed equipment.

3. **Emissions:** We understand that providing an environmentally friendly boiler is critical to any new installation today.

Every boiler manufactured by RENTECH Boiler Systems is ***custom engineered***, giving us the flexibility to assure that the equipment fits your needs rather than ***forcing*** your needs into a ***pre-designed boiler model***.

RENTECH Solution:

The following are features that we have included in this proposal to meet specific requirements for this boiler project:

1. We have proposed a boiler with a conservative furnace design, as noted in the below discussion regarding furnace heat release rate. This design assures that the equipment will fit your needs, minimize emissions and provide the longest life expectance possible.

2. This design maximizes the shop fabrication of the boilers.

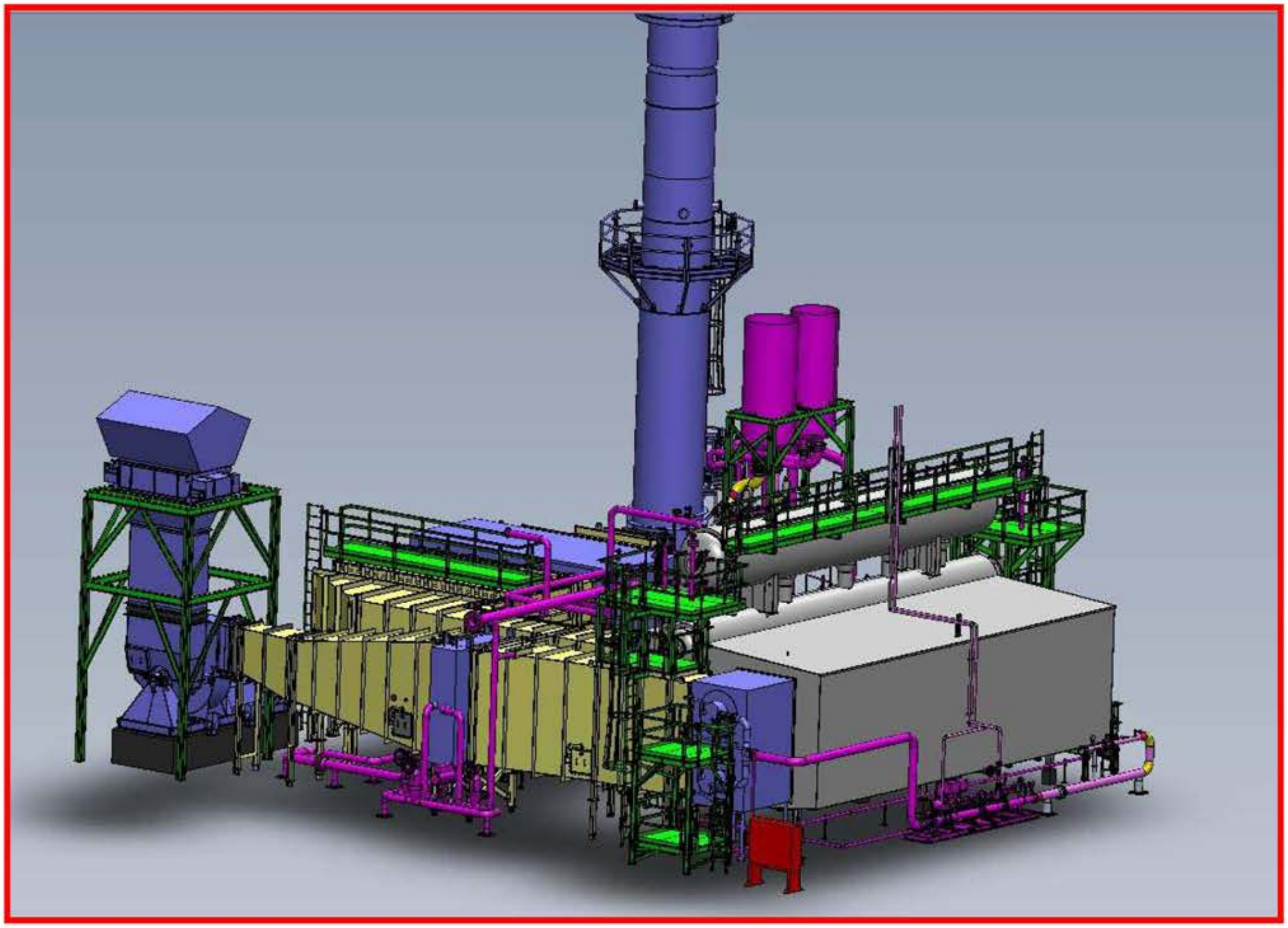
3. We have offered a 100% membrane wall construction furnace for this boiler, including the front and rear walls. This design is essential in minimizing the need for refractory in the furnace. Rentech's headered wall construction in the furnace assures that furnace gas seals do not fail due to high furnace temperatures and refractory failure.

This will significantly reduce downtime and maintenance cost over the life of the equipment.

Rentech Boiler Systems, Inc.
Abilene Office: 5025A E. Business 20 • Abilene, TX 79601 • Phone: 325-672-3400 • Fax: 325-672-9996
Lincoln Office: 145 North 46th Street • Lincoln, NE 68503 • Phone: 325-672-3400 Fax: 402-474-4243

4. Rentech will pre-fit all structural steel including ladders and platforms in our shop. Once they are assembled, photos will be taken and they will be disassembled for shipment. This added process is unique to Rentech and we have found will significantly save on field fit-up issues which could result in costly delays.

5. Rentech will utilize 3-D modeling in the engineering and design of your system. This will significantly improve fit up accuracy and avoid costly field modifications.



**Example of 3-D modeling software with entire boiler system.*

Package Boiler Scope of Supply and Installation Breakdown

Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
X		One Fully Assembled Packaged D-Type Boiler		X
Not Required		Boiler (field) assembly		
X		Boiler hydrostatic test (shop)		
X		Superheater, single stage inverted loop type	X	
X		Downstream desuperheater		X
X		Low NO_x Burner:	X	
X		Main fuel gas train		X
X		Pilot fuel train		X
	X	Interconnecting piping to windbox		X
X		PLC based Burner Management System (BMS)		X
X		PLC based logic for combustion controls		X
	X	Configuration of DCS		
X		One Arr. #7, API 673 FD Fan:		X
X		Inlet silencer		X
X		Motor drive		X
	X	VFD		X
	X	Motor controls and starter		X
X		Coupling		X
X		Dampers		X
X		Insulation clips on fan housing	X	
X		Forced Oil Lubrication System		X
	X	Vibration Monitoring System		X
Not Furnished		Steam coil air heater		
X		Fresh air ductwork from inlet silencer to windbox		X
X		Expansion joints in ductwork supplied		X
Not Required		FGR dampers and ductwork,		
X		Boiler Outlet (SCR Inlet) Transition		X
		Aqueous Ammonia SCR system:		
X		Ammonia Flow Control Unit (AFCU)		X
X		PLC based controls		X
X		SCR catalyst		X
X		Catalyst housing		X
X		Ammonia Injection Grid (AIG)		X
	X	Ammonia forwarding pumps		X
	X	Ammonia storage tank		X

Package Boiler Scope of Supply and Installation Breakdown

Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
X		SCR Outlet (Economizer Inlet) Transition		X
X		CO catalyst		X
X		Economizer (Factory Assembled)		X
X		Economizer Outlet Transition		X
X		Individual stack extending to 100' above grade		X
	X	CEMS		X
		Insulation and lagging:		
X		Boiler insulation and lagging	X	
Not Furnished		Windbox front plate		
	X	FD Fan acoustic insulation		X
X		Economizer insulation and lagging	X	
X		Flue gas duct insulation and lagging	X	
Not Required		FGR ductwork insulation and lagging		
	X	Removable insulation for drum heads		X
	X	Insulation and lagging of interconnecting piping		X
		Ladders, stairs, and platforms, galvanized, with no welds required, to provide access to:		
X		Burner/windbox		X
X		Steam drum		X
X		Observation ports		X
X		Stack testing platform		X
		Support steel (galvanized):		
X		Inlet Silencer		X
X		Fresh air ductwork, inlet silencer to windbox		X
X		Flue gas ductwork		X
X		SCR catalyst housing		X
X		Economizer		X
Not Required		FGR ductwork		
X		Piping supplied by Rentech		X

Rentech Boiler Systems, Inc.
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Package Boiler Scope of Supply and Installation Breakdown

Supply		ITEM	Installation	
Rentech	Buyer		Rentech	Buyer
		Piping:		
X		Feedwater piping from feedwater control valve to boiler inlet		X
X		Steam piping from boiler outlet to superheater outlet		X
Not Furnished		Economizer bypass		
	X	Ammonia from AFCU to AIG		X
	X	Piping external of terminal points		X
X		Boiler trim, including safety relief valves as described in the below tables, shipped loose		X
X		O_2 analyzer		X
X		Sample Panel		X
Not Furnished		Mud drum heating coil		
Not Furnished		Sootblowers		
	X	Deaerator		X
	X	Boiler feedwater pumps		X
Option		Chemical feed system		X
	X	Blow down tank(s)		X
	X	Foundation, anchor bolts, concrete, grout		X
	X	Slide plates, bearing plates, and shim plates		X
Option		Freight from Abilene, Texas to the jobsite		
	X	Unloading boiler and auxiliary equipment at Jobsite		
	X	Boil-Out chemicals, including disposal		
	X	Interconnecting wiring or cabling, all instrument and scanner cooling/purge air tubing		X
	X	Electrical Power Supply and Lighting Protection		
	X	Heat tracing		X
	X	Spare Parts		X
	X	Installation Consultant (see Per Diem rates)		
	X	Start-Up Service (see Per Diem rates)		
	X	Field Testing Labor, Equipment and Consumables		
X		Documentation		
X		Operation & Maintenance Manuals (3 sets)		

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TECHNICAL DISCUSSION

To meet your process and mechanical requirements, we are pleased to offer one (1), **100% membrane wall construction**, D-Type watertube boiler. The boiler has been designed for natural gas firing and will have a design pressure of **875 psig**. The unit will generate 200,000 lbs/hr of superheated steam at 740 psig and 725°F while firing NG. This is assuming the feedwater is supplied at **281°F**. Please refer to the attached Data Sheets for performance at the design conditions.

The boiler will be designed with ***complete membrane wall construction of the furnace***, including the front wall. This design minimizes the need for refractory and refractory seals, even in the corners. By minimizing the refractory, ***faster start-ups are possible***. Slow ramp-up time required to sustain the refractory at a constant temperature is not necessary. Of course, ***the absence of refractory rules out the possibility for cracking and crumbling*** problems that traditionally are associated with refractory in packaged boilers. The water-cooled front and rear walls also allow the furnace to operate at a lower temperature, which helps to reduce the formation of NO_x.

RADIANT FURNACE

The furnace section of the proposed boilers is of ***100% membrane wall design*** and is constructed of ***2.0"OD x 0.135"MW ERW SA-178A*** tubes on 4" centers. The tubes are connected by ¼" x 2" carbon steel membranes to form a totally water cooled enclosure, including the front and rear walls. This design avoids the traditional problems that package boilers have with firebrick and refractory maintenance. Membrane walls will be constructed as multiple tube panels maximizing machine welding and eliminating a fin to fin weld between tubes. The membrane wall construction is unique in that it utilizes a headered construction, which

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eliminates the need for, and traditional problems associated with gas seals in the corners of the furnace. Our competition would utilize steel box seals at the locations where one furnace wall joins another. These gas seals require the use of refractory or ceramic fiber to protect them from the high temperatures in the furnace. Problems with gas seal failures arise over time as the refractory or ceramic fiber fails, exposing the gas seals to 2,000°F temperatures. ***With RENTECH'S headered wall design, the water cooled header forms the corners. It simply cannot fail by overheating.***

The furnace will have two observation ports located on each side wall to allow for viewing the flame in the furnace. The front of the furnace can be viewed through ports located on the burner. The rear wall of the furnace will have a davited 15"x18" access door, with a 9" refractory lining.

FURNACE DATA

Item	Units	Natural Gas
Furnace Dimensions	Ft – in	Height: 10'-9" ; Width: 7'-7"; Length: 38'-6"
Total Heat Input	MMBtu/Hr	269.3
Furnace Volume	Ft^3	3,125
Flat Projected Furnace Surface	Ft^2	1,549
Volumetric Heat Release Rate	$Btu/Hr\text{-}ft^3$	84,856
Square Foot Heat Release Rate	$Btu/Hr\text{-}ft^2$	171,164

Notes:

- Volumetric Heat Release Rate = Total Heat Input (includes all losses from the boiler) at MCR / Actual Furnace Volume Available for Combustion (This would exclude any volume occupied by a radiant superheater if such a design were offered). The heat input is a known value and will change depending on unit efficiency and fuel fired. The furnace volume is simply a calculation of the open volume in the furnace. This results in a value in $Btu/Hr\text{-}ft^3$.
- Square Foot Heat Release Rate = Total Heat Input at MCR / Flat Projected Furnace Heating Surface. The Flat Projected Furnace Heating Surface is the heating in the furnace not taking into account the curvature of the tubes. If one were to look at the furnace membrane wall, it a square foot of Flat Projected Heating Surface would simple be a 1 foot by 1 foot square.

CONVECTION TUBES

The convection tubes are ***2.0"OD x 0.135"MW ERW SA-178A*** and attach to the drums by rolling. Each tube hole will be serrated and carefully cleaned and polished just prior to tube installation. The ends of each tube will also be polished just prior to installation.

Please refer to the attached Mechanical Data for details of the convection section tube layout. This tube layout was specifically selected to meet your process and space requirements.

Rentech performs an acoustic analysis on all sections of the boiler at various loads to determine if longitudinal, vertical baffles are required to eliminate problems associated with acoustic vibration. Rentech will include these when necessary.

DRUMS

The steam drum is 54" ID and approximately 41'-0" in length, seam to seam. This combination of diameter and length has been optimized for the capacity of the boiler. This steam drum will allow the boiler to react to load swings while reducing the likelihood of excess moisture carryover or nuisance trips due to high or low water level. The drum is provided with primary belly pan and chevrons to assure that steam leaving the drum contains less than 1.0 PPM TDS carryover. Any steam purity guarantee will not include vaporous silica carryover. All other drum internal piping is also included as needed to make the unit operational. Each steam drum head will have a 12"X16" elliptical manway with davited cover, to provide access for inspection.

The lower drum will be 26" ID. The mud drum is complete with bottom blowdown connections to allow for the proper intermittent blowdown of solids that accumulate in the bottom of the drums. The mud drum will have two 12" X 16" elliptical manways. The boiler is supported from grade on channel saddles. It will be fixed on the burner end and the other end will free to slide and accommodate thermal expansion

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DOWNCOMERS

Two unheated downcomers are included, one located at either end of the steam drum. They will stabilize the drum level during rapid changes in firing rate without the use of conventional convection tubes being used as downcomers. The downcomers also support the steam drum to reduce stresses on the tubes.

SUPERHEATER

The superheater is an inverted loop, fully drainable, type design. It will be constructed as a separate module and shop hydrostatically tested prior to installation in the boiler. The superheater will be located behind the division wall and behind the screen tubes so that it will be protected from direct radiation.

This is a single stage superheater with a desuperheater downstream the main steam outlet that uses boiler feedwater as a cooling medium. This two stage superheater will provide a guaranteed constant steam temperature of 725°F (+/- 10°F) over the operating range of 50% to 100% MCR.

BURNER

RENTECH is offering a single ZEECO Free Jet low NO_x burner for the auxiliary boiler. The maximum emission levels, **NOT using FGR**, from the burner when firing natural gas from 25% to 100% MCR, with all concentrations corrected to 3% oxygen, on a dry basis:

NOx	35 ppm
CO	50 ppm

The following scope related to the burner is included:

One (1) Zeeco Free Jet burner for a total of 1 boiler, each consisting of the following:

1. Zeeco non-insulated front plate, equipped with:
    a. Zeeco register assembly fabricated with carbon steel
    b. Zeeco carbon steel removable center equipped with center-fired gas gun assembly equipped with stainless steel tip assembly and swirler
    c. Two (2) sight ports
    d. One (1) **Fireye** scanner with swivel mount and 10m cable
2. Zeeco staged gas firing assembly equipped with carbon steel gas ring
3. Zeeco refractory throat tile, one (1) per burner

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Zeeco ZA2 Igniter
One (1) ZA2 igniter constructed out of CS, equipped with:

1. One (1) spark electrode
2. One (1) ionization sensing rod
3. One (1) high tension direct spark rod
4. One (1) Ignition transformer and ionization amplifier to provide the spark and flame detection signals
5. One (1) three foot long stainless steel flexible hose for gas supplied to the igniter
6. One (1) six foot long HT/ionization cable to connect the ignition transformer and the ionization amplifier to the igniter lance

Windbox

1. Zeeco standard construction windbox non-insulated, fabricated with ¼" A36 steel plate including distribution baffles as required per the Zeeco Physical Air Flow Modeling study.
2. Windbox Mounted Devices
   a. **Three (3)** purge air and combustion air proving transmitter
   b. **Three (3)** High steam drum pressure transmitter
   c. NEMA 4X junction box(es) for devices and scanners

Valve Trains for Free Jet burner

1. Natural gas
   a. One (1) pressure gauge with isolation valve
   b. Six (6) pressure transmitters, **three (3)** low and **one (3)** high pressure
   c. Two (2) automatic safety shutoff valves
   d. One (1) automatic vent valve
   e. One (1) manual vent valve
   f. One (1) manual shutoff valve
   g. Two (2) flow control valves (CFG and outer ring)
   h. Two (2) pressure gauges with isolation valves (CFG and outer ring)
   i. Two (2) flex hoses (CFG and outer ring)

Igniter for the Free Jet burner

a. Two (2) manual shutoff valves
b. One (1) inlet wye strainer
c. One (1) pressure regulating valve
d. Two (2) automatic safety shutoff valves
e. One (1) automatic vent valve
f. Two (2) pressure gauges with isolation valves
g. One (1) flex hose

Components for Natural Gas Train

a. One (1) manual shutoff valve
b. One (1) wye strainer
c. One (1) pressure gauge with isolation valve
d. One (1) pressure regulating valve
e. One (1) manual vent valve
f. One (1) gas flow meter

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General Construction and Wiring for Rack Mounted Valve Trains

1. Basic instrument air system comprised of **three (3)** low pressure transmitter (VT mounted), one pressure gauge, and individual component hand valves
2. Conduit and wire electrical (vs. cable and tray)
3. Base Valve Train Construction:
    a. Piping 2" and under shall be A-106 seamless pipe, schedule 80, socket welded end connections, 3000lb fittings
    b. Piping 2 ½" and larger will be A-106 seamless pipe, schedule 40, CL150 flanged or butt welded connections
    c. All valve rack lifting lugs 100% dye penetration inspection testing
    d. Bolts shall be ASTM A-193 Grade B7 – Zinc Plated
    e. Nuts shall be ASTM A-194 Grade 2H – Zinc Plated
    f. Flat-washer: (2) per Stud, (1) per bolt, Type F436 – Zinc Plated
    g. Gaskets shall be Garlock Blue-Gard 3000, 1/16" thick, or equal
4. NEMA 4X junction box(es)

FD FAN

An arrangement #7, 1780 rpm API 673 draft fan with a **600 HP** motor drive has been included for the auxiliary boiler. The fan being offered is an **Airfoil** design to help with efficiency of the fan and to decrease the required motor HP. Mechanical dampers, air silencer and the necessary air inlet ducting supports are also included.

Test block for the fan and drives is based on 110% of volumetric flow and 121% of static pressure. Fan performance is summarized below

Fan Blade Type		Airfoil	
Fan Model		***A55S-5875***	
Condition	Units	Test Block	Max Fire Case
Inlet Volume Flow Rate	acfm	58,948	51,215
Inlet Temperature	°F	105	80
Inlet Density	lb/ft^3	0.0703	0.0736
Inlet Total Pressure	in.wg	0.00	0.00
Outlet Static Pressure	in.wg	42.60	35.20
Fan Static Pressure Rise	in.wg	42.60	35.20
Fan Speed	rpm	1,780	1,780
Power Consumption	HP	538	428
Approximate VIV Angle	°	90	43

NOTE - The fan will also include a **forced oil lubrication system**, designed per API-614. This system will ensure the bearings on the fan and motor are cooled for equipment longevity.

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ECONOMIZER

A horizontal gas flow economizer has been included for each boiler. The tubes are horizontal and fully drainable, finned with 6 fins/in, 0.75" H x 0.05" W and serrated fins.

The economizer casing inner casing is ¼" carbon steel, and is gas tight and externally insulated with mineral fiber block insulation and lagged to match the boiler.

SCR & CO SYSTEM

This proposal includes a standard medium temperature **SCR catalyst** system for to reduce NOx emissions from the burner. The system is designed to utilize 19% aqueous ammonia as a reagent in the SCR process.

NOx emissions will be reduced as depicted in the following table:

	From Burner	**SCR Outlet**
NO_x, ppm	35 ppm	2 ppm

SCR CATALYST DESCRIPTION	
SCR Catalyst Manufacturer	Cormetech CM-21™
Catalyst Type	Homogeneous Honeycomb
Active Catalyst Material	Ti-V-W
Catalyst Flow Passage (pitch)	2.1 mm
Gas Flow	Horizontal
Module Arrangement	14 X 12.75
Flue Gas Maldistribution at Inlet to Catalyst:	
Velocity	+/- 15% RMS normal
Temperature	+/- 20°F
N_3 to NO_x Molar Ratio	+/- 10% RMS normal
Number of SCR Modules	4
Total SCR Catalyst Weight	2,400 lbs.
Guarantee Life	43,800 hours
Ammonia Slip	10 ppmvdc @ 3% O_2

An **ammonia package control unit (APCU)** is included with dilution components for aqueous ammonia per the following:

- Stainless steel structural skid base with lifting and grounding lugs
- Two regenerative blowers, one primary and one secondary, rated at 130 SCFM @ 42"WC, Electric motor rated 460/3/60, 3 HP, IEEE-841, 1.15 SF; inlet filter/silencers are included.
- Stainless steel dilution air line with expansion joints, check valves, automated damper vale assemblies, pressure gauges with a block and bleed valve, orifice flange assembly with a manifold/flow transmitter
- Two 100 kW 480/3/60 immersion heaters, one primary and one secondary, housed in stainless steel pipe, with type K thermocouples on each circuit. Vertical down flow; insulated and jacketed. Stainless steel piping downstream of the heaters will include expansion joints, automated damper valve assemblies, and a thermocouple/thermo well assembly with a temperature transmitter.
- One upward flow, stainless steel vertical vaporizer with internal mixing element and injection nozzle. The outlet stainless steel piping will have a thermocouple/thermo well assembly with a temperature transmitter.
- Class 150 stainless steel aqueous ammonia line, including manual isolation valves, duplex strainers with a common differential pressure gauge, a Micro Motion Coriolis mass meter, automated isolation ball valve assemblies with open/close limit switches, pressure gauges with block and bleed valves, a Fisher/Baumann flow control valve with a globe valve bypass, and a flex line to the injection nozzle
- Class 150 stainless steel instrument air header with manual isolation valves, a pressure switch, and a pressure gauge w/block and bleed valve to provide actuation of pneumatic valves
- NEMA 4X junction box for the termination of analog and discrete instrumentation
- NEMA 4X heater power panel containing components for modulated heater control and safety interlocks; with PLC based Compact Logix, I/O modules for control, and a 10" color touch screen; includes an A/C unit and Z purge.

Ammonia will be injected into the flue gas via distribution manifold header and an ammonia injection grid (AIG). The distribution manifold header consists of one header with an inlet intake and take off branches. Each branch contains a manual gate valve, orifice plate, and Dwyer Capsuhelic pressure gage for balancing flow. The ammonia injection grid consists of assemblies with three 3" lances per assembly. A total of twenty one stainless steel lances are provided.

- CFD modeling of the flue gas flow path and AIG has been included.

An **Allen Bradley PLC system** is included and is housed in a NEMA 4X enclosure located on APCU skid. It will consist of the following:

- Compact Logix PLC platform
- Redundant processors
- I/O modules for control of SCR system
- 10" color touch screen with sun shade

This proposal includes a standard medium temperature **CO catalyst** system for to reduce carbon monoxide emissions from the burner from 50 ppm down to 4 ppm, a destruction of 91.76%.

BOILER AND BURNER CONTROLS

Zeeco will provide a new Burner Management System (BMS) utilizing a redundant Allen Bradley Control Logix processors. The BMS will control the automatic sequencing during light off of the burner on Natural Gas and continuously monitor all safety interlocks to ensure safe firing of the boiler. If a hazardous situation does occur, the BMS will shut down the boiler automatically. A Control Narrative and SAMA Diagram showing the Combustion Control System Logic will be provided (to be programmed into the DCS by others).

Zeeco will provide all new hardware which will be mounted inside a NEMA 12 Free Standing enclosure. A 12" Red Lion HMI will be mounted on the door. The enclosure is not rated for any hazardous areas and must be installed in an unclassified climate controlled area. The BMS shall not be provided with any provisions for Intrinsically Safe instrumentation as Zeeco's standard is Ex d and Ex e.

The BMS can be controlled with the HMI or remotely through the DCS. "First Out" and alarm conditions will be displayed locally as well as annunciated to the DCS. Alarm and Indication communication with the DCS shall be done over redundant Fiber Optic Ethernet (using 1756-EN2F modules); permissives and control will be done through dry contacts.

A programming laptop with the latest version of Studio 5000 and the HMI software will be provided.

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Notes:

- BMS shall meet all the latest NFPA 85 2015 standards
- The BMS is engineered utilizing an external safety watchdog timer to continuously monitor the PLC for processor faults.
- All critical PLC Input and Outputs shall be continuously monitored for faults during operation.
- Programming and Screen development for HMI screens.
- All BMS outputs shall be fused. Terminals will be Phoenix Contact.
- All digital I/O (switches, valves, etc.) shall be 24 VDC.
- Technical control package will include the following documents:
    a) BMS Panel Arrangement
    b) BMS Electrical Equipment List
    c) BMS Electrical Wiring Schematics
    d) BMS Sequence of Operations
    e) BMS Boolean Diagrams
    f) CCS Control Narrative
    g) CCS SAMA Diagram
    h) I/O List
    i) Install (Hook Up) Diagrams
    j) DCS Communication Map
    k) Utility Consumption List
    l) HMI Screen Shots
    m) Certifications for Hazardous Area

BMS Exceptions:

- Loop Drawings (Information will be presented in the wiring diagrams)
- Interconnect Drawings
- Cause and Effect Drawings (Information is better presented as Booleans)
- SAT Procedure
- The BMS will not accept any pneumatic (3-15 PSIG) signals.
- A Blower will not be installed in the BMS panel.
- A printer will not be provided.

STACK

Individual single wall freestanding stacks, extending to 100' above grade are included. The stack diameter is 72" at the discharge, sized for a discharge velocity of 50 ft/sec with both boilers operating at 100% MCR.

One 360° x 3'- 6" OSHA approved test platform will be included to access the test ports. Expanded metal personnel protection will be provided, 6' - 0", at the test platform, and behind the caged ladder.

DUCTWORK

The boiler outlet transition (SCR inlet), SCR and CO catalyst housing, SCR outlet (economizer inlet) and economizer outlet transition will be fabricated of 0.25" carbon steel material, stiffened as required. All ductwork will be insulated and lagged prior to shipment. Access doors will be provided.

BOILER TRIM AND INSTRUMENTATION

The boiler trim included in the base pricing is itemized on the trim list. Boiler trim appurtenances and instrumentation will be crated and shipped for safe delivery to site where it will be mounted by end user and/or his site contractor. Wiring in the field is supplied by others.

PIPING

We have included the piping as indicated in the above scope table. All piping supplied by RENTECH will analyzed for stresses and will come with the necessary supports to properly carry the loads. Field welds will be required to complete the feedwater piping installation.

INSULATION, LAGGING, AND PAINTING

The mud drum, excluding the drum heads, and all of the walls of the unit will be insulated with 3-4" mineral fiber insulation and protected with steel lagging. The roof of the furnace will be covered with steel casing. The steam drum, excluding the heads, will be insulated and lagged with steel. The drum heads will be provided with removable insulation covers. Exterior surfaces that will not be insulated will be cleaned and painted with one coat of inorganic zinc primer. Vendor supplied equipment will receive their standard paint application. Piping components, ductwork interior and surfaces that will be insulated will not be painted.

FIELD SERVICE

All field service is available at the below per diem rates.

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Boiler Trim

Safety Relief Valves

2	Boiler		Drip pan elbows
1	Superheater	X	Vent stacks
0	Economizer	2	Silencer(s)
	Gags	X	Silencer supports
X	Spring covers		

Water Columns

				Level Switches			
1	Qty.						
X	Probe Type		Float Type	Column 1		Column 2	
	Valves			X	HI-HI		HI-HI
X	Process block			X	HI		HI
X	Drain			X	LO		LO
	Vent			X	LO-LO		LO-LO

Aux. LWCO

1	Qty.		Valves
X	Probe type	X	Process block
	Float type	X	Drain
			Vent

Water Level Gage Glass

Water Level Gage Glass	Glass 1	Glass 2
Prismatic		
Flat glass	X	X
Bi-Color		
Illuminator	X	X
Direct vision hood		
Remote viewing hood with mirrors		
Fiber optic remote		
Valves		
Water gage	X	X
Drain	X	X
Vent		

Remote Level Indicator

Remote Level Indicator	
Probe Type	1
Number of remote indicators	1
Number of lights per indicator	
Valves	10
Process block	
Drain	
Vent	

Controllers / Analyzers

	Drum level controller		Conductivity analyzer (steam)
	Desuperheater controller		Conductivity analyzer (water)
1	Desuperheater		PH analyzer (water)
1	O2 Analyzer	4	Sample Coolers (one panel)

Flow Elements

Service	Orifice Plate	Flow Nozzle	Venturi	Piezometer
Steam	1	0	0	0
Water	1	0	0	0
Combustion air	0	0	0	1
Flue gas	0	0	0	0
Fuel gas	1	0	0	0
Fuel oil	0	0	0	0

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Boiler Trim

Sootblowers – Qty.

Service	Retractable	Manual Rotary	Electric Rotary		Controls
Boiler	0	0	0		Motor starters
Superheater	0	0	0		Piping
Economizer	0	0	0		

Description	PI	PT	TI	TT	TC/TW	PS	LT	FT
Flue Gas								
Fresh air inlet				1	1			3 (*)
FGR								
Air preheater outlet								
Mix – Fan inlet								
Fan discharge		1						
Burner windbox								
Furnace	1	3						
Convection section								
SH inlet								
SH intermediate								
SH outlet								
Boiler outlet								
Economizer inlet	1		1	1	1			
Economizer outlet	1		1	1	1			
Water								
Upstream control valve station	1							1
Downstream control valve station								
Upstream economizer	1		1	1	1			
Downstream economizer	1		1	1	1			
Steam								
Boiler outlet								
SH Interstage								
SH outlet	1	1		1	1			1
Steam drum	1	3					4 (*)	
Continuous blowdown								
SH Tubes					4			
Fuel								
Gas								1
Oil								

PI = Pressure Indicator
PT = Pressure Transmitter
TI = Temperature Indicator
TT = Temperature Transmitter
TC/TW = Thermocouple/Thermowell
PS = Pressure Switch
LT =Level Transmitter
FT = Flow Transmitter

- **NOTE WE ARE INCLUDING 2-o-o-3 TRANSMITTERS FOR SIL-2 BMS**
- **AIR FLOW METERS WILL BE PIEZOMETER TUBE + DP TRANSMITTER (2 UNITS) + 1 THERMAL DISPERSION MASS FLOW TRANSMITTER**
- **LEVEL TRANSMITTERS WILL BE DP (2 UNITS) + 1 GUIDED WAVE RADAR LEVEL TRANSMITTER AS SPECIFIED**

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Boiler Trim

Valves	Qty.	Manual	Actuated
Feedwater			
Stop	1	X	
Check	1	X	
Level control	1		X
Control valve block	2	X	
Control valve by-pass	1	X	
Control valve drain	4	X	
Economizer block	0		
Economizer by-pass	0		
Steam non-return	1	X	
Steam stop	1		X
Free blow drain	1	X	
Continuous blowdown control	1		X
Continuous blowdown block	1	X	
Intermittent blowdown	4	X	
Boiler vent	2	X	
Chemical feed block	1	X	
Chemical feed check	1	X	
Superheater start-up	1		X
Start-up block	1	X	
Superheater vent	2	X	
Superheater drain	2	X	
Economizer vent	2	X	
Economizer drain	2	X	
Sootblower steam block	0		
Desuperheater spray water			
Control valve	1		X
Control valve block	1	X	
Control valve by-pass	0		
Control valve drain	4	X	
Power operated block	0		
Stop valve	1	X	
Check valve	1	X	
Boiler drain	2	X	
Steam sample	2	X	
Water sample	0		
Acid clean	0		

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Lincoln Office: 145 North 46th Street • Lincoln, NE 68503 • Phone: 325-672-3400 Fax: 402-474-4243

PROCESS SUMMARY SHEET
Normal Operation – 100% MCR

	FURNACE	SCREEN	SUPERHEATER	EVAPORATOR	ECONOMIZER
Flue Gas Flow Rate, lb/hr	237,717 @ 15% excess air (1)				
Inlet Temperature,°F	Combustion	2,422	2,300	1,838	731
Outlet Temperature,°F	2,422	2,300	1,838	731	330
Fouling, ft²°F/ BTU	0.001				
Heat Loss, %	1.5				
Heat Duty, mmBTU/hr	68.18	9.81	36.63	80.98	26.74
Pressure Drop, " WC	15.5				1.0
STEAM SIDE					
Design Pressure, psig	875				950
Operating Pressure, psig	795 (4)		750	795 (4)	805
Pressure Drop, psi	--		35	--	10
Inlet Temperature, °F	408		520	408	281
Outlet Temperature, °F	520		777 (6)	520	408
Blowdown, %	3		--	3	--
Fouling, ft²°F/ BTU	0.001				
Flow Rate, lb/hr	194,500 (5)		200,000	194,500	200,550
Heating Surface, ft²	1,549	214	964	11,320	34,847

Notes:

(1) Includes **NO** FGR
(2) Predicted HHV Efficiency - 83.01%, Heat Input 269.26 mmBTU/hr
(3) Flue Gas Analysis, % Volume: CO_2 - 8.36 H_2O - 18.14 N_2 - 71.05 O_2 - 2.46
(4) Piping and NRV pressure drop of 12 psi
(5) Desuperheater spray flow of 5,500 lb/hr at 281°F
(6) Outlet at the SH, desuperheater spray will control steam temperature to 725°F

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MECHANICAL DATA SHEET

TUBES

	FURNACE	SCREEN	SUPERHEATER	CONVECTIVE	ECONOMIZER
Diameter, in.	2.0	2.0	2.0	2.0	1.5
Thickness, in.	0.135	0.135	0.150	0.135	0.120
Material	SA-178A	SA-178A	SA-213 T22	SA-178A	SA-178A
Length, ft	--	10.5	7.67	10.5 / 9.55 / 9.55	15.75
Tubes / Row	1	13	12	13 / 12 / 12	30
Rows Deep	117	3	20	39 / 6 / 12	14
Arrangement	Inline	Inline	Inline/ Parallel flow	Inline	Inline / Counter flow
Transverse Pitch, in.		4.75	4.75	4.75	3.5
Longitudinal Pitch, in.	4.0	4.0	5.0	4.0	4.5
Fins	1/4" membrane	--	--	39 rows bare. 6 rows: 3.0 FPI, Solid, 0.50" H, 0.06" W 12 rows: 4.0 FPI, Solid, 0.75" H, 0.06" W	6 fins/inch 0.75"H x 0.05"W CS serrated

DRUMS

	STEAM DRUM	MUD DRUM
Diameter (in.)	54	26
Length, seam-seam, (ft.)	41' - 0"	41' - 0"
Thickness, (in.)	**Per ASME**	**Per ASME**
Material	SA 516 Gr. 70	SA 516 Gr. 70
Manways	Two 12" x 16"	Two 12" x 16"
Corrosion Allowance	0.125"	0.125"

UNIT DIMENSIONS AND WEIGHTS

	UNIT
Height to Steam Outlet, ft	17' - 10"
Width, ft	14' - 0"
Length (including burner), ft	52' - 0"
D-Type Boiler Dry Weight, lbs.	250,000
Economizer, lbs.	60,000

PERFORMANCE GUARANTEES

The performance of the packaged boiler is guaranteed as detailed below:

Fuel Fired		**Natural Gas**	
DESCRIPTION	**UNITS**		
System Performance			
Steam Flow (Net)	lb/hr	200,000	
Steam Pressure	PSIG	740	
Steam Quality @ Drum Outlet	%	0.05	
System Efficiency	**%**	**83.01**	
Emissions			
NOx	ppm	2	
CO	ppm	4	

Notes:

1. System performance guarantees are at 100% MCR only.
2. Feedwater temperature to boiler is 281°F.
3. Ambient temperature is 80°F.
4. The blowdown rate is as defined in the attached Predicted Operating Performance Tables.
5. Feedwater analysis must meet suggested Water Quality Limits per latest edition of ASME.
6. Boiler performance will be measured by a performance test based upon the principles of ASME PTC 4.1. Testing is to be by others.
7. The steam conditions are at the Rentech terminal points.
8. Emission guarantees are from 25% to 100% MCR.

Facility Name: JCEP LNG Terminal Project   Permit Number:

Engine Information

1.	Device ID Number	EU7.FP (Fire Pump Engines)
2.	Existing or future?	Future
3.	Date construction commenced	January 2019
4.	Date installed/completed	April 2021
5.	Special controls (if applicable)	Tier 3
6.	Manufacturer	Caterpillar
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	700 hp
9.	Control device(s) (yes/no)	No
	If yes, enter the identification number(s)	
10.	Description of device:	

Two Caterpillar C18 diesel-fired fire pump engines.

Operating Schedule

11.	Projected maximum hours/day	2
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:	a. Type	b. Hourly usage	c. Annual usage
Primary	ULSD	35.9 gal/hr	7,180 gal
Back-up			
Other			

Stack Information

14.	Exit height (ft)	18
15.	Exit diameter (ft)	0.67
16.	Design flowrate (dscf/min)	

Monitoring Information

17. Monitoring equipment

fuel flow (y/n)		recorder? (y/n)	
engine load (y/n)		recorder? (y/n)	
other (specify)	Hour meter	recorder? (y/n)	Yes

PERFORMANCE DATA [DM9853]

JUNE 06, 2016

For Help Desk Phone Numbers Click here

Perf No: DM9853 **Change Level:** 03

General Heat Rejection Emissions Regulatory Altitude Derate Cross Reference Perf Param Ref

View PDF

SALES MODEL:	C18	**COMBUSTION:**	DI
ENGINE POWER (BHP):	700	**ENGINE SPEED (RPM):**	1,750
COMPRESSION RATIO:	16.3	**ASPIRATION:**	TA
RATING LEVEL:	STANDBY - FMS/ULI	**AFTERCOOLER TYPE:**	SCAC
PUMP QUANTITY:	1	**AFTERCOOLER CIRCUIT TYPE:**	JW+OC, AC
FUEL TYPE:	DIESEL	**AFTERCOOLER TEMP (F):**	95
MANIFOLD TYPE:	DRY	**JACKET WATER TEMP (F):**	192.2
GOVERNOR TYPE:	ELEC	**TURBO CONFIGURATION:**	PARALLEL
INJECTOR TYPE:	EUI	**TURBO QUANTITY:**	2
REF EXH STACK DIAMETER (IN):	6	**TURBOCHARGER MODEL:**	80BMI87N/39DH-DM1.10VO
MAX OPERATING ALTITUDE (FT):	302	**CERTIFICATION YEAR:**	2008
		PISTON SPD @ RATED ENG SPD (FT/MIN):	2,101.4

INDUSTRY	SUB INDUSTRY	APPLICATION
INDUSTRIAL	FIRE PUMP	INDUSTRIAL

General Performance Data Top

PERCENT LOAD	ENGINE POWER	BRAKE MEAN EFF PRES (BMEP)	BRAKE SPEC FUEL CONSUMPTN (BSFC)	VOL FUEL CONSUMPTN (VFC)	INLET MFLD PRES	INLET MFLD TEMP	EXH MFLD TEMP	EXH MFLD PRES	ENGINE OUTLET TEMP
%	BHP	PSI	LB/BHP-HR	GAL/HR	IN-HG	DEG F	DEG F	IN-HG	DEG F
100	700	286	0.359	35.9	60.9	120.0	1,307.1	48.6	948.3
90	630	258	0.366	32.9	57.1	118.0	1,271.0	45.4	928.0
80	560	229	0.371	29.7	52.5	114.6	1,215.2	41.1	888.6
75	525	215	0.373	28.0	50.0	112.7	1,185.6	38.9	867.4
70	490	200	0.378	26.4	47.6	111.3	1,163.2	36.6	853.0
60	420	172	0.389	23.3	42.1	108.5	1,117.1	32.1	825.0
50	350	143	0.400	20.0	35.9	105.5	1,059.3	27.2	790.0
40	280	115	0.399	15.9	25.9	101.0	972.4	20.2	735.3
30	210	86	0.396	11.9	15.9	97.1	855.9	13.7	658.9
25	175	72	0.398	9.9	11.5	95.7	786.3	10.9	612.4
20	140	57	0.410	8.2	8.2	95.1	700.3	8.8	550.2
10	70.0	29	0.493	4.9	3.2	95.2	497.0	5.9	399.5

PERCENT LOAD	ENGINE POWER	COMPRESSOR OUTLET PRES	COMPRESSOR OUTLET TEMP	WET INLET AIR VOL FLOW RATE	ENGINE OUTLET WET EXH GAS VOL FLOW RATE	WET INLET AIR MASS FLOW RATE	WET EXH GAS MASS FLOW RATE	WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)	DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)
%	BHP	IN-HG	DEG F	CFM	CFM	LB/HR	LB/HR	FT3/MIN	FT3/MIN

PERCENT LOAD	ENGINE POWER	COMPRESSOR OUTLET PRES	COMPRESSOR OUTLET TEMP	WET INLET AIR VOL FLOW RATE	ENGINE OUTLET WET EXH GAS VOL FLOW RATE	WET INLET AIR MASS FLOW RATE	WET EXH GAS MASS FLOW RATE	WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)	DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)
100	700	66	388.8	1,435.0	4,042.6	6,454.9	6,706.1	1,411.7	1,286.3
90	630	62	374.1	1,384.4	3,826.3	6,217.0	6,447.4	1,355.7	1,239.8
80	560	57	354.2	1,327.3	3,528.7	5,921.0	6,128.4	1,286.8	1,181.4
75	525	55	343.5	1,296.1	3,380.3	5,758.1	5,953.9	1,252.4	1,152.1
70	490	52	333.0	1,263.9	3,232.1	5,595.3	5,779.9	1,210.6	1,115.7
60	420	46	309.9	1,188.4	2,936.8	5,225.0	5,387.3	1,124.0	1,039.7
50	350	40	283.3	1,096.0	2,635.8	4,786.2	4,926.3	1,037.0	962.9
40	280	29	234.8	937.9	2,142.7	4,057.7	4,169.3	881.6	822.1
30	210	18	185.0	776.8	1,641.2	3,326.2	3,409.4	721.4	675.9
25	175	14	162.3	703.8	1,408.2	2,998.8	3,068.4	645.9	606.8
20	140	10	144.4	646.6	1,214.1	2,747.1	2,804.4	591.1	558.0
10	70.0	5	114.6	553.2	876.1	2,347.9	2,382.4	501.4	478.9

Heat Rejection Data Top

PERCENT LOAD	ENGINE POWER	REJECTION TO JACKET WATER	REJECTION TO ATMOSPHERE	REJECTION TO EXH	EXHUAST RECOVERY TO 350F	FROM OIL COOLER	FROM AFTERCOOLER	WORK ENERGY	LOW HEAT VALUE ENERGY	HIGH HEAT VALUE ENERGY
%	BHP	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN
100	700	10,045	5,379	29,941	17,110	4,100	6,949	29,686	76,976	81,999
90	630	9,499	4,754	27,920	15,840	3,763	6,377	26,717	70,657	75,267
80	560	8,360	4,843	25,188	13,964	3,391	5,681	23,748	63,667	67,821
75	525	7,742	4,916	23,776	13,000	3,201	5,320	22,264	60,098	64,019
70	490	7,351	4,769	22,590	12,246	3,023	4,967	20,780	56,754	60,457
60	420	6,700	4,397	20,164	10,736	2,664	4,214	17,811	50,023	53,288
50	350	6,110	3,868	17,466	9,055	2,285	3,408	14,843	42,895	45,694
40	280	5,203	3,564	13,629	6,669	1,822	2,174	11,874	34,212	36,445
30	210	4,262	2,985	9,844	4,338	1,358	1,171	8,906	25,503	27,167
25	175	3,801	2,578	8,137	3,301	1,137	799	7,421	21,344	22,736
20	140	3,382	2,308	6,555	2,285	936	542	5,937	17,576	18,723
10	70.0	2,590	1,756	3,770	472	563	183	2,969	10,577	11,267

Emissions Data Top

Units Filter All Units

RATED SPEED POTENTIAL SITE VARIATION: 1750 RPM

ENGINE POWER		BHP	700	525	350	175	70.0
PERCENT LOAD		%	100	75	50	25	10
TOTAL NOX (AS NO2)		G/HR	2,407	1,339	795	451	852
TOTAL CO		G/HR	988	1,217	283	456	336
TOTAL HC		G/HR	35	68	59	58	50
PART MATTER		G/HR	135.0	101.8	77.2	80.5	25.5
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	1,517.5	1,082.1	889.0	976.1	3,551.0
TOTAL CO	(CORR 5% O2)	MG/NM3	622.9	979.5	326.2	990.5	1,409.8
TOTAL HC	(CORR 5% O2)	MG/NM3	19.4	47.6	57.6	109.7	182.5
PART MATTER	(CORR 5% O2)	MG/NM3	70.3	69.2	74.9	152.8	97.7
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	739	527	433	475	1,730
TOTAL CO	(CORR 5% O2)	PPM	498	784	261	792	1,128
TOTAL HC	(CORR 5% O2)	PPM	36	89	108	205	341
TOTAL NOX (AS NO2)		G/HP-HR	3.48	2.57	2.29	2.59	12.20
TOTAL CO		G/HP-HR	1.43	2.34	0.81	2.61	4.82
TOTAL HC		G/HP-HR	0.05	0.13	0.17	0.33	0.72
PART MATTER		G/HP-HR	0.20	0.20	0.22	0.46	0.37
TOTAL NOX (AS NO2)		LB/HR	5.31	2.95	1.75	0.99	1.88

ENGINE POWER		BHP	700	525	350	175	70.0
PERCENT LOAD		%	100	75	50	25	10
TOTAL CO		LB/HR	2.18	2.68	0.62	1.01	0.74
TOTAL HC		LB/HR	0.08	0.15	0.13	0.13	0.11
PART MATTER		LB/HR	0.30	0.22	0.17	0.18	0.06

RATED SPEED NOMINAL DATA: 1750 RPM

ENGINE POWER		BHP	700	525	350	175	70.0
PERCENT LOAD		%	100	75	50	25	10
TOTAL NOX (AS NO2)		G/HR	2,229	1,240	736	418	789
TOTAL CO		G/HR	528	651	151	244	180
TOTAL HC		G/HR	19	36	31	31	27
TOTAL CO2		KG/HR	352	272	193	98	48
PART MATTER		G/HR	69.2	52.2	39.6	41.3	13.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	1,405.1	1,001.9	823.2	903.8	3,288.0
TOTAL CO	(CORR 5% O2)	MG/NM3	333.1	523.8	174.4	529.7	753.9
TOTAL HC	(CORR 5% O2)	MG/NM3	10.2	25.2	30.5	58.1	96.6
PART MATTER	(CORR 5% O2)	MG/NM3	36.0	35.5	38.4	78.4	50.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	684	488	401	440	1,602
TOTAL CO	(CORR 5% O2)	PPM	266	419	140	424	603
TOTAL HC	(CORR 5% O2)	PPM	19	47	57	108	180
TOTAL NOX (AS NO2)		G/HP-HR	3.22	2.38	2.12	2.39	11.30
TOTAL CO		G/HP-HR	0.76	1.25	0.44	1.40	2.58
TOTAL HC		G/HP-HR	0.03	0.07	0.09	0.18	0.38
PART MATTER		G/HP-HR	0.10	0.10	0.11	0.24	0.19
TOTAL NOX (AS NO2)		LB/HR	4.91	2.73	1.62	0.92	1.74
TOTAL CO		LB/HR	1.16	1.43	0.33	0.54	0.40
TOTAL HC		LB/HR	0.04	0.08	0.07	0.07	0.06
TOTAL CO2		LB/HR	777	600	426	215	105
PART MATTER		LB/HR	0.15	0.12	0.09	0.09	0.03
OXYGEN IN EXH		%	8.9	10.4	11.8	13.4	16.1
DRY SMOKE OPACITY		%	1.9	1.6	1.4	2.6	0.6
BOSCH SMOKE NUMBER			1.22	1.06	0.96	1.60	0.28

Regulatory Information Top

EPA TIER 3 **2005 - 2010**

GASEOUS EMISSIONS DATA MEASUREMENTS PROVIDED TO THE EPA ARE CONSISTENT WITH THOSE DESCRIBED IN EPA 40 CFR PART 89 SUBPART D AND ISO 8178 FOR MEASURING HC, CO, PM, AND NOX. THE "MAX LIMITS" SHOWN BELOW ARE WEIGHTED CYCLE AVERAGES AND ARE IN COMPLIANCE WITH THE NON-ROAD REGULATIONS.

Locality	Agency	Regulation	Tier/Stage	Max Limits - G/BKW - HR
U.S. (INCL CALIF)	EPA	NON-ROAD	TIER 3	CO: 3.5 NOx + HC: 4.0 PM: 0.20

EPA EMERGENCY STATIONARY **2011 - ----**

GASEOUS EMISSIONS DATA MEASUREMENTS PROVIDED TO THE EPA ARE CONSISTENT WITH THOSE DESCRIBED IN EPA 40 CFR PART 60 SUBPART IIII AND ISO 8178 FOR MEASURING HC, CO, PM, AND NOX. THE "MAX LIMITS" SHOWN BELOW ARE WEIGHTED CYCLE AVERAGES AND ARE IN COMPLIANCE WITH THE EMERGENCY STATIONARY REGULATIONS.

Locality	Agency	Regulation	Tier/Stage	Max Limits - G/BKW - HR
U.S. (INCL CALIF)	EPA	STATIONARY	EMERGENCY STATIONARY	CO: 3.5 NOx + HC: 4.0 PM: 0.20

Altitude Derate Data Top

ALTITUDE CORRECTED POWER CAPABILITY (BHP)

AMBIENT OPERATING TEMP (F)	50	60	70	80	90	100	110	120	130	NORMAL
ALTITUDE (FT)										
0	700	700	700	700	691	679	667	655	644	700
1,000	700	700	691	678	666	654	642	631	621	684
2,000	691	678	665	653	641	629	618	608	597	663

AMBIENT OPERATING TEMP (F)	50	60	70	80	90	100	110	120	130	NORMAL
3,000	665	652	640	628	617	606	595	585	575	643
4,000	640	628	616	604	593	583	573	563	553	622
5,000	615	604	592	581	571	560	551	541	532	603
6,000	592	580	569	559	549	539	529	520	511	583
7,000	569	558	547	537	527	518	509	500	492	565
8,000	546	536	526	516	507	498	489	480	472	546
9,000	525	515	505	496	487	478	469	461	454	528
10,000	504	494	485	476	467	459	451	443	435	511
11,000	483	474	465	456	448	440	432	425	418	494
12,000	464	455	446	438	430	422	415	408	401	477
13,000	445	436	428	420	412	405	398	391	384	461
14,000	426	418	410	402	395	388	381	375	368	445
15,000	408	400	393	386	379	372	365	359	353	429

Cross Reference Top

Engine Arrangement

Arrangement Number	Effective Serial Number	Engineering Model	Engineering Model Version
3149713	NBB00003	E978	-

Test Specification Data

Test Spec	Setting	Effective Serial Number	Engine Arrangement
0K8977	PP6861	NBB00003	3149713

Performance Parameter Reference Top

Parameters Reference: DM9600 - 08

PERFORMANCE DEFINITIONS

PERFORMANCE DEFINITIONS DM9600

APPLICATION:
Engine performance tolerance values below are representative of a typical production engine tested in a calibrated dynamometer test cell at SAE J1995 standard reference conditions. Caterpillar maintains ISO9001:2000 certified quality management systems for engine test Facilities to assure accurate calibration of test equipment. Engine test data is corrected in accordance with SAE J1995. Additional reference material SAE J1228, J1349, ISO 8665, 3046-1:2002E, 3046-3:1989, 1585, 2534, 2288, and 9249 may apply in part or are similar to SAE J1995. Special engine rating request (SERR) test data shall be noted.

PERFORMANCE PARAMETER TOLERANCE FACTORS:
Power +/- 3%
Torque +/- 3%

Exhaust stack temperature +/- 8%
Inlet airflow +/- 5%
Intake manifold pressure-gage +/- 10%
Exhaust flow +/- 6%
Specific fuel consumption +/- 3%
Fuel rate +/- 5%
Specific DEF consumption +/- 3%
DEF rate +/- 5%
Heat rejection +/- 5%
Heat rejection exhaust only +/- 10%
Heat rejection CEM only +/- 10%

Heat Rejection values based on using treated water.

Torque is included for truck and industrial applications, do not use for Gen Set or steady state applications.

On C7 - C18 engines, at speeds of 1100 RPM and under these values are provided for reference only, and may not meet the tolerance listed.

These values do not apply to C280/3600. For these models, see the tolerances listed below.

C280/3600 HEAT REJECTION TOLERANCE FACTORS:
Heat rejection +/- 10%
Heat rejection to Atmosphere +/- 50%
Heat rejection to Lube Oil +/- 20%
Heat rejection to Aftercooler +/- 5%

TEST CELL TRANSDUCER TOLERANCE FACTORS:

Torque +/- 0.5%
Speed +/- 0.2%
Fuel flow +/- 1.0%
Temperature +/- 2.0 C degrees
Intake manifold pressure +/- 0.1 kPa

OBSERVED ENGINE PERFORMANCE IS CORRECTED TO SAE J1995 REFERENCE AIR AND FUEL CONDITIONS.

REFERENCE ATMOSPHERIC INLET AIR
FOR 3500 ENGINES AND SMALLER
SAE J1228 AUG2002 for marine engines, and J1995 JAN2014 for other engines, reference atmospheric pressure is 100 KPA (29.61 in hg), and standard temperature is 25deg C (77 deg F) at 30% relative humidity at the stated aftercooler water temp, or inlet manifold temp.

FOR 3600 ENGINES
Engine rating obtained and presented in accordance with ISO 3046/1 and SAE J1995 JANJAN2014 reference atmospheric pressure is 100 KPA (29.61 in hg), and standard temperature is 25deg C (77 deg F) at 30% relative humidity and 150M altitude at the stated aftercooler water temperature.

MEASUREMENT LOCATION FOR INLET AIR TEMPERATURE
Location for air temperature measurement air cleaner inlet at stabilized operating conditions.

REFERENCE EXHAUST STACK DIAMETER
The Reference Exhaust Stack Diameter published with this dataset is only used for the calculation of Smoke Opacity values displayed in this dataset. This value does not necessarily represent the actual stack diameter of the engine due to the variety of exhaust stack adapter options available. Consult the price list, engine order or general dimension drawings for the actual stack diameter size ordered or options available.

REFERENCE FUEL
DIESEL
Reference fuel is #2 distillate diesel with a 35API gravity;
A lower heating value is 42,780 KJ/KG (18,390 BTU/LB) when used at 29 (84.2), where the density is 838.9 G/Liter (7.001 Lbs/Gal).

GAS
Reference natural gas fuel has a lower heating value of 33.74 KJ/L (905 BTU/CU Ft). Low BTU ratings are based on 18.64 KJ/L (500 BTU/CU FT) lower heating value gas. Propane ratings are based on 87.56 KJ/L (2350 BTU/CU Ft) lower heating value gas.

ENGINE POWER (NET) IS THE CORRECTED FLYWHEEL POWER (GROSS) LESS EXTERNAL AUXILIARY LOAD
Engine corrected gross output includes the power required to drive standard equipment; lube oil, scavenge lube oil, fuel transfer, common rail fuel, separate circuit aftercooler and jacket water pumps. Engine net power available for the external (flywheel) load is calculated by subtracting the sum of auxiliary load from the corrected gross flywheel out put power. Typical auxiliary loads are radiator cooling fans, hydraulic pumps, air compressors and battery charging alternators. For Tier 4 ratings additional Parasitic losses would also include Intake, and Exhaust Restrictions.

ALTITUDE CAPABILITY
Altitude capability is the maximum altitude above sea level at standard temperature and standard pressure at which the engine could develop full rated output power on the current performance data set.

Standard temperature values versus altitude could be seen on TM2001.

When viewing the altitude capability chart the ambient temperature is the inlet air temp at the compressor inlet.

Engines with ADEM MEUI and HEUI fuel systems operating at conditions above the defined altitude capability derate for atmospheric pressure and temperature conditions outside the values defined, see TM2001.

Mechanical governor controlled unit injector engines require a setting change for operation at conditions above the altitude defined on the engine performance sheet. See your Caterpillar technical representative for non standard ratings.

REGULATIONS AND PRODUCT COMPLIANCE
TMI Emissions information is presented at 'nominal' and 'Potential Site Variation' values for standard ratings. No tolerances are applied to the emissions data. These values are subject to change at any time. The controlling federal and local emission requirements need to be verified by your Caterpillar technical representative.

Customer's may have special emission site requirements that need to be verified by the Caterpillar Product Group engineer.

EMISSIONS DEFINITIONS:
Emissions : DM1176

HEAT REJECTION DEFINITIONS:
Diesel Circuit Type and HHV Balance : DM9500

HIGH DISPLACEMENT (HD) DEFINITIONS:
3500: EM1500

RATING DEFINITIONS:
Agriculture : TM6008

Fire Pump : TM6009

Generator Set : TM6035

Generator (Gas) : TM6041

Industrial Diesel : TM6010

Industrial (Gas) : TM6040

Irrigation : TM5749

Locomotive : TM6037

Marine Auxiliary : TM6036

Marine Prop (Except 3600) : TM5747

Marine Prop (3600 only) : TM5748

MSHA : TM6042

Oil Field (Petroleum) : TM6011

Off-Highway Truck : TM6039

On-Highway Truck : TM6038

SOUND DEFINITIONS:
Sound Power : DM8702

Sound Pressure : TM7080

Date Released : 7/7/15

State of Oregon Department of Environmental Quality

Facility Name: JCEP LNG Terminal Project

Permit Number:

Engine Information

1.	Device ID Number	EU8.BSG (Black Start Generators)
2.	Existing or future?	Future
3.	Date construction commenced	January 2019
4.	Date installed/completed	July 2021
5.	Special controls (if applicable)	Tier 2
6.	Manufacturer	Caterpillar
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	4,376, each
9.	Control device(s) (yes/no)	No
	If yes, enter the identification number(s)	
10.	Description of device:	

Caterpillar C175-16EL 3,000 KW diesel-fired black start engine generators will provide power for turbine startups and essential site functions during power loss.

Operating Schedule

11.	Projected maximum hours/day	
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:	a. Type	b. Hourly usage	c. Annual usage
Primary	ULSD	219 gal/hr	42,840 gal
Back-up			
Other			

Stack Information

14.	Exit height (ft)	18
15.	Exit diameter (ft)	1.67
16.	Design flowrate (dscf/min)	25,620 acfm

Monitoring Information

17. Monitoring equipment			
fuel flow (y/n)		recorder? (y/n)	
engine load (y/n)		recorder? (y/n)	
other (specify)	Hour meter	recorder? (y/n)	Yes

Sound Data (Continued)

MECHANICAL: Sound Power (1/3 Octave Frequencies)

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	OVERALL SOUND	100 HZ	125 HZ	160 HZ	200 HZ	250 HZ	315 HZ	400 HZ	500 HZ	630 HZ	800 HZ
EKW	%	BHP	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)
2,997.5	110	4,376	127.5	110.8	118.5	115.4	117.4	115.5	115.7	116.9	116.3	113.6	113.2
2,725.0	100	3,988	127.1	111.7	118.3	116.2	114.9	116.1	116.0	116.7	115.0	113.2	111.9
2,452.5	90	3,619	127.5	111.8	118.5	116.6	115.0	116.0	115.2	116.2	114.6	113.2	111.8
2,180.0	80	3,256	127.6	110.9	118.6	117.1	116.1	117.2	115.4	116.3	114.7	112.7	111.6
2,043.8	75	3,077	127.3	110.5	118.5	117.2	115.9	116.9	115.1	116.1	114.8	112.6	111.4
1,907.5	70	2,894	127.0	110.2	118.4	117.2	115.8	116.7	114.8	115.8	114.8	112.5	111.2
1,635.0	60	2,531	126.4	109.6	118.1	117.1	115.4	116.2	114.2	114.9	114.8	112.2	110.7
1,362.5	50	2,165	125.8	109.2	117.5	116.7	115.0	115.7	113.7	113.9	114.6	111.9	110.1
1,090.0	40	1,798	125.3	108.3	116.5	116.0	114.6	115.3	113.3	113.9	114.0	111.6	109.7
817.5	30	1,421	124.7	107.3	115.3	115.1	114.2	114.8	112.8	114.0	113.3	111.3	109.4
681.2	25	1,226	124.4	106.8	114.7	114.6	113.9	114.5	112.6	114.0	113.0	111.1	109.3
545.0	20	1,024	124.1	106.3	114.1	114.2	113.7	114.3	112.4	114.0	112.7	110.9	109.2
272.5	10	596	123.5	105.7	113.3	113.6	113.1	113.7	112.1	114.1	112.7	110.4	109.2

MECHANICAL: Sound Power (1/3 Octave Frequencies)

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	1000 HZ	1250 HZ	1600 HZ	2000 HZ	2500 HZ	3150 HZ	4000 HZ	5000 HZ	6300 HZ	8000 HZ	10000 HZ
EKW	%	BHP	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)	dB(A)
2,997.5	110	4,376	111.4	111.7	112.8	110.6	112.3	111.2	110.0	110.4	110.9	113.0	116.1
2,725.0	100	3,988	110.8	111.5	112.6	110.6	111.7	110.1	108.3	109.2	108.9	110.4	115.4
2,452.5	90	3,619	111.1	111.1	111.9	110.3	111.4	109.8	108.3	110.0	108.4	110.0	120.3
2,180.0	80	3,256	111.1	111.0	111.4	110.1	111.2	109.4	108.3	109.9	108.5	110.2	119.7
2,043.8	75	3,077	110.9	111.0	111.3	109.8	111.1	109.2	108.0	109.6	108.2	110.2	118.5
1,907.5	70	2,894	110.7	110.9	111.1	109.6	110.9	109.0	107.8	109.4	107.9	110.1	117.3
1,635.0	60	2,531	110.1	110.8	110.8	109.1	110.6	108.5	107.2	108.7	107.1	109.7	114.8
1,362.5	50	2,165	109.5	110.6	110.3	108.6	110.1	108.1	106.5	107.8	106.1	108.9	112.3
1,090.0	40	1,798	109.4	109.9	109.4	108.1	109.2	107.4	105.4	106.3	104.3	107.0	109.8
817.5	30	1,421	109.4	109.2	108.4	107.6	108.1	106.7	104.3	104.8	102.4	104.8	107.2
681.2	25	1,226	109.4	108.9	108.0	107.4	107.7	106.3	103.7	104.0	101.5	103.8	105.9
545.0	20	1,024	109.4	108.7	107.5	107.1	107.3	105.9	103.3	103.3	100.7	102.8	104.5
272.5	10	596	109.3	108.7	107.0	106.6	106.8	105.3	102.8	102.1	99.5	101.3	101.5

Emissions Data

EMISSIONS VALUES ARE TAILPIPE OUT WITH AFTERTREATMENT. VALUES SHOWN AS ZERO MAY BE GREATER THAN ZERO BUT WERE BELOW THE DETECTION LEVEL OF THE EQUIPMENT USED AT TIME OF MEASUREMENT.

CATERPILLAR EMISSIONS CERTIFIED ENGINES TESTED WITHIN EPA SPECIFIED TEST CONDITIONS, AND USING TITLE 40 CFR PART 1065 TEST PROTOCOL, MEET THE NEW SOURCE PERFORMANCE STANDARDS. POTENTIAL SITE VARIATION DATA ACCOUNT FOR PRODUCTION ENGINE AND SYSTEM VARIABILITY IN ADDITION TO MEASUREMENT VARIABILITY FOR TYPICAL FIELD TEST METHODS AS DESCRIBED IN DM1176. THIS DATA ASSUMES SITE CORRECTIONS FOR AMBIENT HUMIDITY TO 75 GRAINS, AND STANDARD CONDITIONS OF 25 C (77 F) AIR TO TURBO TEMPERATURE AND 152.4 M (500 FT) ALTITUDE. GUIDANCE ON HUMIDITY CORRECTION METHODS ARE AVAILABLE IN TITLE 40 CFR SECTION 1065.670. FOR APPLICATIONS WITH GEOGRAPHIC OR AMBIENT CONDITIONS BEYOND THESE PUBLISHED VALUES, CONSULT CATERPILLAR (APPLICATION SUPPORT CENTER) FOR ADDITIONAL VARIABILITY INFORMATION.

RATED SPEED POTENTIAL SITE VARIATION: 1800 RPM

GENSET POWER WITH FAN		EKW	2,997.5	2,725.0	2,043.8	1,362.5	681.2
PERCENT LOAD		%	110	100	75	50	25
ENGINE POWER		BHP	4,376	3,988	3,077	2,165	1,226
TOTAL NOX (AS NO2)		G/HR	3,372	2,971	1,701	953	615
TOTAL CO		G/HR	470	439	262	224	161
TOTAL HC		G/HR	206	192	171	145	104
PART MATTER		G/HR	104.8	77.9	88.6	103.8	92.9
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	342.8	335.0	236.5	167.6	172.1
TOTAL CO	(CORR 5% O2)	MG/NM3	50.9	52.8	38.4	41.7	47.0
TOTAL HC	(CORR 5% O2)	MG/NM3	19.3	20.0	21.7	23.4	26.3
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	167	163	115	82	84
TOTAL CO	(CORR 5% O2)	PPM	41	42	31	33	38
TOTAL HC	(CORR 5% O2)	PPM	36	37	40	44	49
TOTAL NOX (AS NO2)		G/HP-HR	0.78	0.75	0.56	0.44	0.50
TOTAL CO		G/HP-HR	0.11	0.11	0.09	0.10	0.13
TOTAL HC		G/HP-HR	0.05	0.05	0.06	0.07	0.09

PART MATTER		G/HP-HR	0.02	0.02	0.03	0.05	0.08
TOTAL NOX (AS NO2)		LB/HR	7.43	6.55	3.75	2.10	1.36
TOTAL CO		LB/HR	1.04	0.97	0.58	0.49	0.36
TOTAL HC		LB/HR	0.45	0.42	0.38	0.32	0.23
PART MATTER		LB/HR	0.23	0.17	0.20	0.23	0.20

RATED SPEED NOMINAL DATA: 1800 RPM

GENSET POWER WITH FAN		EKW	2,997.5	2,725.0	2,043.8	1,362.5	681.2
PERCENT LOAD		**%**	**110**	**100**	**75**	**50**	**25**
ENGINE POWER		**BHP**	**4,376**	**3,988**	**3,077**	**2,165**	**1,226**
TOTAL NOX (AS NO2)		G/HR	2,294	2,021	1,157	648	418
TOTAL CO		G/HR	49	46	28	24	17
TOTAL HC		G/HR	9	8	7	6	5
TOTAL CO2		KG/HR	2,043	1,843	1,494	1,155	733
PART MATTER		G/HR	38.7	28.7	32.7	38.3	34.3
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	233.2	227.9	160.9	114.0	117.0
TOTAL CO	(CORR 5% O2)	MG/NM3	5.3	5.6	4.0	4.4	4.9
TOTAL HC	(CORR 5% O2)	MG/NM3	0.8	0.9	0.9	1.0	1.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	114	111	78	56	57
TOTAL CO	(CORR 5% O2)	PPM	4	4	3	4	4
TOTAL HC	(CORR 5% O2)	PPM	2	2	2	2	2
FORMALDEHYDE	(CORR 15% O2)	PPM	0.01	0.01	0.01	0.01	0.01
ACROLEIN	(CORR 15% O2)	PPM	0.00	0.00	0.00	0.00	0.00
ACETALDEHYDE	(CORR 15% O2)	PPM	0.00	0.00	0.00	0.00	0.00
METHANOL	(CORR 15% O2)	PPM	0.00	0.00	0.00	0.00	0.00
TOTAL NOX (AS NO2)		G/HP-HR	0.53	0.51	0.38	0.30	0.34
TOTAL CO		G/HP-HR	0.01	0.01	0.01	0.01	0.01
TOTAL HC		G/HP-HR	0.00	0.00	0.00	0.00	0.00
PART MATTER		G/HP-HR	0.01	0.01	0.01	0.02	0.03
TOTAL NOX (AS NO2)		LB/HR	5.06	4.46	2.55	1.43	0.92
TOTAL CO		LB/HR	0.11	0.10	0.06	0.05	0.04
TOTAL HC		LB/HR	0.02	0.02	0.02	0.01	0.01
TOTAL CO2		LB/HR	4,505	4,064	3,295	2,546	1,615
PART MATTER		LB/HR	0.09	0.06	0.07	0.08	0.08
OXYGEN IN EXH		%	9.8	10.2	11.1	11.9	12.9
DRY SMOKE OPACITY		%	0.2	0.2	0.3	0.4	0.5
BOSCH SMOKE NUMBER			0.09	0.10	0.13	0.17	0.20

State of Oregon Department of Environmental Quality

Facility Name:	JCEP LNG Terminal Project	Permit Number:	

Engine Information

1.	Device ID Number	EU9.EG (Backup Gen Engines)
2.	Existing or future?	Future
3.	Date construction commenced	January 2019
4.	Date installed/completed	October 2021
5.	Special controls (if applicable)	Tier 2
6.	Manufacturer	Caterpillar
7.	Date manufactured	
8.	Maximum rating (MMbtu/hr for turbines, Hp for others)	1,214, each
9.	Control device(s) (yes/no)	No
	If yes, enter the identification number(s)	
10.	Description of device:	

Two Caterpillar C27 SR5 800 eKW diesel-fired emergency backup engine generators.

Operating Schedule

11.	Projected maximum hours/day	2
12.	Projected maximum hours/year	200

Fuel Information

13. Fuel usage:	a. Type	b. Hourly usage	c. Annual usage
Primary	ULSD	57.3 gal/hr	11,460 gal
Back-up			
Other			

Stack Information

14.	Exit height (ft)	13
15.	Exit diameter (ft)	0.67
16.	Design flowrate (dscf/min)	6011.7 acfm

Monitoring Information

17. Monitoring equipment			
fuel flow (y/n)		recorder? (y/n)	
engine load (y/n)		recorder? (y/n)	
other (specify)	Hour meter	recorder? (y/n)	Yes

JORDAN COVE LNG
EQUIPMENT SUBMITTAL FOR APPROVAL

PREPARED FOR
BLACK & VEATCH

TWO (2) CATERPILLAR MODEL C27, FEDERAL EPA TIER II RATED 800KW/1000KVA, 480/277VAC, THREE PHASE, FOUR WIRE, 60 HZ, .8PF STANDBY DIESEL ENGINE GENERATOR SET AND THREE (3) ATS

PROVIDED BY
PETERSON POWER SYSTEMS, INC.
PROJECT NUMBER 160383
JULY 12, 2016

Since 1936
4421 NE Columbia Blvd. Portland, OR 97218 Telephone (503) 288-6411 www.petersonpower.com
Project Manager: Scott Posey 503.718.8650 Fax 503.280.1552 SMPosey@PetersonPower.com

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
2015 MODEL YEAR
CERTIFICATE OF CONFORMITY
WITH THE CLEAN AIR ACT OF 1990

OFFICE OF TRANSPORTATION
AND AIR QUALITY
ANN ARBOR, MICHIGAN 48105

Certificate Issued To: **Caterpillar Inc.**
(U.S. Manufacturer or Importer)

Certificate Number: FCPXL27.0NZS-005

Effective Date:
07/01/2014

Expiration Date:
12/31/2015

Byron J. Bunker, Division Director
Compliance Division

Issue Date:
07/01/2014

Revision Date:
N/A

Model Year: 2015
Manufacturer Type: Original Engine Manufacturer
Engine Family: FCPXL27.0NZS

Mobile/Stationary Indicator: Stationary
Emissions Power Category: 560<kW<=2237
Fuel Type: Diesel
After Treatment Devices: No After Treatment Devices Installed
Non-after Treatment Devices: Electronic Control, Engine Design Modification

Pursuant to Section 111 and Section 213 of the Clean Air Act (42 U.S.C. sections 7411 and 7547) and 40 CFR Part 60, and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following engines, by engine family, more fully described in the documentation required by 40 CFR Part 60 and produced in the stated model year.

This certificate of conformity covers only those new compression-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 60 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 60.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR 1068 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to revocation or suspension of this certificate for reasons specified in 40 CFR Part 60. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void *ab initio* for other reasons specified in 40 CFR Part 60.

This certificate does not cover engines sold, offered for sale, or introduced, or delivered for introduction, into commerce in the U.S. prior to the effective date of the certificate.

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

Specifications

Generator Set Specifications	
Minimum Rating	680 ekW
Maximum Rating	800 ekW
Voltage	208 to 600
Frequency	60 Hz
Speed	1800 RPM

Generator Set Configurations	
Emissions/Fuel Strategy	Low Fuel Consumption, U.S. EPA Certified for Stationary Emergency Use Only (Tier 2 Nonroad Equivalent Emission Standards)

Engine Specifications		
Engine Model	C27 ATAAC, V-12, 4-Stroke, Water-Cooled Diesel	
Compression Ratio	16.5:1	
Aspiration	TA	
Governor Type	Adem™A4	
Fuel System	MEUI	
Bore	137.2 mm	5.4 in
Displacement	27.03 L	1649.47 in^3
Stroke	152.4 mm	6 in

Benefits And Features

Cat Diesel Engine

- Reliable, rugged, durable design
- Field-proven in thousands of applications worldwide
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight

Generator

- Matched to the performance and output characteristics of Cat engines
- Industry leading mechanical and electrical design
- Industry leading motor starting capabilities
- High Efficiency

Cat EMCP Control Panel

The EMCP controller features the reliability and durability you have come to expect from your Cat equipment. EMCP4 is a scalable control platform designed to ensure reliable generator set operation, providing extensive information about power output and engine operation. EMCP4 systems can be further customized to meet your needs through programming and expansion modules.

Seismic Certification

- Seismic Certification available.
- Anchoring details are site specific, and are dependent on many factors such as generator set size, weight, and concrete strength.
- IBC Certification requires that the anchoring system used is reviewed and approved by a Professional Engineer
- Seismic Certification per Applicable Building Codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007, CBC 2010
- Pre-approved by OSHPD and carries an OSP-0321-10 for use in healthcare projects in California

Design Criteria

The generator set accepts 100% rated load in one step per NFPA 110 and meets ISO 8528-5 transient response.

UL 2200 / CSA - Optional

- UL 2200 listed packages
- CSA Certified
- Certain restrictions may apply.
- Consult with your Cat® Dealer.

Single-Source Supplier

Fully prototype tested with certified torsional vibration analysis available

World Wide Product Support

Cat Dealers provide extensive post sale support including maintenance and repair agreements. Cat dealers have over 1,800 dealer branch stores operating in 200 countries. The Cat® SOSSM program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products.

Standard Equipment

Air Inlet

- Air Cleaner

Cooling

- Package mounted radiator

Exhaust

- Exhaust flange outlet

Fuel

- Primary fuel filter with integral water separator
- Secondary fuel filter
- Fuel priming pump

Generator

- Matched to the performance and output characteristics of Cat engines
- Load adjustment module provides engine relief upon load impact and improves load acceptance and recovery time
- IP23 Protection

Power Termination

- Bus Bar

Control Panel

- EMCP 4 Genset Controller

General

- Paint - Caterpillar Yellow except rails and radiators gloss black

Optional Equipment

Exhaust

- Exhaust mufflers

Generator

- Anti-condensation heater
- Excitation: [ ] Permanent Magnet Excited (PM) [ ] Internally Excited (IE)
- Oversize and premium generators

Power Termination

- Circuit breakers, UL listed
- Circuit breakers, IEC compliant

Control Panels

- EMCP (4.2) (4.3) (4.4)
- Generator temperature monitoring & protection
- Load share module
- Digital I/O module
- Remote monitoring software

Mounting

- Rubber anti-vibration mounts
- Spring-type vibration isolator
- IBC isolators

Starting/Charging

- Battery chargers
- Oversize batteries
- Jacket water heater
- Heavy-duty starting system
- Charging alternator
- Air starting motor with control and silencer

General

- The following options are based on regional and product configuration:
- Seismic Certification per applicable building codes: IBC 2000, IBC 2003, IBC 2006, IBC 2009, CBC 2007
- UL 2200 package
- EU Certificate of Conformance (CE)
- CSA Certification
- EEC Declaration of Conformity
- Enclosures: sound attenuated, weather protective
- Automatic transfer switches (ATS)
- Integral & sub-base fuel tanks
- Integral & sub-base UL listed dual wall fuel tanks

ELECTRIC POWER - Technical Spec Sheet
STANDARD

C27 ACERT
800 ekW/ 1000 kVA/ 60 Hz/ 1800 rpm/ 480 V/ 0.8 Power Factor

Rating Type: STANDBY

Emissions: U.S. EPA Certified for Stationary Emergency Use Only (Tier 2 Nonroad Equivalent Emission Standards)

Image shown may not reflect actual configuration

C27 ACERT

800 ekW/ 1000 kVA
60 Hz/ 1800 rpm/ 480 V

	Metric	English
Package Performance		
Genset Power Rating with Fan @ 0.8 Power Factor	800 ekW	
Genset Power Rating	1000 kVA	
Aftercooler (Separate Circuit)	N/A	N/A
Fuel Consumption		
100% Load with Fan	216.9 L/hr	57.3 gal/hr
75% Load with Fan	171.7 L/hr	45.4 gal/hr
50% Load with Fan	122.3 L/hr	32.3 gal/hr
25% Load with Fan	73.9 L/hr	19.5 gal/hr
Cooling System[1]		
Engine Coolant Capacity	55.0 L	14.5 gal
Inlet Air		
Combustion Air Inlet Flow Rate	62.8 m³/min	2216.4 cfm
Max. Allowable Combustion Air Inlet Temp	49 ° C	121 ° F
Exhaust System		
Exhaust Stack Gas Temperature	511.4 ° C	952.5 ° F
Exhaust Gas Flow Rate	170.3 m³/min	6011.7 cfm
Exhaust System Backpressure (Maximum Allowable)	6.7 kPa	27.0 in. water

Rating Type: STANDBY

Emissions: U.S. EPA Certified for Stationary Emergency Use Only (Tier 2 Nonroad Equivalent Emission Standards)

Heat Rejection		
Heat Rejection to Jacket Water	330 kW	18785 Btu/min
Heat Rejection to Exhaust (Total)	796 kW	45257 Btu/min
Heat Rejection to Aftercooler	162 kW	9235 Btu/min
Heat Rejection to Atmosphere from Engine	110 kW	6240 Btu/min
Heat Rejection to Atmosphere from Generator	40 kW	2292 Btu/min

Alternator[2] See Generator Data

Emissions (Nominal)[3]		
NOx	2580.0 mg/Nm³	5.2 g/hp-hr
CO	115.1 mg/Nm³	0.2 g/hp-hr
HC	12.5 mg/Nm³	0.0 g/hp-hr
PM	9.7 mg/Nm³	0.0 g/hp-hr

DEFINITIONS AND CONDITIONS

1. For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.

2. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40° C ambient per NEMA MG1-32.

3. Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77° F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

C27 ACERT
800 ekW/ 1000 kVA/ 60 Hz/ 1800 rpm/ 480 V/ 0.8 Power Factor

Rating Type: STANDBY

Emissions: U.S. EPA Certified for Stationary Emergency Use Only (Tier 2 Nonroad Equivalent Emission Standards)

Applicable Codes and Standards:
AS1359, CSA C22.2 No100-04, UL142,UL489, UL869, UL2200,
NFPA37, NFPA70, NFPA99, NFPA110, IBC, IEC60034-1, ISO3046, ISO8528,
NEMA MG1-22,NEMA MG1-33, 2006/95/EC, 2006/42/EC, 2004/108/EC.

Note: Codes may not be available in all model configurations. Please consult your local Cat Dealer representative for availability.

STANDBY: Output available with varying load for the duration of the interruption of the normal source power. Average power output is 70% of the standby power rating. Typical operation is 200 hours per year, with maximum expected usage of 500 hours per year.

Ratings are based on SAE J1349 standard conditions. These ratings also apply at ISO3046 standard conditions

Fuel Rates are based on fuel oil of 35º API [16º C (60º F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29º C (85º F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements, contact your Cat representative for details. For information regarding Low Sulfur fuel and Biodiesel capability, please consult your Cat dealer.

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Performance No.: DM7696-02

Feature Code: C27DR70

Generator Arrangement: 3850624

Date: 07/04/2016

Source Country: U.S.

Systems Data

Reference Number: DM7696

CATERPILLAR

July 11, 2016
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AIR INTAKE SYSTEM		
THE INSTALLED SYSTEM MUST COMPLY WITH THE SYSTEM LIMITS BELOW FOR ALL EMISSIONS CERTIFIED ENGINES TO ASSURE REGULATORY COMPLIANCE.		
MAXIMUM ALLOWABLE INTAKE RESTRICTION WITH CLEAN ELEMENT	15	IN-H20
MAXIMUM ALLOWABLE INTAKE RESTRICTION WITH DIRTY ELEMENT	25	IN-H20
MAXIMUM PRESSURE DROP FROM COMPRESSOR OUTLET TO MANIFOLD INLET (OR MIXER INLET FOR EGR)	4.4	IN-HG
MAXIMUM TURBO INLET AIR TEMPERATURE	122	DEG F
MAXIMUM AIR FILTER INLET AIR TEMPERATURE	122	DEG F
CHARGE AIR FLOW AT RATED SPEED	166.7	LB/MIN
TURBO COMPRESSOR OUTLET PRESSURE AT RATED SPEED (ABSOLUTE)	90.6	IN-HG
COOLING SYSTEM		
ENGINE ONLY COOLANT CAPACITY	14.5	GAL
MAXIMUM ALLOWABLE JACKET WATER OUTLET TEMPERATURE	210	DEG F
REGULATOR LOCATION FOR JW (HT) CIRCUIT	OUTLET	
MAXIMUM UNINTERRUPTED FILL RATE	5.0	G/MIN
MINIMUM ALLOWABLE COOLANT LOSS (PERCENTAGE OF TOTAL)	12	PERCENT
COOLANT LOSS-MAXIMUM PERCENTAGE OF PUMP PRESSURE RISE LOSS	15	PERCENT
ENGINE SPEC SYSTEM		
CYLINDER ARRANGEMENT	VEE	
NUMBER OF CYLINDERS	12	
CYLINDER BORE DIAMETER	5.4	IN
PISTON STROKE	6.0	IN
TOTAL CYLINDER DISPLACEMENT	1649	CU IN
STANDARD CRANKSHAFT ROTATION FROM FLYWHEEL END	CCW	
STANDARD CYLINDER FIRING ORDER	1-10-9-6-5-12-11-4-3-8-7-2	
NUMBER 1 CYLINDER LOCATION	LEFT FRONT	
STROKES/COMBUSTION CYCLE	4	
EXHAUST SYSTEM		
THE INSTALLED SYSTEM MUST COMPLY WITH THE SYSTEM LIMITS BELOW FOR ALL EMISSIONS CERTIFIED ENGINES TO ASSURE REGULATORY COMPLIANCE.		
MAXIMUM ALLOWABLE SYSTEM BACK PRESSURE	27	IN-H20
MANIFOLD TYPE	DRY	
MAXIMUM ALLOWABLE STATIC WEIGHT ON EXHAUST CONNECTION	110.2	LB
MAXIMUM ALLOWABLE STATIC BENDING MOMENT ON EXHAUST CONNECTION	0	LB-FT

FUEL SYSTEM		
MAXIMUM FUEL FLOW FROM TRANSFER PUMP TO ENGINE	227.2	G/HR
MAXIMUM ALLOWABLE FUEL SUPPLY LINE RESTRICTION	8.9	IN-HG
MAXIMUM ALLOWABLE FUEL TEMPERATURE AT TRANSFER PUMP INLET	149	DEG F
MAXIMUM FUEL FLOW TO RETURN LINE FROM ENGINE	198.1	G/HR
MAXIMUM ALLOWABLE FUEL RETURN LINE RESTRICTION	10.2	IN-HG
NORMAL FUEL PRESSURE IN A CLEAN SYSTEM	90.9	PSI
FUEL SYSTEM TYPE	DI	
MAXIMUM TRANSFER PUMP PRIMING LIFT WITHOUT PRIMING PUMP	12.1	FT
LUBE SYSTEM		
CRANKCASE VENTILATION TYPE	TO ATM	
MOUNTING SYSTEM		
CENTER OF GRAVITY LOCATION - X DIMENSION - FROM REAR FACE OF BLOCK - (REFERENCE TM7077)	23.0	IN
CENTER OF GRAVITY LOCATION - Y DIMENSION - FROM CENTERLINE OF CRANKSHAFT - (REFERENCE TM7077)	11.5	IN
CENTER OF GRAVITY LOCATION - Z DIMENSION - FROM CENTERLINE OF CRANKSHAFT - (REFERENCE TM7077)	0.0	IN
DRY WEIGHT - ENGINE ONLY (REFERENCE VALUE)	6462	LB
STARTING SYSTEM		
MINIMUM CRANKING SPEED REQUIRED FOR START-RPM	100	
LOWEST AMBIENT START TEMPERATURE WITHOUT AIDS	32	DEG F

PACKAGE DATA [DM7696]

JULY 11, 2016

For Help Desk Phone Numbers Click here

Feature Code:	C27DR70	**Rating Type:**	STANDBY	**Sales model Package:**	C27 SR5
Engine Sales Model:	C27 T2/ESE	**Engine Arrangement Number:**	3495619	**Hertz:**	60
EKW W/F:	800.0	**Noise Reduction:**	0 dBA	**Back Pressure:**	0.0 inH2O

Engine Package Information

Engine Package Data

Package Cooling Information

SA Level 2 Canopy Cooling Data

% Load	Airflow Rate scfm	Ambient Capability Sea Level (Deg F)	Ambient Capability 300 m (Deg F)	Ambient Capability 600 m (Deg F)	Ambient Capability 900 m (Deg F)
100.0	N/A	N/A	111	107	105

Package Sound Information

Sound Comments :

Open Sound Data

Distance: 3.3 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	108.0	98.3	107.1	102.5	102.5	104.0	100.8	96.5	97.3
600.0	75.0	107.6	97.2	106.9	101.9	102.4	104.0	100.5	95.3	92.8
400.0	50.0	107.3	96.5	106.6	101.6	102.2	104.0	100.3	94.4	89.9
200.0	25.0	107.2	96.2	106.1	101.7	102.2	104.0	100.2	94.1	88.3

Distance: 23.0 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	98.0	88.3	97.1	92.5	92.6	94.0	90.8	86.5	87.3
600.0	75.0	97.6	87.2	96.9	91.9	92.4	94.0	90.5	85.3	82.8
400.0	50.0	97.3	86.5	96.6	91.6	92.2	94.0	90.3	84.4	79.8
200.0	25.0	97.2	86.2	96.1	91.7	92.2	94.0	90.2	84.1	78.3

Distance: 49.2 Feet

EKW	%	OVERALL	OBCF	OBCF	OBCF	OBCF	OBCF	OBCF	OBCF	OBCF

W/F	LOAD	SOUND DB(A)	63HZ DB	125HZ DB	250HZ DB	500HZ DB	1000HZ DB	2000HZ DB	4000HZ DB	8000HZ DB
800.0	100.0	92.0	82.3	91.1	86.5	86.6	88.0	84.8	80.5	81.3
600.0	75.0	91.6	81.2	90.9	85.9	86.4	88.0	84.5	79.3	76.8
400.0	50.0	91.3	80.5	90.6	85.6	86.2	88.0	84.3	78.4	73.8
200.0	25.0	91.2	80.2	90.1	85.7	86.2	88.0	84.2	78.1	72.3

SA Level 2 Canopy Sound Data

Distance: 3.3 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	88.6	89.7	94.3	91.1	87.5	81.4	75.8	70.1	67.8
600.0	75.0	87.5	87.4	73.3	89.6	87.2	79.6	74.2	67.9	64.4
400.0	50.0	88.2	86.0	93.8	88.1	88.2	81.2	75.9	69.6	65.9
200.0	25.0	87.2	85.0	94.5	87.0	86.5	80.6	75.2	67.9	63.9

Distance: 23.0 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	75.0	84.3	81.6	78.0	73.2	67.2	62.4	56.5	56.5
600.0	75.0	74.8	82.8	81.7	76.8	74.1	66.5	61.6	55.5	52.8
400.0	50.0	75.1	81.2	83.6	77.1	73.6	67.7	62.1	56.8	52.0
200.0	25.0	74.7	79.0	83.8	77.1	72.4	67.3	62.2	55.8	50.6

Distance: 49.2 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	73.7	75.3	82.9	76.4	72.7	63.6	59.4	53.4	52.7
600.0	75.0	73.6	74.4	81.7	74.9	73.7	63.2	58.7	52.9	49.5
400.0	50.0	73.1	73.5	82.0	74.4	72.7	64.0	59.3	53.7	49.0
200.0	25.0	72.8	72.4	82.4	75.0	71.5	63.6	59.2	52.9	48.0

Open Exhaust Sound Data

Distance: 3.3 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	110.0	73.8	100.1	109.7	105.9	104.7	104.3	95.0	75.8

Open Mechanical Sound Data

Distance: 3.3 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	101.6	88.7	95.2	94.6	95.6	96.9	94.7	91.8	90.4

Distance: 23.0 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	91.4	80.2	86.8	85.6	85.7	87.0	84.7	80.5	78.5

Distance: 49.2 Feet

EKW W/F	% LOAD	OVERALL SOUND DB(A)	OBCF 63HZ DB	OBCF 125HZ DB	OBCF 250HZ DB	OBCF 500HZ DB	OBCF 1000HZ DB	OBCF 2000HZ DB	OBCF 4000HZ DB	OBCF 8000HZ DB
800.0	100.0	85.0	76.6	81.6	80.7	79.1	81.1	77.7	73.9	68.5

PERFORMANCE DATA[DM7696]

Performance Number: DM7696 **Change Level: 02**

SALES MODEL:	C27
ENGINE POWER (BHP):	1,214
GEN POWER WITH FAN (EKW):	800.0
COMPRESSION RATIO:	16.5
RATING LEVEL:	STANDBY
PUMP QUANTITY:	1
FUEL TYPE:	DIESEL
MANIFOLD TYPE:	DRY
GOVERNOR TYPE:	ADEM4
ELECTRONICS TYPE:	ADEM4
IGNITION TYPE:	CI
INJECTOR TYPE:	EUI
REF EXH STACK DIAMETER (IN):	10
MAX OPERATING ALTITUDE (FT):	7,999
COMBUSTION:	DI
ENGINE SPEED (RPM):	1,800
HERTZ:	60
FAN POWER (HP):	39.3
ADDITIONAL PARASITICS (HP):	52.2
ASPIRATION:	TA
AFTERCOOLER TYPE:	ATAAC
AFTERCOOLER CIRCUIT TYPE:	JW+OC, ATAAC
INLET MANIFOLD AIR TEMP (F):	120
JACKET WATER TEMP (F):	210.2
TURBO CONFIGURATION:	PARALLEL
TURBO QUANTITY:	2
TURBOCHARGER MODEL:	GTA5008BS-56T-1.60
CERTIFICATION YEAR:	2010
PISTON SPD @ RATED ENG SPD (FT/MIN):	1,800.0

INDUSTRY	SUBINDUSTRY	APPLICATION
ELECTRIC POWER	STANDARD	PACKAGED GENSET
OIL AND GAS	LAND PRODUCTION	PACKAGED GENSET

General Performance Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	BRAKE MEAN EFF PRES (BMEP)	BRAKE SPEC FUEL CONSUMPTN (BSFC)	VOL FUEL CONSUMPTN (VFC)	INLET MFLD PRES	INLET MFLD TEMP	EXH MFLD TEMP	EXH MFLD PRES	ENGINE OUTLET TEMP
EKW	%	BHP	PSI	LB/BHP-HR	GAL/HR	IN-HG	DEG F	DEG F	IN-HG	DEG F
800.0	100	1,214	324	0.330	57.3	58.6	120.5	1,230.6	41.1	952.5
720.0	90	1,100	294	0.334	52.5	53.7	115.2	1,195.3	37.5	932.4
640.0	80	988	264	0.339	47.8	48.4	113.4	1,168.6	33.4	919.7
600.0	75	932	249	0.341	45.4	45.5	113.0	1,155.3	31.2	913.8
560.0	70	876	234	0.342	42.9	42.2	111.6	1,138.9	28.8	906.0
480.0	60	765	204	0.344	37.6	34.9	107.3	1,095.6	23.9	882.8
400.0	50	654	175	0.346	32.3	27.3	102.5	1,039.6	19.1	850.4
320.0	40	545	145	0.349	27.1	20.4	98.3	967.7	14.9	804.3
240.0	30	436	116	0.355	22.1	14.5	95.0	875.5	11.4	739.0
200.0	25	380	101	0.359	19.5	11.7	93.6	822.1	9.9	699.4
160.0	20	324	86	0.366	17.0	9.1	92.4	763.2	8.5	654.7
80.0	10	210	56	0.402	12.0	5.1	92.2	626.6	6.3	544.7

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	COMPRESSOR OUTLET PRES	COMPRESSOR OUTLET TEMP	WET INLET AIR VOL FLOW RATE	ENGINE OUTLET WET EXH GAS VOL FLOW RATE	WET INLET AIR MASS FLOW RATE	WET EXH GAS MASS FLOW RATE	WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)	DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)
EKW	%	BHP	IN-HG	DEG F	CFM	CFM	LB/HR	LB/HR	FT3/MIN	FT3/MIN
800.0	100	1,214	61	362.1	2,216.4	6,011.7	9,543.1	9,944.2	2,093.1	1,894.9
720.0	90	1,100	57	341.6	2,124.9	5,659.3	9,125.9	9,493.8	1,998.8	1,815.5
640.0	80	988	51	320.7	2,001.3	5,260.8	8,572.1	8,906.9	1,875.2	1,707.1
600.0	75	932	48	309.9	1,930.4	5,042.0	8,257.4	8,575.1	1,805.0	1,645.1
560.0	70	876	44	295.4	1,851.1	4,797.3	7,907.3	8,207.3	1,727.2	1,576.0
480.0	60	765	37	264.1	1,678.1	4,260.9	7,148.0	7,411.6	1,560.5	1,427.2
400.0	50	654	29	233.3	1,497.7	3,697.0	6,361.6	6,588.0	1,387.5	1,272.0
320.0	40	545	22	203.3	1,329.0	3,157.0	5,630.4	5,820.5	1,228.0	1,129.6
240.0	30	436	16	173.6	1,175.4	2,643.8	4,970.3	5,124.7	1,084.4	1,003.3
200.0	25	380	13	158.7	1,102.8	2,392.1	4,660.7	4,797.2	1,014.7	942.2
160.0	20	324	10	143.8	1,032.8	2,142.5	4,363.5	4,482.1	945.3	881.3
80.0	10	210	6	121.2	926.9	1,716.6	3,911.4	3,995.6	840.3	792.1

Heat Rejection Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	REJECTION TO JACKET WATER	REJECTION TO ATMOSPHERE	REJECTION TO EXH	EXHUAST RECOVERY TO 350F	FROM OIL COOLER	FROM AFTERCOOLER	WORK ENERGY	LOW HEAT VALUE ENERGY	HIGH HEAT VALUE ENERGY
EKW	%	BHP	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN
800.0	100	1,214	18,785	6,240	45,257	25,637	6,549	9,235	51,468	122,961	130,984
720.0	90	1,100	18,137	5,061	42,000	23,586	6,007	8,276	46,664	112,779	120,138
640.0	80	988	17,141	4,437	38,642	21,600	5,462	7,119	41,902	102,550	109,241
600.0	75	932	16,243	4,573	36,868	20,559	5,186	6,513	39,533	97,376	103,729
560.0	70	876	15,133	4,950	34,899	19,383	4,898	5,822	37,162	91,965	97,965
480.0	60	765	13,933	4,599	30,563	16,728	4,301	4,488	32,445	80,759	86,028
400.0	50	654	12,297	4,489	26,024	13,914	3,694	3,331	27,748	69,364	73,890
320.0	40	545	10,665	4,336	21,575	11,109	3,103	2,367	23,120	58,261	62,063
240.0	30	436	9,960	3,213	17,222	8,311	2,521	1,564	18,469	47,340	50,429
200.0	25	380	9,576	2,592	15,113	6,955	2,231	1,215	16,122	41,885	44,618
160.0	20	324	9,057	2,021	13,057	5,639	1,939	898	13,745	36,402	38,778
80.0	10	210	7,177	1,693	9,288	3,167	1,375	455	8,885	25,814	27,498

Emissions Data

RATED SPEED POTENTIAL SITE VARIATION: 1800 RPM

GENSET POWER WITH FAN		EKW	800.0	600.0	400.0	200.0	80.0
PERCENT LOAD		%	100	75	50	25	10
ENGINE POWER		BHP	1,214	932	654	380	210
TOTAL NOX (AS NO2)		G/HR	7,541	4,507	2,865	1,989	1,253
TOTAL CO		G/HR	517	644	630	514	567
TOTAL HC		G/HR	66	83	90	71	85
PART MATTER		G/HR	55.4	52.1	86.3	99.7	101.9
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	3,121.8	2,374.5	2,149.1	2,626.2	2,606.8
TOTAL CO	(CORR 5% O2)	MG/NM3	215.2	343.4	483.1	717.2	1,372.2
TOTAL HC	(CORR 5% O2)	MG/NM3	23.7	38.9	59.2	87.9	183.2
PART MATTER	(CORR 5% O2)	MG/NM3	18.9	22.9	55.1	113.5	210.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,521	1,157	1,047	1,279	1,270
TOTAL CO	(CORR 5% O2)	PPM	172	275	386	574	1,098
TOTAL HC	(CORR 5% O2)	PPM	44	73	111	164	342
TOTAL NOX (AS NO2)		G/HP-HR	6.27	4.86	4.40	5.25	6.00
TOTAL CO		G/HP-HR	0.43	0.69	0.97	1.36	2.72
TOTAL HC		G/HP-HR	0.05	0.09	0.14	0.19	0.41
PART MATTER		G/HP-HR	0.05	0.06	0.13	0.26	0.49
TOTAL NOX (AS NO2)		LB/HR	16.63	9.94	6.32	4.38	2.76
TOTAL CO		LB/HR	1.14	1.42	1.39	1.13	1.25
TOTAL HC		LB/HR	0.15	0.18	0.20	0.16	0.19
PART MATTER		LB/HR	0.12	0.11	0.19	0.22	0.22

RATED SPEED NOMINAL DATA: 1800 RPM

GENSET POWER WITH FAN		EKW	800.0	600.0	400.0	200.0	80.0
PERCENT LOAD		%	100	75	50	25	10
ENGINE POWER		BHP	1,214	932	654	380	210
TOTAL NOX (AS NO2)		G/HR	6,233	3,725	2,368	1,644	1,036
TOTAL CO		G/HR	276	344	337	275	303
TOTAL HC		G/HR	35	44	48	37	45
TOTAL CO2		KG/HR	563	445	315	188	116
PART MATTER		G/HR	28.4	26.7	44.2	51.1	52.3
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	2,580.0	1,962.4	1,776.1	2,170.4	2,154.4
TOTAL CO	(CORR 5% O2)	MG/NM3	115.1	183.6	258.3	383.5	733.8
TOTAL HC	(CORR 5% O2)	MG/NM3	12.5	20.6	31.3	46.5	96.9
PART MATTER	(CORR 5% O2)	MG/NM3	9.7	11.8	28.3	58.2	107.7
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,257	956	865	1,057	1,049
TOTAL CO	(CORR 5% O2)	PPM	92	147	207	307	587
TOTAL HC	(CORR 5% O2)	PPM	23	38	58	87	181
TOTAL NOX (AS NO2)		G/HP-HR	5.18	4.02	3.63	4.34	4.96
TOTAL CO		G/HP-HR	0.23	0.37	0.52	0.72	1.45
TOTAL HC		G/HP-HR	0.03	0.05	0.07	0.10	0.22

PERFORMANCE DATA[DM7696]

PART MATTER	G/HP-HR	0.02	0.03	0.07	0.13	0.25
TOTAL NOX (AS NO2)	LB/HR	13.74	8.21	5.22	3.62	2.28
TOTAL CO	LB/HR	0.61	0.76	0.74	0.61	0.67
TOTAL HC	LB/HR	0.08	0.10	0.11	0.08	0.10
TOTAL CO2	LB/HR	1,240	982	694	414	255
PART MATTER	LB/HR	0.06	0.06	0.10	0.11	0.12
OXYGEN IN EXH	%	8.9	10.0	11.1	13.1	15.4
DRY SMOKE OPACITY	%	0.2	1.1	2.6	4.3	5.3
BOSCH SMOKE NUMBER		0.14	0.39	0.96	1.51	1.69

Regulatory Information

EPA TIER 2		2006 - 2010		
GASEOUS EMISSIONS DATA MEASUREMENTS PROVIDED TO THE EPA ARE CONSISTENT WITH THOSE DESCRIBED IN EPA 40 CFR PART 89 SUBPART D AND ISO 8178 FOR MEASURING HC, CO, PM, AND NOX. THE "MAX LIMITS" SHOWN BELOW ARE WEIGHTED CYCLE AVERAGES AND ARE IN COMPLIANCE WITH THE NON-ROAD REGULATIONS.				
Locality	**Agency**	**Regulation**	**Tier/Stage**	**Max Limits - G/BKW - HR**
U.S. (INCL CALIF)	EPA	NON-ROAD	TIER 2	CO: 3.5 NOx + HC: 6.4 PM: 0.20

EPA EMERGENCY STATIONARY		2011 - ----		
GASEOUS EMISSIONS DATA MEASUREMENTS PROVIDED TO THE EPA ARE CONSISTENT WITH THOSE DESCRIBED IN EPA 40 CFR PART 60 SUBPART IIII AND ISO 8178 FOR MEASURING HC, CO, PM, AND NOX. THE "MAX LIMITS" SHOWN BELOW ARE WEIGHTED CYCLE AVERAGES AND ARE IN COMPLIANCE WITH THE EMERGENCY STATIONARY REGULATIONS.				
Locality	**Agency**	**Regulation**	**Tier/Stage**	**Max Limits - G/BKW - HR**
U.S. (INCL CALIF)	EPA	STATIONARY	EMERGENCY STATIONARY	CO: 3.5 NOx + HC: 6.4 PM: 0.20

Altitude Derate Data

ALTITUDE CORRECTED POWER CAPABILITY (BHP)

AMBIENT OPERATING TEMP (F)	50	60	70	80	90	100	110	120	130	NORMAL
ALTITUDE (FT)										
0	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
1,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
2,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
3,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
4,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
5,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214
6,000	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,197	1,214
7,000	1,214	1,214	1,214	1,214	1,214	1,212	1,191	1,170	1,150	1,214
8,000	1,214	1,214	1,214	1,207	1,185	1,164	1,144	1,124	1,105	1,214
9,000	1,214	1,204	1,181	1,159	1,138	1,118	1,098	1,079	1,061	1,214
10,000	1,178	1,155	1,134	1,113	1,092	1,073	1,054	1,036	1,018	1,195
11,000	1,130	1,109	1,088	1,067	1,048	1,029	1,011	994	977	1,154
12,000	1,084	1,063	1,043	1,024	1,005	987	970	953	937	1,115
13,000	1,039	1,019	1,000	981	964	946	930	914	898	1,077
14,000	996	977	958	940	923	907	891	876	861	1,039
15,000	954	935	918	901	884	869	853	839	824	1,003

Cross Reference

Engine Arrangement			
Arrangement Number	**Effective Serial Number**	**Engineering Model**	**Engineering Model Version**
2671232	MJE00001	GS327	-
3495619	MJE00001	GS603	LS
3541450	PEN00001	GS582	-

Test Specification Data						
Test Spec	**Setting**	**Effective Serial Number**	**Engine Arrangement**	**Governor Type**	**Default Low Idle Speed**	**Default High Idle Speed**
0K7925	PP5660	MJE00001	2671232			
3704841	GG0523	MJE00001	3495619			
0K4031	GG0383	PEN00001	3541450			

Performance Parameter Reference

Parameters Reference:DM9600-08
PERFORMANCE DEFINITIONS

PERFORMANCE DEFINITIONS DM9600

APPLICATION:
Engine performance tolerance values below are representative of a typical production engine tested in a calibrated dynamometer test

cell at SAE J1995 standard reference conditions. Caterpillar maintains ISO9001:2000 certified quality management systems for engine test Facilities to assure accurate calibration of test equipment. Engine test data is corrected in accordance with SAE J1995. Additional reference material SAE J1228, J1349, ISO 8665, 3046-1:2002E, 3046-3:1989, 1585, 2534, 2288, and 9249 may apply in part or are similar to SAE J1995. Special engine rating request (SERR) test data shall be noted.

PERFORMANCE PARAMETER TOLERANCE FACTORS:

Power	+/- 3%
Torque	+/- 3%
Exhaust stack temperature	+/- 8%
Inlet airflow	+/- 5%
Intake manifold pressure-gage	+/- 10%
Exhaust flow	+/- 6%
Specific fuel consumption	+/- 3%
Fuel rate	+/- 5%
Specific DEF consumption	+/- 3%
DEF rate	+/- 5%
Heat rejection	+/- 5%
Heat rejection exhaust only	+/- 10%
Heat rejection CEM only	+/- 10%

Heat Rejection values based on using treated water.

Torque is included for truck and industrial applications, do not use for Gen Set or steady state applications.

On C7 - C18 engines, at speeds of 1100 RPM and under these values are provided for reference only, and may not meet the tolerance listed.

These values do not apply to C280/3600. For these models, see the tolerances listed below.

C280/3600 HEAT REJECTION TOLERANCE FACTORS:

Heat rejection	+/- 10%
Heat rejection to Atmosphere	+/- 50%
Heat rejection to Lube Oil	+/- 20%
Heat rejection to Aftercooler	+/- 5%

TEST CELL TRANSDUCER TOLERANCE FACTORS:

Torque	+/- 0.5%
Speed	+/- 0.2%
Fuel flow	+/- 1.0%
Temperature	+/- 2.0 C degrees
Intake manifold pressure	+/- 0.1 kPa

OBSERVED ENGINE PERFORMANCE IS CORRECTED TO SAE J1995 REFERENCE AIR AND FUEL CONDITIONS.

REFERENCE ATMOSPHERIC INLET AIR
FOR 3500 ENGINES AND SMALLER
SAE J1228 AUG2002 for marine engines, and J1995 JAN2014 for other engines, reference atmospheric pressure is 100 KPA (29.61 in hg), and standard temperature is 25deg C (77 deg F) at 30% relative humidity at the stated aftercooler water temp, or inlet manifold temp.

FOR 3600 ENGINES
Engine rating obtained and presented in accordance with ISO 3046/1 and SAE J1995 JANJAN2014 reference atmospheric pressure is 100 KPA (29.61 in hg), and standard temperature is 25deg C (77 deg F) at 30% relative humidity and 150M altitude at the stated aftercooler water temperature.

MEASUREMENT LOCATION FOR INLET AIR TEMPERATURE
Location for air temperature measurement air cleaner inlet at stabilized operating conditions.

PERFORMANCE DATA[DM7696]

REFERENCE EXHAUST STACK DIAMETER
The Reference Exhaust Stack Diameter published with this dataset is only used for the calculation of Smoke Opacity values displayed in this dataset. This value does not necessarily represent the actual stack diameter of the engine due to the variety of exhaust stack adapter options available. Consult the price list, engine order or general dimension drawings for the actual stack diameter size ordered or options available.

REFERENCE FUEL
DIESEL
Reference fuel is #2 distillate diesel with a 35API gravity;
A lower heating value is 42,780 KJ/KG (18,390 BTU/LB) when used at 29 (84.2), where the density is 838.9 G/Liter (7.001 Lbs/Gal).

GAS
Reference natural gas fuel has a lower heating value of 33.74 KJ/L (905 BTU/CU Ft). Low BTU ratings are based on 18.64 KJ/L (500 BTU/CU FT) lower heating value gas. Propane ratings are based on 87.56 KJ/L (2350 BTU/CU Ft) lower heating value gas.

ENGINE POWER (NET) IS THE CORRECTED FLYWHEEL POWER (GROSS) LESS EXTERNAL AUXILIARY LOAD
Engine corrected gross output includes the power required to drive standard equipment; lube oil, scavenge lube oil, fuel transfer, common rail fuel, separate circuit aftercooler and jacket water pumps. Engine net power available for the external (flywheel) load is calculated by subtracting the sum of auxiliary load from the corrected gross flywheel out put power. Typical auxiliary loads are radiator cooling fans, hydraulic pumps, air compressors and battery charging alternators. For Tier 4 ratings additional Parasitic losses would also include Intake, and Exhaust Restrictions.

ALTITUDE CAPABILITY
Altitude capability is the maximum altitude above sea level at standard temperature and standard pressure at which the engine could develop full rated output power on the current performance data set.

Standard temperature values versus altitude could be seen on TM2001.

When viewing the altitude capability chart the ambient temperature is the inlet air temp at the compressor inlet.

Engines with ADEM MEUI and HEUI fuel systems operating at conditions above the defined altitude capability derate for atmospheric pressure and temperature conditions outside the values defined, see TM2001.

Mechanical governor controlled unit injector engines require a setting change for operation at conditions above the altitude defined on the engine performance sheet. See your Caterpillar technical representative for non standard ratings.

REGULATIONS AND PRODUCT COMPLIANCE
TMI Emissions information is presented at 'nominal' and 'Potential Site Variation' values for standard ratings. No tolerances are applied to the emissions data. These values are subject to change at any time. The controlling federal and local emission requirements need to be verified by your Caterpillar technical representative.

Customer's may have special emission site requirements that need to be verified by the Caterpillar Product Group engineer.

EMISSIONS DEFINITIONS:
Emissions : DM1176

HEAT REJECTION DEFINITIONS:

PERFORMANCE DATA[DM7696]

Diesel Circuit Type and HHV Balance : DM9500

HIGH DISPLACEMENT (HD) DEFINITIONS:
3500: EM1500

RATING DEFINITIONS:
Agriculture : TM6008

Fire Pump : TM6009

Generator Set : TM6035

Generator (Gas) : TM6041

Industrial Diesel : TM6010

Industrial (Gas) : TM6040

Irrigation : TM5749

Locomotive : TM6037

Marine Auxiliary : TM6036

Marine Prop (Except 3600) : TM5747

Marine Prop (3600 only) : TM5748

MSHA : TM6042

Oil Field (Petroleum) : TM6011

Off-Highway Truck : TM6039

On-Highway Truck : TM6038

SOUND DEFINITIONS:
Sound Power : DM8702

Sound Pressure : TM7080

Date Released : 7/7/15

EMCP 4.2 GENERATOR SET CONTROLLER

STANDARD FEATURES

Generator Monitoring	• Voltage (L-L, L-N) • Current (Phase) • Average Volt, Amp, Frequency • kW, kVAr, kVA (Average, Phase, %) • Power Factor (Average, Phase) • kW-hr, kVAr-hr (total) • Excitation voltage and current (with CDVR) • Generator stator and bearing temp (with optional module)
Generator Protection	• Generator phase sequence • Over/Under voltage (27/59) • Over/Under frequency (81 O/U) • Reverse Power (kW) (32) • Reverse Reactive Power (kVAr) (32RV) • Overcurrent (50/51)
Engine Monitoring	• Coolant temperature • Oil pressure • Engine speed (RPM) • Battery voltage • Run hours • Crank attempt and successful start counter • Enhanced engine monitoring (with electronic engines)
Engine Protection	• Control switch not in auto (alarm) • High coolant temp (alarm and shutdown) • Low coolant temp (alarm) • Low coolant level (alarm) • High engine oil temp (alarm and shutdown) • Low, high, and weak battery voltage • Overspeed • Overcrank
Control	• Run / Auto / Stop control • Speed and voltage adjust • Local and remote emergency stop • Remote start/stop • Cycle crank
Inputs & Outputs	• Two dedicated digital inputs • Six programmable digital inputs • Six programmable form A dry contacts • Two programmable form C dry contacts • Two digital outputs
Communications	• Primary and accessory CAN data links • RS-485 annunciator data link • Modbus RTU (RS-485 Half duplex)
Language Support	Arabic, Bulgarian, Chinese, Czech, Danish, Dutch, English, Estonian, Finnish, French, German, Greek, Hungarian, Icelandic, Italian, Latvian, Lithuanian, Japanese, Norwegian, Polish, Portuguese, Romanian, Russian, Slovak, Slovene, Spanish, Swedish, Turkish
Environmental	• Control module operating temperature: -40°C to 70°C • Display operating temperature: -20°C to 70°C • Humidity: 100% condensing 30°C to 60°C • Storage temperature: -40°C to 85°C • Vibration: Random profile, 24-1000 Hz, 4.3G rms

MISCELLANEOUS PROCESS OR DEVICE

FORM AQ230
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project

Permit Number:

Process Information

1. ID Number	EU10.GC (Gas Conditioning)
2. Descriptive name	Acid Gas Thermal Oxidizer
3. Existing or future?	Future
4. Date commenced	January 2019
5. Date installed/completed	October 2021

6. Description of process:

The Gas Conditioning train includes a system for mercury removal via sulfur impregnated activated carbon, carbon dioxide (CO2) and acid gas removal via an amine system, and dehydration via a molecular sieve adsorbent system. A thermal oxidizer combusts the acid gas from the amine process.

Operating Schedule

7. Seasonal or year-round?	Year-round
8. Batch or continuous operation?	Continuous
9. Projected maximum hours/day	24
10. Projected maximum hours/year	8,760

11. Process/device capacity:	Short term capacity		Annual usage	
Raw materials	Amount	Units	Amount	Units
Pipeline Natural Gas	50,000	MMBtu/hr		
Products				
Fuel Gas	3,905	lb/hr		
Acid Gas	124,710	lb/hr		
Flash Gas	1.276	lb/hr		

12. Control devices(s) (yes/no): Yes

If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

Thermal Oxidizer CD.TO on AQ307

MISCELLANEOUS
CONTROL DEVICE INFORMATION

FORM AQ307
ANSWER SHEET

Facility Name: JCEP LNG Terminal Project   Permit Number:

1.	Control Device ID	CD.TO (Thermal Oxidizer)
2.	Process/Device(s) Controlled	EU10.GC (Gas Conditioning)
3.	Year installed	2021
4.	Manufacturer/Model No.	Zeeco, custom design
5.	Control Efficiency (%)	99.9%
6.	Design inlet gas flow rate (acfm)	177,370 acfm
7.	Design parameter(s)	238,142 lb/hr inlet with 102 MMBtu/ hr heat release, 1,600 degrees F, 1 second residence time
8.	Inlet gas pretreatment? (yes/no) If yes, list control device ID and complete a separate control device form	No
9.	Describe the control device	
	Thermal oxidizer to control emissions from the acid gas removal system. The thermal oxidizer has a destruction efficiency of 99.9 percent for H_2S, VOC, and HC.	

• Burners
• Flares
• Incinerators
• Combustion Systems

22151 East 91st Street
Broken Arrow, OK 74014 USA
Phone: 918-258-8551
Fax: 918-251-5519

www.zeeco.com
sales@zeeco.com

May 18, 2016

JGC Corporation
Yokohama World Operations Center
3-1, Minato Mirai 2-Chome, Nishi-Ku, Yokohama 220-6001

Attention: Hajime Kudo
Kudo.hajime@jgc.com

Reference: Thermal Oxidizers
Jordan Cove LNG Project
Oregon, USA
RFQ E0-7271-67.6320
Zeeco Proposal No. 2016-03002IN-01 Rev. 0

Gentlemen:

Thank you for your continued interest in Zeeco. We appreciate this opportunity to provide a technical description/proposal for the equipment described in the above referenced inquiry.

The attached proposal describes the specific operating conditions and mechanical features of the combustion equipment. The design and materials of construction have been chosen to maximize on-line time and operational life while minimizing the capital cost of the equipment. In addition, the proposed equipment is in accordance with our understanding of data sheets and specifications.

Zeeco has unique capabilities and experience in delivering large incineration systems. The experience lists attached to our proposal include incinerators larger than those in this proposal, and we have experience with large gas-gas heat exchangers with waste gas as the heated media. We can provide *in-house* Computational Fluid Dynamics (CFD) modeling for the purpose of fluid flow analysis, gas mixing, and temperature profiles inside the incinerator chamber, and dynamic vortex shedding, and standing-wave analysis to avoid vibration problems in the preheaters. Zeeco has a license and engineers with experience using FEM software to analyze natural frequency problems. Zeeco can do in-house 3D modeling using Autodesk Inventor software.

Again, we appreciate the opportunity to provide our quotation in full accordance with your requirements. After you have had an opportunity to review our proposal, should you have any questions or require additional information, please contact me using the contact information noted below.

Sincerely,

P. W. Pickard

Peter Pickard
Senior Applications Engineer
Email: peter_pickard@zeeco.com
Phone: 918-893-8421

TABLE OF CONTENTS

1.0 INTRODUCTION

Zeeco, Inc. has been designing and manufacturing burners, flares, incinerators, air preheaters, and combustion systems for world wide use since 1980. Zeeco, Inc., headquartered in the Tulsa, Oklahoma area, is privately held by a family who has successfully designed, developed and supplied combustion equipment for over 80 years.

Zeeco's Engineering Staff offers over 1,000 years of experience in the development, design, and testing of Combustion Systems. Zeeco has the proven skills and innovative abilities to design a practical and environmentally friendly combustion system to thermally treat virtually any industrial waste. This learned "art" gained by research and design efforts which are refined by testing and field experience has been implemented in the process plants of numerous industries throughout the world.

From project planning through design, procurement, manufacturing, installation, and even start-up, Zeeco, Inc. will provide project management and support as deemed necessary. It is our world class HANDS ON type design skills, quality products, experienced staff, and especially our responsiveness to our customers needs that truly set Zeeco apart from our competition.

Quality. Our customers expect it; we demand it.

4.0 DESIGN SUMMARY

4.1 Site Conditions

Wind Loading Code	ASCE/SEI 7-10
Maximum Hourly Sustained Peak Wind (Design)	150mph
3 second gust	183 mph
Occupancy category	IV
Importance factor	1.0
Exposure category	C
Wind Topographic Factor	1.0
Seismic Loading Code	ASCE/SEI 7-10 and IBC 2010
FERC Seismic Structural Category	II
Site classification	D
Importance factor (seismic loads) for structures (I)	1.5
Importance factor for Systems/Components (Ip)	1.5
Occupancy category	IV
Ss	1.50g
S1	1.00g
SDS	1.00g
SD1	1.00g
Site location	Coos Bay, Oregon
Elevation	Unknown
Atmospheric Pressure	Unknown
Ambient Temperature	Unknown
Electrical Area Classification	Class 1, Division 2, Group C & D

4.2 Waste Stream Summary – See attached excerpt from the spec

4.3 Process Summary

Case Name:	**Max Case**
FLOW RATE:	**lb/hr**
Acid Gas	124,710
Flash Gas	1276
Fuel Gas	3905
Combustion air	108,251
TOTAL, lb/hr	**238,142**
HEAT RELEASE:	**MMBtu/hr**
Acid Gas	1
Flash Gas	22
HP Fuel Gas	79
TOTAL, MMBtu/hr	**102**
Incinerator Temperature, ^{o}F	1600
Residence time, seconds	1
Flue Gas Mole Weight	34.29
FLUE GAS COMPOSITION:	**mol %**
CO_2	44.84
H_2O	10.05
N_2	42.39
O_2	2.72*
SO_2	< 10 ppm
TOTAL Flue Gas, mol %	**100**

*3% O2 on dry basis

4.4 Utilities

Instrument air, psig	60
Instrument air, usage	15 SCFM
Max Fuel gas usage, lb/hr	3905
Fuel gas at burner, psig	15
Connected HP for combustion air fan	50 at 480 volts, 3ph, 60 hz

4.5 System Performance

Emissions @ Stack Conditions	Guaranteed, less than:
VOC	99.9% DRE
NOx	< 50 ppm
CO	< 50 ppm
SO2	3.22 lb/hr
Correction basis for above	3% O2, dry volume

These values are understood to apply only when the system is operated in accordance with the operating conditions stipulated in the design summary and for the waste(s) stipulated in the design basis sections of this proposal and when the system is operated according to Zeeco's instructions.

Special note regarding SO2 emissions:
According to Zeeco calculation, the SO2 content in the flue gas at maximum condition is 3.43 lb/hr instead of 3.22 lb/hr. Zeeco assumes that JGC does not want to add an SO2 scrubber in order to account for a small difference in calculated SO2 quantity. Therefore, Zeeco is willing to guarantee the SO2 emission provided that it is understood that Zeeco will not be required to make any equipment modification if the SO2 emissions are exceeded. This is because there is nothing in the burner/thermal oxidizer that can be changed in order to reduce SO2 emissions. SO2 emissions are a direct result of the sulfur content in the feed gas. The only way to decrease the emissions without a change in feed condition is to add a scrubber which would roughly double or triple the cost of the system.

5.0 EQUIPMENT DESCRIPTION

5.1 Thermal Oxidizer

One (1) vertical, up-fired thermal oxidizer/stack designed to operate at 1600°F with excess air to ensure complete combustion of the waste gas combustible components. Each Incinerator has the following features:

- Nominal 9'-6" OD x 85 feet tall from grade
- ASME Section VIII, Div 1 design
- ASME STS-1
- No hydrotest
- No Code stamp
- Shell material SA-516-70N carbon steel
- 1/8" corrosion allowance
- Designed to be supported by concrete tabletop foundation (by others)
- All Carbon Steel External Surfaces Sandblasted SSPC-SP6
- Thermal shroud 360 degree carbon steel galvanized 26 gauge (panels ship loose for field assembly)
- Ladders and Platforms are provided to sampling port elevation
- 360 degree sample port platform
- Connections per GA Drawing
- Refractory lining per refractory schedule shown on GA drawing
- Refractory material is shipped loose for field installation by others
- Top 10'-0" of stack shell is 316 stainless steel
- Damping pad
- Stainless steel rain cap for protection of refractory at stack exit
- Assembly designed to ship as one piece, approximately 60 feet long
- Flanged burner connection
- Oregon PE stamped applicable documents

5.2 Burner

One (1) Zeeco Combination Waste Gas, Flash Gas and Fuel Gas Burner is offered per system and has the following features:

- 110 MMBtu/hr maximum fuel gas heat release (includes 10% safety factor)
- Zeeco AR/GS pilot for burner ignition
- High Energy Electric Spark Ignition System
- A-36 carbon steel construction
- See additional information about pilots here: http://www.zeeco.com/incinerators/incinerators-pilots.php

5.4 Combustion Air Fans

Two (2) Combustion Air Fans (one 100% installed spare) are offered and have the following features and preliminary design details:

Case	Mass Flow, lb/hr	Outlet Static Press., in WC	Power, BHP
Test Block	26,231	7.3	46
Operating Case	23,846	6.0	34

Preliminary design details:

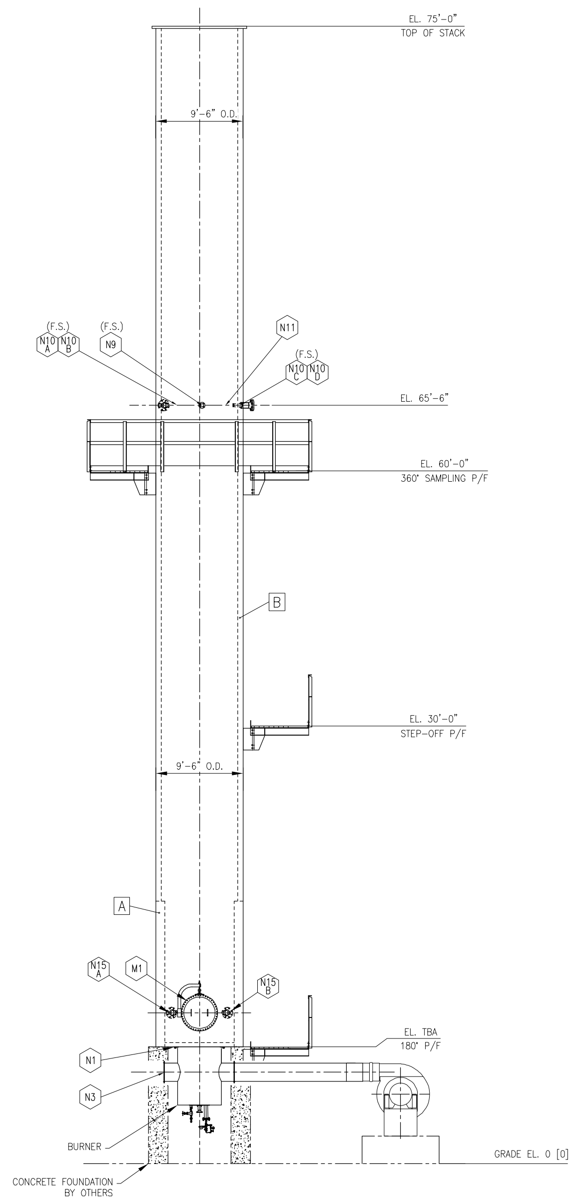
- API 560 Design, Annex E
- Direct drive
- Fan antifriction bearings, grease lube
- Coupling guard
- Nameplate - Quantity per fan (1)
- A-36 or equivalent housing construction
- Paint Specification; Manufacturer's standard
- Motor drive: 50 HP, 3600 RPM, TEFC, 460 V / 3 phase / 60 Hz electric motor

5.5 Instrumentation & Controls

Zeeco scope of supply is depicted on the attached P&ID and includes the following:

- Fuel gas skid with valves, instruments and wiring
- Local control panel with pushbuttons and lights
- Ship loose instrumentation and valves as shown on P&ID
- Designed for analog control to be in customer's DCS
- Logic control hardware for burner management function, such as a PLC is NOT included.
- Cause and effect diagrams
- Logic diagrams
- Process control narrative descriptions of control loops

Attachment E
General Arrangement Drawing



ELEVATION VIEW

– NOZZLE LEGEND –

ITEM	QTY	DESCRIPTION	SIZE	RATING	TYPE	FLG. MATERIAL
N1	1	BURNER CONNECTION	TBD	150#	RFWN	--
N2	1	DRAIN W/ BLIND	2"	150#	RFWN	--
N3	1	WASTE GAS CONNECTION	24"	150#	RFWN	--
N9	1	ANALYZER CONNECTION	4"	150#	RFWN	--
N10A~D	4	FLUE GAS SAMPLING CONNECTION	4"	150#	RFWN	--
N11	1	TEMPERATURE ELEMENT	2"	150#	RFWN	--
N14A/B	2	TEMPERATURE ELEMENT	2"	150#	RFWN	--
N15A/B	2	SIGHT GLASS	4"	150#	RFWN	--
M1	1	MANWAY	30"	--	--	--

– REFRACTORY LEGEND –

REFRACTORY TO BE INSTALLED BY OTHERS.

A	4" [102] THK 3000°F RATED CASTABLE BACKED W/ 3" [76] THK INSULATING CASTABLE W/ 31022 ANCHORS
B	4" [102] THK CASTABLE RATED FOR 2500°F W/ 310SS ANCHORS

– GENERAL NOTES –

1.	ALL NOZZLE BOLTING SHOULD STRADDLE TRUE VERTICAL AND TRUE HORIZONTAL.
2.	ALL FABRICATION IN ACCORDANCE WITH A.I.S.C. STANDARDS UNLESS OTHERWISE NOTED.
3.	ALL PAINTING/COATING PER CUSTOMER SPECIFICATIONS.
4.	ALL BUTT WELDS CONTINUOUS WITH FULL PENETRATION.
5.	LADDERS AND PLATFORMS TO BE HOT-DIPPED GALVANIZED. (SHOP TRIAL FIT & DISASSEMBLED FOR SHIPMENT.)

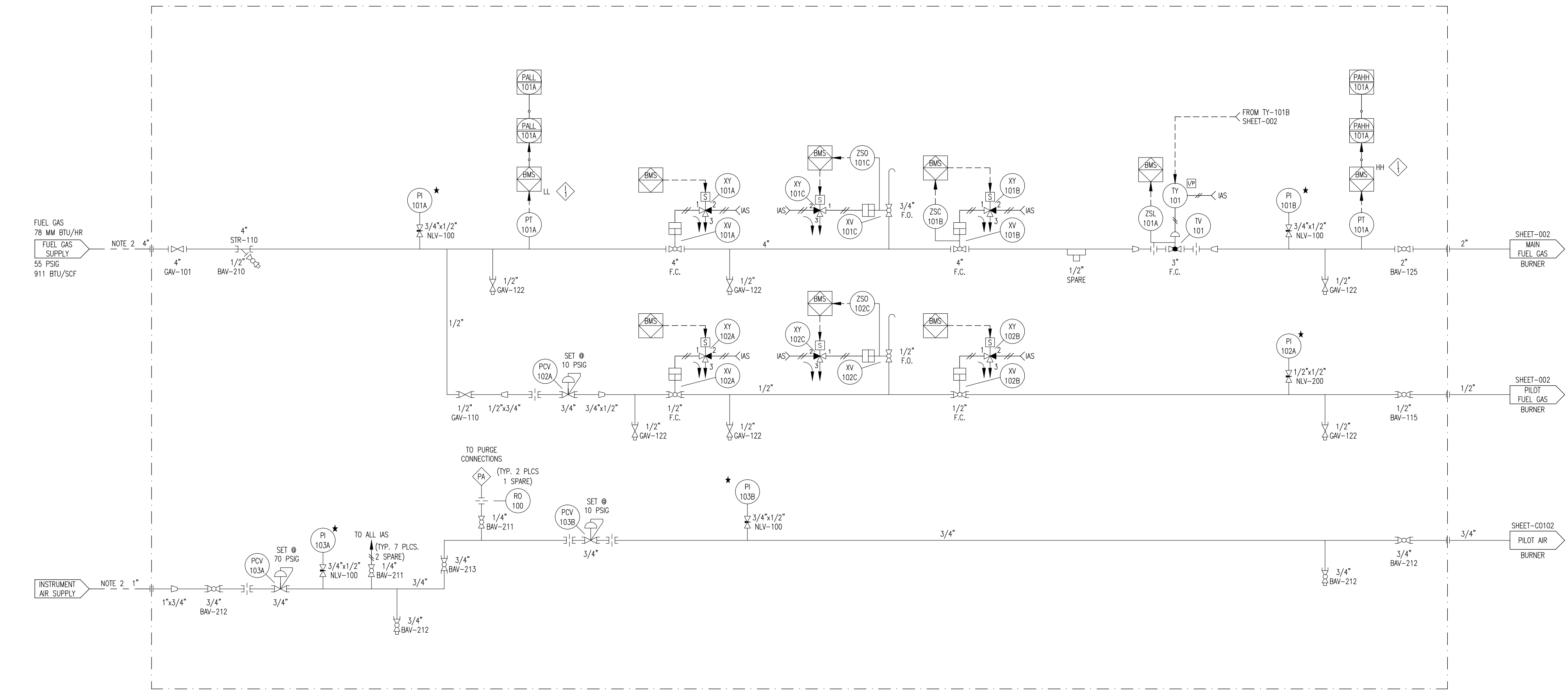
– MATERIALS –

SHELL	SA516-70N
NOZZLE PIPE	A106B
FLANGE FORGINGS	A105
PLATE FLANGES	A-36
STUD BOLTS/NUTS	–
GASKETS	COMP. NON-ASB.
L&P STRUCTURAL SHAPES	A-36
RAINSHIELD RING/CLIPS	A-36
WELDED FITTINGS	–
S.W. FITTING	–
TAILING LUGS	A-36
LIFTING TRUNNIONS	A-36

** PRELIMINARY DRAWING, NOT TO SCALE **

JOBSITE: COOS BAY, OREGON			
END USER: JORDAN COVE LNG			
S.O. NO.: 2016-03002IN-01	P.O. NO.:		APP PPK
ZEECO, INC. 22151 EAST 91st STREET BROKEN ARROW, OK 74014 PHONE: (918) 258-8551 FAX: (918) 251-5519 www.zeeco.com sales@zeeco.com	GENERAL ARRANGEMENT THERMAL OXIDIZERS	DRAWN BLC	DATE 19MAY16
		CHK PP	APP PP
		SCALE NONE	REV A
PROPRIETARY DATA IS INCLUDED IN THE INFORMATION DISCLOSED HEREIN AND IS THE PROPERTY OF ZEECO,INC. THIS INFORMATION IS SUBMITTED IN CONFIDENCE AND MUST BE USED IN CONNECTION WITH WORK DONE FOR ZEECO, INC. AND ALL RIGHTS OF DESIGN OR INVENTION ARE RESERVED. UNAUTHORIZED DISCLOSURE OR USE IS PROHIBITED BY LAW.	FOR: KBJ J.V.	DRAWING NUMBER 03008IN-G01001	

Attachment F
Piping & Instrumentation Diagram



LEGEND:

- PIPING
- PIPING BY OTHERS
- WIRING
- SOFTWARE
- SKID LIMITS
- 316SS TUBING & FITTINGS (SWAGELOK OR EQUAL) 3/8" UNLESS NOTED OTHERWISE
- ★ ITEMS SHIPPED LOOSE
- ★★ ITEMS FURNISHED AND INSTALLED BY OTHERS
- ★★★ OPTIONAL

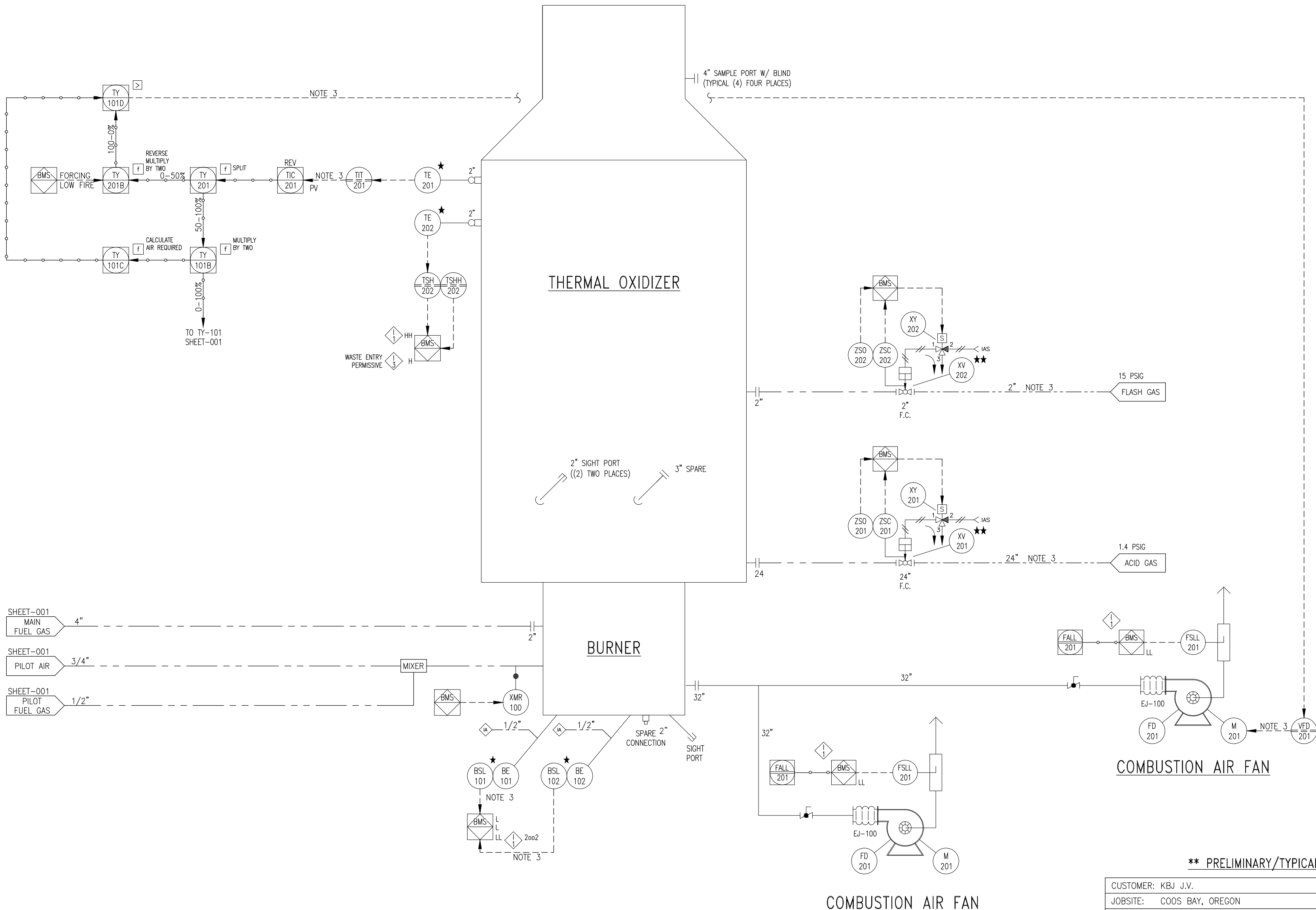
- INSTRUMENT (LOCALLY MOUNTED)
- INSTRUMENT (MOUNTED ON MAIN PANEL)
- INSTRUMENT (MOUNTED ON LOCAL PANEL)
- INSTRUMENT (MOUNTED INSIDE PANEL)
- DCS-CONTROL ROOM BY OTHERS
- BMS-HMI (BY ZEECO)
- BMS PLC-PROGRAMMABLE LOGIC CONTROL (BY ZEECO)

NOTES

1. INCINERATOR: UNCLASSIFIED
   REMOTE CONTROL PANEL: CLASS I, DIV II, GROUP D
2. MOUNTED ON FUEL SKID / RACK.
3. FIELD PIPING, TUBING, WIRING FURNISHED AND INSTALLED BY OTHERS.

** PRELIMINARY/TYPICAL DRAWRING **

CUSTOMER: KBJ J.V.					
JOBSITE: COOS BAY, OREGON					
END USER: JORDAN COVE LNG					
P.O. NO.: 2016-03002IN-01					
ZEECO, INC. 22151 EAST 91st STREET BROKEN ARROW, OK 74014 PHONE: (918) 258-8551 FAX: (918) 251-5519 www.zeeco.com sales@zeeco.com	P&I DIAGRAM THERMAL OXIDIZERS	DRAWN BLC	DATE 19MAY16		
		CHK PP	APP PP		
		SCALE N.T.S	APP PP		
S.O. NO. 03002IN	GROUP 04	DWG. & SUB CAT. 110	SYSTEM NO. 01	DWG. NO. 001	REV. NO. A



** PRELIMINARY/TYPICAL DRAWRING **

CUSTOMER: KBJ J.V.
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P&I DIAGRAM
THERMAL OXIDIZERS

DRAWN	DATE
BLC	19MAY16
CHK PP	APP PP
SCALE N.T.S	APP PP

S.O. NO.	GROUP	DWG. & SUB CAT.	SYSTEM NO.	DWG. NO.	REV. NO.
03002IN	04	110	01	002	A

SEE SHEET-001 FOR LEGEND AND NOTES

Attachment G
Waste Feed Conditions

DATA SHEET FOR THERMAL OXIDIZER PACKAGE 10-PK-0103

Rev.			Acid Gas To BeThermal Oxidized (DGLT) (% MOL)	Fuel Gas Sources (NOTE6)									
				Flash Gas (%MOL)	Feed Gas (Note 7, 12)				BOG				
					Acid Gas Design case (% MOL)	Design case (% MOL)	Rich case (% MOL)	Lean case (% MOL)	Acid Gas Design case (% MOL)	Design case (% MOL)	Rich case (% MOL)	Lean case (%MOL)
	51												
	52	Composition											
	53	CO2	97.656352	7.009624	2.000000	0.748500	0.288800	0.858500	0.000000	0.000000	0.000000	0.000000
	54	Nitrogen	0.000069	0.150292	0.445200	0.450900	0.332400	0.979600	5.574295	5.500124	4.051529	10.439232
	55	Methane	0.106577	85.851157	94.132500	95.334600	92.934400	96.732800	93.186305	92.998682	83.142649	88.770083
	56	Ethane	0.007724	4.158075	3.136200	3.176300	5.174600	1.266500	0.005646	0.112709	2.395021	0.002223
	57	Propane	0.000000	0.209259	0.156100	0.158100	0.915500	0.083200	0.000000	0.132390	5.661934	0.000000
	58	i-Butane	0.000050	0.024366	0.017200	0.017400	0.110600	0.004500	0.000000	0.037980	1.344879	0.000000
	59	n-Butane	0.000050	0.025828	0.018300	0.018500	0.129800	0.004000	0.000000	0.052895	1.826311	0.000000
	60	C5 (neopentane, i-pentane, n-pentane, cyclopentane)	0.000023	0.010136	0.006500	0.006600	0.054500	0.000000	0.000000	0.034136	0.949844	0.000000
	61	C6 (2.2-dimethylbutane, 2-Methylpentane, 3-methylpentane, n-hexane, Methylcyclopentane, Cyclohexane)	0.000004	0.001657	0.001001	0.001013	0.013818	0.000159	0.000000	0.015684	0.262360	0.000000
	62	C7 (2-methylhexane, 3-methylhexane, n-heptane, mMethylcyclohexane)	0.000008	0.002924	0.001333	0.001350	0.003743	0.000073	0.000000	0.021527	0.083582	0.000000
	63	C8 (2,2,4-Trimethylpentane, 2-methylheptane, 3-Methylheptane, n-octane)	0.000004	0.001170	0.000487	0.000494	0.000822	0.000026	0.000000	0.006612	0.019532	0.000000
	64	n-C9	0.000004	0.000292	0.000112	0.000113	0.000123	0.000006	0.000000	0.001845	0.001936	0.000000
	65	n-C10	0.000000	0.000000	0.000012	0.000012	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	66	n-C13	0.000000	0.000000	0.000012	0.000012	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	67	Helium		0.000000	0.049031	0.049657	0.012995	0.037473	0.989699	0.870609	0.196550	0.601176
	68	Hydrogen		0.000000	0.009766	0.009891	0.000000	0.006895	0.200708	0.166218	0.000000	0.145188
	69	Oxygen			0.009874	0.010000	0.010000	0.010000	0.043347	0.045360	0.039943	0.042098
	70	H2S	0.000000	0.000487	0.000395	0.000400	0.000400	0.000400	0.000000	0.000000	0.000000	0.000000
	71	COS	0.000050	0.002924	0.000395	0.000400	0.000400	0.000400	0.000000	0.000000	0.000000	0.000000
	72	CH3SH (Methyl Mercaptan)	0.000924	0.008577	0.000465	0.000471	0.000471	0.000471	0.000000	0.002922	0.011438	0.000000
	73	C2H5SH (Ethyl Mercaptan)	0.000342	0.003216	0.000186	0.000188	0.000188	0.000188	0.000000	0.000000	0.000000	0.000000
	74	Other mercaptans (Propyl / Butyl Mercaptan, methyl ethyl sulfide)	0.000036	0.001267	0.000138	0.000141	0.000141	0.000141	0.000000	0.000000	0.000000	0.000000
	75	Benzene	0.000489	0.001657	0.000027	0.000027	0.000740	0.000005	0.000000	0.000308	0.012493	0.000000
	76	Toluene	0.000489	0.001462	0.000075	0.000076	0.000535	0.000005	0.000000	0.000000	0.000000	0.000000
	77	Ethylbenzene	0.000061	0.000161	0.000012	0.000012	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	78	p-Xylene	0.000196	0.000487	0.000027	0.000027	0.000082	0.000002	0.000000	0.000000	0.000000	0.000000
	79	m-Xylene	0.000196	0.000487	0.000027	0.000027	0.000082	0.000002	0.000000	0.000000	0.000000	0.000000
	80	o-Xylene / 1,2,4-Trimethylbenzene	0.000084	0.000161	0.000024	0.000024	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	81	MDEA	(Note 14)	(Note 14)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	82	H2O	2.226271	2.534331	0.014559	0.014745	0.014745	0.014745	0.000000	0.000000	0.000000	0.000000
	83											
	84	Total	100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000
	85											
	86											
	87	Mol Weight lb/lbmol	43.40	18.76	17.16	16.81	16.73	20.59	16.57	16.73	20.59	17.21
	88	Weight Flow lb/hr	124,710	1275.5	VTS (Note 1, 6)							
	89	Temperature oF	104.6	110	50.0				149.7	148.4	137.7	149.7
	90	Pressure @Inlet psia	16.1	VTS (Note 1, 6)								
	91											
	92											
	93											
	94											
	95											
	96											
	97											
	98											
	99											
	100											
	101											
	102											

State of Oregon Department of Environmental Quality

Facility Name: JCEP LNG Terminal Project Permit Number:

Process Information

1. ID Number	EU11.MPGF (Multipoint Ground Flares)
2. Descriptive name	Warm and Cold Flares
3. Existing or future?	Future
4. Date commenced	January 2019
5. Date installed/completed	October 2021

6. Description of process:

Warm and cold ground flares used to burn gas released from the process during emergencies or while purging equipment in preparation for maintenance. Each flare system has seven stages with 2 pilots per stage. Together these warm and cold flare lines comprise a multi-point ground flare (MPGF) where the array of burners is arranged in a grid surrounded by barrier walls.

Operating Schedule

7. Seasonal or year-round?	Year-round
8. Batch or continuous operation?	Continuous (pilot and purge gas)
9. Projected maximum hours/day	24
10. Projected maximum hours/year	8,760

11. Process/device capacity:	Short term capacity		Annual usage	
Raw materials	Amount	Units	Amount	Units
Pilot Gas	1.82	MMBtu/hr	15,943	MMBtu/yr
Purge Gas	0.31	MMBtu/hr	2,715.6	MMBtu/yr
Products				
NA				

12. Control devices(s) (yes/no): No

If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

MISCELLANEOUS PROCESS OR DEVICE

Facility Name: JCEP LNG Terminal Project   Permit Number:

Process Information

1. ID Number	EU12.MF (Marine Flare)
2. Descriptive name	Marine Flare
3. Existing or future?	Future
4. Date commenced	January 2019
5. Date installed/completed	July 2022

6. Description of process:

One enclosed marine flare.

Operating Schedule

7. Seasonal or year-round?	Year-round
8. Batch or continuous operation?	Continuous (pilot and purge gas)
9. Projected maximum hours/day	24
10. Projected maximum hours/year	8,760

11. Process/device capacity:	Short term capacity		Annual usage	
Raw materials	Amount	Units	Amount	Units
Pilot Gas	0.39	MMBtu/hr	3,416	MMBtu/yr
Purge Gas	0.35	MMBtu/hr	3,066	MMBtu/yr
Products				
NA				

12. Control devices(s) (yes/no) No

If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

State of Oregon Department of Environmental Quality

PLANT SITE EMISSIONS DETAIL SHEET **FORM AQ402**

CURRENT/FUTURE OPERATIONS **ANSWER SHEET**

Facility Name: JCEP LNG Terminal Project Permit Number:

Table 1

1. Emissions Point	**Production Rates**		4. Pollutant	**Emissions Factors**			**Emissions**	
	2. Short-term (Specify units)	3. Annual (Specify units)		5. Short-term	6. Long-term	7. Reference(s)	8. Short-term (Specify units)	9. Annual (tons/year)
			Please see	Appendix B.				
Example	200 tons of rock/hr	400,000 tons	PM	0.04 lb/ton	0.04 lb/ton	DEQ	8.0 lb/hr	8.0

Facility Name: JCEP LNG Terminal Project Permit Number:

Table 2

1. Device/process ID	2. PM_{10} PSEL (tons/year)	3. $PM_{2.5}$ fraction (f)	4. Reference	5. $PM_{2.5}$ PSEL (tons/yr)
Please see Appendix B.				
TOTAL	0.0			0.0

Facility Name: JCEP LNG Terminal Project Permit Number:

Emissions Data

1. Emissions Point	2. Annual Production Rate (specify units)	3. Pollutant	4. Emission Factor	5. EF reference	6. Annual Emissions (tons/yr)
		Please see	Appendix B		

Applications for Standard ACDPs must also include the most recent Toxics Release Inventory report, if applicable (see instructions).

State of Oregon Department of Environmental Quality

Facility name: JCEP LNG Terminal Project Permit Number: ____________

Indicate which of the following categorically insignificant activities are present at the facility by placing an "X" in the "Yes" or "No" column.

Yes	No	Type of activity — Categorically Insignificant Activities
✓		Constituents of a chemical mixture present at less than 1 percent by weight of any chemical or compound regulated under divisions 200 through 268 excluding divisions 248 and 262 of this chapter, or less than 0.1 percent by weight of any carcinogen listed in the U.S. Department of Health and Human Service's Annual Report on Carcinogens when usage of the chemical mixture is less than 100,000 pounds/year
✓		Evaporative and tail pipe emissions from on-site motor vehicle operation
	✓	Distillate oil, kerosene, gasoline, natural gas or propane burning equipment, provided the aggregate expected actual emissions of the equipment identified as categorically insignificant do not exceed the de minimis level for any regulated pollutant, based on the expected maximum annual operation of the equipment. If a source's expected emissions from all such equipment exceed the de minimis levels, then the source may identify a subgroup of such equipment as categorically insignificant with the remainder not categorically insignificant. The following equipment may never be included as categorically insignificant: A. Any individual distillate oil, kerosene or gasoline burning equipment with a rating greater than 0.4 million Btu/hour; B. Any individual natural gas or propane burning equipment with a rating greater than 2.0 million Btu/hour
	✓	Distillate oil, kerosene, gasoline, natural gas or propane burning equipment brought on site for six months or less for maintenance, construction or similar purposes, such as but not limited to generators, pumps, hot water pressure washers and space heaters, provided that any such equipment that performs the same function as the permanent equipment, must be operated within the source's existing PSEL
✓		Office activities
✓		Food service activities
✓		Janitorial activities
✓		Personal care activities
✓		Grounds keeping activities, including, but not limited to building painting and road and parking lot maintenance
✓		On-site laundry activities
	✓	On-site recreation facilities
✓		Instrument calibration
✓		Maintenance and repair shop
	✓	Automotive repair shops or storage garages;
✓		Air cooling or ventilating equipment not designed to remove air contaminants generated by or released from associated equipment
✓		Refrigeration systems with less than 50 pounds of charge of ozone depleting substances regulated under Title VI, including pressure tanks used in refrigeration systems but excluding any combustion equipment associated with such systems
✓		Bench scale laboratory equipment and laboratory equipment used exclusively for chemical and physical analysis, including associated vacuum producing devices but excluding research and development facilities

Yes	No	Type of activity
✓		Temporary construction activities
	✓	Warehouse activities
	✓	Accidental fires
✓		Air vents from air compressors
✓		Air purification systems
✓		Continuous emissions monitoring vent lines
	✓	Demineralized water tanks
	✓	Pre-treatment of municipal water, including use of deionized water purification systems
	✓	Electrical charging stations
	✓	Fire brigade training
✓		Instrument air dryers and distribution
	✓	Process raw water filtration systems
	✓	Pharmaceutical packaging
✓		Fire suppression
	✓	Blueprint making
✓		Routine maintenance, repair, and replacement such as anticipated activities most often associated with and performed during regularly scheduled equipment outages to maintain a plant and its equipment in good operating condition, including but not limited to steam cleaning, abrasive use, and woodworking
✓		Electric motors
✓		Storage tanks, reservoirs, transfer and lubricating equipment used for ASTM grade distillate or residual fuels, lubricants, and hydraulic fluids
✓		On-site storage tanks not subject to any New Source Performance Standard (NSPS), including underground storage tanks (UST), storing gasoline or diesel used exclusively for fueling of the facility's fleet of vehicles
✓		Natural gas, propane, and liquefied petroleum gas (LPG) storage tanks and transfer equipment
✓		Pressurized tanks containing gaseous compounds
	✓	Vacuum sheet stacker vents
✓		Emissions from wastewater discharges to publicly owned treatment works (POTW) provided the source is authorized to discharge to the POTW, not including on-site wastewater treatment and/or holding facilities
	✓	Log ponds
✓		Storm water settling basins
✓		Fire suppression and training
	✓	Paved roads and paved parking lots within an urban growth boundary
✓		Hazardous air pollutant emissions in fugitive dust from paved and unpaved roads except for those sources that have processes or activities that contribute to the deposition and entrainment of hazardous air pollutants from surface soils
✓		Health, safety, and emergency response activities

Yes	No	Type of activity
	✓	Emergency generators and pumps used only during loss of primary equipment or utility service due to circumstances beyond the reasonable control of the owner or operator, or to address a power emergency, provided that the aggregate horsepower rating of all stationary emergency generator and pump engines is not more than 3,000 horsepower. If the aggregate horsepower rating of all stationary emergency generator and pump engines is more than 3,000 horsepower, then no emergency generators and pumps at the source may be considered categorically insignificant
✓		Non-contact steam vents and leaks and safety and relief valves for boiler steam distribution systems
✓		Non-contact steam condensate flash tanks
✓		Non-contact steam vents on condensate receivers, deaerators and similar equipment
✓		Boiler blow down tanks
	✓	Industrial cooling towers that do not use chromium-based water treatment chemicals
	✓	Ash piles maintained in a wetted condition and associated handling systems and activities
	✓	Uncontrolled oil/water separators in effluent treatment systems, excluding systems with a throughput of more than 400,000 gallons per year of effluent located at the following sources: A. Petroleum refineries; B. Sources that perform petroleum refining and re-refining of lubricating oils and greases including asphalt production by distillation and the reprocessing of oils and/or solvents for fuels; or C. Bulk gasoline plants, bulk gasoline terminals, and pipeline facilities
✓		Combustion source flame safety purging on startup
	✓	Broke beaters, pulp and repulping tanks, stock chests and pulp handling equipment, excluding thickening equipment and repulpers
	✓	Stock cleaning and pressurized pulp washing, excluding open stock washing systems
	✓	White water storage tanks

Oregon Department of Environmental Quality

Land Use Compatibility Statement

State of Oregon
Department of
Environmental
Quality

What is a land use compatibility statement?

A LUCS is a form developed by DEQ to determine whether a DEQ permit or approval will be consistent with local government comprehensive plans and land use regulations.

Why is a LUCS required?

DEQ and other state agencies with permitting or approval activities that affect land use are required by Oregon law to be consistent with local comprehensive plans and have a process for determining consistency. DEQ activities affecting land use and the requirement for a LUCS may be found in Oregon Administrative Rules (OAR) Chapter 340, Division 18.

When is a LUCS required?

A LUCS is required for nearly all DEQ permits and certain approvals of plans or related activities that affect land use prior to issuance of a DEQ permit or approval. These permits and activities are listed in section 1.D on p. 2 of this form. A single LUCS can be used if more than one DEQ permit or approval is being applied for concurrently.

Permit modifications or renewals also require a LUCS when any of the following applies:

1. Physical expansion on the property or proposed use of additional land;
2. Alterations, expansions, improvements or changes in method or type of disposal at a solid waste disposal site as described in OAR 340-093-0070(4)(b);
3. A significant increase in discharges to water;
4. A relocation of an outfall outside of the source property; or
5. Any physical change or change of operation of an air pollutant source that results in a net significant emission rate increase as defined in OAR 340-200-0020.

How to complete a LUCS:

Step	Who Does It?	What Happens?
1	Applicant	Applicant completes Section 1 of the LUCS and submits it to the appropriate city or county planning office.
2	City or County Planning Office	City or county planning office completes Section 2 of the LUCS to indicate whether the activity or use is compatible with the acknowledged comprehensive plan and land use regulations, attaches written findings supporting the decision of compatibility, and returns the signed and dated LUCS to the applicant.
3	Applicant	Applicant submits the completed LUCS and any supporting information provided by the city or county to DEQ along with the DEQ permit application or approval request.

Where to get help:

For questions about the LUCS process, contact the DEQ staff responsible for processing the permit or approval. DEQ staff may be reached at 1-800-452-4011 (toll-free, inside Oregon) or 503-229-5630. For general questions, please contact DEQ land use staff listed on our Land Use Compatibility Statement page online.

***CULTURAL RESOURCES PROTECTION LAWS**: Applicants involved in ground-disturbing activities should be aware of federal and state cultural resources protection laws. ORS 358.920 prohibits the excavation, injury, destruction, or alteration of an archeological site or object or removal of archeological objects from public and private lands without an archeological permit issued by the State Historic Preservation Office. 16 USC 470, Section 106, National Historic Preservation Act of 1966 requires a federal agency, prior to any undertaking, to take into account the effect of the undertaking that is included on or eligible for inclusion in the National Register. For further information, contact the State Historic Preservation Office at 503-378-4168, ext. 232.*

SECTION 1 - TO BE COMPLETED BY APPLICANT	
1A. Applicant Name: Jordan Cove Energy Project, L.P.	**1B. Project Name: JCEP LNG Terminal Project**
Contact Name: Rose Haddon	**Physical Address: Jordan Cove Road**
Mailing Address: Suite 500, 5615 Kirby	**City, State, Zip: Unincorporated Coos County, OR**
City, State, Zip: Houston, TX 77005	**Tax Lot #: Not yet partitioned**
Telephone: 713-400-2834	**Township: T25S Range: R13W Section: 5**
Tax Account #:	**Latitude: 43.434024 N**
	Longitude: 124.243219 W

1C. Describe the project, include the type of development, business, or facility and services or products provided (attach additional information if necessary):

Jordan Cove Energy Project is a natural gas liquefaction and export terminal in Coos County, Oregon to serve overseas markets around the Pacific Rim. Natural gas will be delivered to the terminal by pipeline from the Malin hub located in southern Oregon. The liquefaction and export facility will have an LNG production capacity of 7.8 mtpa. The facility will be developed on approximately 265 acres of industrial-zoned land owned by affiliates of JCEP.

1D. Check the type of DEQ permit(s) or approval(s) being applied for at this time.

- ☐ Air Quality Notice of Construction
- ☑ Air Contaminant Discharge Permit *(excludes portable facility permits)*
- ☐ Air Quality Title V Permit
- ☐ Air Quality Indirect Source Permit
- ☐ Parking/Traffic Circulation Plan
- ☐ Solid Waste Land Disposal Site Permit
- ☐ Solid Waste Treatment Facility Permit
- ☐ Solid Waste Composting Facility Permit (includes Anaerobic Digester)
- ☐ Conversion Technology Facility Permit
- ☐ Solid Waste Letter Authorization Permit
- ☐ Solid Waste Material Recovery Facility Permit
- ☐ Solid Waste Energy Recovery Facility Permit
- ☐ Solid Waste Transfer Station Permit
- ☐ Waste Tire Storage Site Permit
- ☐ Pollution Control Bond Request
- ☐ Hazardous Waste Treatment, Storage, or Disposal Permit
- ☐ Clean Water State Revolving Fund Loan Request
- ☐ Wastewater/Sewer Construction Plan/Specifications *(includes review of plan changes that require use of new land)*
- ☐ Water Quality NPDES Individual Permit
- ☐ Water Quality WPCF Individual Permit *(for onsite construction-installation permits use the DEQ Onsite LUCS form)*
- ☐ Water Quality NPDES Stormwater General Permit *(1200-A, 1200-C, 1200-CA, 1200-COLS, and 1200-Z)*
- ☐ Water Quality General Permit *(all general permits, except 600, 700-PM, 1700-A, and 1700-B when they are mobile.)*
- ☐ Water Quality 401 Certification for federal permit or license

1E. This application is for: ☐ Permit Renewal ☑ New Permit ☐ Permit Modification ☐ Other:

SECTION 2 - TO BE COMPLETED BY CITY OR COUNTY PLANNING OFFICIAL

Instructions: Written findings of fact for all local decisions are required; written findings from previous actions are acceptable. For uses allowed outright by the acknowledged comprehensive plan, DEQ will accept written findings in the form of a reference to the specific plan policies, criteria, or standards that were relied upon in rendering the decision with an indication of why the decision is justified based on the plan policies, criteria, or standards.

2A. The project proposal is located: ☐ Inside city limits ☐ Inside UGB ☐ Outside UGB

2B. Name of the city or county that has land use jurisdiction (the legal entity responsible for land use decisions for the subject property or land use):

SECTION 2 - TO BE COMPLETED BY CITY OR COUNTY PLANNING OFFICIAL	
Applicant Name:	**Project Name:**

2C. Is the activity allowed under Measure 49 (2007)? ☒ No, Measure 49 is not applicable ☐ Yes; if yes, then check one:

☐ Express; approved by DLCD order #:

☐ Conditional; approved by DLCD order #:

☐ Vested; approved by local government decision or court judgment docket or order #:

2D. Is the activity a composting facility?
☒ No ☐ Yes; Senate Bill 462 (2013) notification requirements have been met.

2E. Is the activity or use compatible with your acknowledged comprehensive plan as required by OAR 660-031?
Please complete this form to address the activity or use for which the applicant is seeking approval (see 1.C on the previous page). If the activity or use is to occur in multiple phases, please ensure that your approval addresses the phases described in 1.C. For example, if the applicant's project is described in 1.C as a subdivision and the LUCS indicates that only clearing and grading are allowed outright but does not indicate whether the subdivision is approved, DEQ will delay permit issuance until approval for the subdivision is obtained from the local planning official.

☐ The activity or use is specifically exempt by the acknowledged comprehensive plan; explain:

☐ **Yes**, the activity or use is pre-existing nonconforming use allowed outright by *(provide reference for local ordinance)*:

☐ **Yes**, the activity or use is allowed outright by *(provide reference for local ordinance)*:

☒ **Yes**, the activity or use received preliminary approval that includes requirements to fully comply with local requirements; findings are attached.

☐ **Yes**, the activity or use is allowed; findings are attached.

☐ **No**, see 2.C above, activity or use allowed under Measure 49; findings are attached.

☐ **No**, *(complete below or attach findings for noncompliance and identify requirements the applicant must comply with before compatibility can be determined)*:
Relevant specific plan policies, criteria, or standards:

Provide the reasons for the decision:

Additional comments (attach additional information as needed):

Planning Official Signature: Jill Rolfo **Title:** Planning Director

Print Name: Jill Rolfe **Telephone #:** 541-396-7770 **Date:** 9/20/17

If necessary, depending upon city/county agreement on jurisdiction outside city limits but within UGB:

Planning Official Signature: **Title:**

Print Name: **Telephone #:** **Date:**

Coos County Planning Department
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Jill Rolfe, Planning Director

NOTICE OF ADOPTION

August 31, 2016

Re: Coos County Planning Department File No. HBCU-15-05/FP-15-09
Final Decision and Order No. 16-08-071PL

On August 30, 2016, the Board of Commissioners Adopted Final Decision and Order No. 16-08-071PL in the matter of approving conditional use application for Jordan Cove Energy Project L.P. file Numbers HBCU-15-05/FP-15-09.

The final decision and order that was adopted can be found on the Coos County Planning Department webpage at:
http://www.co.coos.or.us/Departments/Planning/2015Applications.aspx.

The adoption of these final decisions and orders can be appealed to the Land Use Board of Appeals (LUBA), pursuant to ORS 197.830 to 197.845, by filing a Notice of Intent to Appeal within 21 days of the date of the final decision and order. For more information on this process, contact LUBA by telephone at 503-373-1265, or in writing at 775 Summer St. NE #330, Salem, Oregon 97301.

All documents related to this file are available for inspection, at no cost, in the Planning Department located at 225 North Adams Street, Coquille, Oregon. Copies may be purchased at a cost of 50 cents per page.

If you have any questions, please contact the Planning Department by telephone at (541) 396-7770, or visit the Planning Department at 225 North Adams Street, Coquille, Oregon, Monday through Friday, 8:00 AM - 5:00 PM (closed Noon - 1:00 PM).

COOS COUNTY PLANNING DEPARTMENT

Jill Rolfe

Jill Rolfe, Planning Director

C: Planning Commission
Parties
File

EC: Planning Commission
Sam Sprague
Sarah Robertson
Dave Perry, DLCD
Board of Commissioners
Curt Clay
Richard Knablin
Rob Taylor

CERTIFICATE OF MAILING

I hereby certify that on August 31, 2016, I deposited the attached NOTICE OF ADOPTION into the U.S. mail, in an envelope with first class postage affixed thereto to the parties listed out below.

Dated: August 31, 2016

Troy May

Troy May, Planning Assistant

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Barry Winters PO Box 706 Bandon, OR 97411	Bill Walsh & Shirley Weathers 1020 Butte Falls Highway Eagle Point, OR 97524	
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Tobe Burdett 1349 Bayview Ave North Bend, OR 97459	Tonia L. Moro 19 S. Orange Street Medford, OR 97501	Wayne Miller 88908 Gretna Green Ln Bandon, OR 97411
Wim De Friend 573 South 12th Coos Bay, OR 97420		

APPENDIX B

DETAILED EMISSION CALCULATIONS

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Table 1. Annual Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Source	NO_X (tpy)	CO (tpy)	SO_2 (tpy)	VOC (tpy)	$PM/PM_{10}/PM_{2.5}$ (tpy)	H_2SO_4 (tpy)	NH_3 (tpy)	Lead (tpy)	CO_2e (tpy)	HAPs (tpy)
Turbines	81.99	97.82	35.19	32.72	112.26	23.61	75.43	---	1,292,706	5.06
Turbines Startup/Shutdown	0.23	0.73	4.4E-03	0.10	0.11	--	--	---	188	6.2E-04
Oxidizer	63.25	38.50	19.84	1.08	3.85	--	--	2.5E-04	622,154	0.96
Auxiliary Boiler	0.96	1.16	0.36	0.67	1.30	2.4E-01	0.87	6.3E-05	15,193	0.24
Fire-Water Pumps	1.59	0.80	2.1E-03	4.5E-02	9.0E-02	1.6E-04	--	2.1E-05	241	3.6E-03
Backup Generators	3.33	0.28	2.5E-03	0.04	0.04	1.9E-04	--	2.4E-05	278	4.1E-03
Black Start Generators	1.49	0.21	8.8E-03	0.09	0.05	6.8E-04	--	8.6E-05	1,002	1.5E-02
Flares	0.86	3.90	3.9E-02	8.31	0.38	3.0E-03	--	7.3E-06	2,177	4.3E-02
Gas Up	2.09	9.5	0.16	17.53	1.12	1.3E-02	--	2.1E-05	4,351	3.8E-02
Fugitives	--	--	--	7.98	--	--	--	--	13,116	1.77
AIE	1.00	1.00	1.00	1.00	1.00	0.70	--	--	--	--
Potential Emissions	**156.8**	**153.9**	**56.6**	**69.5**	**120.2**	**24.6**	**76.3**	**4.8E-04**	**1,951,406**	**8.1**
PSD ACDP PSELs	**221.0**	**156.1**	**63.5**	**209.3**	**181.9**	**55.8**	**196.9**	**7.8E-03**	**2,165,917**	**8.9**
Percent Change (%)	**-29**	**-1**	**-11**	**-67**	**-34**	**-56**	**-61**	**-94**	**-10**	**-9**
Federal Major Source Threshold	**250**	**250**	**250**	**250**	**250**					
SER	**40**	**100**	**40**	**40**	**25/15/10**	**7**		**0.6**	**75,000**	
New Source Review/PSD?	Type B State NSR	Type B State NSR	Type B State NSR	Type B State NSR	Type B State NSR	Type B State NSR			No GHG State NSR	

Table 2. Combustion Unit Rates and Operational Characteristics
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Parameter		Turbines	Thermal Oxidizer	Auxiliary Boiler	Marine Enclosed Flare	Multipoint Ground Flare	Firewater Pumps	Black Start Generator Engines	Backup Generators
Fuel	(1)	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Diesel	Diesel	Diesel
Fuel Type	(2)	Pipeline	Pipeline	Pipeline	Pipeline	Pipeline	ULSD	ULSD	ULSD
Sulfur Content	(3)	0.01 grains/dscf	0.01 grains/dscf	0.01 grains/dscf	0.01 grains/dscf	0.01 grains/dscf	15 ppmvd	15 ppmvd	15 ppmvd
Heating Value of Fuel, HHV	(3)	952 Btu/scf	952 Btu/scf	1024.6 Btu/scf	868 Btu/scf	868 Btu/scf	140,005 Btu/gal	140,005 Btu/gal	140,005 Btu/gal
Number of Units	(1)	5	1	1	6	28	3	2	2
Hours of Operation	(1)	8,760	8,760	876	8,760	8,760	200	200	200
Rating	(1)	524.1 MMBtu/hr	110 MMBtu/hr	296.2 MMBtu/hr	0.74 MMBtu/hr	2.13 MMBtu/hr	700 hp	4,376 hp	800 kW
Stack Inside Diameter (ft)	(1)	10	9.5	6	45	Wall Heights = 85' on E+S and 60' on N+W	0.67	1.67	0.67
Stack Height (ft)	(1)	119	131	100	100	Field Dimensions = 259' E-W x 227' N-S	18	18	13
Exhaust Flowrate (acfm)	(1)								
Exit Velocity (ft/sec)	(1)	71	42	49	30		193	177	287
Exit Temperature (˚F)	(1)	243	1,600	330	1832	ambient	948.3	873.6	952.5

Notes:
(1) Provided by KBJ.
(2) Engines are required to combust fuel with 15 ppm sulfur or less per 40 CFR 60 Subpart IIII.
(3) Site-specific data provided by KBJ.

Table 3. Natural Gas Turbines Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon
Scenario: 4000 hours 100% load DB, 4760 hours 100% load no DB

Pollutant		Emission Factor		Hourly Emissions per Unit [(a)] (lb/hr)	Annual Emissions [(b)] (tons/yr)
Criteria Pollutants					
NO_X	100% Load - DB fired	3.8 lb/hr	(1)	3.75	81.99
	100% Load - DB unfired	3.7 lb/hr			
CO	100% Load - DB fired	4.6 lb/hr	(1)	4.47	97.82
	100% Load - DB unfired	4.4 lb/hr			
SO_2	100% Load - DB fired	1.64 lb/hr	(1), (2)	1.61	35.19
	100% Load - DB unfired	1.58 lb/hr			
VOC	100% Load - DB fired	1.7 lb/hr	(1)	1.49	32.72
	100% Load - DB unfired	1.3 lb/hr			
$PM/PM_{10}/PM_{2.5}$	100% Load - DB fired	5.4 lb/hr		5.13	112.26
	100% Load - DB unfired	4.9 lb/hr	(1)		
H_2SO_4	100% Load - DB fired	1.10 lb/hr	(1)	1.08	23.61
	100% Load - DB unfired	1.06 lb/hr			
NH_3	100% Load - DB fired	3.5 lb/hr	(1)	3.45	75.43
	100% Load - DB unfired	3.4 lb/hr			
Lead		---	(3)	---	---
CO_2e		---	(4)	59,053	1,292,706
CO_2	100% Load - DB fired	60,218 lb/hr	(1)	58,990	1,291,320
	100% Load - DB unfired	57,958 lb/hr			
CH_4		0.001 kg/MMBtu	(5)	1.155	25.293
N_2O		0.0001 kg/MMBtu	(5)	0.116	2.529
Hazardous Air Pollutants					
Acetaldehyde - Turbine		4.0E-05 lb/MMBtu	(6)	2.0E-02	4.4E-01
Acrolein - Turbine		6.4E-06 lb/MMBtu	(6)	3.2E-03	7.1E-02
Benzene - Turbine		1.2E-05 lb/MMBtu	(6)	6.1E-03	1.3E-01
Benzene - Duct Burner		2.1E-03 lb/MMscf	(7)	4.3E-05	4.3E-04
1,3-Butadiene - Turbine		4.3E-07 lb/MMBtu	(6)	2.2E-04	4.7E-03
Dichlorobenzene - Duct Burner		1.2E-03 lb/MMscf	(7)	2.5E-05	2.5E-04
Ethylbenzene - Turbine		3.2E-05 lb/MMBtu	(6)	1.6E-02	3.5E-01
Formaldehyde - Turbine		1.0E-04 lb/MMBtu	(8)	5.0E-02	1.1E+00
Formaldehyde - Duct Burner		7.5E-02 lb/MMscf	(7)	1.6E-03	1.6E-02
Hexane - Duct Burner		1.8E+00 lb/MMscf	(7)	3.7E-02	3.7E-01
Naphthalene - Turbine		1.3E-06 lb/MMBtu	(6)	6.6E-04	1.4E-02
Naphthalene - Duct Burner		6.1E-04 lb/MMscf	(7)	1.3E-05	1.3E-04
PAH - Turbine		2.2E-06 lb/MMBtu	(6)	1.1E-03	2.4E-02
PAH - Duct Burner		8.9E-05 lb/MMscf	(7)	1.8E-06	1.8E-05
Propylene Oxide - Turbine		2.9E-05 lb/MMBtu	(6)	1.5E-02	3.2E-01
Toluene - Turbine		1.3E-04 lb/MMBtu	(6)	6.6E-02	1.4E+00
Toluene - Duct Burner		3.4E-03 lb/MMscf	(7)	7.0E-05	7.0E-04
Xylenes - Turbine		6.4E-05 lb/MMBtu	(6)	3.2E-02	7.1E-01
Arsenic		2.0E-04 lb/MMscf	(3)	1.1E-04	2.4E-03
Beryllium		1.2E-05 lb/MMscf	(3)	6.6E-06	1.4E-04
Cadmium		1.1E-03 lb/MMscf	(3)	6.1E-04	1.3E-02
Chromium		1.4E-03 lb/MMscf	(3)	7.7E-04	1.7E-02
Cobalt		8.4E-05 lb/MMscf	(3)	4.6E-05	1.0E-03

Pollutant	Emission Factor		Hourly Emissions per Unit [(a)] (lb/hr)	Annual Emissions [(b)] (tons/yr)
Manganese	3.8E-04 lb/MMscf	(3)	2.1E-04	4.6E-03
Mercury	2.6E-04 lb/MMscf	(3)	1.4E-04	3.1E-03
Nickel	2.1E-03 lb/MMscf	(3)	1.2E-03	2.5E-02
Selenium	2.4E-05 lb/MMscf	(3)	1.3E-05	2.9E-04
Total HAPs			**0.25**	**5.06**
Maximum Individual HAP				**1.44**

Calculations:

(a) Hourly Emissions (lb/hr) = [Emission Factor for 100% load (lb/hr)] x [Time at 100% load (%) / 100] + [Emission Factor for 75% load (lb/hr)] x [Time at 75% load (%) / 100]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (MMBtu/hr)] x [2.20462 (lb/kg)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Heat Rate (MMBtu/hr)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMscf)] x [Heat Rate (MMBtu/hr)] / [Fuel Heat Content (MMBtu/MMscf)]

Hours at 100% load DB fired (%) =	4000	(9)
Hours at 100% load DB unfired (%) =	4760	(9)
Turbine Maximum Heat Rate (MMBtu/hr) =	504.4	(10)
Duct Burner Maximum Heat Rate (MMBtu/hr) =	19.7	(10)
Maximum Heat Rate (MMBtu/hr) =	524.1	(10)
Fuel Heat Content (Btu/scf) =	952	(11)

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Turbine Hours of Operation (hr/yr) - Startup/Shutdown Hours (hr/yr)] x [Number of Units] / [2,000 (lb/ton)]

Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Duct Burner Hours of Operation (hr/yr)] x [Number of Units] / [2,000 (lb/ton)]

Number of Units =	5	(9)
Duct Burner Hours of Operation (hr/yr) =	4,000	(12)
Turbine Hours of Operation (hr/yr) =	8,760	(9)
Startup/Shutdown Hours (hr/yr) =	3.8	(13)

Notes:

(1) Emission estimates provided by manufacturer.

(2) SO_2 emissions include assumptions of 20 percent by volume oxidation rate in CO catalyst and 3 percent by volume oxidation rate in SCR.

(3) AP-42, Chapter 1.4, Table 1.4-4. Emission Factors for Metals from Natural Gas Combustion, July 1998. Note emission factor for lead is ND as indicated in AP-42, Chapter 3.1-2a, Table 3.1, Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines.

(4) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(5) Emission Factors from Table C-2 to Subpart C of 40 CFR Part 98 - Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

(6) AP-42, Chapter 3.1, Table 3.1-3. Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines, April 2000.

(7) AP-42, Chapter 1.4, Table 1.4-3. Emission Factors for Speciated Organic Compounds from Natural Gas Combustion, July 1998. HAP emission factors used for Duct Burners.

(8) California Air Resource Board (CARB) emission inventory for NG turbine.

(9) Percentage of time at specific loads, number of units, and hours of operation provided by KBJ.

(10) Maximum heat rate at 100% load with duct burners provided by manufacturer (see Table 13).

(11) Provided by KBJ.

(12) Provided by KBJ.

(13) KBJ estimates 12 startup per year at 10 minutes per startup and 12 shutdowns per year at 9 minutes per shutdown. See Table 4 for additional startup and shutdown calculations.

Table 4. Natural Gas Turbines Startup/Shutdown Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Startup Emission Factor per Event		Shutdown Emission Factor per Event		Emissions per Startup Event [(a)] (lb)	Emissions per Shutdown Event [(a)] (lb)	Annual Emissions [(b)] (tons/yr)
Criteria Pollutants							
NO_X	3.8 lb	(1)	3.7 lb	(1)	3.80	3.70	0.23
CO	11.5 lb	(1)	12.8 lb	(1)	11.50	12.80	0.73
SO_2	7.7E-02 lb	(2)	6.9E-02 lb	(2)	7.7E-02	6.9E-02	4.4E-03
VOC	1.6 lb	(1)	1.8 lb	(1)	1.60	1.80	0.10
$PM/PM_{10}/PM_{2.5}$	0.40 lb	(1)	3.3 lb	(1)	0.40	3.30	0.11
H_2SO_4	---		---		---	---	---
NH_3	---		---		---	---	---
Lead	---	(3)	---	(3)	---	---	---
CO_2e	---	(4)	---	(4)	3,319	2,948	188.02
CO_2	3,316 lb	(1)	2,945 lb	(1)	3,316	2,945	187.83
CH_4	0.001 kg/MMBtu	(5)	0.001 kg/MMBtu	(5)	5.7E-02	5.7E-02	3.4E-03
N_2O	0.0001 kg/MMBtu	(5)	0.0001 kg/MMBtu	(5)	5.7E-03	5.7E-03	3.4E-04
Hazardous Air Pollutants							
Acetaldehyde	4.0E-05 lb/MMBtu	(6)	4.0E-05 lb/MMBtu	(6)	1.0E-03	9.2E-04	5.8E-05
Acrolein	6.4E-06 lb/MMBtu	(6)	6.4E-06 lb/MMBtu	(6)	1.7E-04	1.5E-04	9.4E-06
Benzene	1.2E-05 lb/MMBtu	(6)	1.2E-05 lb/MMBtu	(6)	3.1E-04	2.8E-04	1.8E-05
1,3-Butadiene	4.3E-07 lb/MMBtu	(6)	4.3E-07 lb/MMBtu	(6)	1.1E-05	9.9E-06	6.3E-07
Ethylbenzene	3.2E-05 lb/MMBtu	(6)	3.2E-05 lb/MMBtu	(6)	8.3E-04	7.3E-04	4.7E-05
Formaldehyde	1.0E-04 lb/MMBtu	(8)	1.0E-04 lb/MMBtu	(8)	2.6E-03	2.3E-03	1.5E-04
Naphthalene	1.3E-06 lb/MMBtu	(6)	1.3E-06 lb/MMBtu	(6)	3.4E-05	3.0E-05	1.9E-06
PAH	2.2E-06 lb/MMBtu	(6)	2.2E-06 lb/MMBtu	(6)	5.7E-05	5.0E-05	3.2E-06
Propylene Oxide	2.9E-05 lb/MMBtu	(6)	2.9E-05 lb/MMBtu	(6)	7.5E-04	6.6E-04	4.2E-05
Toluene	1.3E-04 lb/MMBtu	(6)	1.3E-04 lb/MMBtu	(6)	3.4E-03	3.0E-03	1.9E-04
Xylenes	6.4E-05 lb/MMBtu	(6)	6.4E-05 lb/MMBtu	(6)	1.7E-03	1.5E-03	9.4E-05
Arsenic	2.0E-04 lb/MMscf	(3)	2.0E-04 lb/MMscf	(3)	5.4E-06	4.8E-06	3.1E-07
Beryllium	1.2E-05 lb/MMscf	(3)	1.2E-05 lb/MMscf	(3)	3.3E-07	2.9E-07	1.8E-08
Cadmium	1.1E-03 lb/MMscf	(3)	1.1E-03 lb/MMscf	(3)	3.0E-05	2.7E-05	1.7E-06
Chromium	1.4E-03 lb/MMscf	(3)	1.4E-03 lb/MMscf	(3)	3.8E-05	3.4E-05	2.2E-06
Cobalt	8.4E-05 lb/MMscf	(3)	8.4E-05 lb/MMscf	(3)	2.3E-06	2.0E-06	1.3E-07
Manganese	3.8E-04 lb/MMscf	(3)	3.8E-04 lb/MMscf	(3)	1.0E-05	9.2E-06	5.8E-07
Mercury	2.6E-04 lb/MMscf	(3)	2.6E-04 lb/MMscf	(3)	7.0E-06	6.3E-06	4.0E-07
Nickel	2.1E-03 lb/MMscf	(3)	2.1E-03 lb/MMscf	(3)	5.7E-05	5.1E-05	3.2E-06
Selenium	2.4E-05 lb/MMscf	(3)	2.4E-05 lb/MMscf	(3)	6.5E-07	5.8E-07	3.7E-08
Total HAPs					**0.01**	**0.01**	**6.2E-04**
Maximum Individual HAP							**1.9E-04**

Calculations:

(a) Emission Factor (lb/Event) = [Sulfur Content (grains/scf)] / [7,000 (grains/lb)] x [Fuel Consumption (lb)] / [Fuel Density (lb/scf)] x [Molecular Weight SO_2 (lb/lb-mole)] \ [Molecular Weight S (lb/lb-mole)]

Emission Factor (lb/Event) = [Emission Factor (kg/MMBtu)] x [2.20462 (lb/kg)] x [Fuel Consumption (lb)] / [Fuel Density (lb/scf)] x [Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]

Emission Factor (lb/Event) = [Emission Factor (lb/MMscf)] x [Fuel Consumption (lb)] / [Fuel Density (lb/scf)] / [1,000,000 (scf/MMscf)]

Emission Factor (lb/Event) = [Emission Factor (lb/MMBtu)] x [Fuel Consumption (lb)] / [Fuel Density (lb/scf)] x [Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]

Fuel Sulfur Content (grains/scf) =	0.01	(2)
Startup Fuel Consumption (lb) =	1,200	(1)
Shutdown Fuel Consumption (lb) =	1,067	(1)
Fuel Heat Content (Btu/scf) =	952	(8)
Fuel Density (lb/scf) =	0.044	(9)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	

(b) Annual Emissions (tons/yr) = {[Emissions per Startup Event (lb/Event)] x [Count of Startup Events (Event)] + [Emissions per Shutdown Event (lb/Event)] x [Count of Shutdown Events (Event)]} x [Number of Units] / [2,000 (lb/ton)]

Count of Startup Events =	12	(10)

Pollutant	Startup Emission Factor per Event	Shutdown Emission Factor per Event	Emissions per Startup Event [a] (lb)	Emissions per Shutdown Event [a] (lb)	Annual Emissions [b] (tons/yr)

Count of Shutdown Events =	12	(10)
Number of Units =	5	(11)

Notes:

(1) Emission estimates and fuel use provided by manufacturer.
(2) Sulfur content provided by KBJ as site data.
(3) AP-42, Chapter 1.4, Table 1.4-4. Emission Factors for Metals from Natural Gas Combustion, July 1998. Note emission factor for lead is ND as indicated in AP-42, Chapter 3.1, Table 3.1-2a, Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines.
(4) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.
(5) Emission Factors from Table C-2 to Subpart C of 40 CFR Part 98 - Default CH_4 and N_2O Emission Factors for Various Types of Fuel.
(6) AP-42, Chapter 3.1, Table 3.1-3. Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines, April 2000.
(7) California Air Resource Board (CARB) emission inventory.
(8) Provided by KBJ
(9) Provided by KBJ
(10) KBJ estimates 12 startup per year at 10 minutes per startup and 12 shutdowns per year at 9 minutes per shutdown.
(11) Number of units provided by KBJ.

Table 5. Zeeco Natural Gas Thermal Oxidizer Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	14.44	lb/hr	(1)	14.44	63.25
CO	8.79	lb/hr	(1)	8.79	38.50
SO_2	4.53	lb/hr	(1)	4.53	19.84
VOC	0.01	lb/hr	(1)	0.01	0.03
VOC (venting)	6.00	lb/hr	(1)	6.00	1.05
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	(2)	0.88	3.85
H_2SO_4	---			---	---
NH_3	---			---	---
Lead	5.0.E-04	lb/MMscf	(2)	5.78E-05	2.5E-04
CO_2e	---		(3)	261,758	622,154
CO_2	137,049	lb/hr	(1)	137,049	600,274
CO_2 (venting)	123,471	lb/hr		123,471	21,607
CH_4	0.001	kg/MMBtu	(4)	0.24	1.06
CH_4 (venting)	49.00	lb/hr		49.00	8.57
N_2O	0.0001	kg/MMBtu	(4)	2.4E-02	1.1E-01
Hazardous Air Pollutants					
Benzene	2.1E-03	lb/MMscf	(5)	2.4E-04	1.1E-03
Dichlorobenzene	1.2E-03	lb/MMscf	(5)	1.4E-04	6.1E-04
Formaldehyde	7.5E-02	lb/MMscf	(5)	8.7E-03	3.8E-02
Hexane	1.8E+00	lb/MMscf	(5)	0.21	0.91
Naphthalene	6.1E-04	lb/MMscf	(5)	7.1E-05	3.1E-04
Polycyclic Organic Matter	8.8E-05	lb/MMscf	(5)	1.0E-05	4.5E-05
Toluene	3.4E-03	lb/MMscf	(5)	3.9E-04	1.7E-03
Arsenic	2.0E-04	lb/MMscf	(6)	2.3E-05	1.0E-04
Beryllium	1.2E-05	lb/MMscf	(6)	1.4E-06	6.1E-06
Cadmium	1.1E-03	lb/MMscf	(6)	1.3E-04	5.6E-04
Chromium	1.4E-03	lb/MMscf	(6)	1.6E-04	7.1E-04
Cobalt	8.4E-05	lb/MMscf	(6)	9.7E-06	4.3E-05
Manganese	3.8E-04	lb/MMscf	(6)	4.4E-05	1.9E-04
Mercury	2.6E-04	lb/MMscf	(6)	3.0E-05	1.3E-04
Nickel	2.1E-03	lb/MMscf	(6)	2.4E-04	1.1E-03
Selenium	2.4E-05	lb/MMscf	(6)	2.8E-06	1.2E-05
Total HAPs				**0.22**	**0.96**
Maximum Individual HAP					**0.91**

Calculations:

(a) Hourly Emissions (lb/hr) = [Emission Factor (lb/MMscf)] x [Heat Rate (MMBtu/hr)] / [Fuel Heat Content (MMBtu/MMscf)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (MMBtu/hr)] x [2.20462 (lb/kg)]

Maximum Heat Rate (MMBtu/hr) =	110	(7)
Fuel Heat Content (Btu/scf) =	952	(8)

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] x [Number of Units] / [2,000 lb/ton]

Number of Units =	1	(9)
Hours of Operation (hr/yr) =	8,760	(9)

Notes:

(1) Emission estimates provided by KBJ. VOC emissions include 350 hours of venting.

(2) AP-42, Chapter 1.4, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, July 1998.

(3) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(4) Emission Factors from Table C-2 to Subpart C of 40 CFR Part 98 - Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

(5) AP-42, Chapter 1.4, Table 1.4-3. Emission Factors for Speciated Organic Compounds from Natural Gas Combustion, July 1998.

(6) AP-42, Chapter 1.4, Table 1.4-4. Emission Factors for Metals from Natural Gas Combustion, July 1998.

(7) Manufacturer specification sheet.

(8) Fuel gas system heat content.

(9) Number of units and hours of operation provided by KBJ.

Table 6. Natural Gas Auxiliary Boiler Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	2	ppmvd @ 15% O_2	(1)	2.18	0.96
CO	4	ppmvd @ 15% O_2	(1)	2.66	1.16
SO_2	0.01	grains S/scf	(2),(3)	0.83	0.36
VOC	4	ppmvd @ 15% O_2	(1)	1.52	0.67
$PM/PM_{10}/PM_{2.5}$	0.01	lb/MMBtu	(2)	2.96	1.30
H_2SO_4	---		(3)	0.56	0.24
NH_3	0.0067	lb/MMBtu	(1)	1.98	0.87
Lead	0.0005	lb/MMscf	(4)	1.45E-04	6.3E-05
CO_2e	---		(5)	34,688	15,193
CO_2	53.06	kg/MMBtu	(6)	34,652	15,178
CH_4	0.001	kg/MMBtu	(6)	0.65	0.29
N_2O	0.0001	kg/MMBtu	(6)	0.07	2.9E-02
Hazardous Air Pollutants					
Benzene	2.1E-03	lb/MMscf	(7)	6.1E-04	2.7E-04
Dichlorobenzene	1.2E-03	lb/MMscf	(7)	3.5E-04	1.5E-04
Formaldehyde	7.5E-02	lb/MMscf	(7)	2.2E-02	9.5E-03
Hexane	1.8E+00	lb/MMscf	(7)	0.52	0.23
Naphthalene	6.1E-04	lb/MMscf	(7)	1.8E-04	7.7E-05
Polycyclic Organic Matter	8.8E-05	lb/MMscf	(7)	2.6E-05	1.1E-05
Toluene	3.4E-03	lb/MMscf	(7)	9.8E-04	4.3E-04
Arsenic	2.0E-04	lb/MMscf	(8)	5.8E-05	2.5E-05
Beryllium	1.2E-05	lb/MMscf	(8)	3.5E-06	1.5E-06
Cadmium	1.1E-03	lb/MMscf	(8)	3.2E-04	1.4E-04
Chromium	1.4E-03	lb/MMscf	(8)	4.0E-04	1.8E-04
Cobalt	8.4E-05	lb/MMscf	(8)	2.4E-05	1.1E-05
Manganese	3.8E-04	lb/MMscf	(8)	1.1E-04	4.8E-05
Mercury	2.6E-04	lb/MMscf	(8)	7.5E-05	3.3E-05
Nickel	2.1E-03	lb/MMscf	(8)	6.1E-04	2.7E-04
Selenium	2.4E-05	lb/MMscf	(8)	6.9E-06	3.0E-06
Total HAPs				**0.55**	**0.24**
Maximum Individual HAP					**0.23**

Calculations:

(a) Hourly Emissions (lb/hr) = [Emission Concentration (ppmvd @ 15% O_2)] x [Conversion Factor (lb/scf-ppm)] x
[F_d (dscf/MMBtu)] x [20.9 / (20.9 - 15) (%)] x [Maximum Heat Rate (MMBtu/hr)]
Hourly Emissions (lb/hr) = [S Content (grains/scf)] x [Molecular Weight SO_2 (lb/lb-mole)] /
[Molecular Weight S (lb/lb-mole) x [Pilot and Purge Fuel Consumption (scf/hr)] / [7000 (grains/lb)] x
[1 - Conversion of SO_2 to H_2SO_4 (percent)]
Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Heat Rate (MMBtu/hr)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMscf)] x [Heat Rate (MMBtu/hr)] / [Fuel Heat Content (MMBtu/MMscf)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (MMBtu/hr)] x [2.20462 (lb/kg)]

Maximum Heat Rate, LHV (MMBtu/hr) =	269.3	(9)
Maximum Heat Rate, HHV (MMBtu/hr) =	296.2	(9)
Fuel Heat Content (Btu/scf) =	1,024.6	(10)
F_d (dscf/MMBtu) =	8,710	(11)
NO_X Conversion Factor (lb/scf-ppm) =	1.194E-07	(11)
CO Conversion Factor (lb/scf-ppm) =	7.268E-08	(11)
VOC Conversion Factor (lb/scf-ppm) =	4.153E-08	(11)
Conversion of SO_2 to H_2SO_4 (percent) =	44	(3)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] x [Number of Units] / [2,000 lb/ton]

Number of Units =	1	(12)
Hours of Operation (hr/yr) =	876	(12)

Notes:

(1) Emission estimates provided by manufacturer.

(2) Provided by KBJ.

(3) Assume conversion of SO_2 to SO_3 of 44 percent by volume as provided by KBJ.

(4) AP-42, Chapter 1.4, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, July 1998. Note lead is a HAP and is included in the HAP total.

(5) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(6) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(7) AP-42, Chapter 1.4, Table 1.4-3. Emission Factors for Speciated Organic Compounds from Natural Gas Combustion, July 1998.

(8) AP-42, Chapter 1.4, Table 1.4-4. Emission Factors for Metals from Natural Gas Combustion, July 1998.

(9) Maximum heat rate in LHV is supplied by KBJ. HHV is assumed to be 10% higher.

(10) Pipeline feed gas fuel heat content provided by JCLNG.

(11) See EPA Method 19 Tables 19-1 - Conversion Factors for Concentration, and 19-2 - F Factors for Various Fuels. Conversion factor for CO and VOC calculated used identical basis.

(12) Number of units and hours of operation provided by KBJ.

Table 7. Diesel Firewater Pump Engine Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	5.31	lb/hr	(1)	5.31	1.59
CO	2.68	lb/hr	(1)	2.68	0.80
SO_2	0.0015	weight percent S	(2)	7.1E-03	2.1E-03
VOC	0.15	lb/hr	(1)	0.15	0.05
$PM/PM_{10}/PM_{2.5}$	0.30	lb/hr	(1)	0.30	9.0E-02
H_2SO_4	---		(3)	5.4E-04	1.6E-04
NH_3	---			---	---
Lead	1.40E-05	lb/MMBtu	(4)	6.9E-05	2.1E-05
CO_2e	---		(5)	802	241
CO_2	73.96	kg/MMBtu	(6)	799	240
CH_4	0.003	kg/MMBtu	(6)	3.2E-02	9.7E-03
N_2O	0.0006	kg/MMBtu	(6)	6.5E-03	1.9E-03
Hazardous Air Pollutants					
Acetaldehyde	2.52E-05	lb/MMBtu	(7)	1.2E-04	3.7E-05
Acrolein	7.88E-06	lb/MMBtu	(7)	3.9E-05	1.2E-05
Benzene	7.76E-04	lb/MMBtu	(7)	3.8E-03	1.1E-03
Formaldehyde	7.89E-05	lb/MMBtu	(7)	3.9E-04	1.2E-04
Naphthalene	1.30E-04	lb/MMBtu	(8)	6.4E-04	1.9E-04
Polycyclic Organic Matter	8.20E-05	lb/MMBtu	(8)	4.0E-04	1.2E-04
Toluene	2.81E-04	lb/MMBtu	(7)	1.4E-03	4.1E-04
Xylenes	1.93E-04	lb/MMBtu	(7)	9.5E-04	2.8E-04
Arsenic	1.1E-05	lb/MMBtu	(9)	5.4E-05	1.6E-05
Beryllium	3.1E-07	lb/MMBtu	(9)	1.5E-06	4.6E-07
Cadmium	4.8E-06	lb/MMBtu	(9)	2.4E-05	7.1E-06
Chromium	1.1E-05	lb/MMBtu	(9)	5.4E-05	1.6E-05
Manganese	7.9E-04	lb/MMBtu	(9)	3.9E-03	1.2E-03
Mercury	1.2E-06	lb/MMBtu	(9)	5.9E-06	1.8E-06
Nickel	4.6E-06	lb/MMBtu	(9)	2.3E-05	6.8E-06
Selenium	2.5E-05	lb/MMBtu	(9)	1.2E-04	3.7E-05
Total HAPs				**0.01**	**3.6E-03**
Maximum Individual HAP					**1.2E-03**

Calculations:

(a) Hourly Emissions (lb/hr) = [S (wt%) / 100] x [Fuel Density (lb/gal)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr) / [Fuel Heat Content (Btu/gal)] x [SO_2 Molecular Weight (lb/lb-mol)] / [S Molecular Weight (lb/lb-mol)] x [1 - Conversion of SO_2 to H_2SO_4 (percent)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] / [1,000,000 (Btu/MMBtu)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] x

[2.20462 (lb/kg)] / [1,000,000 (Btu/MMBtu)]

Maximum Rate (hp) =	700	(10)
Fuel Density (lb/gal) =	7.1	(11)
Fuel Heat Content (Btu/gal) =	140,005	(11)
Engine Heat Rate (Btu/hp-hr) =	7,000	(12)
Conversion of SO_2 to H_2SO_4 (percent) =	5	(3)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] x [Number of Units] / [2,000 lb/ton]

Number of Units =	3	(13)
Hours of Operation (hr/yr) =	200	(13)

Notes:

(1) Emissions performance data provided by manufacturer at rated speed potential site variation (1750 rpm). Maximum value at 50% of load or greater. Conservative to use lower load (highest) emission rates for CO, VOC, and PM.

(2) Engine is required to combust fuel with 15 ppm sulfur or less per 40 CFR 60 Subpart IIII.

(3) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(4) AP-42, Chapter 3.1, Table 3.1-2a. Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines, April 2000. Note lead is a HAP and is included in the HAP total.

(5) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(6) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(7) AP-42, Chapter 3.4, Table 3.4-3. Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(8) AP-42, Chapter 3.4, Table 3.4-4. PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(9) AP-42, Chapter 3.1, Table 3.1-5. Emission Factors for Metallic Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines, April 2000.

(10) Maximum engine rate supplied by KBJ.

(11) Site specific fuel heat content and fuel density provided by KBJ.

(12) AP-42, Chapter 3.3, Table 3.1-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines, footnote a, October 1996.

(13) Number of units and hours of operation provided by KBJ.

Table 8. Backup Diesel Generator Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [(a)] (lb/hr)	Annual Emissions [(b)] (tons/yr)
Criteria Pollutants					
NO_X	16.63	lb/hr	(1)	16.63	3.33
CO	1.42	lb/hr	(1)	1.42	0.28
SO_2	0.0015	weight percent S	(2)	1.2E-02	2.5E-03
VOC	0.20	lb/hr	(1)	0.20	0.04
$PM/PM_{10}/PM_{2.5}$	0.19	lb/hr	(1)	0.19	0.04
H_2SO_4	---		(3)	9.4E-04	1.9E-04
NH_3	---			---	---
Lead	1.40E-05	lb/MMBtu	(4)	1.2E-04	2.4E-05
CO_2e	---		(5)	1,390	278
CO_2	73.96	kg/MMBtu	(6)	1,386	277
CH_4	0.003	kg/MMBtu	(6)	0.06	1.1E-02
N_2O	0.0006	kg/MMBtu	(6)	1.1E-02	2.2E-03
Hazardous Air Pollutants					
Acetaldehyde	2.52E-05	lb/MMBtu	(7)	2.1E-04	4.3E-05
Acrolein	7.88E-06	lb/MMBtu	(7)	6.7E-05	1.3E-05
Benzene	7.76E-04	lb/MMBtu	(7)	6.6E-03	1.3E-03
Formaldehyde	7.89E-05	lb/MMBtu	(7)	6.7E-04	1.3E-04
Naphthalene	1.30E-04	lb/MMBtu	(8)	1.1E-03	2.2E-04
Polycyclic Organic Matter	8.20E-05	lb/MMBtu	(8)	7.0E-04	1.4E-04
Toluene	2.81E-04	lb/MMBtu	(7)	2.4E-03	4.8E-04
Xylenes	1.93E-04	lb/MMBtu	(7)	1.6E-03	3.3E-04
Arsenic	1.1E-05	lb/MMBtu	(9)	9.3E-05	1.9E-05
Beryllium	3.1E-07	lb/MMBtu	(9)	2.6E-06	5.3E-07
Cadmium	4.8E-06	lb/MMBtu	(9)	4.1E-05	8.2E-06
Chromium	1.1E-05	lb/MMBtu	(9)	9.3E-05	1.9E-05
Manganese	7.9E-04	lb/MMBtu	(9)	6.7E-03	1.3E-03
Mercury	1.2E-06	lb/MMBtu	(9)	1.0E-05	2.0E-06
Nickel	4.6E-06	lb/MMBtu	(9)	3.9E-05	7.8E-06
Selenium	2.5E-05	lb/MMBtu	(9)	2.1E-04	4.2E-05
Total HAPs				**0.02**	**4.1E-03**
Maximum Individual HAP					**1.3E-03**

Calculations:

(a) Hourly Emissions (lb/hr) = [S (wt%) / 100] x [Fuel Density (lb/gal)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr) / [Fuel Heat Content (Btu/gal)] x [SO_2 Molecular Weight (lb/lb-mol)] / [S Molecular Weight (lb/lb-mol)] x [1 - Conversion of SO_2 to H_2SO_4 (percent)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] / [1,000,000 (Btu/MMBtu)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] x

[2.20462 (lb/kg)] / [1,000,000 (Btu/MMBtu)]

Maximum Rate (kW) =	800	(10)
Maximum Rate (hp) =	1,214	(10)
Fuel Density (lb/gal) =	7.1	(11)
Fuel Heat Content (Btu/gal) =	140,005	(11)
Engine Heat Rate (Btu/hp-hr) =	7,000	(12)
Conversion of SO_2 to H_2SO_4 (percent) =	5	(3)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] x [Number of Units] / [2,000 lb/ton]

Number of Units =	2	(13)
Hours of Operation (hr/yr) =	200	(13)

Notes:

(1) Emissions performance data provided by manufacturer at rated speed potential site variation (1800 rpm). Maximum value at 50% of load or greater. Conservative to use lower load (highest) emission rates for CO, VOC, and PM.

(2) Engine is required to combust fuel with 15 ppm sulfur or less per 40 CFR 60 Subpart IIII.

(3) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(4) AP-42, Chapter 3.1, Table 3.1-2a. Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines, April 2000. Note lead is a HAP and is included in the HAP total.

(5) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(6) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(7) AP-42, Chapter 3.4, Table 3.4-3. Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(8) AP-42, Chapter 3.4, Table 3.4-4. PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(9) AP-42, Chapter 3.1, Table 3.1-5. Emission Factors for Metallic Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines, April 2000.

(10) Maximum engine rate supplied by KBJ.

(11) Site specific fuel heat content and fuel density provided by KBJ.

(12) AP-42, Chapter 3.3, Table 3.1-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines, footnote a, October 1996.

(13) Number of units and hours of operation provided by KBJ.

Table 9. Black Start Diesel Generator Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [(a)] (lb/hr)	Annual Emissions [(b)] (tons/yr)
Criteria Pollutants					
NO_X	7.43	lb/hr	(1)	7.43	1.49
CO	1.04	lb/hr	(1)	1.04	0.21
SO_2	0.0015	weight percent S	(2)	4.4E-02	8.8E-03
VOC	0.45	lb/hr	(1)	0.45	0.09
$PM/PM_{10}/PM_{2.5}$	0.23	lb/hr	(1)	0.23	0.05
H_2SO_4	---		(3)	3.4E-03	6.8E-04
NH_3	---			---	---
Lead	1.40E-05	lb/MMBtu	(4)	4.3E-04	8.6E-05
CO_2e	---		(5)	5,012	1,002
CO_2	73.96	kg/MMBtu	(6)	4,995	999
CH_4	0.003	kg/MMBtu	(6)	0.20	4.1E-02
N_2O	0.0006	kg/MMBtu	(6)	4.1E-02	8.1E-03
Hazardous Air Pollutants					
Acetaldehyde	2.52E-05	lb/MMBtu	(7)	7.7E-04	1.5E-04
Acrolein	7.88E-06	lb/MMBtu	(7)	2.4E-04	4.8E-05
Benzene	7.76E-04	lb/MMBtu	(7)	2.4E-02	4.8E-03
Formaldehyde	7.89E-05	lb/MMBtu	(7)	2.4E-03	4.8E-04
Naphthalene	1.30E-04	lb/MMBtu	(8)	4.0E-03	8.0E-04
Polycyclic Organic Matter	8.20E-05	lb/MMBtu	(8)	2.5E-03	5.0E-04
Toluene	2.81E-04	lb/MMBtu	(7)	8.6E-03	1.7E-03
Xylenes	1.93E-04	lb/MMBtu	(7)	5.9E-03	1.2E-03
Arsenic	1.1E-05	lb/MMBtu	(9)	3.4E-04	6.7E-05
Beryllium	3.1E-07	lb/MMBtu	(9)	9.5E-06	1.9E-06
Cadmium	4.8E-06	lb/MMBtu	(9)	1.5E-04	2.9E-05
Chromium	1.1E-05	lb/MMBtu	(9)	3.4E-04	6.7E-05
Manganese	7.9E-04	lb/MMBtu	(9)	2.4E-02	4.8E-03
Mercury	1.2E-06	lb/MMBtu	(9)	3.7E-05	7.4E-06
Nickel	4.6E-06	lb/MMBtu	(9)	1.4E-04	2.8E-05
Selenium	2.5E-05	lb/MMBtu	(9)	7.7E-04	1.5E-04
Total HAPs				**0.07**	**1.5E-02**
Maximum Individual HAP					**4.8E-03**

Calculations:

(a) Hourly Emissions (lb/hr) = [S (wt%) / 100] x [Fuel Density (lb/gal)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr) / [Fuel Heat Content (Btu/gal)] x [SO_2 Molecular Weight (lb/lb-mol)] / [S Molecular Weight (lb/lb-mol)] x [1 - Conversion of SO_2 to H_2SO_4 (percent)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Maximum Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] / [1,000,000 (Btu/MMBtu)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Heat Rate (hp)] x [Engine Heat Rate (Btu/hp-hr)] x

[2.20462 (lb/kg)] / [1,000,000 (Btu/MMBtu)]

Maximum Rate (hp) =	4,376	(10)
Fuel Density (lb/gal) =	7.1	(11)
Fuel Heat Content (Btu/gal) =	140,005	(11)
Engine Heat Rate (Btu/hp-hr) =	7,000	(12)
Conversion of SO_2 to H_2SO_4 (percent) =	5	(3)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] x [Number of Units] / [2,000 lb/ton]

Number of Units =	2	(13)
Hours of Operation (hr/yr) =	200	(13)

Notes:

(1) Emissions performance data provided by manufacturer at rated speed potential site variation (1800 rpm). Maximum value at 50% of load or greater. Conservative to use lower load (highest) emission rates for CO, VOC, and PM.

(2) Engine is required to combust fuel with 15 ppm sulfur or less per 40 CFR 60 Subpart IIII.

(3) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(4) AP-42, Chapter 3.1, Table 3.1-2a. Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines, April 2000. Note lead is a HAP and is included in the HAP total.

(5) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(6) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(7) AP-42, Chapter 3.4, Table 3.4-3. Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(8) AP-42, Chapter 3.4, Table 3.4-4. PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines, October 1996.

(9) AP-42, Chapter 3.1, Table 3.1-5. Emission Factors for Metallic Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines, April 2000.

(10) Maximum engine rate supplied by KBJ.

(11) Site specific fuel heat content and fuel density provided by KBJ.

(12) AP-42, Chapter 3.3, Table 3.1-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines, footnote a, October 1996.

(13) Number of units and hours of operation provided by KBJ.

Table 10. Natural Gas Ground Flare Pilot and Purge Gas Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	0.068	lb/MMBtu	(1)	0.14	0.64
CO	0.31	lb/MMBtu	(2)	0.66	2.90
SO_2	0.01	grains S/scf	(3),(4)	6.7E-03	2.9E-02
VOC	0.66	lb/MMBtu	(2)	1.41	6.16
$PM/PM_{10}/PM_{2.5}$	40	μg/L	(1)	6.5E-02	0.28
H_2SO_4	---		(4)	5.1E-04	2.2E-03
NH_3	---			---	---
Lead	0.0005	lb/MMscf	(5)	1.2E-06	5.4E-06
CO_2e	---		(6)	329	1,439.47
CO_2	53.06	kg/MMBtu	(7)	249.43	1,092.50
CH_4	0.001	kg/MMBtu	(7)	0.80	3.52
N_2O	0.0001	kg/MMBtu	(7)	0.20	0.87
Hazardous Air Pollutants					
Acetaldehyde	4.30E-02	lb/MMscf	(8)	1.1E-04	4.6E-04
Acrolein	1.00E-02	lb/MMscf	(8)	2.5E-05	1.1E-04
Benzene	1.59E-01	lb/MMscf	(8)	3.9E-04	1.7E-03
Ethylbenzene	1.44E+00	lb/MMscf	(8)	3.5E-03	1.6E-02
Formaldehyde	1.17E+00	lb/MMscf	(8)	2.9E-03	1.3E-02
N-Hexane	2.90E-02	lb/MMscf	(8)	7.1E-05	3.1E-04
Toluene	5.80E-02	lb/MMscf	(8)	1.4E-04	6.2E-04
Xylenes	2.90E-02	lb/MMscf	(8)	7.1E-05	3.1E-04
Polycyclic Organic Matter	1.40E-02	lb/MMscf	(8)	3.4E-05	1.5E-04
Arsenic	2.0E-04	lb/MMscf	(5)	4.9E-07	2.2E-06
Beryllium	1.2E-05	lb/MMscf	(5)	2.9E-08	1.3E-07
Cadmium	1.1E-03	lb/MMscf	(5)	2.7E-06	1.2E-05
Chromium	1.4E-03	lb/MMscf	(5)	3.4E-06	1.5E-05
Cobalt	8.4E-05	lb/MMscf	(5)	2.1E-07	9.0E-07
Manganese	3.8E-04	lb/MMscf	(5)	9.3E-07	4.1E-06
Mercury	2.6E-04	lb/MMscf	(5)	6.4E-07	2.8E-06
Nickel	2.1E-03	lb/MMscf	(5)	5.2E-06	2.3E-05
Selenium	2.4E-05	lb/MMscf	(5)	5.9E-08	2.6E-07
Total HAPs				**7.27E-03**	**3.2E-02**
Maximum Individual HAP					**1.6E-02**

Calculations:
(a) Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Pilot and Purge Fuel Consumption (scf/hr)] x
[Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]
Hourly Emissions (lb/hr) = [S Content (grains/scf)] x [Molecular Weight SO_2 (lb/lb-mole)] /

[Molecular Weight S (lb/lb-mole) x [Pilot and Purge Fuel Consumption (scf/hr)] / [7000 (grains/lb)] x [1 - Conversion of SO_2 to H_2SO_4 (percent)]

Hourly Emissions (lb/hr) = [Emission Factor (µg/L)] / [1,000,000 (µg/g)] x [0.00220462 (lb/g)] x [28.317 (L/ft^3)] x [10.6 (ft^3 exhaust/ft^3 fuel)] x [Pilot and Purge Fuel Consumption (scf/hr)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMscf)] x [Pilot and Purge Fuel Consumption (scf/hr) / [1,000,000 (scf/MMscf)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Pilot and Purge Fuel Consumption (scf/hr)] x [2.20462 (lb/kg)] x [Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]

No. of Unit =	28	
Total Pilot Fuel Consumption (MMBtu/hr) =	1.82	(9)
Total Purge Gas Consumption (scf/hr) =	360	(9)
Fuel Heat Content (Btu/scf) =	868	(10)
Pilot Fuel Consumption (scf/hr) =	2,098	
Purge Gas Consumption (MMBtu/hr) =	0.31	
Conversion of SO_2 to H_2SO_4 (percent) =	5	(4)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] / [2,000 lb/ton]

Hours of Operation (hr/yr) =	8,760	(11)

Notes:

(1) AP-42, Chapter 13.5, Table 13.5-1. THC and Soot Emissions Factors for Flare Operations, December 2016. PM emission factor is for lightly smoking flare.

(2) AP-42, Chapter 13.5, Table 13.5-2. VOC and CO Emissions Factors for Flare Operations, December 2016.

(3) Sulfur content of 0.01 grains per scf provided by KBJ.

(4) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(5) AP-42, Chapter 1.4, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, July 1998. Note lead is a HAP and is included in the HAP total.

(6) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(7) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(8) Ventura County Air Pollution Control District.

(9) Manufacturer specifications provided by KBJ. Ground flare consists of a warm and cold flare (combined multi-point ground flare).

(10) Site specific fuel heat content provided by KBJ.

(11) Hours of operation provided by KBJ.

Table 11. Natural Gas Marine Flare Pilot and Purge Gas Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions per Unit [a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	0.068	lb/MMBtu	(1)	0.05	0.22
CO	0.31	lb/MMBtu	(2)	0.23	1.01
SO_2	0.01	grains S/scf	(3),(4)	2.3E-03	1.0E-02
VOC	0.66	lb/MMBtu	(2)	0.49	2.14
$PM/PM_{10}/PM_{2.5}$	40	μg/L	(1)	2.3E-02	0.10
H_2SO_4	---		(4)	1.8E-04	7.8E-04
NH_3	---			---	---
Lead	0.0005	lb/MMscf	(5)	4.3E-07	1.9E-06
CO_2e	---		(6)	168	737.66
CO_2	53.06	kg/MMBtu	(7)	86.72	379.83
CH_4	0.001	kg/MMBtu	(7)	0.90	3.96
N_2O	0.0001	kg/MMBtu	(7)	0.20	0.87
Hazardous Air Pollutants					
Acetaldehyde	4.30E-02	lb/MMscf	(8)	3.7E-05	1.6E-04
Acrolein	1.00E-02	lb/MMscf	(8)	8.5E-06	3.7E-05
Benzene	1.59E-01	lb/MMscf	(8)	1.4E-04	6.0E-04
Ethylbenzene	1.44E+00	lb/MMscf	(8)	1.2E-03	5.4E-03
Formaldehyde	1.17E+00	lb/MMscf	(8)	1.0E-03	4.4E-03
N-Hexane	2.90E-02	lb/MMscf	(8)	2.5E-05	1.1E-04
Toluene	5.80E-02	lb/MMscf	(8)	5.0E-05	2.2E-04
Xylenes	2.90E-02	lb/MMscf	(8)	2.5E-05	1.1E-04
Polycyclic Organic Matter	1.40E-02	lb/MMscf	(8)	1.2E-05	5.2E-05
Arsenic	2.0E-04	lb/MMscf	(5)	1.7E-07	7.5E-07
Beryllium	1.2E-05	lb/MMscf	(5)	1.0E-08	4.5E-08
Cadmium	1.1E-03	lb/MMscf	(5)	9.4E-07	4.1E-06
Chromium	1.4E-03	lb/MMscf	(5)	1.2E-06	5.2E-06
Cobalt	8.4E-05	lb/MMscf	(5)	7.2E-08	3.1E-07
Manganese	3.8E-04	lb/MMscf	(5)	3.2E-07	1.4E-06
Mercury	2.6E-04	lb/MMscf	(5)	2.2E-07	9.7E-07
Nickel	2.1E-03	lb/MMscf	(5)	1.8E-06	7.9E-06
Selenium	2.4E-05	lb/MMscf	(5)	2.1E-08	9.0E-08
Total HAPs				**2.53E-03**	**1.1E-02**
Maximum Individual HAP					**5.4E-03**

Calculations:

(a) Hourly Emissions (lb/hr) = [Emission Factor (lb/MMBtu)] x [Pilot and Purge Fuel Consumption (scf/hr)] x [Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]

Hourly Emissions (lb/hr) = [S Content (grains/scf)] x [Molecular Weight SO_2 (lb/lb-mole)] / [Molecular Weight S (lb/lb-mole) x [Pilot and Purge Fuel Consumption (scf/hr)] / [7000 (grains/lb)] x

[1 - Conversion of SO_2 to H_2SO_4 (percent)]

Hourly Emissions (lb/hr) = [Emission Factor (µg/L)] / [1,000,000 (µg/g)] x [0.00220462 (lb/g)] x [28.317 (L/ft^3)] x [10.6 (ft^3 exhaust/ft^3 fuel)] x [Pilot and Purge Fuel Consumption (scf/hr)]

Hourly Emissions (lb/hr) = [SO_2 Hourly Emissions (lb/hr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Hourly Emissions (lb/hr) = [Emission Factor (lb/MMscf)] x [Pilot and Purge Fuel Consumption (scf/hr) / [1,000,000 (scf/MMscf)]

Hourly Emissions (lb/hr) = [Emission Factor (kg/MMBtu)] x [Pilot and Purge Fuel Consumption (scf/hr)] x [2.20462 (lb/kg)] x [Fuel Heat Content (Btu/scf)] / [1,000,000 (Btu/MMBtu)]

No. of Unit =	6	
Total Pilot Fuel Consumption (MMBtu/hr) =	0.39	(9)
Total Purge Gas Consumption (scf/hr) =	405	(9)
Fuel Heat Content (Btu/scf) =	868	(10)
Total Pilot Fuel Consumption (scf/hr) =	450	
Total Purge Gas Consumption (MMBtu/hr) =	0.35	
Conversion of SO_2 to H_2SO_4 (percent) =	5	(4)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] / [2,000 lb/ton]

Hours of Operation (hr/yr) =	8,760	(11)

Notes:

(1) AP-42, Chapter 13.5, Table 13.5-1. THC and Soot Emissions Factors for Flare Operations, December 2016. PM emission factor is for lightly smoking flare.

(2) AP-42, Chapter 13.5, Table 13.5-2. VOC and CO Emissions Factors for Flare Operations, December 2016.

(3) Sulfur content of 0.01 grains per scf provided by KBJ.

(4) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(5) AP-42, Chapter 1.4, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, July 1998. Note lead is a HAP and is included in the HAP total.

(6) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(7) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(8) Ventura County Air Pollution Control District.

(9) Manufacturer specifications provided by KBJ. Flare is a marine flare (enclosed ground flare).

(10) Site specific fuel heat content provided by KBJ.

(11) Hours of operation provided by KBJ.

Table 12. LNG Ship Gas Up Emissions (from Marine Flare)
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Emission Factor			Hourly Emissions[a] (lb/hr)	Annual Emissions [b] (tons/yr)
Criteria Pollutants					
NO_X	0.068	lb/MMBtu	(1)	62.31	2.09
CO	0.31	lb/MMBtu	(2)	284.07	9.53
SO_2	0.01	grains S/scf	(3),(4)	4.89	0.16
VOC	0.57	lb/MMBtu	(2)	522.31	17.53
$PM/PM_{10}/PM_{2.5}$	40	µg/L	(1)	33.43	1.12
H_2SO_4	---		(4)	0.37	0.01
NH_3	---			---	
Lead	0.0005	lb/MMscf	(5)	6.3E-04	0.00002
CO_2e	---		(6)	129,644	4,351
CO_2	53.06	kg/MMBtu	(7)	129,510	4,346
CH_4	0.001	kg/MMBtu	(7)	2.4	0.08
N_2O	0.0001	kg/MMBtu	(7)	0.2	0.01
Hazardous Air Pollutants					
Acetaldehyde	4.30E-02	lb/MMscf	(8)	3.6E-02	5.5E-04
Acrolein	1.00E-02	lb/MMscf	(8)	8.4E-03	1.3E-04
Benzene	1.59E-01	lb/MMscf	(8)	1.3E-01	2.0E-03
Ethylbenzene	1.44E+00	lb/MMscf	(8)	1.2E+00	1.8E-02
Formaldehyde	1.17E+00	lb/MMscf	(8)	9.9E-01	1.5E-02
N-Hexane	2.90E-02	lb/MMscf	(8)	2.4E-02	3.7E-04
Toluene	5.80E-02	lb/MMscf	(8)	4.9E-02	7.4E-04
Xylenes	2.90E-02	lb/MMscf	(8)	2.4E-02	3.7E-04
Polycyclic Organic Matter	1.40E-02	lb/MMscf	(8)	1.2E-02	1.8E-04
Arsenic	2.0E-04	lb/MMscf	(5)	1.7E-04	2.5E-06
Beryllium	1.2E-05	lb/MMscf	(5)	1.0E-05	1.5E-07
Cadmium	1.1E-03	lb/MMscf	(5)	9.3E-04	1.4E-05
Chromium	1.4E-03	lb/MMscf	(5)	1.2E-03	1.8E-05
Cobalt	8.4E-05	lb/MMscf	(5)	7.1E-05	1.1E-06
Manganese	3.8E-04	lb/MMscf	(5)	3.2E-04	4.8E-06
Mercury	2.6E-04	lb/MMscf	(5)	2.2E-04	3.3E-06
Nickel	2.1E-03	lb/MMscf	(5)	1.8E-03	2.7E-05
Selenium	2.4E-05	lb/MMscf	(5)	2.0E-05	3.0E-07
Total HAPs					**3.8E-02**
Maximum Individual HAP					**1.8E-02**

Flaring of Excess Boil off gas generated during gas up of the LNG carrier each time it returns to LNG transportation service following a drydock overhaul period (when the entire cargo system needs to be fully warmed up and gas freed) is expected to occur at the JCLNG terminal for up to 4 ships per year. The operational assumption is 50% of the gas up volume would be recovered and 50% flared. A worst-case scenario would be flaring of 100% of the gas. Inert gas and methane are routed to the marine flare for combustion.

Calculations:

(a) Hourly Emissions (lb/hr) = [Annual Emissions (tons/yr)] x [2000 lbs/ton)] / [Number of gas up events/year] / [Duration of flaring for event (hours/event)]

Average tanker size hull gas relief (LNG tonnes/ship) =	355.7	(9)
Average flared gas -Turbulent mixing (MMBtu/ship, LHV) =	22,264	(9)
Duration of turbulent event flaring (hours/event) =	30	(9)
Number of turbulent events per year (ships/year) =	1	(9)
Average flared gas - Laminar mixing (MMBtu/ship, LHV) =	19,619	(9)

Duration of non-turbulent event flaring (hours/event) =	18.52	(9)
Number of non-turbulent events per year (ships/year) =	2	(9)
Average flared gas per year (MMBtu/year) =	61,502	
Average duration of event flaring (hours/event) =	22.37	(9)
Fuel Heat Content (Btu/scf) =	877	(9)
Conversion of SO_2 to H_2SO_4 (percent) =	5	(4)
Molecular Weight S (lb/lb-mole) =	32	
Molecular Weight SO_2 (lb/lb-mole) =	64	
Molecular Weight H_2SO_4 (lb/lb-mole) =	98	

(b) Annual Emissions (tons/yr) = [Flared gas per year (MMBtu/yr)] x [Emission factor (lb/MMBtu)] / [2,000 lb/ton]

Annual Emissions (ton/yr) = [S Content (grains/scf)] x [Molecular Weight SO_2 (lb/lb-mole)] / [Molecular Weight S (lb/lb-mole) x [Flared gas (MMBtu/yr)/ Flared Gas HHV (Btu/scf)* 1,000,000 Btu/MMBtu] / [7000 (grains/lb)] x [1 - Conversion of SO_2 to H_2SO_4 (percent)]

Annual Emissions (ton/yr) = [Emission Factor (μg/L)] / [1,000,000 (μg/g)] x [0.00220462 (lb/g)] x [28.317 (L/ft^3)] x [10.6 (ft^3 exhaust/ft^3 fuel)] x [Flared gas (MMBtu/yr) / Flared Gas HHV (Btu/scf) * 1,000,000 Btu/MMBtu]

Annual Emissions (ton/yr) = [SO_2 Annual Emissions (ton/yr)] x [Conversion of SO_2 to H_2SO_4 (percent)] x [Molecular Weight H_2SO_4 (lb/lb-mole)] / [Molecular Weight SO_2 (lb/lb-mole)]

Annual Emissions (tons/yr) = [Emission Factor (lb/MMscf)] x [Flared Gas (MMBtu/yr) / [Flared gas HHV (Btu/scf)] / [2,000 lb/ton]

Annual Emissions (ton/yr) = [Emission Factor (kg/MMBtu)] x [Flared Gas (MMBtu/yr)] x [2.20462 (lb/kg)] / [2,000 (lb/ton)]

Notes:

(1) AP-42, Chapter 13.5, Table 13.5-1. THC and Soot Emissions Factors for Flare Operations, October 1996. PM emission factor is for lightly smoking flare.

(2) AP-42, Chapter 13.5, Table 13.5-2. VOC and CO Emissions Factors for Flare Operations, October 1996.

(3) Sulfur content of 0.01 grains per scf provided by KBJ.

(4) Assume conversion of SO_2 to SO_3 of 5 percent by volume as provided by KBJ.

(5) AP-42, Chapter 1.4, Table 1.4-2. Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion, July 1998. Note lead is a HAP and is included in the HAP total.

(6) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25, N_2O = 298.

(7) Emission Factors from Tables C-1 and C-2 to Subpart C of 40 CFR Part 98 - Default CO_2, CH_4 and N_2O Emission Factors for Various Types of Fuel.

(8) Ventura County Air Pollution Control District.

(9) Information provided by JCLNG for gas up/cool down procedures. Ship vapor (14% CO_2, 84% N_2, 2% O_2) is displaced with LNG. When hydrocarbon is detected it is sent to the flare. When the gas contains less than 50 ppm CO_2 it is sent to be used as fuel gas. Two scenarios were supplied, with and without turbulence for the gas up procedure. The scenario with the greater emissions (turbulence) is included. During the cool down procedure all gas is sent to the fuel gas system.

Table 13. Fugitive Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Pollutant	Annual Emissions (tons/yr)			
	LNG Tank	Equipment Leaks	Total	
Criteria Pollutants				
NO_X	---	---	---	
CO	---	---	---	
SO_2	---	---	---	
VOC	0.114	7.87	7.98	(1)
$PM/PM_{10}/PM_{2.5}$	---	---	---	
H_2SO_4	---	---	---	
NH_3	---	---	---	
Lead	---	---	---	
CO_2e			13,116	(2)
CO_2	9.21E-04	1.64	1.64	(3)
CH_4	23.06	501.52	524.58	(1)
N_2O	---	---	---	
Hazardous Air Pollutants				
N-Hexane [(a)]	2.5E-02	1.75	1.77	(4)
Total HAPs			**1.77**	
Maximum Individual HAP			**1.77**	

Calculations:
(a) Annual Emissions (tons/yr) = [VOC Hourly Emissions (tons/yr)] x [N-Hexane/CO_2 Content (mass %)] / [VOC Content (mass %)]

N-Hexane Content (mass %) =	0.31	(4)
VOC Content (mass %) =	1.38	(4)

Notes:
(1) The tank size is the same as in the original permit application. Therefore, the tons/yr emissions for the tanks are from original permit application. See Table 17 for the Equipment Leak Emission calculations.
(2) Carbon dioxide equivalent, global warming potentials; CO_2 = 1, CH_4 = 25
(3) Carbon dioxide emissions are based on a gas composition of 0.36 mol percent VOC and 0.11 mol percent CO_2. See KBJ fuel gas composition provided in Zeeco flare quote.
(4) N-Hexane emissions are based on a fuel gas composition provided by KBJ.

Table 14. Equipment Leaks Potential Emissions
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Components	Phase	TOC/VOC Emission Factor (lb/hr/component)		Actual Component Count		Hourly CH_4 Emissions [(a),(b)] (lb/hr)	Annual CH_4 Emissions [(d)] (tons/yr)	Hourly CO_2 Emissions [(a),(b)] (lb/hr)	Annual CO_2 Emissions [(d)] (tons/yr)	Hourly VOC Emissions [(a),(c)] (lb/hr)	Annual VOC Emissions [(d)] (tons/yr)
Valves	Gas/Vapor	9.9E-03	(1)	9277	(3)	89.52	392.12	0.29	1.28	1.40	6.15
Pressure Relief Valves	Gas/Vapor	1.9E-02	(1)	287	(3)	5.42	23.72	1.8E-02	7.7E-02	8.5E-02	0.37
Pump Seals	Gas/Vapor	5.3E-03	(1)	47	(3)	0.24	1.06	7.9E-04	3.5E-03	3.8E-03	1.7E-02
Flanges	Gas/Vapor	8.6E-04	(1)	559	(3)	0.47	2.05	1.5E-03	6.7E-03	7.3E-03	3.2E-02
Connectors	Gas/Vapor	4.4E-04	(1)	8752	(3)	3.75	16.44	1.2E-02	5.4E-02	5.9E-02	0.26
Compressor Seals	Gas/Vapor	1.9E-02	(1)	18	(3)	0.34	1.49	1.1E-03	4.9E-03	5.3E-03	2.3E-02
Sampling Connections	All	3.3E-02	(2)	7	(3)	14.76	64.65	4.8E-02	0.21	0.23	1.01
Total							**501.52**		**1.64**		**7.87**

Calculations:

(a) Hourly Emissions (lb/hr) = [Emission Factor (lb TOC/hr/component)] x [Count (component)] x [CH_4/CO_2//VOC Content (Mass %)] / [TOC Content (Mass %)]

(b) Hourly Emissions (lb/hr) = [Emission Factor (lb VOC/hr/component)] x [Count (component)] x [CH_4/CO_2 Content (Mass %)] / [VOC Content (Mass%)]

(c) Hourly Emissions (lb/hr) = [Emission Factor (lb VOC/hr/component)] x [Count (component)]

CH_4 Content (mass %) =	88.3	(4)
CO_2 Content (mass %) =	0.29	(4)
VOC Content (mass %) =	1.38	(4)
TOC Content (mass %) =	90.77	(4)

(d) Annual Emissions (tons/yr) = [Hourly Emissions (lb/hr)] x [Hours of Operation (hr/yr)] / [2,000 lb/ton]

Hours of Operation (hr/yr) =	8,760	(3)

Notes:

(1) EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates, EPA, November 1995. Table 2-4. Oil and Gas Production Operations Average Emission Factors (page 2-15), total organic compounds emission factors (TOC).

(2) EPA-453/R-95-017 Protocol for Equipment Leak Emission Estimates, EPA, November 1995. Table 2-2. Refinery Average Emission Factors (page 2-13), non-methane organic compounds emission factor (VOC).

(3) Component counts and hours supplied by KBJ.

(4) Assumed methane and CO_2 content of fuel gas provided in Table 16.

Table 15: GE Natural Gas Turbines Parameters
Black & Veatch Emission Estimates
Jordan Cove, Coos Bay, Oregon

COMBUSTION TURBINE	
CTG Manufacturer	GE
CTG Model	LM6000PF+
CTG Combustor Type	DLN
CTG Fuel Type	Natural Gas
CTG Inlet Air Cooling Type	Chiller
Duct Burner Fuel Type	Natural Gas
CTG Fuel HHV, Btu/lb	21,500
Post Combustion NO_X Emissions Control	SCR
Post Combustion CO Emissions Control	CO Catalyst

	Design Scenario - Steady State Emissions																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Combustion Turbine Parameters																		
Ambient Dry Bulb Temperature, ° F	42	42	59	59	59	59	59	59	59	59	90	90	90	90	90	90	90	90
CTG Load Level, percent of base load	*100*	*100*	*50*	*75*	*100*	*100*	*50*	*75*	*100*	*100*	*50*	*75*	*100*	*100*	*50*	*75*	*100*	*100*
Gross CTG Output, kW	55,607	55,607	25,794	38,692	51,589	51,589	27,581	41,371	55,162	55,162	22,189	33,283	44,378	44,378	24,672	37,008	49,343	49,343
CTG Heat Input, MBtu/h (HHV)	504.4	504.4	327.3	395.7	476.6	476.6	336.9	413.6	500.2	500.2	301.2	359.1	427.3	427.3	319.4	378.1	461.4	461.4
CTG Inlet Air Cooling Status, On/Off	OFF	OFF	OFF	OFF	OFF	OFF	ON	ON	ON	ON	OFF	OFF	OFF	OFF	ON	ON	ON	ON
HRSG Duct Firing	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Fired
Duct Burner Heat Input, MBtu/h (HHV)	0	19.7	0	0	0	8.7	0	0	0	20.9	0	0	0	0	0	0	0	3.1
Stack Exhaust Analysis (Volume Basis - Wet)																		
Ar, % vol.			0.93	0.93	0.93	0.93	0.94	0.94	0.94	0.93	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92
CO_2, % vol.			3.25	3.25	3.38	3.44	3.2	3.26	3.39	3.53	3.29	3.27	3.36	3.36	3.26	3.19	3.36	3.38
H_2O, % vol.			7.83	7.82	8.07	8.19	7.33	7.44	7.7	7.96	10.41	10.37	10.55	10.55	9.12	9	9.33	9.37
N_2, % vol.			74.47	74.47	74.38	74.33	74.82	74.78	74.68	74.58	72.48	72.5	72.43	72.43	73.46	73.51	73.38	73.37
O_2, % vol.			13.52	13.52	13.24	13.11	13.71	13.58	13.3	13	12.91	12.96	12.75	12.75	13.24	13.38	13.01	12.96
SO_2, (after SO_2 oxidation), % vol.			0.00005	0.00005	0.00005	0.00004	0.00004	0.00005	0.00005	0.00004	0.00005	0.00005	0.00005	0.00005	0.00005	0.00004	0.00005	0.00004
SO_3, (after SO_2 oxidation), % vol.			0.00001	0.00001	0.00001	0.00002	0.00001	0.00001	0.00001	0.00002	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00001	0.00002
Stack Exit Temperature, ° F	242.8	242.8	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420
Stack Flow, lb/hr			754,560	912,844	1,057,879	1,058,281	790,163	952,982	1,108,096	1,109,067	680,835	816,908	944,053	944,053	732,348	884,766	1,024,149	1,024,292
Stack Flow, scfm			168,023	203,270	235,566	235,832	175,556	211,890	246,379	246,780	153,082	183,677	212,265	212,265	163,810	197,902	229,250	229,282
Stack Flow, acfm			284,357	344,007	398,840	399,169	297,247	358,656	417,219	417,770	259,184	310,849	359,387	359,387	277,329	335,047	388,001	388,226
Stack Exit Velocity, ft/s	71	71	60	73	85	85	63	76	89	89	55	66	76	76	59	71	82	82
Total Stack Emission Rates (Controlled) [1]																		
NO_X, ppmvd (dry, 15% O_2)	2.0	2.0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO, ppmvd (dry, 15% O2)	4.0	4.0	3.8	3.8	3.8	3.9	3.8	3.8	3.8	4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.9
SO_2, ppmvd (dry, 15% O_2) [2]			0.46	0.46	0.46	0.42	0.46	0.46	0.46	0.42	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.42
VOC, ppmvd (dry, 15% O_2)	2.1	2.5	2.1	2.1	2.1	2.3	2.1	2.1	2.1	2.5	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2
NO_X, lb/hr as NO_2	3.7	3.8	2.4	2.9	3.5	3.5	2.5	3	3.6	3.8	2.2	2.6	3.1	3.1	2.3	2.8	3.4	3.4
CO, lb/hr	4.4	4.6	2.8	3.4	4.1	4.2	2.9	3.5	4.3	4.6	2.6	3.1	3.6	3.6	2.7	3.2	3.9	4
SO_2, lb/hr [2]	0.9	0.9	0.77	0.93	1.12	1.03	0.79	0.97	1.18	1.1	0.71	0.85	1.01	1.01	0.75	0.89	1.09	0.98
VOC, lb/hr as CH_4	1.3	1.7	0.9	1.1	1.3	1.4	0.9	1.1	1.3	1.7	0.8	1	1.1	1.1	0.9	1	1.2	1.3
CO_2, lb/hr	57,958	60,218	38,037	46,009	55,406	56,412	39,161	48,083	58,155	60,585	35,013	41,735	49,658	49,658	37,137	43,960	53,631	53,991
Particulate, lb/hr	4.9	5.4	4	4.1	4.2	4.7	4	4.1	4.3	5	4	4	4.1	4.1	4	4.1	4.2	4.5
PM_{10}, lb/hr	4.9	5.4	4	4.1	4.2	4.7	4	4.1	4.3	5	4	4	4.1	4.1	4	4.1	4.2	4.5
$PM_{2.5}$, lb/hr	4.9	5.4	4	4.1	4.2	4.7	4	4.1	4.3	5	4	4	4.1	4.1	4	4.1	4.2	4.5
Maximum Stack Sulfur Mist [H_2SO_4] (assuming 100% conversion from SO_3 to H_2SO_4), lb/hr	0.48	0.5	0.37	0.45	0.54	0.73	0.38	0.47	0.57	0.78	0.34	0.41	0.48	0.48	0.36	0.43	0.52	0.69
SCR NH_3 slip, lb/hr	3.4	3.5	2.2	2.66	3.21	3.27	2.27	2.78	3.37	3.51	2.03	2.42	2.88	2.88	2.15	2.55	3.11	3.13
NO_X, lb/MBtu (HHV) as NO_2	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
CO, lb/MBtu (HHV)	0.0087	0.0087	0.0085	0.0085	0.0085	0.0086	0.0085	0.0085	0.0085	0.0088	0.0085	0.0085	0.0085	0.0085	0.0085	0.0085	0.0085	0.0086
SO_2, lb/MBtu (HHV) (incl. duct burner fuel)[2]	0.0017	0.0018	0.0024	0.0024	0.0024	0.0021	0.0024	0.0024	0.0024	0.0021	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0021
VOC, lb/MBtu (HHV) as CH_4	0.0026	0.0032	0.0027	0.0027	0.0027	0.0029	0.0027	0.0027	0.0027	0.0032	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0028
CO_2, lb/MBtu (HHV)	115	115	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116
Particulate, lb/MBtu (HHV) (incl. duct burner fuel)	0.0097	0.0103	0.0122	0.0104	0.0089	0.0096	0.0119	0.01	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097
PM_{10}, lb/MBtu (HHV) (incl. duct burner fuel)	0.0097	0.0103	0.0122	0.0104	0.0089	0.0096	0.0119	0.01	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097
$PM_{2.5}$, lb/MBtu (HHV) (incl. duct burner fuel)	0.0097	0.0103	0.0122	0.0104	0.0089	0.0096	0.0119	0.01	0.0085	0.0097	0.0131	0.0113	0.0097	0.0097	0.0125	0.0108	0.0091	0.0097

Notes

[1] Emissions include massflow added to match CTG manufacturer estimate and duct burner emissions.

[2] SO_2 emissions include assumptions of 20 percent by volume oxidation rate in CO catalyst and 3 percent by volume oxidation rate in SCR.

Table 16. Turbine Fuel Specifications
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Component	Component Molecular Weight (lb/lb-mol)	Mole % [1]	Mass % [1]	Mixture Molecular Weight (lb/lb-mol)
Hydrogen (H_2)	2.02	0.20	0.02	0.004
Nitrogen (N_2)	28.01	5.16	8.60	1.446
Carbon Dioxide (CO_2)	44.01	0.11	0.29	0.048
Helium (He)	4.00	0.99	0.24	0.040
Oxygen (O_2)	32.00	0.04	0.08	0.013
Methane (CH_4)	16.04	92.48	88.30	14.837
Ethane (C_2H_6)	30.07	0.61	1.09	0.183
Propane (C_3H_8)	44.10	0.20	0.52	0.088
Butane (C_4H_{10})	58.12	0.11	0.38	0.064
Pentane (C_5H_{12})	72.15	0.04	0.17	0.029
Hexanes (C_6H_{14})	86.18	0.06	0.31	0.052
			Molecular Weight (lb/lb-mol)	**16.80**
			Volume per Mole (scf/lb-mol) [2]	**379.5**
			Density (lb/scf)	**0.044**
			Lower Heating Value, LHV (Btu/lb) [1]	**19,536**
			Lower Heating Value, LHV (Btu/scf)	**865**
			Higher Heating Value, HHV (Btu/scf) [3]	**952**

Notes

[1] Fuel gas specification supplied by KBJ.

[2] Calculated at standard conditions (T = 60^{o}F, P = 1 atm).

[3] Higher heating value is assumed to be 10% higher.

Table 17. Flare Supporting Information
Jordan Cove Energy Project L.P. - Emission Inventory
Coos Bay, Oregon

Warm and Cold Flare (Combined Multi-Point Ground Flare [MPGF]) Specifications

Parameter	Warm	Cold	Combined
Number of Stages	7	7	14
Pilots per stage		2	
Number of pilots	14	14	28
Btu/h per pilot		65,000	
MMBtu/h from pilots	0.91	0.91	1.82
Stage 1 burners purged	4	4	8
Purge flow per burner (SCFH)		45	
Purge flow (SCFH)	180	180	360
Btu/SCF (LHV)		867.5	
MMBtu/h from purge	0.16	0.16	0.31

Fuel Sulfur Content	1	gr/100 scf
Hours of Operation	8,760	hrs/year
Conversion of SO_2 to SO_3	5	%(v)

Marine Flare (Enclosed Ground Flare [EGF]) Specifications

Parameter	Value
Number of Stages	6
Pilots per stage	1
Number of pilots	6
Btu/h per pilot	65,000
MMBtu/h from pilots	0.39
Stage 1 burners purged	9
Purge flow per burner (SCF	45
Purge flow (SCFH)	405
Btu/SCF (LHV)	867.5
MMBtu/h from purge	0.35

Fuel Sulfur Content	1	gr/100 scf
Hours of Operation	8,760	hrs/year
Conversion of SO_2 to SO_3	5	%(v)

Table 18. Zeeco Natural Gas Thermal Oxidizer Parameters
Black & Veatch Emission Estimates
Jordan Cove, Coos Bay, Oregon

Process Flow Rate and Heat Input

Component	lb/hr	MMBtu/hr	MW (lb/mole)
Acid Gas	124,710	1	43.4
Flash Gas	1,276	22	
Fuel Gas	3,905	79	
Combustion Air	108,251		
Total	**238,142**	**102**	

Exhaust Composition

Component	lb/hr	MW (lb/mole)	lb-mol/hr	mol %
CO_2	137,049	44.01	3,114	44.84
H_2O	12,574	18.02	698	10.05
N_2	82,472	28.01	2,944	42.39
SO_2	4	64.06	0.07	1.0E-03
O_2	6,044	32.00	189	2.72
Total	**238,142.00**	**34.29**	**6,944.94**	**100.00**

Exhaust Parameters

Exhaust Temperature (°F)	1,600
Exhaust Flowrate (acfm) [1]	177,370

Notes

[1] Exhaust flowrate calculated based on exit velocity of 41.7 ft/sec. Using ideal gas law results in a rate of 174,083 acfr

Exhaust Composition

Component	lbmol/h	mole% (Dry)	Number of Carbons	Methane Equivalents (lbmol/hr)
CO_2	2806.157525	97.66	Not a VOC	
H_2S	0	0.0E+00	Not a VOC	
N_2	0.001982717	6.9E-05	Not a VOC	
C1	3.062492551	0.11	Not a VOC	
C2	0.221949318	0.01	Not a VOC	
C3	0	0.0E+00	3	0.00
iC4	0.001436751	5.0E-05	4	5.7E-03
nC4	0.001436751	5.0E-05	4	5.7E-03
C5	0.000660906	2.3E-05	5	3.3E-03
C6	0.00011494	4.0E-06	6	6.9E-04
C7	0.00022988	8.0E-06	7	1.6E-03
C8	0.00011494	4.0E-06	8	9.2E-04
C9	0.00011494	4.0E-06	9	1.0E-03
C10	0	0	10	0
COS	0.001436751	5.0E-05	1	1.4E-03
CH_3SH (Methyl Mercaptan)	0.026551161	9.2E-04	1	2.7E-02
C_2H_5SH (Ethyl Mercaptan)	0.009241183	3.2E-04	2	1.8E-02
C_3H_7SH (Propyl Mercaptan)	0.001034461	3.6E-05	3	3.1E-03
Benzene	0.014051426	4.9E-04	6	8.4E-02
Toluene	0.014051426	4.9E-04	7	0.10
Ethylbenzene	0.001752836	6.1E-05	8	1.4E-02
o-Xylene	0.002413742	8.4E-05	8	1.9E-02
m-Xylene	0.005632065	2.0E-04	8	4.5E-02
p-Xylene	0.005632065	2.0E-04	8	4.5E-02
Total:	**2873.50**			
			Total Input VOCs	0.37
			VOC Destruction Removal Efficiency	99.9
			Total Output VOCs	3.7E-04

APPENDIX C

NSPS SUBPART Db APPLICABILITY SUMMARY

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Table C-1 40 CFR Part 60 Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	
	Auxiliary Boiler
Applicability §60.40b(a) and (j)	(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)). (j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).
Sulfur dioxide (SO_2) Standards §60.42b(k)(2)	Units firing only gaseous fuel with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in §60.42b(k)(1).
Particulate Matter (PM) Standards §60.43b	PM standards do not apply to units combusting only natural gas.
Nitrogen Oxides (NO_X) Standards §60.44b (h), (i), and (l)(1)	Do not discharge into the atmosphere any gases that contain NO_X in excess of 0.20 lb/MMBtu heat input determined on a 30-day rolling average basis. This standard applies at all times including periods of startup, shutdown, or malfunction. Based on the calculated heat release rate (design heat capacity divided by furnace volume), the auxiliary boiler has a high heat release rate. (See attachment for calculation).
Monitoring §60.48b(b), (e), (f)	Install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring NO_x and O_2 (or CO_2) emissions discharged to the atmosphere, and record the output of the system. When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 or 7A, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.
Recordkeeping §60.45b(k), §60.48b(b), and §60.49b(d)(1), (g), (h), (o), (p), and (r)	1) Record and maintain records of the amounts of natural gas combusted during each day and calculate the annual capacity factor for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. [§60.49b(d)] 2) Obtain and maintain fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the gaseous fuel meets the definition of natural gas and has a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less. [§60.45b(k) and §60.49b(r)] 3) Record the NO_x and O_2 (or CO_2) output of the CEMS. [§60.48b(b)] 4) For each auxiliary boiler operating day, record: a) Calendar date; b) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted; c) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly NO_X emission rates for the preceding 30 steam generating unit operating days; d) Identification of the steam generating unit operating days when the calculated

Table C-1 40 CFR Part 60 Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	
	Auxiliary Boiler
	30-day average NO_X emission rates are in excess of the NO_X emissions standards, with the reasons for such excess emissions as well as a description of corrective actions taken; e) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken; f) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data; g) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted; h) Identification of the times when the pollutant concentration exceeded full span of the CEMS; i) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and j) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of 40 CFR Part 60. 5) Submit excess emission reports for any excess emissions that occurred during the reporting period. 6) Calculate a new annual capacity factor at the end of each calendar month (12-month rolling average). 7) Records shall be maintained for a period of two years following the date of the record.
Reporting §60.49b(a), (i), (r), (v), and (w)	1) Submit a notification of the date of initial startup and include the following: k) The design heat input capacity of the auxiliary boiler; l) Identification of the fuel to be combusted (natural gas); and m) Annual capacity factor anticipated for the auxiliary boiler based on all fuels fired. 2) Submit performance test data from the initial performance test and performance evaluation of the CEMS. 3) Submit reports containing the information above in Recordkeeping, paragraph 4. Reports shall be submitted to the Administrator certifying that only natural gas that is known to contain insignificant amounts of sulfur were combusted in the auxiliary boiler during the reporting period. 4) Submit written reports semi-annually (every six months). All reports submitted to the Administrator must be postmarked by the 30th day following the end of the reporting period. 5) Quarterly electronic records of CEMS data or excess emissions reports may be submitted in lieu of semi-annual written reports.
Performance Test §60.46b(c), (e)(1) and (3)	Initial Compliance Test: Use the CEMS to monitor NO_X for 30 successive steam generating unit operating days. The 30-day average emission rate is used to determine compliance with the NO_x emission standards. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period. Following the initial compliance test, determine compliance with the NO_x standards on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

Jordan Cove
40 CFR 60 Subpart Db
Appendix C

Annual Capacity Factor

$$\text{Annual Capacity Factor} = \frac{\text{Actual Heat Input from Fuel}}{\text{Potential Heat Input to Boiler at 8,760 hr/yr}}$$

Actual Heat Input from Fuel								
Annual fuel consumption rate =	296.20	MMBtu/hr	x	876	hr/yr	=	259,471.20	**MMBtu/yr**

Potential Heat Input to Boiler at 8,760 hr/yr								
Potential heat input to boiler =	296.2	MMBtu/hr	x	8,760	hr/yr	=	**2,594,712.0**	**MMBtu/yr**

Annual Capacity Factor								
Annual Capacity Factor =	259,471	MMBtu/yr	/	2,594,712	MMBtu/yr	=	0.10	10%

Jordan Cove Energy Project is not taking a federally enforceable limit on the annual capacity factor of 10%.

Heat Release Rate

$$\text{Heat Release Rate} = \frac{\text{Boiler Design Heat Input Capacity}}{\text{Furnace Volume}}$$

Heat Release Rate								
Heat Release Rate =	296.2	MMBtu/hr	/	3,125	ft3	=	**94,784.0**	**Btu/hr-ft^3**

High Heat Release Rate is defined as a heat release rate greater than 70,000 Btu/hr-ft^3

Notes:

Heat input from fuel =	1024.6	Btu/scf
Project operating hours =	876	hr/yr
Boiler heat input capacity =	296.2	MMBtu/hr
Furnace volume (boiler specification sheet) =	3,125	ft^3

APPENDIX D

MODELING PROTOCOL

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

June 1, 2017

Mr. Philip Allen
Department of Environmental Quality
Air Quality Program
700 NE Multnomah Street, Suite 600
Portland, Oregon 97232

Re: Jordan Cove Energy Project L.P.
Jordan Cove LNG Terminal, Coos Bay, Oregon
Type B State New Source Review Dispersion Modeling Protocol

Dear Mr. Allen,

On behalf of Jordan Cove Energy Project, L.P., SLR International Corporation (SLR) is submitting a dispersion modeling protocol for a proposed Type B State New Source Review (NSR) permit modification application for the Jordan Cove LNG terminal located in Coos Bay, Oregon. Jordan Cove was issued the Prevention of Significant Deterioration (PSD) Air Contaminant Discharge Permit (ACDP) 06-0118-ST-01 on June 16, 2015. A technical permit modification application will be submitted to incorporate changes for the final design of the facility. Included in the protocol are:

- Project description and background
- Emissions data
- Regulatory applicability for a Type B State New Source Review project
- Methodology proposed for demonstrating compliance with the NAAQS and PSD increments in Class II areas
- Methodology proposed for addressing PSD Class I area requirements
- Methodology proposed for assessment of the potential for $PM_{2.5}$ and ozone secondary formation

Under separate cover Jordan Cove is submitting a White Paper on PSD applicability for LNG terminals to summarize research and findings on applicability and determinations for permitting of other LNG projects nationally.

The air quality analysis will be performed following approval of this protocol. After submission of the air permit modification application to DEQ, a copy of the complete application will be included in the FERC application Resource Report 9 (RR9) as an appendix. A version of the RR9 is being submitted to FERC this month which includes dispersion modeling results for a preliminary analysis performed to inform the design process. Those results will be replaced in a future RR9 version with the final air quality analysis results, when available.

SLR International Corporation 1800 Blankenship Road, Suite 440, West Linn, OR 97068
T: (503) 723-4423 **F:** (503) 723-4436
www.slrconsulting.com

We look forward to receiving your approval on the proposed methodologies contained within the dispersion modeling protocol. If you have questions, please contact Jason Reed at (970) 999-3970 or Meagan Masten at (541) 280-9099.

Sincerely,
SLR International Corporation

Jessica Stark

Jason Reed

Jessica Stark, P.E.
Principal Engineer

Jason Reed, CCM
Senior Scientist

Enc Attachment – Type B State NSR Dispersion Modeling Protocol global environmental solutions

Jordan Cove Energy Project, L.P.

Jordan Cove LNG Terminal

Type B State New Source Review Dispersion Modeling Protocol

June 2017

CONTENTS

TABLES

CONTENTS (CONTINUED)

FIGURES

(Figures appear at the end of the document.)

ACRONYMS

ACDP	Air Contaminant Discharge Permit
AMSL	Above Mean Sea Level
AQRV	Air Quality Related Value
ARM	Ambient Ratio Method
FLM	Federal Land Manager
GEP	Good Engineering Practice Stack Height
H_2SO_4	Hydrogen Sulfate
HRSG	Heat Recovery Steam Generator
JCEP	Jordan Cove Energy Project, L. P.
K	Kelvin
kg	Kilogram
km	Kilometer
LNG	Liquefied Natural Gas
LNGC	LNG Carrier
m	Meter
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Dataset
NLCD92	National Land Cover Data 1992
NNSR	Nonattainment New Source Review
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
OAR	Oregon Administrative Rule
O_3	Ozone
OC	Organic Carbon
ODEQ	Oregon Department of Environmental Quality
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter Less Than 2.5 microns
PM_{10}	Particulate Matter Less Than 10 microns
ppb	Parts Per Billion
PSD	Prevention of Significant Deterioration

ACRONYMS (CONTINUED)

SER	Significant Emission Rate
SIA	Source Impact Area
SIL	Significant Impact Level
SLR	SLR International Corporation
SMCs	Significant Monitoring Concentration
SO_2	Sulfur Dioxide
SO_4	Sulfate
tpy	Tons per Year
µg	Micrograms
EPA	United States Environmental Protection Agency
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compounds
yr	Year

1. INTRODUCTION

Jordan Cove Energy Project, L.P. (JCEP) plans to construct and operate a natural gas liquefaction and export facility (LNG Terminal or Project) located on the bay side of the North Spit of Coos Bay, Oregon. The LNG Terminal will include five gas-fired turbine-driven compressors, an auxiliary boiler, emergency fire water booster pumps, backup engine generators, a thermal oxidizer, and three flares. Standard Air Contaminant Discharge Permit (ACDP) No. 06- 0118-ST-01 was issued for the Project, but due to facility design changes, a permit modification is sought. This dispersion modeling protocol proposes the analysis methodologies for the Standard ACDP Technical Modification application. An illustration of the area is provided in Figure 1-1 and an illustration of the site layout is provided in Figures 1-2A and 1-2B.

The LNG Terminal is located in Coos County, Oregon, which is in attainment or unclassified for all pollutants. The proposed Jordan Cove LNG Project has the potential to emit nitrogen oxides (NO_X), volatile organic compounds (VOC), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), particulate matter less than 10 micrometers (PM_{10}), particulate matter less than 2.5 micrometers ($PM_{2.5}$), and sulfuric acid mist (H_2SO_4) above Oregon Significant Emission Rates (SERs) but below the Prevention of Significant Deterioration (PSD) threshold of 250 tons per year.[1] Therefore, a Type B State New Source Review (NSR) air quality impact analysis will be conducted for CO, SO_2, PM_{10}, $PM_{2.5}$ and NO_X.

The air quality impact analysis will be conducted to demonstrate that predicted ambient air concentrations from NO_X, CO, SO_2, PM_{10}, and $PM_{2.5}$ emissions comply with the National Ambient Air Quality Standards (NAAQS) and PSD Increments, as they apply to Class I and Class II areas. The purpose of this modeling protocol is to obtain approval from the Oregon Department of Environmental Quality (DEQ) for the proposed modeling inputs and methodologies. NAAQS and PSD Increment modeling methodologies will follow DEQ and United States Environmental Protection Agency (EPA) modeling guidance as further described in this document.[1]

[1] OAR 340-224-0010(1)(a)(A) and 340-224-0010(2)(b)(A)

2. PROJECT DESCRIPTION

Jordan Cove Energy Project, L.P. (JCEP) is proposing to construct and operate a natural gas liquefaction and export facility (LNG Terminal or Project), located on the bay side of the North Spit of Coos Bay, Oregon. The Project would include a facility capable of liquefying natural gas and storing the liquefied natural gas (LNG) for export. Once completed, the Project facilities would be placed in service and natural gas would be delivered to the LNG Terminal via the proposed Pacific Connector Gas Pipeline, which would connect the Project with existing interstate natural gas pipeline systems.

Natural gas received at the LNG Terminal would be cooled into liquid form and stored in two 160,000 cubic meter (m^3) full-containment LNG storage tanks. The Project facilities would have the capability to allow export of 7.8 million metric tons per annum (MMTPA) via LNG carriers.

JCEP is proposing to utilize the following equipment at the LNG terminal:

- Five (5) combined-cycle natural gas turbines with duct burners
- One (1) Auxiliary boiler
- Three (3) liquefaction area fire pumps
- Four (4) emergency generators
- One (1) thermal oxidizer
- Three (3) flares

LNG carrier (LNGC) emissions are not part of the stationary source, but LNGC emissions and downwash will be included in the cumulative source emissions modeling as competing sources.

2.1 SOURCE EMISSION RATES

The potential annual emission rates for each criteria air pollutant from each source are shown in Table 2-1. The EPC contractor, KBJ, has completed the pre-FEED design stage of the project and is currently developing the detailed facility design.

Table 2-1 Stationary Source Criteria Air Pollutant Potential Emissions

Unit	$PM/PM_{10}/PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	H_2SO_4 (tpy)	Pb (tpy)	CO2e (tpy)
Turbines (with 4000 hours DB)	112.26	35.19	81.99	97.82	32.72	23.61	--	1,292,706
Turbines Startup/Shutdown	0.11	4.4E-03	0.23	0.73	0.10	--	--	188
Thermal Oxidizer	3.59	19.84	63.25	38.50	1.12	--	2.4E-04	624,730
Auxiliary Boiler	2.47	0.36	0.96	1.16	0.67	2.4E-01	6.4E-05	15,193
Fire-Water Pumps	9.0E-02	2.1E-03	1.59	0.80	4.5E-02	1.6E-04	2.1E-05	241
Generators	0.09	1.1E-02	4.81	0.49	0.13	8.7E-04	1.1E-04	1,280
Flares	0.36	3.7E-02	0.80	3.64	7.74	2.8E-03	6.8E-06	2,077
Gas Up	1.12	0.16	2.09	9.50	17.53	1.3E-02	2.1E-05	4,351
Fugitives	--	--	-	--	7.98	--	--	13,116
AIE	1.00	1.00	1.00	1.00	1.00	0.70		
Total Emissions	121.1	56.6	156.7	153.7	69.0	24.6	4.6E-04	1,953,883

Note: The LNGC emissions are not included in this table because they are not subject to federal or state stationary source permitting regulations.

2.2 REGULATORY APPLICABILITY

The LNG terminal was permitted as a PSD source under ACDP No. 06- 0118-ST-01 in 2015. The facility design included six 70 megawatt (MW) combined-cycle gas turbines to be operated at the South Dunes Power Plant. The Project was classified as a 'fossil fuel-fired steam electric plant of more than 250 million BTU/hour heat input.' Electricity was to be generated at the South Dunes Power plant to power the facility.

With the change in design to remove the power plant from the LNG Terminal, the source operations no longer fall within any of the listed 28 source categories, and the applicable PSD threshold is 250 tons per year of any regulated pollutant, excluding GHGs.[2]

The Project will have a fossil fuel-fired boiler capacity in excess of 250 MMBtu per hour heat input. One of the designated source categories for purposes of identifying Federal Major Sources is "fossil fuel fired boilers, or combination thereof, totaling more than 250 million BTU per hour heat input." Therefore, the fossil fuel-fired boiler must be evaluated to determine if it constitutes a Federal Major Source.[3]

Consistent with EPA guidance, the boiler is evaluated independently of the facility as a whole based on the boiler being a "nested source" or "source within a source." EPA guidance recognizes that listed source categories can exist within an unlisted source category. However, the presence of a listed source category does not make the entire facility subject to the 100 tpy threshold. As EPA has explained:

> In other words, a source subject to the 100 TPY applicability test that emits greater than 100 TPY is subject to the PSD requirements even if that source is located within a facility for which the primary activity is subject to a 250 TPY applicability threshold and emits less than 250 TPY. In this situation, only the source that exceeds its applicability threshold is subject to PSD, not the entire facility.[4]

This guidance means that the fossil fuel-fired boiler is subject to the 100 tpy PSD threshold while the parent facility is subject to the 250 tpy threshold. Emissions from the auxiliary boiler will not exceed 100 tpy. The auxiliary boiler is only planned to operate for up to 10 percent of any given year, except during the first year of facility commissioning. The auxiliary boiler emissions are compared to the PSD threshold in Table 2-2.

[2] *See* White Paper on applicability of the Federal Major Source categories to LNG Facilities.
[3] The duct burners on the turbines do not meet the definition for 'boiler' in EPA's NSPS rules. Therefore, the auxiliary boiler is the only unit to consider against the 250 MMBtu/hr threshold.
[4] March 24, 1995, letter from EPA Region 3 to Henry Nickel on behalf of Consolidation Coal Company.

Table 2-2 Auxiliary Boiler Emissions Comparison to PSD Threshold

Source	NOX (tpy)	CO (tpy)	SO_2 (tpy)	VOC (tpy)	$PM_{10}/PM_{2.5}$ (tpy)
Auxiliary Boiler	0.96	1.16	0.36	0.67	2.47
Federal Major Source Threshold	100	100	100	100	100
PSD?	No	No	No	No	No

Jordan Cove does not need to request that DEQ impose a 99 tpy limit on emissions of any of the criteria pollutants from the fossil fuel-fired boiler at the facility. The auxiliary boiler PTE is below 100 tpy for all criteria pollutants. Because the criteria pollutant potential to emit from the fossil fuel-fired boiler will be limited to less than 100 tpy, the fossil fuel-fired boiler is not a Federal Major Source.

PSD only applies to a Federal Major Source. Because LNG terminals are not within any of the 28 listed source categories in OAR 340-200 0020(55), the Jordan Cove LNG Terminal emissions must be compared to the 250 tpy threshold to determine whether it is a Federal Major Source. As shown in Table 2-1, the potential to emit of the plant as a whole will be limited to less than 250 tpy for each regulated pollutant.

As neither the facility as a whole nor the fossil fuel-fired boiler qualifies as a Federal Major Source, the Jordan Cove LNG terminal is not subject to PSD program requirements. The project is subject to Type B State NSR requirements.

2.3 POLLUTANTS TO BE EVALUATED

JCEP is located in Coos County, which is currently designated as attainment or unclassified for all criteria pollutants. Because the project does not fall under any of the 28 categories of named sources in OAR-340-200-0020(66)(c), the applicable threshold for being considered a Federal Major Source is 250 tons per year of any individual regulated pollutant, excluding GHG. As shown in Table 2-1, the project does not have the potential to emit more than 250 tons of any one of these pollutants. Therefore, the Project is not a Federal Major Source. However, since the potential emissions of PM_{10}, $PM_{2.5}$, NOx, CO, SO_2, H_2SO_4, VOC, and GHG are greater than the Oregon SER, the proposed project is subjected to Type B State NSR and must meet the requirements of OAR 340-224-0270, *Requirement for Sources in Attainment and Unclassified Areas*.

The dispersion modeling analysis will therefore include an evaluation of PM_{10}, $PM_{2.5}$, CO, NO_X, SO_2, and VOC emissions to demonstrate compliance with their respective significance levels, NAAQS and PSD Increments, as applicable. The sulfuric acid mist is included in the $PM_{2.5}$ emission rates and not evaluated individually. VOC, SO_2, and NOx are considered precursors for pollutants ozone and $PM_{2.5}$ and will be evaluated using the latest federal modeling guidance for pollutants with secondary formation as described further in Section 4.

2.4 SOURCE LOCATION

The area surrounding the facility (within 3 kilometers) consists mainly of forested areas, sand dunes, and water bodies to the east, north, and west of the site with some industrial use along the bay to the south. The residential area of North Bend as well as North Bend Municipal Airport (currently known as the Southwest Oregon Regional Airport) is located to the south of the facility. Approximately 90 percent of the land uses within 3 kilometers of the facility consist of water, forest/undeveloped areas and sand dunes.

The graded elevation of the proposed facility site will vary from 30 to 60 feet above mean sea level (MSL). Topography proximate of the facility is relatively flat with elevations ranging from MSL to 160 feet above MSL within 1 kilometer of the site. To the east of the site lies some rolling terrain with hill top elevations ranging up to approximately 600 feet above MSL.

The proposed facility will be located at approximately 43.434024° North Latitude, 124.243219° West Longitude, North American Datum 1983 (NAD83). The approximate Universal Transverse Mercator (UTM) coordinates of the proposed facility are 399,383 meters Easting, 4,809,765 meters Northing, in Zone 10, NAD83.

2.5 STACK PARAMETERS

2.5.1 COMBUSTION TURBINES

JCEP proposes to use five (5) combustion turbines, each equipped with duct burner. The five turbines would be direct compressor-driver turbines located in the Ingram Yard area of the project. Each turbine is rated at 504.4 MMBtu/hr with an additional duct burner heat input of 19.7 MMBtu/hr, for a total input (HHV) of 524.1 MMBtu/hr per turbine. Twelve startups at 10 minutes per startup and twelve shutdowns at 9 minutes per shutdown will be modeled for each unit. Normal, full load operation is assumed for the remainder of the year. Additional information regarding the turbine parameters is shown in Table 2-3 and Table 2-4.

For the annual emissions, the modeled emission rate was determined by developing a weighted emission factor that encompasses the following operating scenarios to be encountered over the year:

- 8,760 hours of operation at full load and 42°F with 4,000 hours of duct burner firing
- 8,760 hours of operation at full load and 42°F without duct burner firing

From the scenarios and operating times discussed above, a weighted emission factor for the entire year of operation can be obtained. This weighted emission factor is then used over the entire year, minus the hours in which the turbine is in startup or shutdown, to determine the total annual emissions.

Table 2-3 Turbine Parameters with Duct Burner Firing

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
243	71	10	119	3.8	5.4	1.64	4.6

Table 2-4 Turbine Parameters without Duct Burner Firing

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
243	71	10	119	3.7	4.9	1.58	4.4

2.5.2 AUXILIARY BOILER

The natural gas-fired auxiliary boiler, with the maximum hourly heat input capacity of 269 MMBtu/hr, will be utilized during turbine startups. Total time of operation is conservatively estimated as 876 hours per year. Potential maximum hourly emissions and stack parameters for the auxiliary boiler are provided in Table 2-5 below.

Table 2-5 Auxiliary Boiler Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
330	49	6	100	2.18	5.63	0.83	2.66

2.5.3 OXIDIZER

The thermal oxidizer will be used to combust acid gas from the hydrogen sulfide removal process. The unit will have a maximum heat rate of 110 MMBtu/hr and operate 8,760 hours per year. Potential emissions and stack parameters for the thermal oxidizer are provided in Table 2-6 below.

Table 2-6 Oxidizer Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
1,600	42	9.5	131	14.44	0.82	4.53	8.79

2.5.4 FLARES

Three (3) separate flares will be used to handle gas relieved during emergency upset conditions. The design has warm and cold flares (a combined multi-point ground flare) and a marine flare (enclosed ground flare). However, emissions are not evaluated for emergency upset conditions because of the unpredictability and rarity of this occurrence. Emissions from the continuous operation of the pilot and purge gas on each flare will be included in the dispersion modeling.

If an LNG tanker arrives which requires cooling of the hull prior to LNG loading, hull gas must be vented. The inert gas and some methane is routed to the marine flare and combusted. Due to the intermittent nature of LNG gas up of warm interted LNGC events, the annualized emissions will be used in the dispersion modeling analysis. The stack parameters and potential hourly emissions for the flares are provided in Table 2-7 below for the marine flare. The gas-up annual emissions will also be included with this source.

Table 2-7 Marine Flare Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (K)	Velocity (m/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
ambient	negligible	45	100	0.04	0.017	0.0017	0.17

The flare parameters and potential hourly emissions for the multi-point ground flare, modeled as an area source, are provided in Table 2-8 below.

Table 2-8 Ground Flare Parameters and Emissions

Flare Parameters		Potential Emission Rates			
Area of Enclosure	Enclosure Height	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
259 ft x 227 ft	85 ft	0.14	0.065	0.0067	0.66

2.5.5 FIRE WATER PUMPS

Three (3) 700 hp fire water pumps will be placed in the liquefaction area. These pumps are expected to operate less than 1 hour per short-term period for reliability testing and maintenance and no more than 200 hours per year per pump. Stack parameters and potential hourly emissions for each fire water pump are provided in Table 2-9 below. Due to their intermittent nature, the annualized emissions will be used in the dispersion modeling analysis.

Table 2-9 Fire Water Pumps Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
948.3	193	0.67	18	5.31	0.30	0.0071	2.68

2.5.6 GENERATORS

JCEP proposes a total of four generators at the site. There will be two different types of generators at the site. Two of the generators will be black start generators and rated at 4,376 hp each, and the other two generators will be backup generators and rated at 1,214 hp each. Annual operation is not expected to exceed 200 hours per year per generator. Stack parameters and potential hourly emissions for the generators are provided in Tables 2-10 and 2-11 below. Due to their intermittent nature, the annualized emissions will be used in the dispersion modeling analysis.

Table 2-10 1,214 hp Backup Generator Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
952.5	287	0.67	13	16.63	0.19	0.012	1.42

Table 2-3 4,376 hp Black Start Generator Stack Parameters and Emissions

Stack Parameters				Potential Emission Rates			
Temperature (°F)	Velocity (ft/sec)	Stack Diameter (ft)	Stack Height (ft)	NO_X (lb/hr)	$PM_{10}/PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	CO (lb/hr)
873.6	177	1.67	13	7.43	0.23	0.044	1.04

3. CLASS II AIR QUALITY ANALYSIS

This section discusses the modeling methodology that will be used to demonstrate compliance with the NAAQS and PSD Increments in Class II Areas. The air dispersion modeling analysis will be organized into two tiers: a Significant Impact Analysis and a Full Impact Analysis. The techniques used in the air dispersion modeling analysis will be consistent with the modeling protocol discussion held on March 13, 2017 with Oregon DEQ, current EPA modeling guidelines, OAR 340, and other agency guidance as applicable.[5,6]

3.1 MODEL SELECTION AND INPUTS

SLR will use the latest version of the AERMOD modeling system (currently version 16216r) to perform the Class II analysis. AERMOD is the official guideline model for short-range (i.e., <50 km) analyses recommended in 40 CFR 51 Appendix W. Since the land use in a 3 km radius surrounding the proposed facility is rural in nature, the rural option will be used. All other model settings will be set to their default values.

3.1.1 UTM COORDINATE SYSTEM

The Coos Bay area of western Oregon is located in UTM Zone 10. All emission points, building, and receptor locations will be converted to UTM coordinates in Zone 10, North American Datum of 1983. Table 3-1 summarizes the coordinates and elevation of all emission sources included in the modeling.

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[5] Code of Federal Regulations, Title 40-Protection of Environment, Part 51, Appendix W, January 17, 2017.
[6] The contents of a modeling analysis were discussed with Phil Allen (Oregon DEQ) on March 13, 2017 in Portland, Oregon. The methodology and inputs described herein are based on that discussion.

Table 3-1 Stationary Source UTM Coordinates

Source ID	Source Description	UTM Easting (meters)	UTM Northing (meters)	Elevation (meters)
Turb1	Turbine 1	397644.88	4809333.42	14
Turb2	Turbine 2	397642.86	4809401.18	14
Turb3	Turbine 3	397640.84	4809468.96	14
Turb4	Turbine 4	397638.82	4809536.74	14
Turb5	Turbine 5	397636.80	4809604.52	14
ThermOx	Oxidizier	397464.17	4809693.73	14
AuxBoil	Auxiliary Boiler	397385.32	4809623.54	14
FP1	Firewater Pump 1	397822.97	4809674.74	16.5
FP2	Firewater Pump 2	397830.32	4809674.96	16.5
FP3	Firewater Pump 3	397835.46	4809675.11	16.5
Gen1	Generator 1	397296.40	4809619.99	19.2
Gen2	Generator 2	397288.79	4809619.76	19.2
MFlare	Marine Flare	397361.50	4809302.31	14
GFlare	Ground Flare	397296.45	4809827.91	14*

*Fence height

3.1.2 METEOROLOGICAL DATA

The surface data to be used in the analysis will be the five most-recent complete years of data collected at the Southwest Oregon Regional Airport (call sign KOTH), located at 43.419°N, 124.243°W, which is approximately 2 km southeast of the project site. The meteorological sensors at KOTH are Automated Weather Observing System (AWOS III)[7], which does not collect 1- or 5-minute data for use in the analysis. Upper air data from McNary Field in Salem, OR (44.92°N, 123.02°W) will also be used, which is approximately 197 km northeast of the project site. The period of meteorological data to be used is January 1, 2012 to December 31, 2016.

As detailed in the prior modeling assessment as part of the Prevention of Significant Deterioration (PSD) application, the surface meteorological data collected at the Southwest Regional Airport is temporally and spatially representative of the project location and areas of concern.[8] A topographic map with both the project site and the location of the AWOS instruments is provided in Figure 1-1. A windrose of the meteorological data is provided in Figure 3-1.

[7] https://www.faa.gov/air_traffic/weather/asos/?state=OR
[8] Jordan Cove Energy Project, L.P. PSD Air Permit Application, TRC, May 2013.

Since the instrumentation is a standard AWOS system, it does not collect atmospheric turbulence data for input into AERMET/AERMOD. As a result, this dataset meets the criteria for use of the AJD_u* model option[9], which is contained within the latest AERMET/AERMOD models as default, if invoked. SLR will review the processed meteorological datasets and will document and justify the use of this model option if it is invoked.

3.1.3 LAND COVER ANALYSIS

A land cover analysis will also be conducted to define the surface characteristics (surface albedo, Bowen ratio, and roughness length) for input into stage 3 of AERMET. The EPA-provided AERSURFACE program (version 13016) will be run with 1992 National Land Cover Data 1992 (NLCD92)[10] to generate surface characteristics for the area surrounding the meteorological site. The inputs to AERSURFACE are provided in Table 3-2 below. Figure 3-2 shows a plot of the NLCD92 data for the area surrounding the facility.

Table 3-2 Summary of AERSURFACE Inputs

Parameter	Value
Surface roughness study radius	1 km
Bowen ratio and albedo study region	10 km by 10 km
Vary by sector?	Yes, 12 sectors, each 30 degrees in width.
Temporal Resolution	Summer: June, July, August Autumn: September, October, November Winter: December, January, February Spring: March, April, May
Continuous snow-cover most of the winter?	No
Is the site near an airport?	Yes
Is the site an arid region?	No
Surface Moisture	TBD on a monthly basis

3.1.4 DOMAIN AND RECEPTOR GRIDS

Ground-level concentrations will be calculated within a nested, Cartesian receptor grid. The nested grids will cover an area extending up to 30 km from the proposed facility, but truncated over the Pacific Ocean. The grids will be defined as follows:

1) receptors spaced every 25 m along the facility fenceline;
2) receptors spaced every 25 m that extend 100 m from the facility fenceline;
3) receptors spaced every 100 m that extend from 100 m to 3 km;

[9] From the preamble to Title 40-Protection of Environment, Part 51, Appendix W, January 17, 2017 "the model performance and diagnostic evaluations strongly support the finding that the ADJ_U* option provides for an appropriate adjustment to the surface friction velocity parameter when standard National Weather Service (NWS) airport meteorological data".

[10] http://www.mrlc.gov/nlcd92_data.php

4) receptors spaced every 250 m that extend from 3 km to 5 km;
5) receptors spaced every 500 m that extend from 5 km to 20 km; and
6) receptors spaced every 1,000 m that extend from 20 km to 30 km.

The locations of the fenceline receptors and near-field gridded receptors are shown in Figure 3-3. Figure 3-4 illustrates the receptor grid out to 30 km. If the maximum concentration is predicted at any receptor in the coarse grids (greather than 100 m spacing) and is within 75% of an ambient standard, then, a refined grid with 100 m receptor spacing will be centered on the "hot spot".

3.1.5 TERRAIN DATA

Significant grading of the existing site is expected; therefore the graded elevations of the sources, buildings, fenceline and any ambient air receptors will be based on project-supplied information. For those areas outside of the graded area, terrain elevations for the receptors within the modeling domain will be taken from National Elevation Dataset (NED) terrain data using AERMAP (version 11103). All receptors, graded or not, will be run through AERMAP in order to obtain the appropriate scale heights. The NED data will be at a 1/3 arcsecond resolution, which translates into a resolution of approximately 10 meter spacing for the terrain.

3.1.6 DOWNWASH AND GEP STACK HEIGHT ANALYSIS

The effects of plume downwash will be considered for all stationary point sources. The effects of plume downwash will also be considered for the marine carriers when considered for the multisource modeling. Direction-specific building dimensions will be calculated using the current version of the EPA-approved Building Profile Input Program (BPIPPRM Version 04274). The site layout, dimensions and heights will be obtained from facility drawings. In addition to calculating direction-specific building dimensions, the BPIPPRM program also calculates the Good Engineering Practice (GEP) stack height. All facility stack heights will be checked to verify that they are within the GEP stack height limit.

3.2 BASELINE AIR QUALITY AND SIGNIFICANCE ANALYSIS

The first step in the air quality impact analysis will be to model the proposed project emissions and compare the maximum modeled concentrations to the applicable significant impact levels (SILs), provided in Table 3-3 below.[11] Comparison to these thresholds is used to determine the scope of the modeling analysis by pollutant/averaging period. However, use of the SILs in a tiered modeling analysis first requires an assessment of the background concentration relative to the ambient air quality standards i.e., the headroom; as well as recent emission changes in the nearby area. The headroom analysis (ambient standard minus background value with the difference compared to the SIL) is provided in Table 3-3 and demonstrates sufficient headroom to support the use of the SILs as protective of air quality. For this analysis, the NW AIRQUEST database was used as representative background data for the area. The NW AIRQUEST

[11] U.S. EPA, Office of Air Quality Planning and Standards, Guidance for PM2.5 Permit Modeling, May 20, 2014. This guidance describes the vacation of the $PM_{2.5}$ SILs and SMC for use in permitting analyses. However, the SILs in Table 3-1 are provided in OAR 340-200-0020(163) and will be used in this analysis based on an assessment of the headroom.

project used air quality observations and archived CMAQ model data from daily air quality forecast models from Idaho, Oregon, and Washington to compute the design values on a 12-km grid for the period of 2009-2011. The values were obtained from the grid cell representative of the proposed facility location (latitude 43.434, longitude -124.2538). The 2009 – 2011 NW AIRQUEST data are the most recent data available.

With regard to second criteria for using the SILs, SLR has reviewed the past three National Emission Inventory releases for years 2008, 2011, and 2014 for Coos County, Oregon to assess recent changes in local emission changes.[12] The emission summaries for the area are shown in Table 3-4 and reveal generally flat levels of emissions in the area, which indicates the NW AIRQUEST background values for the area should be considered temporally and spatially representative. It is noted that there is an increase in primary PM_{10} emission in 2014 over 2011; review of the data indicates there was a substantial increase (+8,000 tons) in 'miscellaneous' PM_{10} emissions in 2014.

[12] The Tier 1 summaries consolidate the emission inventory sectors into 14 main categories and can be summarized by county. https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei

Table 3-3 Applicable Class II Significant Thresholds, Ambient Standards, and Headroom Analysis

Pollutant	Averaging Period	Applicable Thresholds	Applicable Standards[3]		NW AIRQUEST Background Data ($\mu g/m^3$)	Headroom ($\mu g/m^3$) [2] / Is Headroom > SIL?
		Class II SILs[1] ($\mu g/m^3$ or as noted)	NAAQS ($\mu g/m^3$ or as noted)	Class II PSD Increment ($\mu g/m^3$)		
SO_2	1-hour	8.0	196	--	3.1	193 / Yes
	3-hour	25.0	1,300	512	2.9	1,297 / Yes
	24-hour	5.0	262	91	2.9	259 / Yes
	Annual	1.0	52	20	1.1	51 / Yes
NO_2	1-hour	8.0	188	--	16	172 / Yes
	Annual	1.0	100	25	1.9	98 / Yes
CO	1-hour	2,000	40,000	--	755	39,245 / Yes
	8-hour	500	10,000	--	591	9,409 / Yes
Ozone	8-hour	1 ppb	70 ppb	--	46	24 / Yes
PM_{10}	24-Hour	1.0	150	30	35	115 / Yes
	Annual	0.20	--	17	--	--
$PM_{2.5}$	24-hour	1.2	35	9	9.9	25 / Yes
	Annual	0.2 | 0.3	12	4	6.7	5 / Yes

(1) OAR 340-200-0020(163) All SILS are based on the first highest concentration at any one location. For ozone, the SIL is proposed by EPA in Revised August 18, 2016 Guidance on Significant Impact Levels for Ozone and Fine Particulates in the Prevention of Significant Deterioration Permitting Program. For $PM_{2.5}$, the 0.2 $\mu g/m^3$ value is also from the August 18, 2016 guidance.

(2) Headroom values represent NAAQS minus NW AIRQUEST background data; the result is compared to the SILs for an assessment if the headroom is greater the SIL.

(3) The form of the standards are as defined in OAR 340-202

Table 3-4 Summary of Recent National Emission Inventories in Coos County, Oregon

Pollutant (tons/year)	2008	2011	2014
CO	104,684	103,304	94,009
NO_x	3,381	3,048	2,491
Primary PM_{10}	14,097	13,452	21,148
Primary $PM_{2.5}$	7,937	8,074	7,971
SO_2	572	558	513
VOC	41,783	38,850	44,262

3.2.1 OPERATING SCENARIOS

The potential operating scenarios for the turbines include normal operation and SU/SD. The support equipment will be held constant for both turbine scenarios. The scenario will include the following:

- Normal operation - where the turbine operates in normal mode (full load) for the entire period (short-term); and
- SU/SD mode - where the turbine undergoes start-up for a portion of the period (e.g., 10 minutes) and operates in normal mode for the remainder of the period (short-term).

The annual emissions scenario will include the total emissions from the expected number of startups and shutdowns plus normal operation for the remainder of the year. Any other project non-baseload source will also be considered in the development of modeled scenarios.

3.3 TIER I: PROJECT SIGNIFICANCE ANALYSIS

As noted above, the first step in the air quality impact analysis will be to model the proposed project scenarios with the worst-case equipment and compare the maximum modeled concentrations to the applicable Class II SILs. If the maximum modeled concentrations for a pollutant/averaging time are less than the applicable SILs, then no additional modeling is required for that pollutant/averaging period. If the maximum modeled concentrations for a pollutant/averaging time are equal to or above the SIL, then a tier 2 analysis for NAAQS and Class II PSD increment compliance is required for that pollutant/averaging time. This modeling step is also used to determine the Source Impact Area (SIA) of the proposed source, by pollutant/averaging period. The SIA is any location with a predicted concentration equal to or above the SIL, defined for each pollutant and averaging period. In the event that there are no predicted significant impacts, the SIA is zero. Once the SIA is determined, it will be provided to DEQ in order for the offsite source inventory to be updated, if needed.

3.4 TIER 2: REFINED ANALYSIS

For those pollutants/averaging periods shown to have a significant impact, a refined air quality analysis will be conducted to demonstrate compliance with the NAAQS and Class II PSD increments. The same project operating scenario/equipment configuration used in the SIL analysis will be combined with the DEQ-provided competing source inventory as defined following OAR 340-225. In addition, LNGC emissions will be included in the cumulative impact analyses, similar to the prior modeling demonstration. For the NAAQS analysis, background air quality concentrations will be added to the project and competing source inventory modeled impacts; background will not be added for the increment analysis. The background values shown in Table 3-3 will be used for the NAAQS analysis.

3.5 CHEMICAL TRANSFORMATION

3.5.1 NO_2 FORMATION

The modeling analysis will follow the tiered approach described in the latest EPA guidance:

- The first Tier will assume a full, 100% conversion of NO_x to NO_2.
- If needed, the second tier will utilize the ambient ratio method (ARM2) method implemented and documented per EPA guidance.
- If needed, the third tier will utilize the Ozone Limiting Method (OLM) or Plume Volume Molar Ratio Method (PVMRM) implemented and documented per EPA guidance.

3.5.2 $PM_{2.5}$ AND OZONE FORMATION

In consultation with DEQ, the draft EPA guidance on addressing secondary formation of $PM_{2.5}$ and ozone will be used to develop a project-specific evaluation of the potential impacts from these VOC, SO_2, and NOx.[13,14] Project emissions will be compared to the information provided in the EPA guidance for Maximum Emission Rates for Precursors (MERPs). This EPA guidance is based on a suite of photochemical modeling runs across the continental U.S. designed to assess secondary ozone and $PM_{2.5}$ formation from various, hypothetical sources. These runs were used to establish modeled responses to precursor emissions, which can be used to determine:

- emission thresholds below which insignificant secondary formation is expected to occur and
- secondarily-formed downwind concentrations of ammonium sulfate, ammonium nitrate or ozone from emitted precursors.

The first step of the guidance is to compare Project emissions to the emission thresholds. Since the Project emits more than one precursor pollutant, an additional calculation is needed to account for the combined effect of the precursors. This is accomplished by adding ratios (project emissions divided by an emission threshold) for each precursor together. If the

[13] Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, December 2016.

[14] Distribution of the EPA's modeling data used to develop illustrative examples in the draft Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, February, 2017.

combined ratios of the precursors are greater than one, then significant secondary formation is possible and needs to be quantified.

The second use of the guidance allows for quantification of the secondary formation. Since the EPA modeling was for a limited number of sources, several inputs were varied by EPA to obtain more robust model responses. The inputs that were varied include stack height and parameters, precursor emission levels, and inherently based on the source's location, regional emissions and geophysical characteristics (i.e., climate, terrain, proximity to other large sources or cities). If the quantification of secondary effects is required, Appendix A of the EPA guidance will be reviewed to find a source-impact relationship that is representative of the Project. Representativeness will be determined by stack parameters, emission levels, local/regional emissions, and geophysical environment.

Table 3-5 compares the lowest (most conservative) ozone emission threshold values for NOx and VOCs in the Western U.S to Project emissions. Since both NOx and VOC are emitted, the combined effect is accounted for as shown in Table 3-5. Following the draft EPA guidance, since the sum of the combined ratios (project emissions/emission threshold value) for each precursor is less than a value of 1, significant ozone concentrations will not be generated from the Project.

Table 3-5 Summary of MERPs Analysis for Ozone

Precursor	Project Emissions (tpy)	8-hr O3 MERP (tpy) [1]	Ratio of Project Emissions to Daily Ozone MERP	Sum of Ratios
NOx	155.0	184	0.84	0.91
VOC	72.5	1,049	0.07	

[1] These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

A similar analysis for daily and annual $PM_{2.5}$ is shown in Tables 3-6 and 3-7, respectively. The approach for secondary $PM_{2.5}$ formation from NOx and SO_2 emissions is the same as ozone, but $PM_{2.5}$ also needs to include direct $PM_{2.5}$ impacts as modeled in AERMOD.[15] As shown in Tables 3-6 and 3-7, insignificant secondary formation is expected to occur for both daily and annual $PM_{2.5}$. However, if Project direct $PM_{2.5}$ impacts (i.e., modeled in AERMOD) are above the significant impact level, then the reported $PM_{2.5}$ will include the expected secondary formation using representative modeled responses in Appendix A of the EPA guidance as discussed further below.

[15] Total $PM_{2.5}$ is the sum of direct $PM_{2.5}$ plus secondary $PM_{2.5}$. Direct $PM_{2.5}$ emissions and downwind impacts are modeled in AERMOD. The secondary formation of Project NOx and SO_2 emissions into $PM_{2.5}$ is crux of the MERPs guidance.

While the lowest (most conservative) emission thresholds are useful for screening project emissions, they are not necessarily representative of potential secondary formation due to Project emissions. For instance, the sources with the lowest SO_2 and NOx emission thresholds are in interior California, which is not representative of the climatology or source environment of the proposed Project. Furthermore, both of these sources were modeled with 'low' source heights (release height of 1 m), which is not representative of Project sources.

The summarized modeling results for 24-hour average concentrations of secondary formation for precursor SO_2 and NOx in Appendix A of the modeling guidance was further reviewed. The data was sorted to only include:

- sources located in Oregon or Washington (considered to be more representative of climate at the Project site);
- Precursor emissions of 500 tpy (similar in magnitude, yet conservative, to Project emissions); and
- And 'high' stack heights (similar to Project sources).

The results of this analysis are summarized in Table 3-8. Taking the two highest modeled responses, 0.15 $\mu g/m^3$ and 0.24 $\mu g/m^3$ for NOx and SO_2, respectively, the combined potential secondary formation from Project emissions is 0.39 $\mu g/m^3$.

Table 3-6 Summary of MERPs Analysis for Daily $PM_{2.5}$

Precursor	Project Emissions (tpy)	Daily $PM_{2.5}$ MERP (tpy) [1]	Ratio of Project Emissions to Daily $PM_{2.5}$ MERP	Sum of Ratios
Direct $PM_{2.5}$	AERMOD			0.34
NOx	155.0	1,075	0.14	
SO_2	40.2	210	0.19	

[1] These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

Table 3-7 Summary of MERPs Analysis for Annual $PM_{2.5}$

Precursor	Project Emissions (tpy)	Annual $PM_{2.5}$ MERP (tpy) [1]	Ratio of Project Emissions to Annual $PM_{2.5}$ MERP	Sum of Ratios
Direct $PM_{2.5}$	AERMOD			0.07
NOx	155.0	2,289	0.05	
SO_2	40.2	3,184	0.02	

[1] These are the most conservative (lowest) MERP values for ozone in the Western U.S. as summarized in the February 23, 2017 memorandum.

Table 3-8 Summary of Modeled Responses for Representative Sources

Precursor	Area	Emissions (tpy)	Height	Source	FIPs	State	County	Modeled Response (μg/m^3)
NOx	WUS	500	H	18	41049	Oregon	Morrow	0.15
NOx	WUS	500	H	22	53057	Washington	Skagit	0.05
NOx	WUS	500	H	23	53039	Washington	Klickitat	0.03
SO_2	WUS	500	H	23	53039	Washington	Klickitat	0.24
SO_2	WUS	500	H	18	41049	Oregon	Morrow	0.19
SO_2	WUS	500	H	22	53057	Washington	Skagit	0.08

4. CLASS I AIR QUALITY ANALYSIS

Federal Class I areas are afforded the highest level of protection under the Clean Air Act. As such, the Class I area analysis for Type B State NSR projects includes the assessment of ambient impacts in terms of pollutant concentrations. The model inputs and scenarios described in Section 3 will be used for the Class I analyses for all Class I areas located within 200 km from the project location (provided in Table 4-1 below).

Table 4-1 Distance to Class I Areas

Class I Area	State	Distance (km)
Crater Lake National Park	OR	165
Redwood National Park	CA	177
Kalmiopsis Wilderness Area	OR	110
Diamond Peak Wilderness Area	OR	165
Three Sisters Wilderness Area	OR	178

There are no Class I areas within 50 km of the project.

4.1 Q/D SCREENING ANALYSIS

An air quality related values (AQRV) analysis is not required for a Type B State NSR project, but is required as part of other regulatory requirements the Project will be required to meet.[16] Therefore for consistency and informational purposes a Q/D calculation for regional haze and deposition will be used to screen for the air quality related values (AQRVs).[17] The screening analysis is based on distance from the source to the Class I area and the annualized daily emissions of AQRV-impacting pollutants. If the Q/D analysis results are less than or equal to the screening factor of 10, then FLM agencies do not require any further Class I AQRV impact analyses from those sources.

Using the emissions summarized in Table 2-1 for the visibility impairing pollutants of NOx, SO_2, PM, and H_2SO_4 the calculated Q value is 327.6. Using the shortest distance, D, from Table 4-1 above, the Q/D value is calculated to be 2.98, which is below the threshold value of 10.

4.2 CLASS I SIGNIFICANCE ANALYSIS

An assessment of project impacts in comparison to the Class I significant impact level for the Class I PSD increments will be run using AERMOD as a screening tool. Receptors will be

[16] The 2017 FERC analysis requirements specify that visibility impacts at Class I areas must be considered.

[17] U.S. Forest Service – Air Quality Program, National Park Service – Air Resources Division, U.S. Fish and Wildlife Service – Air Quality Branch, *Phase I Report of the Federal Land Managers' Air Quality Related Values Workgroup (FLAG)- Revised*, Section 3.2. October 2010.

placed at a distance of 50 km from the project in arcs that will be located to capture plume impacts in the direction of each Class I area. The elevation of the receptors will be based on the actual elevation of each receptor location as determined by AERMAP and standard NED data. Results from the screening modeling will be compared to the Class I SILs defined in the OAR and proposed by EPA, which are listed in Table 4-2, below. Similar to the Class II analyses, direct $PM_{2.5}$ impacts from AERMOD at 50 km will be added to the representative secondary formation discussed in Section 3.5.2, if applicable.

If Project impacts are above the Class I SILs then a qualitative approach will be developed to demonstrate that Project impacts will be less than the Class I SILs at the actual distance of the Class I areas.

Table 4-2 Class I Significant Impact Levels and PSD Increments

Pollutant	Averaging Period	OAR Class I SILs(1) (µg/m³)	EPA Class I SILs(2) (µg/m³)	Class I Increments(3) (µg/m³)
SO_2	3-hour	1.0	--	2
	24-hour	0.2	--	5
	Annual	0.1	--	25
NO_2	Annual	0.1	--	2.5
PM_{10}	24-Hour	0.3	--	8
	Annual	0.2	--	4
$PM_{2.5}$	24-hour	0.07	0.27	2
	Annual	0.06	0.05	1

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.
(2) Revised August 18, 2016 Guidance on Significant Impact Levels for Ozone and Fine Particulates in the Prevention of Significant Deterioration Permitting Program
(3) OAR 340-202-0210. For any period other than an annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

FIGURES

FIGURE 1-: PROJECT AREA

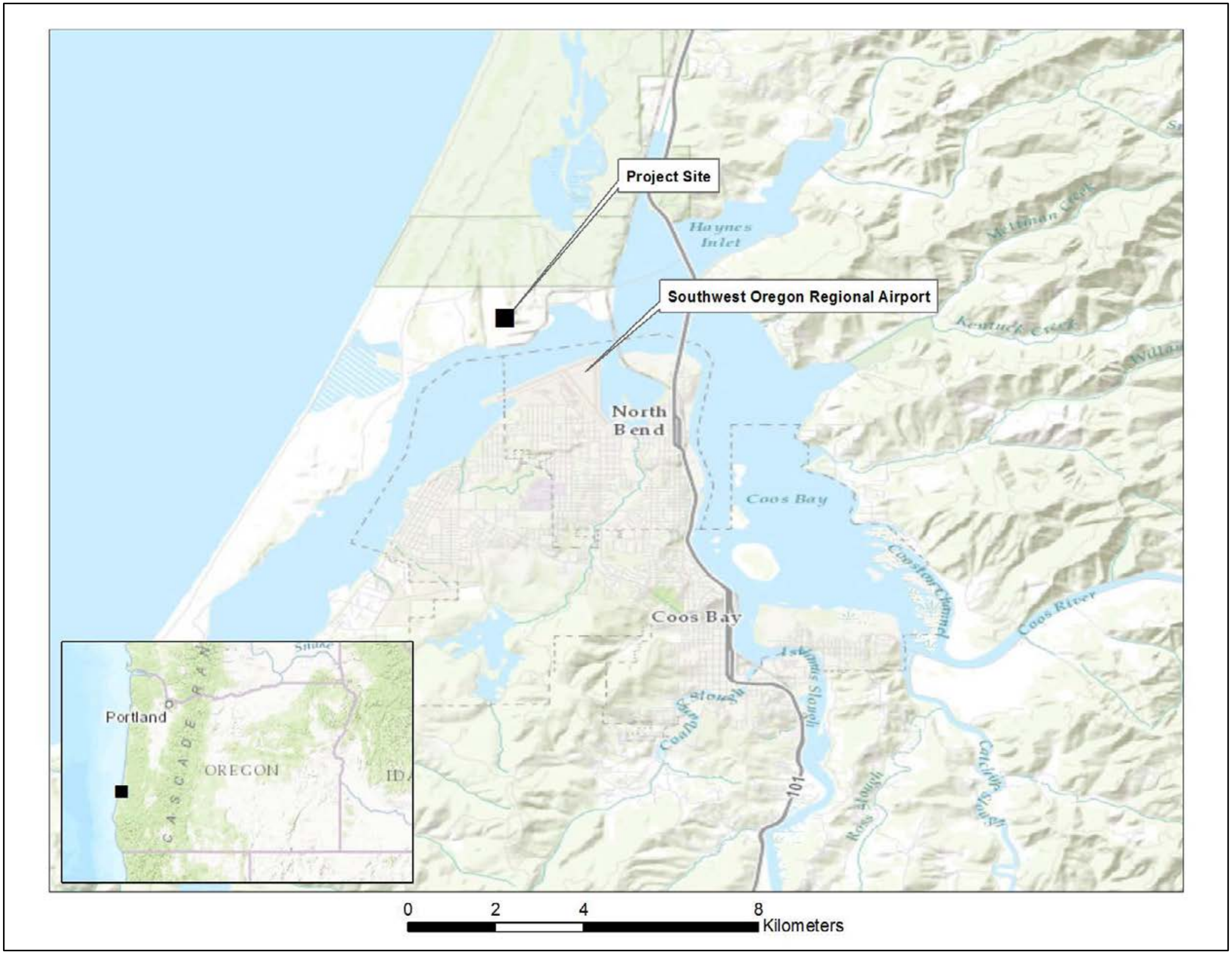


FIGURE 1-2A: SITE LAYOUT – SOUTH DUNES

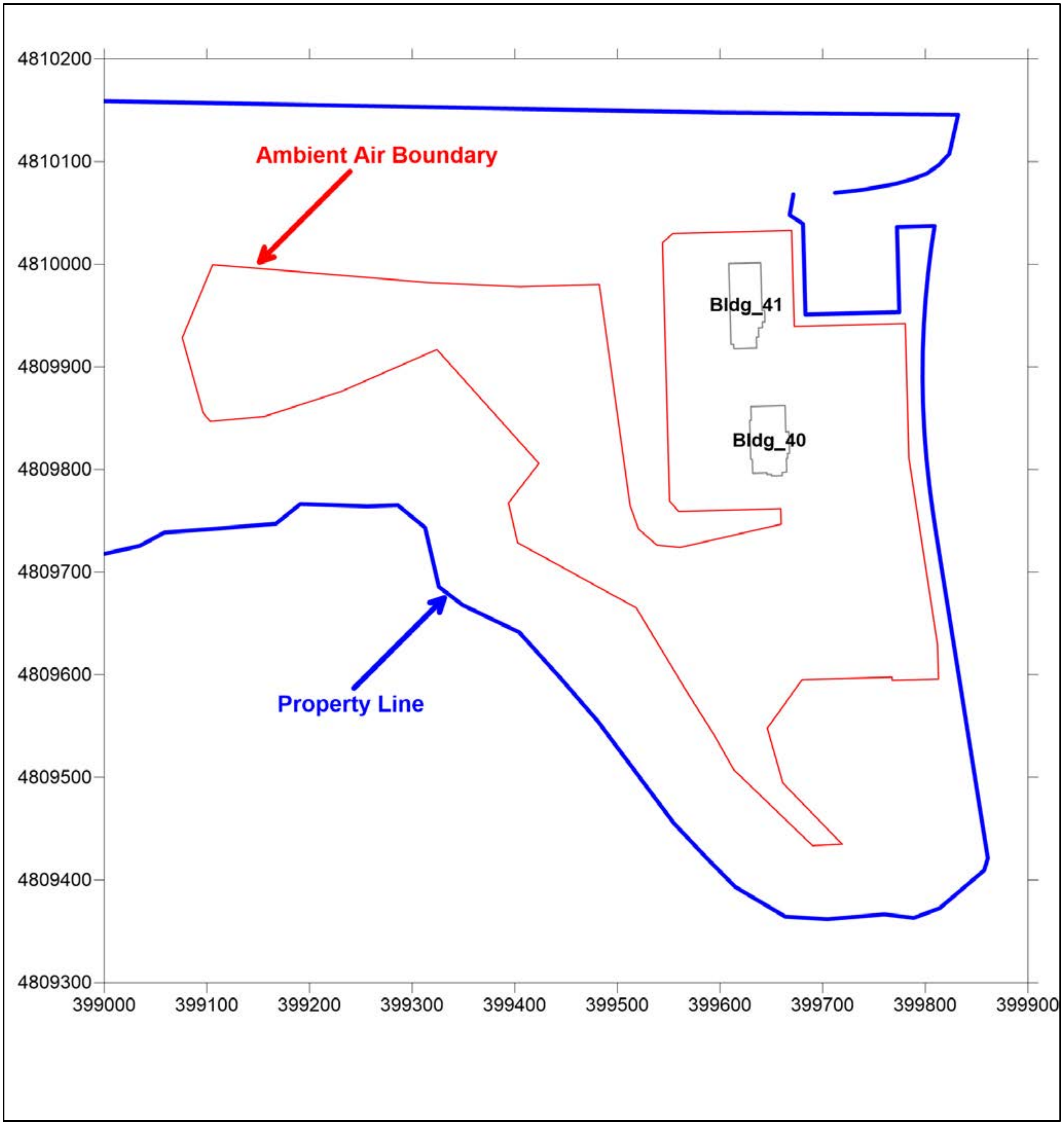


FIGURE 1-2B: SITE LAYOUT – TERMINAL

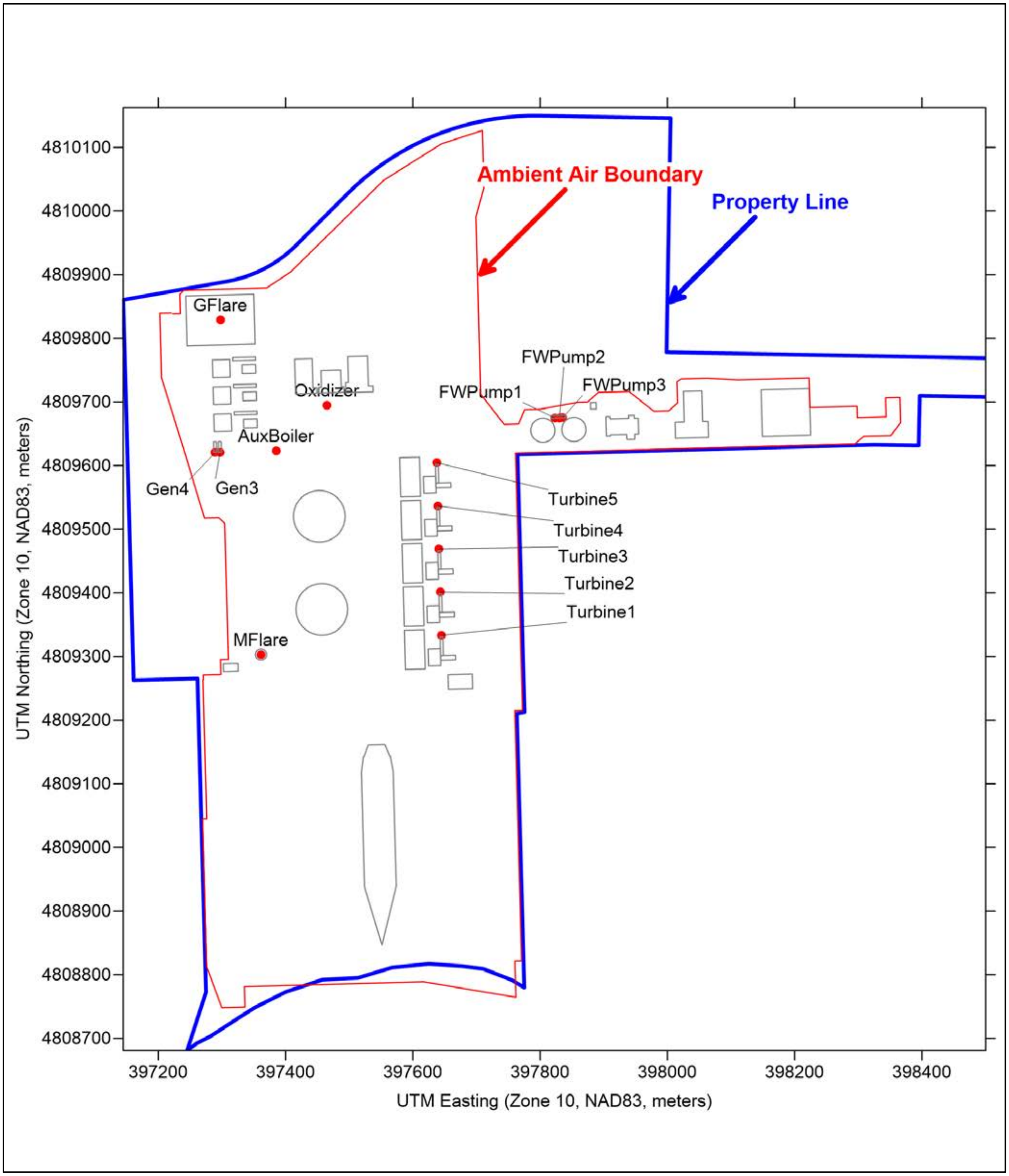


FIGURE 3-1: 2012-2016 WINDROSE FROM SOUTHWEST OREGON REGIONAL AIRPORT (KOTH)

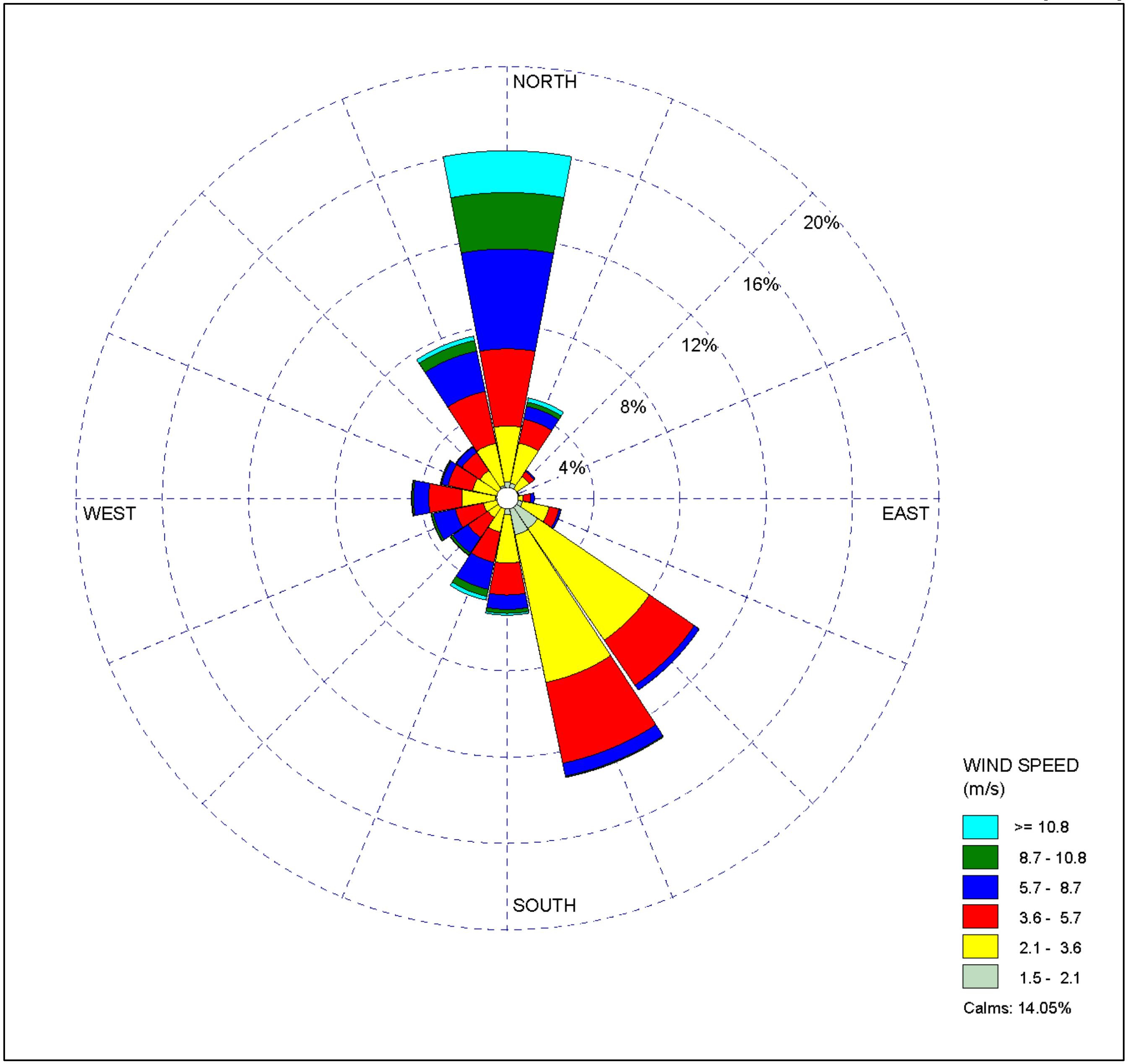


FIGURE 3-2: 1992 NLCD DATA AT PROJECT SITE

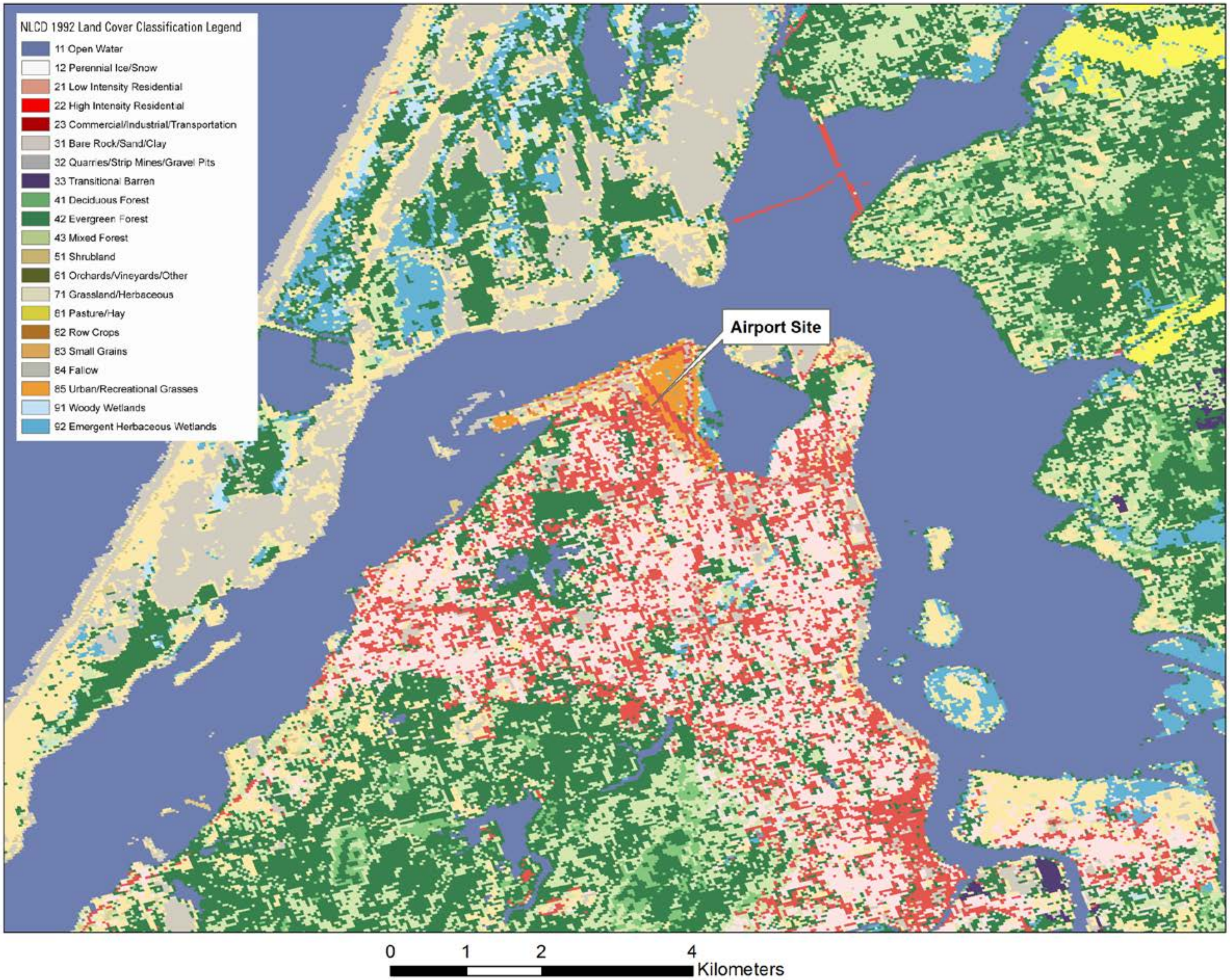


FIGURE 3-3: NEARFIELD RECEPTORS

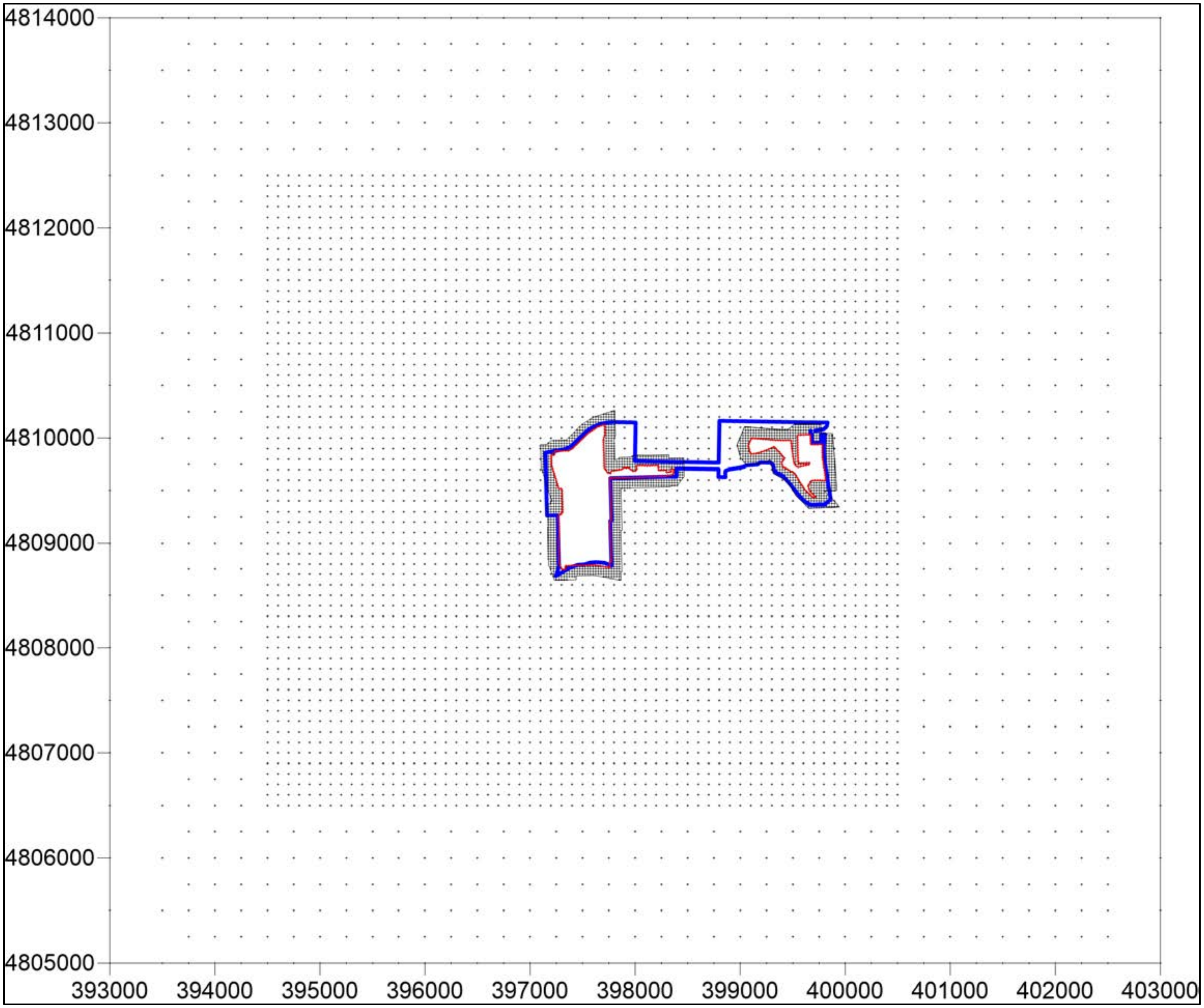


FIGURE 3-4: EXTENT OF RECEPTOR GRIDS

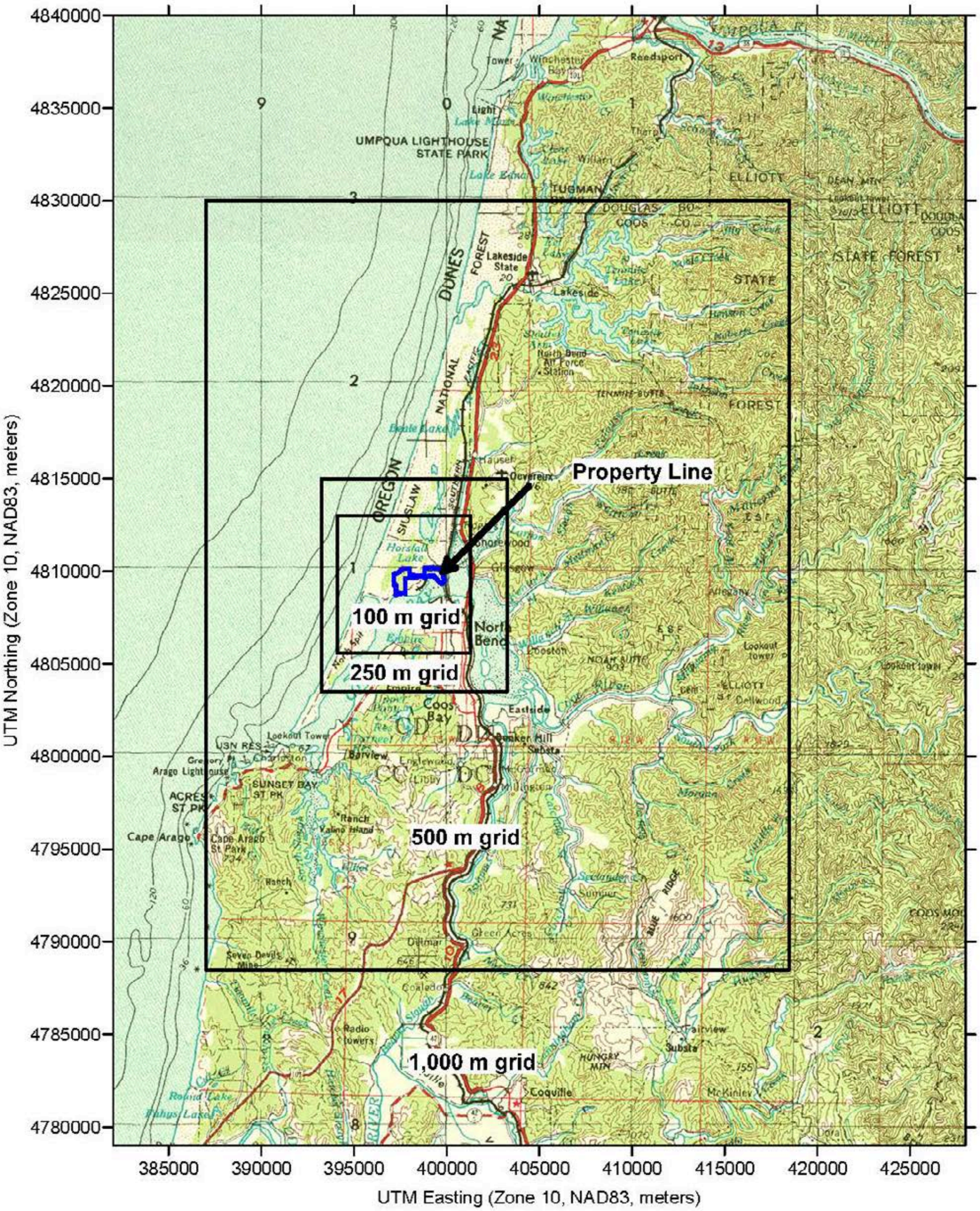
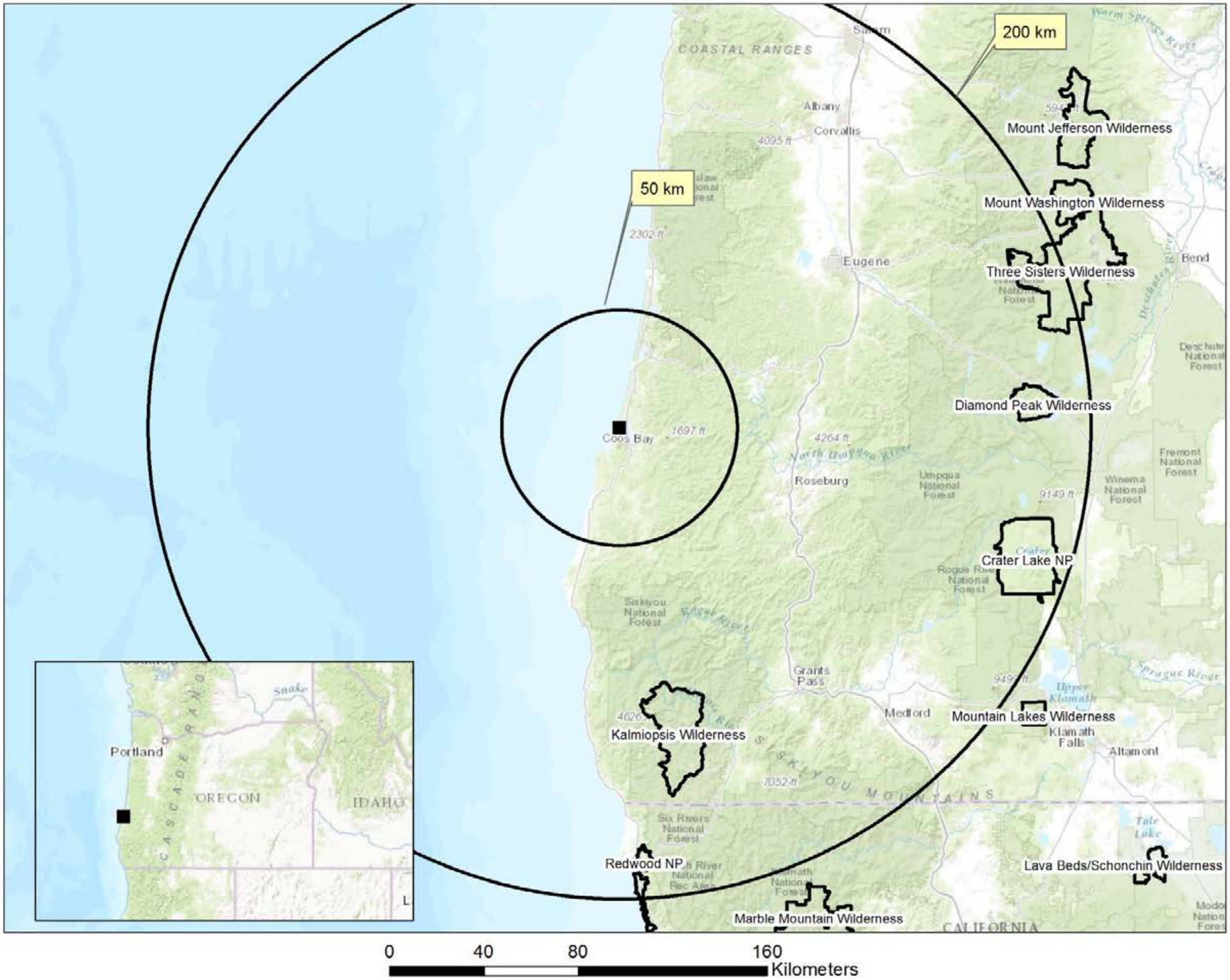


FIGURE 4-1: ILLUSTRATION OF CLASS I AREAS AND DISTANCE FROM PROJECT



Memorandum

To: Michael Eisele, P.E./Oregon Department of Environmental Quality

From: Jessica Stark, P.E.

Date: June 1, 2017

Subject: **Applicability of the Prevention of Significant Deterioration Enumerated Source Categories to Natural Gas Liquefaction Facilities**

This paper addresses whether natural gas liquefaction facilities are, per se, within one of the 28 source categories listed in the Clean Air Act ("CAA" or "the Act") that are subject to the Prevention of Significant Deterioration ("PSD") program if they emit 100 tons per year or more of a regulated pollutant. This paper also summarizes recent permits issued to natural gas liquefaction facilities in the United States, and discusses whether, and on what basis, the relevant state agencies evaluated whether the facility was subject to the PSD program.

A. Summary

As further discussed below, LNG liquefaction facilities are not, per se, within one of the 28 source categories listed in the CAA that are subject to the PSD program if they emit 100 tons per year ("tpy") or more of a regulated pollutant. In its regulations and guidance documents, EPA has not concluded that LNG liquefaction facilities are per se within one of the 28 source categories listed in the Act. A review of recent permitting decisions for other LNG liquefaction facilities has reached the same conclusion.

B. Background

Under the CAA, certain facilities are subject to the PSD program if they emit, or have the potential to emit, one hundred tpy or more of any air pollutant.[1] Other sources not specifically listed in the CAA are subject to the PSD program if they emit, or have the potential to emit, two hundred and fifty tpy or more of any air pollutant.[2] The 28 source categories that are subject to the 100 tpy limit are listed in the Act and its implementing regulations.[3]

The list of 28 source categories included in the Act and its implementing regulations was derived from a list that EPA included in an early PSD rulemaking. In 1974, before Congress amended the Clean Air Act to include the PSD program, EPA issued a final rule that established an early version of the PSD program.[4] In that final rule, EPA included a list of 18 source

[1] 42 U.S.C. § 7479(1).
[2] *Id*.
[3] *Id*.; 40 C.F.R. § 52.21(b)(1)(i).
[4] 39 Fed. Reg. 42,510 (Dec. 5, 1974).

categories that would be subject to the early PSD program.[5] When Congress amended the Clean Air Act in 1977 to include the PSD program, it relied on the list of 18 sources included in EPA's earlier rule and added ten additional sources to that list.

The 28 source categories listed in the Act and in EPA's PSD regulations are not clearly defined in the statute or regulations. EPA has acknowledged this and has explained that where a facility does not clearly fall into any of the 28 categories, the facility should consult the definitions in EPA's New Source Performance Standards ("NSPS") regulations to determine whether the facility is a listed source.[6] EPA has also clarified the meaning of many of the 28 source categories in guidance documents.

C. Listed Source Categories

As described in more detail below, under the Act, EPA regulations, and EPA guidance documents, LNG liquefaction facilities have not per se been considered to be included under one of the 28 listed source categories for purposes of PSD applicability. An analysis of certain listed source categories is presented below. The remaining source categories would not apply to LNG liquefaction facilities.

1. <u>Fuel Conversion Plants</u>

Nothing in the Act, EPA regulations or EPA Guidance suggest that an LNG liquefaction facility is a "fuel conversion plant" for purposes of PSD applicability. The Act, the PSD regulations, and the NSPS regulations do not define "fuel conversion plant." However, EPA has explained in guidance that a facility is a "fuel conversion plant" if it changes the state (e.g., solid to gas) or form (e.g., coal gasification, oil shale processing, conversion of waste to fuel gas and processes saw dust into pellets) of a fuel.[7] However, even if a facility changes the state of a fuel (e.g., liquid to gas), it is <u>not</u> a fuel conversion plant if the change requires only minimal processing.[8]

EPA has specifically considered whether LNG vaporization facilities are "fuel conversion plants" for purposes of PSD applicability. In a 2003 guidance document, EPA examined whether a facility that converted LNG into natural gas was a "fuel conversion plant" under the PSD program.[9] EPA explained that, while the facility did change the state of the fuel (liquid to gas), it did so with only minimal processing.[10] EPA stated that the facility was not a "fuel conversion plant" because converting LNG into natural gas could be done "without the need for

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[5] *Id*.
[6] U.S. EPA, Prevention of Significant Deterioration, Workshop Manual I-A-9 (Oct. 1980), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/1980wman.pdf.
[7] Memorandum from Edward J. Lillis, Chief, Permits Programs Branch, U.S. EPA Headquarters, to George T. Czerniak, Chief, Air Enforcement Branch, U.S. EPA Region V (May 26, 1992), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/clvlndel.pdf.
[8] Memorandum from Racqueline Shelton, Group Leader, U.S. EPA Integrated Implementation Group, to Guy Donaldson, Acting Chief, U.S. EPA Region 6 Air Permits Section (July 31, 2003), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/pelican.pdf.
[9] *Id*.
[10] *Id*.

chemical or process change that generally occurs at other sources that EPA considers as 'fuel conversion plants' (e.g., coal gasification, oil shale processing, conversion of municipal waste to fuel gas, processing of sawdust into pellets) under the PSD rules."[11]

For the same reasons described by EPA in its 2003 guidance, an LNG liquefaction facility (converting natural gas to liquid) is not a "fuel conversion plant." Like converting LNG to natural gas, converting natural gas to LNG does not require significant chemical or process changes. Both LNG vaporization facilities and LNG liquefaction facilities rely on changing the temperature of the fuel to convert it from one state to another, and neither requires any other chemical or process changes. As a result, like an LNG vaporization facility, an LNG liquefaction facility would not be considered a "fuel conversion plant" for purposes of PSD applicability.

2. <u>Petroleum Storage and Transfer Facility</u>

Nothing in the Act, EPA regulations or EPA Guidance suggest that an LNG liquefaction facility is a "petroleum storage and transfer facility" for purposes of PSD applicability. The Act, the PSD regulations, and the NSPS regulations do not define "petroleum storage and transfer facility." The NSPS regulations do, however, define "petroleum" as "the crude oil removed from the earth and the oils derived from tar sands, shale, and coal."[12] EPA has further stated that a facility that stores or transfers gasoline is not considered a "petroleum storage and transfer facility."[13] In its guidance, EPA explained that "it is our determination that the named category [petroleum storage and transfer facility] was limited to crude oil and not its refined products."[14] Because an LNG liquefaction facility does not store "petroleum," it is not a "petroleum storage and transfer facility" for purposes of PSD applicability.

3. <u>Petroleum Refinery</u>

Nothing in the Act, EPA regulations or EPA Guidance suggest that an LNG liquefaction facility is a "petroleum refinery" for purposes of PSD applicability. Neither the Act nor the PSD regulations define "petroleum refinery." The NSPS regulations define "petroleum refinery" as "any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a petroleum refinery."[15] An LNG liquefaction facility does produce petroleum products through distillation, cracking or reforming. Because an LNG liquefaction facility does not meet the definition of "petroleum refinery" under the NSPS regulations, it is not a "petroleum refinery" for purposes of PSD applicability.

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[11] *Id*. at 1-2.
[12] 40 CFR §§ 60.101(b), 60.111(d), 60.111a(d), 60.111b.
[13] Letter from R. Douglas Neely, Chief, U.S. EPA Region 4 Air and Radiation Technology Branch to Chun-chi S. Liu, Mecklenburg County Department of Environmental Protection (Feb. 18, 1998), *available at* https://www3.epa.gov/ttn/naaqs/aqmguide/collection/t5/apl_mek1.pdf.
[14] *Id*.
[15] 40 CFR § 60.101a.

4. Fossil Fuel-Fired Steam Electric Plant

Nothing in the Act, EPA regulations or EPA Guidance suggest that an LNG liquefaction facility is a "fossil fuel-fired steam electric plant" for purposes of PSD applicability. The Act, the PSD regulations, and the NSPS regulations do not define "fossil fuel-fired steam electric plant." However, EPA's initial PSD program and the legislative history of the Act indicate that this source category was intended to cover large electric power plants, not LNG liquefaction facilities even if electricity is produced.

As described above, the list of 28 source categories in the CAA and in the current PSD regulations was derived from a list that EPA established in an earlier version of the PSD program. In the Federal Register notices promulgating that earlier rule, EPA explained that the list of source categories was intended to include the largest emitters in the nation.[16] In the proposed rule, EPA stated that the listed source categories "account for approximately 30 percent of the particulate matter and 75 percent of the sulfur dioxide emitted" each year.[17] Similarly, in a technical support document that was part of the PSD rulemaking, EPA stated that the listed source categories were "the largest present emitters of SO2 and [total suspended particulates] on a nationwide basis."[18] At the time of EPA's initial rulemaking in 1974, there were few (if any) operating LNG liquefaction facilities. There is nothing in EPA's supporting documents which suggests that EPA intended to regulate under this category LNG liquefaction facilities.

Further, rulemaking documents confirm that the source category "fossil fuel-fired steam electric plant" was intended to cover large power plants. In a technical support document prepared as part of the PSD rulemaking, EPA repeatedly refers to "fossil fuel-fired steam electric power plants" when discussing various aspects of the rule.[19] While the regulations remove the term "power" in the list of covered sources, this rulemaking document confirms that EPA understood this category to cover what are commonly thought of as electric power plants.

Similarly, the legislative history of the 1977 amendments to the CAA, which formalized the PSD program, indicate that the source category "fossil fuel-fired steam electric plant" was understood to cover large electric power plants. In Congressional debate over the proposed amendments, the representatives repeatedly discuss the impact of the proposed amendments on the construction of large power plants.[20]

While EPA has issued a few short guidance documents describing the meaning of "fossil fuel-fired steam electric plant," it has not found that LNG liquefaction plants are part of this source category. In a 1987 applicability determination, EPA concluded that certain equipment that was ancillary to a gas turbine should be considered when determining whether the turbine

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[16] 38 Fed. Reg. 18,986, 18,989 (July 16, 1973); U.S. EPA, TECHNICAL SUPPORT DOCUMENT – EPA REGULATIONS FOR PREVENTING THE SIGNIFICANT DETERIORATION OF AIR QUALITY, EPA-450/2-75-001 (Jan. 1975) [hereinafter "Technical Support Document"].
[17] 38 Fed. Reg. at 18,989.
[18] Technical Support Document at 28.
[19] *See* e.g., Technical Support Document at 34 (emphasis added).
[20] *See* e.g., 123 Cong. Rec. 18,154 (June 9, 1977).

satisfied the 250 mmbtu heat input requirement for this source category.[21] EPA did not, however, describe the facility in which the turbine was located or describe whether and why the facility was considered a "fossil fuel-fired steam electric plant." EPA only addressed the narrow issue of what ancillary equipment should be considered when calculating the heat input of a "fossil fuel-fired steam electric plant."[22] Similarly, in a 1993 applicability determination, EPA concluded that gas turbine combined cycle cogeneration plants could be considered "fossil fuel-fired electric plants," but did not discuss whether that determination extended to combined cycle cogeneration plants at LNG liquefaction facilities.[23] In a 1978 applicability determination, EPA concluded that a steam generating unit that produced electricity could be considered a "fossil fuel-fired steam electric plant" even if it was not part of a large power plant.[24] This determination from almost forty years ago, however, does not address whether gas turbines used to drive compressors that do not directly generate electricity would be considered "fossil fuel-fired steam electric plants." The applicability determination was also issued when there were very few, if any, LNG liquefaction facilities in the United States and does not address whether LNG liquefaction facilities are considered part of this source category.

Finally, turbines used at LNG liquefaction facilities are used to drive compressors for refrigeration and do not produce electric output through the shaft work to drive generators. Therefore the turbines do not produce electricity and would not be considered a "fossil fuel-fired steam <u>electric</u> plant" for purposes of PSD applicability. As a result, an LNG liquefaction facility would not be considered a "fossil fuel-fired steam electric plant" for purposes of PSD applicability.

5. <u>Fossil-Fuel Boilers and LNG Gas Turbines with Duct Burners</u>

Nothing in the Act, EPA regulations or EPA Guidance suggest that gas turbines with duct burners at an LNG liquefaction facility qualify as "fossil-fuel boilers" for purposes of PSD applicability. Neither the Act nor the PSD regulations define "fossil fuel boilers of more than [250 mmbtu] per hour heat input." However, the NSPS regulations define "boiler" as "any enclosed device that extracts useful energy in the form of steam."[25] The term boiler does not include "duct burners." In contrast, a duct burner is "a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit."[26] When a duct burner is connected to and part of a combined cycle gas turbine, it is considered part of the gas turbine

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[21] Letter from David Kee, Director, U.S. EPA Air and Radiation Division to Dell Collins, Impell Power Projects (Sept. 30, 1987), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/equptmnt.pdf.
[22] *Id*.
[23] Letter from Edward J. Lillis, Chief, U.S. EPA Permits Program Branch to Bernard E. Turlinski, Chief, U.S. EPA Region III Air Enforcement Branch and George T. Czerniak, Chief, U.S. EPA Region V Air Enforcement Branch (Feb. 2, 1993), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/turbines.pdf.
[24] Letter from Director, U.S. EPA Division of Stationary Source Enforcement to Thomas W. Devine, Chief, U.S. EPA Region I Air Branch (Feb. 13, 1978, *available at* https://www.epa.gov/sites/production/files/2015-07/documents/m021378.pdf.
[25] 40 C.F.R. §§ 60.561, 60.611, 60.661.
[26] 40 C.F.R. § 60.41Da.

and is regulated as part of the turbine under NSPS Subpart KKKK, and is explicitly exempted from the NSPS requirements for boilers.[27],[28]

To the extent that an LNG liquefaction facility uses a combined cycle gas turbine with an attached duct burner to drive the refrigeration compressor and also has a fossil-fuel fired boiler on site, the heat input capacity of the duct burner is not combined with the boiler to determine whether the 250 mmbtu heat input threshold is met. As described above, a duct burner is not a boiler and should not be considered when determining the heat input of the boiler. Similarly, if the duct burner is not even attached to the boiler, it would be inappropriate to consider the heat input of the duct burner when determining PSD applicability with respect to the boiler. As a result, an LNG liquefaction facility using gas turbines with duct burners to drive refrigeration compressors would not be considered a "fossil-fuel boiler" for purposes of PSD applicability.

6. Sulfur Recovery Plants

Nothing in the Act, EPA regulations or EPA Guidance suggest that gas treatment systems at an LNG liquefaction facility qualify as "sulfur recovery plants" for purposes of PSD applicability. Neither the Act nor the PSD regulations define "sulfur recovery plants." Under EPA's NESHAPs regulations a "*Sulfur recovery unit*" means "a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide. This definition does not include a unit where the modified reaction is carried out in a water solution which contains a metal ion capable of oxidizing the sulfide ion to sulfur, e.g., the LO-CAT II process."[29] Similarly, sulfur recovery as defined by AP-42 refers to the conversion of hydrogen sulfide to elemental sulfur.[30] Gas treatment systems at LNG liquefaction facilities treat the natural gas to reduce hydrogen sulfide followed by a carbon dioxide removal process using a primary amine process to remove CO_2 and a dehydration system to remove water and mercury. The remaining acid gas is typically sent to a thermal oxidizer for combustion. Elemental sulfur is not recovered. Because the gas treatment systems at an LNG liquefaction facility do not recover sulfur, an LNG liquefaction facility is not a "sulfur recovery plant" for purposes of PSD applicability.

7. Chemical Process Plants

Nothing in the Act, EPA regulations or EPA Guidance suggest that an LNG liquefaction facility is a "chemical process plant" for purposes of PSD applicability. The Act, the PSD regulations, and the NSPS regulations do not define "chemical process plant." Chemical process plants are described in the SIC manual, and cited in EPA applicability determination, as "establishments producing basic chemicals, and establishments manufacturing products by predominantly chemical processes." The SIC manual notes these facilities manufacture three general classes of products: "(1) basic chemicals, such as acids, alkalines, salts, and organic chemicals; (2) chemical products to be used in further manufacture, such as synthetic fibers, plastics materials, dry colors and pigments; and (3) finished chemical products to be used for

[27] 40 C.F.R. § 60.4305(a).
[28] Note that duct burners installed on turbines not subject to NSPS Subpart KKKK can be subject to other NSPS regulations but have not been considered to be "boilers" as is referenced in the PSD listed source category.
[29] 40 C.F.R. § 63.1579.
[30] AP-42, Section 8.13 (7/93, reformatted 1/95).

ultimate consumption, such as drugs, cosmetics, and explosives."[31] The purpose of a LNG liquefaction facility is to liquefy natural gas by refrigeration, not manufacture the types of chemicals described above. Liquefying natural gas is not a process included in the list described in the SIC manual. For these reasons, an LNG liquefaction facility would not be considered a "chemical process plant" for purposes of PSD applicability.

D. LNG Facility Permit Review

As described above, an LNG liquefaction facility does not, per se, fall within one of the 28 source categories listed in the Act. Several permitting authorities have recently reached the same conclusion and found that LNG liquefaction facilities are not listed sources subject to the 100 tpy threshold for purposes of the PSD program. The discussion below examines PSD permits that were recently issued to LNG liquefaction facilities and confirms that the permitting authorities did not treat the LNG liquefaction facilities as being within one of the 28 listed source categories. No permitting decisions have been located that reached a different conclusion.

1. Port Arthur LNG, LLC, TX, Permit Numbers 131769, PSDTX1456, and GHGPSDTX134

Port Arthur LNG, LLC received a PSD permit on February 17, 2016 for the proposed construction and operation of a natural gas liquefaction and export terminal near Port Arthur, Jefferson County and the Sabine Pass in Southeast Texas. The proposed liquefaction plant will consist of two liquefaction trains, each capable of producing 5.0 MMTPA of LNG. Each LNG train will consist of one propane and one mixed refrigeration compression turbine and an Acid Gas Removal Unit.

The facility will be located in Jefferson County, which is classified as an attainment or unclassified area for all criteria pollutants. The major source threshold of 250 tpy was used for the PSD applicability of this project.

2. Golden Pass Products LLC, TX, Permit Numbers 116055 and PSDTX1386

Golden Pass Products, LLC received a PSD permit on January 16, 2015 for the proposed construction and operation of a natural gas liquefaction and export plant near the Sabine Pass in Southeast Texas. The proposed liquefaction plant will consist of three liquefaction trains. Each train will consist of two gas-fired refrigeration compressor turbines equipped with heat recovery steam generating units.

The facility will be located in Jefferson County, which is classified as an attainment or unclassified area for all criteria pollutants. The major source threshold of 250 tpy was used for the PSD applicability of this project.

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[31] Letter dated August 8, 1997 from Carla E. Pierce, Chief, Operating Source Section, U.S. EPA Air & Radiation Technology Branch, to Chun-chi S. Liu, Mecklenburg County Department of Environmental Protection

3. Corpus Christi Liquefaction Stage III, LLC, TX, Permit Numbers 139479, PSDTX1496, and GHGPSDTX157

Corpus Christi Liquefaction Stage III, LLC received a PSD permit on February 14, 2017 for the proposed construction and operation of two new LNG trains, including 12 natural gas compressor turbines, at a preexisting facility in San Patricio County, TX. The original construction at the facility (Permits 70741 and PSDTX1038) was for an LNG import terminal, while the proposed new trains are for natural gas compression. Since the construction is to occur at a pre-existing facility, the permit application was considered under the "major modification" rules and is not relevant for determining whether a new LNG liquefaction facility is one of the 28 listed source categories.

4. Freeport LNG Pretreatment Facility, TX, Permit Numbers 100114, N150, and PSDTX1282

Freeport LNG Development, L.P. received a PSD permit on March 24, 2015 to construct and operate a natural gas liquefaction plant at the site of an existing LNG import terminal near Freeport, Texas. Since the liquefaction plant is proposed at a pre-existing facility, the permit application was considered under "major modification" rules and is not relevant for determining whether a new LNG liquefaction facility is one of the 28 listed source categories.

5. Elba Island LNG Terminal, GA, Permit 4922-051-0003-V-05-0

Kinder Morgan, Inc. proposed to construct the Elba Liquefaction Terminal, an LNG export terminal, at the site of a pre-existing LNG import terminal in Chatham County, Georgia near the city of Savannah. Because the liquefaction terminal was proposed at a pre-existing facility, the permit application was considered a "major modification" and is not relevant for determining whether a new LNG liquefaction facility is one of the 28 listed source categories.

However, the facility's most recent Title V Renewal Application Review (dated April 21, 2014) explains that the facility is not within one of the 28 listed source categories and that the 250 tpy standard is the appropriate standard to use in determining whether the facility is a Federal Major Source for PSD purposes. According to the renewal application, the facility had been subject to the 100 tpy standard at one time because its combined boiler capacity was greater than 250 MMBtu/hr. However, because the combined boiler capacity at the time of the Title V renewal had dropped below 250 MMBtu/hr, the 100 tpy standard no longer applied. This is significant because it confirms that there was nothing other than the boiler capacity that caused the facility to be designated as one of the 28 listed sources.

6. Sabine Pass LNG Terminal, LA, Permit PSD-LA-703(M3, M4, M5)

Sabine Pass LNG has been granted several modifications to its existing PSD permit to allow the construction of natural gas liquefaction facilities at a pre-existing LNG vaporization facility in Johnsons Bayou, Louisiana. The M3 modification of the permit (December 6, 2011) permitted construction of four natural gas liquefaction trains, consisting of 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives. The M4 modification of the permit (March 22, 2013) allowed several changes to the proposed four liquefaction trains. The M5 modification of the permit (June 3, 2015) allowed construction of two additional liquefaction trains, to be similar to the initial four trains.

Since the liquefaction trains were constructed at a pre-existing facility, the application was considered a “major modification” and is not relevant for determining whether a new LNG liquefaction facility is one of the 28 listed source categories.

APPENDIX E

MODEL INPUT SUMMARY

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Table E- 1. Project Sources

Scenario	Source ID	Description	UTM-x (m)	UTM-Y (m)	Elevation (m)	Emission Rates (g/s): NO_x 1-hr	NO_x Annual	SO_2 1-hr	SO_2 3-hr	SO_2 24-hr	SO_2 Annual	CO 1-hr	CO 8-hr	$PM_{2.5}$ 24-hr	$PM_{2.5}$ Ann	PM_{10} 24-hr	PM_{10} Ann	Stack parameters: Height (m)	Diameter(m)	Exit Temp. (K)	Exit Velocity (m/s)
Normal Operation	Turb1	Turbine 1	397644.9	4809333.4	14.0	4.788E-01	4.719E-01	2.066E-01	2.066E-01	2.066E-01	2.025E-01	5.733E-01	5.733E-01	6.804E-01	6.462E-01	6.804E-01	6.462E-01	36.3	3.0	390.3	21.6
	Turb2	Turbine 2	397643.0	4809401.2	14.0	4.788E-01	4.719E-01	2.066E-01	2.066E-01	2.066E-01	2.025E-01	5.733E-01	5.733E-01	6.804E-01	6.462E-01	6.804E-01	6.462E-01	36.3	3.0	390.3	21.6
	Turb3	Turbine 3	397641.2	4809469.0	14.0	4.788E-01	4.719E-01	2.066E-01	2.066E-01	2.066E-01	2.025E-01	5.733E-01	5.733E-01	6.804E-01	6.462E-01	6.804E-01	6.462E-01	36.3	3.0	390.3	21.6
	Turb4	Turbine 4	397639.3	4809536.8	14.0	4.788E-01	4.719E-01	2.066E-01	2.066E-01	2.066E-01	2.025E-01	5.733E-01	5.733E-01	6.804E-01	6.462E-01	6.804E-01	6.462E-01	36.3	3.0	390.3	21.6
	Turb5	Turbine 5	397637.5	4809604.6	14.0	4.788E-01	4.719E-01	2.066E-01	2.066E-01	2.066E-01	2.025E-01	5.733E-01	5.733E-01	6.804E-01	6.462E-01	6.804E-01	6.462E-01	36.3	3.0	390.3	21.6
Startup/Shutdown	Turb1SU	Turbine 1 Startup/Shutdown	397644.9	4809333.4	14.0	8.778E-01	4.730E-01	1.843E-01	1.992E-01	2.057E-01	2.025E-01	2.100E+00	7.642E-01	6.935E-01	6.465E-01	6.935E-01	6.465E-01	36.3	3.0	390.3	21.6
	Turb2SU	Turbine 2 Startup/Shutdown	397643.0	4809401.2	14.0	8.778E-01	4.730E-01	1.843E-01	1.992E-01	2.057E-01	2.025E-01	2.100E+00	7.642E-01	6.935E-01	6.465E-01	6.935E-01	6.465E-01	36.3	3.0	390.3	21.6
	Turb3SU	Turbine 3 Startup/Shutdown	397641.2	4809469.0	14.0	8.778E-01	4.730E-01	1.843E-01	1.992E-01	2.057E-01	2.025E-01	2.100E+00	7.642E-01	6.935E-01	6.465E-01	6.935E-01	6.465E-01	36.3	3.0	390.3	21.6
	Turb4SU	Turbine 4 Startup/Shutdown	397639.3	4809536.8	14.0	8.778E-01	4.730E-01	1.843E-01	1.992E-01	2.057E-01	2.025E-01	2.100E+00	7.642E-01	6.935E-01	6.465E-01	6.935E-01	6.465E-01	36.3	3.0	390.3	21.6
	Turb5SU	Turbine 5 Startup/Shutdown	397637.5	4809604.6	14.0	8.778E-01	4.730E-01	1.843E-01	1.992E-01	2.057E-01	2.025E-01	2.100E+00	7.642E-01	6.935E-01	6.465E-01	6.935E-01	6.465E-01	36.3	3.0	390.3	21.6
Other Project Sources (All Included with both Normal and Startup/Shutdown Scenatios)	ThermOx	Thermal Oxidizer	397465.0	4809694.7	14.0	1.819E+00	1.819E+00	5.708E-01	5.708E-01	5.708E-01	5.708E-01	1.108E+00	1.108E+00	1.107E-01	1.107E-01	1.107E-01	1.107E-01	40.0	2.9	1144.3	12.7
	AuxBoil	Auxiliary Boiler	397385.3	4809623.5	14.0	2.750E-01	2.750E-02	1.044E-01	1.044E-01	1.044E-01	1.044E-02	3.348E-01	3.348E-01	2.769E-01	2.769E-02	2.769E-01	2.769E-02	30.5	1.8	438.7	14.8
	FP1	Fire Pump 1	397823.0	4809674.7	15.8	1.528E-02	1.528E-02	2.035E-05	2.035E-05	2.035E-05	2.035E-05	7.709E-03	7.709E-03	8.630E-04	8.630E-04	8.630E-04	8.630E-04	5.5	0.2	782.2	58.8
	FP2	Fire Pump 2	397830.3	4809674.9	15.8	1.528E-02	1.528E-02	2.035E-05	2.035E-05	2.035E-05	2.035E-05	7.709E-03	7.709E-03	8.630E-04	8.630E-04	8.630E-04	8.630E-04	5.5	0.2	782.2	58.8
	FP3	Fire Pump 3	397835.5	4809675.1	15.8	1.528E-02	1.528E-02	2.035E-05	2.035E-05	2.035E-05	2.035E-05	7.709E-03	7.709E-03	8.630E-04	8.630E-04	8.630E-04	8.630E-04	5.5	0.2	782.2	58.8
	Gen1	Backup Generator 1	399631.0	4809864.4	19.8	4.784E-02	4.784E-02	3.530E-05	3.530E-05	3.530E-05	3.530E-05	4.085E-03	4.085E-03	5.466E-04	5.466E-04	5.466E-04	5.466E-04	4.0	0.2	784.5	87.5
	Gen2	Backup Generator 2	399627.0	4809864.2	19.8	4.784E-02	4.784E-02	3.530E-05	3.530E-05	3.530E-05	3.530E-05	4.085E-03	4.085E-03	5.466E-04	5.466E-04	5.466E-04	5.466E-04	4.0	0.2	784.5	87.5
	BSGen1	Black Start Generator 1	397297.1	4809620.9	14.0	2.137E-02	2.137E-02	1.272E-04	1.272E-04	1.272E-04	1.272E-04	2.992E-03	2.992E-03	6.616E-04	6.616E-04	6.616E-04	6.616E-04	5.5	0.5	740.7	53.9
	BSGen2	Black Start Generator 2	397289.4	4809620.7	14.0	2.137E-02	2.137E-02	1.272E-04	1.272E-04	1.272E-04	1.272E-04	2.992E-03	2.992E-03	6.616E-04	6.616E-04	6.616E-04	6.616E-04	5.5	0.5	740.7	53.9
	MFlare	Marine Flare	397361.3	4809303.0	14.0	6.650E-02	6.650E-02	5.010E-03	5.010E-03	5.010E-03	5.010E-03	3.032E-01	3.032E-01	3.512E-02	3.512E-02	3.512E-02	3.512E-02	30.5	13.7	1273.0	9.1
	GFlare	Ground Flare	397253.6	4809794.1	14.0	3.345E-06	3.345E-06	1.538E-07	1.538E-07	1.538E-07	1.538E-07	1.525E-05	1.525E-05	1.501E-06	1.501E-06	1.501E-06	1.501E-06	N/A	N/A	N/A	N/A

Notes:

"Normal" Scenario includes the five turbines in normal operation mode, and all the other project sources.

"Startup/Shutdown" Scenario includes the five turbines in startup/shutdown mode, and all the other project sources.

Table E- 2. Competing Sources Provided by ODEQ

Source ID	Owner	Source latitude (deg)	Source longitude (deg)	Allowable Emissions (tpy)				Stack parameters			
				NO_x	PM_{10}	$PM_{2.5}$	SO_2	Height (ft)	Diameter(ft)	Exit Temp. (F)	Exit Velocity (ft/s)
106-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	1	1	---	20	50	72	7
206-0010	Roseburg Forest Products Co.	43.1802	-124.2172	73	13	12	17	50	7	521	30
306-0010	Roseburg Forest Products Co.	43.1802	-124.2172	2	10	10	---	40	5	72	40
406-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	---	---	1	40	5	72	40
506-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	---	---	---	20	50	72	7
606-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	---	---	---	20	50	72	7
706-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	6	3	---	40	5	72	40
806-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	4	2	---	20	50	72	7
906-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	17	8	---	40	5	72	40
1006-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	0	0	---	20	50	72	7
1106-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	2	0	---	20	50	72	7
1206-0010	Roseburg Forest Products Co.	43.1802	-124.2172	---	---	---	---	40	5	72	40
1306-0013	Westrum Funeral Services, Inc. dba Myrtle Crest Memorial Gardens, Inc.	43.1637	-124.1557	---	14	9	---	25	2	1500	7
1406-0013	Westrum Funeral Services, Inc. dba Myrtle Crest Memorial Gardens, Inc.	43.1637	-124.1557	39	---	---	39	25	2	1500	7
1506-0014	Bandon Concrete & Development, Inc.	43.1045	-124.4087	---	14	9		20	50	72	7
1606-0027	Southport Forest Products, LLC	43.4380	-124.2393	39	1	1	39	40	3	350	25
1706-0027	Southport Forest Products, LLC	43.4380	-124.2393	---	3	1	---	40	5	72	40
1806-0027	Southport Forest Products, LLC	43.4380	-124.2393	---	4	3	---	40	5	72	40
1906-0027	Southport Forest Products, LLC	43.4380	-124.2393	---	1	0	---	40	5	72	40
2006-0027	Southport Forest Products, LLC	43.4380	-124.2393	---	5	4	---	40	5	72	40
2106-0027	Southport Forest Products, LLC	43.4380	-124.2393	---	---	---	---	20	50	72	7
2206-0028	Allweather Wood, LLC	43.5098	-124.2120	---	---	---	---	20	50	72	7
2306-0084	LTM, Incorporated	43.3350	-124.1952	---	14	9	---	20	50	72	7
2406-0104	Coastal Cremation and Funeral Service, LLC	43.3888	-124.2594	39	---	---	39	25	2	1500	7
2506-0104	Coastal Cremation and Funeral Service, LLC	43.3888	-124.2594	---	14	9	---	25	2	1500	7
2606-0116	Georgia-Pacific Wood Products LLC	43.3557	-124.1952	---	2	1	---	40	5	72	40
2706-0116	Georgia-Pacific Wood Products LLC	43.3557	-124.1952	---	8	4	---	40	5	72	40
2806-0116	Georgia-Pacific Wood Products LLC	43.3557	-124.1952	---	---	---	---	20	50	72	7
2906-0116	Georgia-Pacific Wood Products LLC	43.3557	-124.1952	---	4	4	---	40	5	72	40

Notes:
All ODEQ competing sources are included in the full impact model runs.

Table E-3. Ship Emissions Scenarios for Annual Averaging Periods					
Scenario	Source	Description	Emission Factors for Modeling (g/s)		
			PM_{10}	PM_{25}	NO_2
Steam Turbine Ships Operating on Oil	STHTL1	Berthed, Not Carrying Out Cargo Transfer	7.979E-03	7.979E-03	6.781E-02
	STHTL4	Berthed, Carrying Out Cargo Transfer	5.985E-02	5.985E-02	5.086E-01
	LNG01	Arrival to Berth	1.099E-02	1.099E-02	9.342E-02
	LNG02	Berthing Vessel	1.330E-03	1.330E-03	1.130E-02
	LNG08	Vessel Warm Up and Unberthing	3.990E-03	3.990E-03	3.390E-02
	LNG09	Departure from Berth to Pilot Station	1.099E-02	1.099E-02	9.342E-02
	TUGS01-TUGS04	Tugboats[1]	1.900E-05	1.900E-05	2.378E-01
	VES01-VES68	Vessel Transit through Channel[1]	3.234E-04	3.234E-04	5.015E-02
Steam Turbine Ships Operating on Gas	GSTHTL1	Berthed, Not Carrying Out Cargo Transfer	1.442E-03	1.442E-03	4.375E-01
	GSTHTL4	Berthed, Carrying Out Cargo Transfer	1.081E-02	1.081E-02	1.313E+00
	GLNG01	Arrival to Berth	1.986E-03	1.986E-03	1.808E+00
	GLNG02	Berthing Vessel	2.403E-04	2.403E-04	4.375E-01
	GLNG08	Vessel Warm Up and Unberthing	7.209E-04	7.209E-04	8.750E-01
	GLNG09	Departure from Berth to Pilot Station	1.986E-03	1.986E-03	1.808E+00
	TUGS01-TUGS04	Tugboats[1]	1.900E-05	1.900E-05	2.378E-01
	GVES01-GVES68	Vessel Transit through Channel[1]	5.843E-05	5.843E-05	1.457E-03
DFDE Ships	DFDHTL1	Berthed, Not Carrying Out Cargo Transfer	3.555E-03	3.555E-03	1.757E-01
	DFDHTL4	Berthed, Carrying Out Cargo Transfer	4.854E-02	4.854E-02	8.733E-01
	DFDLNG01	Arrival to Berth	1.185E-03	1.185E-03	5.856E-02
	DFDLNG02	Berthing Vessel	5.925E-04	5.925E-04	2.928E-02
	DFDLNG08	Vessel Warm Up and Unberthing	4.147E-03	4.147E-03	2.050E-01
	DFDLNG09	Departure from Berth to Pilot Station	1.185E-03	1.185E-03	5.856E-02
	TUGS01-TUGS04	Tugboats[1]	1.900E-05	1.900E-05	2.378E-01
	DFDVES01-DFDVES68	Vessel Transit through Channel[1]	3.485E-05	3.485E-05	1.722E-03

[1] Four surrogate tugboat sources and 68 surrogate vessel sources are used to represent the motion of these vessels.
Each surrogate tug is assigned 1/4 of the total tug emissions, and each surrogate vessel 1/68 of the total vessel emissions

Each of the three ship scenarios above (steam turbine ships on oil, steam turbine ships on gas, and DFDE ships) is combined with the ODEQ competing sources and project source scenarios (either normal operation or shartup/shutdown), to come up with the annual scenarios for full impact runs.

Table E-4. Ship Emissions Scenarios for 24-Hour Averaging Periods				
Scenario	Source	Description	Emission Factors for Modeling (g/s)	
			PM_{10}	PM_{25}
Steam Turbine Ships Operating on Oil	STHTL1	Berthed, Not Carrying Out Cargo Transfer	2.427E-02	2.427E-02
	STHTL4	Berthed, Carrying Out Cargo Transfer	1.820E-01	1.820E-01
	LNG01	Arrival to Berth	3.344E-02	3.344E-02
	LNG02	Berthing Vessel	4.045E-03	4.045E-03
	LNG08	Vessel Warm Up and Unberthing	1.214E-02	1.214E-02
	LNG09	Departure from Berth to Pilot Station	3.344E-02	3.344E-02
	TUGS01-TUGS04	Tugboats(1)	7.925E-03	7.925E-03
	VES01-VES68	Vessel Transit through Channel(1)	9.835E-04	9.835E-04
Steam Turbine Ships Operating on Gas	GSTHTL1	Berthed, Not Carrying Out Cargo Transfer	4.385E-03	4.385E-03
	GSTHTL4	Berthed, Carrying Out Cargo Transfer	3.289E-02	3.289E-02
	GLNG01	Arrival to Berth	6.042E-03	6.042E-03
	GLNG02	Berthing Vessel	7.309E-04	7.309E-04
	GLNG08	Vessel Warm Up and Unberthing	2.193E-03	2.193E-03
	GLNG09	Departure from Berth to Pilot Station	6.042E-03	6.042E-03
	TUGS01-TUGS04	Tugboats(1)	7.925E-03	7.925E-03
	GVES01-GVES68	Vessel Transit through Channel(1)	1.777E-04	1.777E-04
DFDE Ships	DFDHTL1	Berthed, Not Carrying Out Cargo Transfer	1.081E-02	1.081E-02
	DFDHTL4	Berthed, Carrying Out Cargo Transfer	1.477E-01	1.477E-01
	DFDLNG01	Arrival to Berth	3.604E-03	3.604E-03
	DFDLNG02	Berthing Vessel	1.802E-03	1.802E-03
	DFDLNG08	Vessel Warm Up and Unberthing	1.261E-02	1.261E-02
	DFDLNG09	Departure from Berth to Pilot Station	3.604E-03	3.604E-03
	TUGS01-TUGS04	Tugboats(1)	7.925E-03	7.925E-03
	DFDVES01-DFDVES68	Vessel Transit through Channel(1)	1.060E-04	1.060E-04

(1) Four surrogate tugboat sources and 68 surrogate vessel sources are used to represent the motion of these vessels.
Each surrogate tug is assigned 1/4 of the total tug emissions, and each surrogate vessel 1/68 of the total vessel emissions.
Each of the three ship scenarios above (steam turbine ships on oil, steam turbine ships on gas, and DFDE ships) is combined with the ODEQ competing sources and project source scenarios (either normal operation or shartup/shutdown), to come up with the 24-hour scenarios for full impact runs.

Table E-5. Emissions Scenarios for 1-Hour Averaging Periods				
Scenario	Source	Description	Emission Factors for Modeling (g/s)	
			NO_2	SO_2
All 1-Hour Scenarios[(1)]	TUGS01-TUGS04	Tugboats[(2)]	2.378E-01	6.500E-02
Steam Turbine Ships Operating on Oil in Transit	VES01-VES68	Vessel Transit through Channel[(2)]	5.015E-02	1.694E-02
Steam Turbine Ships Operating on Gas in Transit	GVES01-GVES68	Vessel Transit through Channel[(2)]	2.659E-02	7.851E-05
DFDE Ships in Transit	DFDVES01-DFDVES68	Vessel Transit through Channel[(2)]	3.143E-02	1.029E-03
Steam Turbine Ships Operating on Oil Arriving at Berth	LNG01	Arrival to Berth	3.410E+00	1.152E+00
Steam Turbine Ships Operating on Gas Arriving at Berth	GLNG01	Arrival to Berth	1.808E+00	5.339E-03
DFDE Ships Arriving at Berth	DFDLNG01	Arrival to Berth	2.138E+00	7.000E-02
Steam Turbine Ships Operating on Oil Berthing	LNG02	Berthing Vessel	8.250E-01	2.788E-01
Steam Turbine Ships Operating on Gas Berthing	GLNG02	Berthing Vessel	4.375E-01	1.292E-03
DFDE Ships Berthing	DFDLNG02	Berthing Vessel	2.138E+00	7.000E-02
Steam Turbine Ships Operating on Oil Hoteling	STHTL1	Berthed, Not Carrying Out Cargo Transfer	8.250E-01	2.788E-01
Steam Turbine Ships Operating on Gas Hoteling	GSTHTL1	Berthed, Not Carrying Out Cargo Transfer	4.375E-01	1.292E-03
DFDE Ships Hoteling	DFDHTL1	Berthed, Not Carrying Out Cargo Transfer	2.138E+00	7.000E-02
Steam Turbine Ships Operating on Oil Loading	STHTL4	Berthed, Carrying Out Cargo Transfer	2.475E+00	8.363E-01
Steam Turbine Ships Operating on Gas Loading	GSTHTL4	Berthed, Carrying Out Cargo Transfer	1.313E+00	1.288E-02
DFDE Ships Loading	DFDHTL4	Berthed, Carrying Out Cargo Transfer	4.250E+00	4.163E-01
Steam Turbine Ships Operating on Oil Warmup/Unberth	LNG08	Vessel Warm Up and Unberthing	1.650E+00	5.575E-01
Steam Turbine Ships Operating on Gas Warmup/Unberth	GLNG08	Vessel Warm Up and Unberthing	8.750E-01	2.583E-03
DFDE Ships Warmup/Unberth	DFDLNG08	Vessel Warm Up and Unberthing	6.413E+00	2.100E-01
Steam Turbine Ships Operating on Oil Departing	LNG09	Departure from Berth to Pilot Station	3.410E+00	1.152E+00
Steam Turbine Ships Operating on Gas Departing	GLNG09	Departure from Berth to Pilot Station	1.808E+00	5.339E-03
DFDE Ships Departing	DFDLNG09	Departure from Berth to Pilot Station	2.138E+00	7.000E-02

(1) The tug emissions are included in all 1-hour scenarios, along with one of the individual activities below.
These are combined with the ODEQ competing sources, and the project sources (either the normal scenario or SUSD scenario), to come up with the 1-hour scenarios for full impact runs.

(2) Four surrogate tugboat sources and 68 surrogate vessel sources are used to represent the motion of these vessels.
Each surrogate tug is assigned 1/4 of the total tug emissions, and each surrogate vessel 1/68 of the total vessel emissions.

APPENDIX F

DETAILED MODELING RESULTS AND CD OF MODELING INPUT AND OUTPUT FILES

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Placeholder Sheet

A CD is provided with the final hardcopies containing Input and Output files

APPENDIX G

LNG CARRIER CALCULATIONS

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Jordan Cove Energy Project, L.P.

Appendix G – LNG Carriers

The fleet of LNG vessels expected to call at the JCEP terminal consists of both vessels that have boiler/steam turbine driven (ST) propulsion systems, as well as vessels powered by duel-fuel diesel-electric (DFDE) propulsion. Further, each type of vessel may be operated on either natural gas or fuel oil. For the DFDE ships, however, operation on oil versus operation on natural gas was confined to different activities during the ship's call. Therefore, three vessel emissions scenarios were created in order to determine worst-case air emissions calculations and associated air quality impacts:

- ST vessels operating on oil
- ST vessels operating on natural gas
- DFDE ships

JCEP expects up to 120 LNG vessel calls per year. For the purposes of the modeling, in each of the three scenarios, it is assumed that all of the 120 vessel calls will be of ships of the same propulsion and fuel type.

The LNG vessel call activities can be divided into the following activities and operating periods per visit. These activity times are not dependent on the ship or fuel type. As can be seen in table F-1 the activities in total will last 29 hours per vessel call.

Emission rates for different activities during the ship's call are developed from the emission factors shown in Table F-2, and the amount of power expected to be consumed during that particular activity. As the emission factors are in a g/kWh basis, and the power will vary depending on activity, the emission rates (on a mass per unit time basis) will vary depending on the activity in which the ship is engaged.

If a ship is engaged in a particular activity for the full averaging period, than the full mass per unit time rate is used for modeling of that activity. If a ship is engaged for the activity for a portion of the averaging period, then the mass per unit time emission factor is weighted by the proportion of the activity time to the time of the averaging period. For example, for an activity that takes four hours, the full mass per unit time emission rate calculated will be used for 1-hour averaging periods (as the activity time is longer than that averaging period), but one-sixth of the full mass per unit time emission rate will be used for 24-hour averaging periods (as the four hours of activity time is one-sixth of the averaging period).

The emission factors are shown in Table F-2. The mass per unit time emission calculations for each of the three types of ships are shown in Tables F-3 through F-5, respectively. The emission rates by pollutant and averaging period for model input are shown in Tables F-6 through F-8, respectively. Vessel source locations and stack parameters are shown in Tables F-9 through F-11, respectively.

In addition to the activities at and in the immediate vicinity of the terminal, the emissions of the ship's transit of the channel and near-shore open water are considered by setting up 68 sources along the geographic track of arriving and departing ships. The transit emission rates are used for these surrogate sources, with the emissions divided equally over the 68 surrogate sources.

In addition to the LNG vessels, tugboats will also be deployed in operation at the JCEP LNG terminal. The worst-case scenario involves use of one tugboat. Since the tugboat will be maneuvering around the ship during the worst case, the tugboat is represented as a series of four surrogate sources in the channel adjacent to the ship dock, with one-quarter of the total tugboat emissions assigned to each surrogate source. The tugboat emissions are shown in Table F-12, and stack parameters and location information of the tugboat are detailed in Table F-13.

Marine vessel emissions scenario summaries for the annual, 24-hour, and 1-hour averaging periods are shown in Tables F-14 through F-16.

Table G-1. LNG Vessel Activities and Operating Periods per Visit		
Category	Activity	Time (hours)
Transit	Arrival to Berth	2
	Transit Berth to Pilot Station	2
Hoteling	Berthing Vessel	1
	Berthed, Not Carrying Out Cargo Transfer	6
	Vessel warm up of main engine and departure preparation	2
	Unberthing time	1
Loading	Berthed carrying out cargo transfer	15

Table G-2. Emission Factors for LNG Vessels (g/kWh)				
Pollutant	DFDE Ships		Steam Turbine Ships	
	Gas	Oil	Gas	Oil
NO_x (1)	1.71E+00	3.40E+00	1.05E+00	1.98E+00
CO (2)	1.09E+00	2.80E+00	4.71E-01	2.10E-01
PM (2)	3.46E-02	1.89E-01	4.21E-02	2.33E-01
VOC (2)	6.59E-01	2.70E-01	3.10E-02	1.18E-02
SO_2 (2,3)	5.60E-02	3.33E-01	3.10E-03	6.69E-01
CO_2 (4)	3.62E+02	5.43E+02	7.28E+02	1.03E+03
CH_4 (5)	4.28E-02	1.45E-02	1.40E-02	4.13E-02
N_2O (5)	7.26E-04	4.84E-03	1.34E-02	4.54E-03

(1) Based on IMO Marine Tier III standards.

(2) Based on Afton, Y. and Ervin, D., "An Assessment of Air Emissions from Liquefied Natural Gas Ships Using Different Power Systems and Different Fuels, " J. Air Waste Management Assoc., vol. 58 (2008), pp. 404-411. DFDE ships are assumed to have a 47% efficiency factor and ST ships a 25% efficiency factor.

(3) Fuel Oil sulfur content was assumed 0.1%.

(4) Based on AP-42 Table 3.4.-1 for Diesel Engines and Tables 1.3-12 and 1.4-2 for ST ships.

(5) ST emission factors based upon AP-42 Tables 1.3-3, 1.3-8, and 1.4-2. DFDE ship emission factors based on California Climate Action Registry General Reporting Protvol, Version 3.0, April 2008, Table C.7.

Table G-3. Emission Calculations Steam Turbine Vessels Powered by Fuel Oil

Period		Transit Time (hr)	Marine Grade Oil - MGO (tonnes)	Marine Grade Oil - MGO (gallons)	NOX			CO			PM			VOC			SO2			CO2			CH4			N2O		
					lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy
Transit																												
	Arrival to Berth at 4-5 knots	2.00	1.2	367	27.06	0.0271	3.25	2.87	0.003	0.34	3.18	0.003	0.38	0.16	0.0002	0.02	9.14	0.01	1.10	14078.72	14.08	1689.45	0.56	0.00	0.07	0.06	0.00	0.01
	Transit Berth to Pilot Station	2.00	1.2	367	27.06	0.0271	3.25	2.87	0.003	0.34	3.18	0.003	0.38	0.16	0.0002	0.02	9.14	0.01	1.10	14078.72	14.08	1689.45	0.56	0.00	0.07	0.06	0.00	0.01
Hotelling																												
	Berthing Vessel	1.00	0.6	184	6.55	0.0033	0.39	0.69	0.000	0.04	0.77	0.000	0.05	0.04	0.0000	0.00	2.21	0.00	0.13	3406.14	1.70	204.37	0.14	0.00	0.01	0.02	0.00	0.00
	Berthed Not Carrying Out Cargo Transfer	6.00	7.2	2,205	6.55	0.0196	2.36	0.69	0.002	0.25	0.77	0.002	0.28	0.04	0.0001	0.01	2.21	0.01	0.80	3406.14	10.22	1226.21	0.14	0.00	0.05	0.02	0.00	0.01
	Vessel warm up of main engine and prep to depart berth	2.00	1.2	367	6.55	0.0065	0.79	0.69	0.001	0.08	0.77	0.001	0.09	0.04	0.0000	0.00	2.21	0.00	0.27	3406.14	3.41	408.74	0.14	0.00	0.02	0.02	0.00	0.00
	Unberthing time	1.00	0.6	184	6.55	0.0033	0.39	0.69	0.000	0.04	0.77	0.000	0.05	0.04	0.0000	0.00	2.21	0.00	0.13	3406.14	1.70	204.37	0.14	0.00	0.01	0.02	0.00	0.00
LNG Loading																												
	Berthed carrying out cargo transfer	15.00	9.0	2,756	19.64	0.1473	17.68	2.08	0.016	1.88	2.31	0.017	2.08	0.12	0.0009	0.11	6.64	0.05	5.97	10218.43	76.64	9196.58	0.41	0.00	0.37	0.05	0.00	0.04
Total		29.00			99.96	0.23	28.10	10.60	0.02	2.98	11.76	0.03	3.31	0.596	0.001	0.17	33.78	0.08	9.50	52,000.43	121.83	14,619.16	2.09	0.00	0.59	0.23	0.00	0.06

Notes:

1.	LNG Capacity (m3)	142,950
	Number of Ship Calls per Year	120
	Total Electric Power Engine Rating (kW)	10,350
	Fuel Consumption Rate (at NCR)	182.2 metric tonnes per day
	Fuel Type	RMH 55
	HHV (kcal/kg)	10,280
	Density (lb/gal)	7.2

Table G-4. Emission Factors Steam Turbine Calculations Powered by Natural Gas

Period		Transit Time (hr)	Total Required Power (kW)	BOG - (tonnes)	BOG (MMscf)	NOX			CO			PM		
						lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy
Transit	Arrival to Berth at 4-5 knots	2.00	6,200	4.6	0.230	14.35	0.0144	1.72	6.44	0.006	0.77	0.58	0.001	0.07
	Transit Berth to Pilot Station	2.00	6,200	4.6	0.230	14.35	0.0144	1.72	6.44	0.006	0.77	0.58	0.001	0.07
Hotelling														
	Berthing Vessel	1.00	1,500	2.3	0.115	3.47	0.0017	0.21	1.56	0.001	0.09	0.14	0.000	0.01
	Berthed Not Carrying Out Cargo Transfer	6.00	1,500	0.0	0.000	3.47	0.0104	1.25	1.56	0.005	0.56	0.14	0.000	0.05
	Vessel warm up of main engine and prep to depart berth	2.00	1,500	4.8	0.241	3.47	0.0035	0.42	1.56	0.002	0.19	0.14	0.000	0.02
	Unberthing time	1.00	1,500	2.4	0.120	3.47	0.0017	0.21	1.56	0.001	0.09	0.14	0.000	0.01
LNG Loading														
	Berthed carrying out cargo transfer	15.00	4,500	51.0	2.555	10.42	0.0781	9.38	4.67	0.035	4.21	0.42	0.003	0.38
Total		29.00	22,900	70	3	53.01	0.12	14.90	23.78	0.06	6.69	2.13	0.00	0.60

Period		VOC			SO2			CO2			CH4			N2O		
		lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy
Transit	Arrival to Berth at 4-5 knots	0.42	0.0004	0.05	0.04	0.00	0.01	9950.78	9.95							
	Transit Berth to Pilot Station	0.42	0.0004	0.05	0.04	0.00	0.01	9950.78	9.95	1194.09	0.19	0.00	0.02	0.18	0.00	0.02
										1194.09	0.19	0.00	0.02	0.18	0.00	0.02
Hotelling																
	Berthing Vessel	0.10	0.0001	0.01	0.01	0.00	0.00	2407.45	1.20	144.45	0.05	0.00	0.00	0.04	0.00	0.00
	Berthed Not Carrying Out Cargo Transfer	0.10	0.0003	0.04	0.01	0.00	0.00	2407.45	7.22	866.68	0.05	0.00	0.02	0.04	0.00	0.02
	Vessel warm up of main engine and prep to depart berth	0.10	0.0001	0.01	0.01	0.00	0.00	2407.45	2.41	288.89	0.05	0.00	0.01	0.04	0.00	0.01
	Unberthing time	0.10	0.0001	0.01	0.01	0.00	0.00	2407.45	1.20	144.45	0.05	0.00	0.00	0.04	0.00	0.00
LNG Loading																
	Berthed carrying out cargo transfer	0.31	0.0023	0.28	0.10	0.00	0.09	7222.34	54.17	6500.11	0.14	0.00	0.13	0.13	0.00	0.12
Total		1.57	0.004	0.44	0.23	0.00	0.11	36,753.70	86.11	10,332.77	0.71	0.00	0.20	0.68	0.00	0.19

Notes:

1.	LNG Capacity (m3)	142,950
	Number of Ship Calls per Year	120
	Total Electric Power Engine Rating (kW)	10,350
	Fuel Consumption Rate (at NCR)	182.2 metric tonnes per day
	Fuel Type	BOG
	HHV (Btu/scf)	946
	Density (lb/scf)	0.044

Table G-5. Emission Calculations DFDE Vessels

Period		Transit Time (hr)	Required Power per Hour (kW)	Total Required Power (kWhr)	Fuel Burned	NOX			CO			PM			VOC			SO2			CO2			CH4			N2O		
						lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy	lb/hr	ton/call	tpy
Transit																													
	Arrival to Berth at 4-5 knots	2.00	4,500	9,000	Gas	16.96	0.0170	2.04	10.81	0.011	1.30	0.34	0.000	0.04	6.54	0.0065	0.78	0.56	0.00	0.07	3591.35	3.59	430.96	0.42	0.00	0.05	0.01	0.00	0.00
	Transit Berth to Pilot Station	2.00	4,500	9,000	Gas	16.96	0.0170	2.04	10.81	0.011	1.30	0.34	0.000	0.04	6.54	0.0065	0.78	0.56	0.00	0.07	3591.35	3.59	430.96	0.42	0.00	0.05	0.01	0.00	0.00
Hotelling																													
	Berthing Vessel	1.00	4,500	4,500	Gas	16.96	0.0085	1.02	10.81	0.005	0.65	0.34	0.000	0.02	6.54	0.0033	0.39	0.56	0.00	0.03	3591.35	1.80	215.48	0.42	0.00	0.03	0.01	0.00	0.00
	Berthed Not Carrying Out Cargo Transfer	6.00	4,500	27,000	Gas	16.96	0.0509	6.11	10.81	0.032	3.89	0.34	0.001	0.12	6.54	0.0196	2.35	0.56	0.00	0.20	3591.35	10.77	1292.89	0.42	0.00	0.15	0.01	0.00	0.00
	Vessel warm up of main engine and prep to depart berth	2.00	13,500	27,000	Gas	50.89	0.0509	6.11	32.44	0.032	3.89	1.03	0.001	0.12	19.61	0.0196	2.35	1.67	0.00	0.20	10774.05	10.77	1292.89	1.27	0.00	0.15	0.02	0.00	0.00
	Unberthing time	1.00	4,500	4,500	Gas	16.96	0.0085	1.02	10.81	0.005	0.65	0.34	0.000	0.02	6.54	0.0033	0.39	0.56	0.00	0.03	3591.35	1.80	215.48	0.42	0.00	0.03	0.01	0.00	0.00
LNG Loading																													
	Berthed carrying out cargo transfer	15.00	0	0	Fuel Oil	33.73	0.2530	30.36	27.78	0.208	25.00	1.88	0.014	1.69	2.68	0.0201	2.41	3.30	0.02	2.97	5387.02	40.40	4848.32	0.14	0.00	0.13	0.05	0.00	0.04
Total		29.00	36,000	81,000		169.45	0.41	48.68	114.29	0.31	36.68	4.62	0.02	2.06	54.98	0.079	9.47	7.75	0.03	3.57	34,117.82	72.72	8,726.98	3.54	0.00	0.59	0.11	0.00	0.05

Notes:

1.	LNG Capacity (m3)	168,162
	Number of Ship Calls per Year	120
	Total Propulsion Engine Rating (kW)	25,400
	Total Electric Power Engine Rating (kW)	39,900

Table G-6. Emission Rates for Model Input - Steam Turbine Vessels Operating on Fuel Oil

Activity		NOx (g/s)		SO2 (g/s)				CO (g/s)		PM (g/s)	
		1 hour	Annual	1 hour	3 hour	24 hour	Annual	1 hour	8 hour	24 hour	Annual
Transit											
	Arrival to Berth at 4-5 knots	3.41E+00	9.34E-02	1.15E+00	7.68E-01	9.60E-02	1.58E-05	3.62E-01	9.04E-02	3.34E-02	1.10E-02
	Transit Berth to Pilot Station	3.41E+00	9.34E-02	1.15E+00	7.68E-01	9.60E-02	1.58E-05	3.62E-01	9.04E-02	3.34E-02	1.10E-02
Hotelling											
	Berthing Vessel	8.25E-01	1.13E-02	2.79E-01	9.29E-02	1.16E-02	1.91E-06	8.75E-02	1.09E-02	4.05E-03	1.33E-03
	Berthed Not Carrying Out Cargo Transfer	8.25E-01	6.78E-02	2.79E-01	2.79E-01	6.97E-02	1.15E-05	8.75E-02	6.56E-02	2.43E-02	7.98E-03
	Vessel warm up of main engine and prep to depart berth	8.25E-01	2.26E-02	2.79E-01	1.86E-01	2.32E-02	3.82E-06	8.75E-02	2.19E-02	8.09E-03	2.66E-03
	Unberthing time	8.25E-01	1.13E-02	2.79E-01	9.29E-02	1.16E-02	1.91E-06	8.75E-02	1.09E-02	4.05E-03	1.33E-03
LNG Loading											
	Berthed carrying out cargo transfer	2.48E+00	5.09E-01	8.36E-01	8.36E-01	5.23E-01	8.59E-05	2.63E-01	2.63E-01	1.82E-01	5.98E-02

Table G-7. Emission Rates for Model Input - Steam Turbine Vessels Operating on Natural Gas

Activity		NOx (g/s)		SO2 (g/s)				CO (g/s)		PM (g/s)	
		1 hour	Annual	1 hour	3 hour	24 hour	Annual	1 hour	8 hour	24 hour	Annual
Transit											
	Arrival to Berth at 4-5 knots	1.81E+00	4.95E-02	5.34E-03	3.56E-03	4.45E-04	7.31E-08	8.11E-01	2.03E-01	6.04E-03	1.99E-03
	Transit Berth to Pilot Station	1.81E+00	4.95E-02	5.34E-03	3.56E-03	4.45E-04	7.31E-08	8.11E-01	2.03E-01	6.04E-03	1.99E-03
Hotelling											
	Berthing Vessel	4.38E-01	5.99E-03	1.29E-03	4.31E-04	5.38E-05	8.85E-09	1.96E-01	2.45E-02	7.31E-04	2.40E-04
	Berthed Not Carrying Out Cargo Transfer	4.38E-01	3.60E-02	1.29E-03	1.29E-03	3.23E-04	5.31E-08	1.96E-01	1.47E-01	4.39E-03	1.44E-03
	Vessel warm up of main engine and prep to depart berth	4.38E-01	1.20E-02	1.29E-03	8.61E-04	1.08E-04	1.77E-08	1.96E-01	4.91E-02	1.46E-03	4.81E-04
	Unberthing time	4.38E-01	5.99E-03	1.29E-03	4.31E-04	5.38E-05	8.85E-09	1.96E-01	2.45E-02	7.31E-04	2.40E-04
LNG Loading											
	Berthed carrying out cargo transfer	1.31E+00	2.70E-01	1.29E-02	1.29E-02	8.05E-03	1.32E-06	5.89E-01	5.89E-01	3.29E-02	1.08E-02

Table G-8. Emission Rates for Model Input - DFDE Vessels

Activity		NOx (g/s)		SO2 (g/s)				CO (g/s)		PM (g/s)	
		1 hour	Annual	1 hour	3 hour	24 hour	Annual	1 hour	8 hour	24 hour	Annual
Transit											
	Arrival to Berth at 4-5 knots	2.14E+00	5.86E-02	7.00E-02	4.67E-02	5.83E-03	1.92E-03	1.36E+00	3.41E-01	3.60E-03	1.18E-03
	Transit Berth to Pilot Station	2.14E+00	5.86E-02	7.00E-02	4.67E-02	5.83E-03	1.92E-03	1.36E+00	3.41E-01	3.60E-03	1.18E-03
Hotelling											
	Berthing Vessel	2.14E+00	2.93E-02	7.00E-02	2.33E-02	2.92E-03	9.59E-04	1.36E+00	1.70E-01	1.80E-03	5.92E-04
	Berthed Not Carrying Out Cargo Transfer	2.14E+00	1.76E-01	7.00E-02	7.00E-02	1.75E-02	5.75E-03	1.36E+00	1.02E+00	1.08E-02	3.55E-03
	Vessel warm up of main engine and prep to depart berth	6.41E+00	1.76E-01	2.10E-01	1.40E-01	1.75E-02	5.75E-03	4.09E+00	1.02E+00	1.08E-02	3.55E-03
	Unberthing time	2.14E+00	2.93E-02	7.00E-02	2.33E-02	2.92E-03	9.59E-04	1.36E+00	1.70E-01	1.80E-03	5.92E-04
LNG Loading											
	Berthed carrying out cargo transfer	4.25E+00	8.73E-01	4.16E-01	4.16E-01	2.60E-01	8.55E-02	3.50E+00	3.50E+00	1.48E-01	4.85E-02

Table G-9. Locations and Stack Parameters for Steam Turbine Ships Operating on Oil

Activity	AERMOD Source ID	Stack Location			Stack Parameters			
		UTM E (m)	UTM N (m)	Elevation (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)
Berthed Not Carrying Out Cargo Transfer	STHTL1	397540.7	4809097.7	0.0	40.0	408.2	6.9	1.5
Berthed carrying out cargo transfer	STHTL4	397540.7	4809097.7	0.0	40.0	408.2	5.9	1.5
Tugboat	TUGS01	397485.0	4809200.0	0.0	10.7	801.0	61.8	0.3
	TUGS02	397485.0	4809100.0	0.0	10.7	801.0	61.8	0.3
	TUGS03	397485.0	4809000.0	0.0	10.7	801.0	61.8	0.3
	TUGS04	397485.0	4808900.0	0.0	10.7	801.0	61.8	0.3
Arrival to Berth at 4-5 knots	LNG01	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Berthing Vessel	LNG02	397540.7	4809097.7	0.0	40.0	408.2	8.4	1.5
Vessel warm up and unberthing	LNG08	397540.7	4809097.7	0.0	40.0	408.2	8.4	1.5
Transit Berth to Pilot Station	LNG09	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Transit in Channel/Near Shore	VES1	389899.8	4801854.5	0.0	40.0	408.2	34.5	1.5
	VES2	390078.0	4801763.5	0.0	40.0	408.2	34.5	1.5
	VES3	390256.2	4801672.5	0.0	40.0	408.2	34.5	1.5
	VES4	390434.4	4801581.5	0.0	40.0	408.2	34.5	1.5
	VES5	390612.5	4801490.5	0.0	40.0	408.2	34.5	1.5
	VES6	390790.7	4801399.5	0.0	40.0	408.2	34.5	1.5
	VES7	390968.9	4801308.5	0.0	40.0	408.2	34.5	1.5
	VES8	391147.1	4801217.5	0.0	40.0	408.2	34.5	1.5
	VES9	391325.3	4801126.5	0.0	40.0	408.2	34.5	1.5
	VES10	391503.5	4801035.5	0.0	40.0	408.2	34.5	1.5
	VES11	391681.7	4800944.5	0.0	40.0	408.2	34.5	1.5
	VES12	391859.9	4800853.5	0.0	40.0	408.2	34.5	1.5
	VES13	392038.2	4800765.0	0.0	40.0	408.2	34.5	1.5
	VES14	392206.6	4800822.0	0.0	40.0	408.2	34.5	1.5
	VES15	392375.1	4800879.0	0.0	40.0	408.2	34.5	1.5
	VES16	392543.4	4800936.0	0.0	40.0	408.2	34.5	1.5
	VES17	392711.8	4800993.0	0.0	40.0	408.2	34.5	1.5
	VES18	392839.0	4801112.0	0.0	40.0	408.2	34.5	1.5
	VES19	392924.7	4801293.0	0.0	40.0	408.2	34.5	1.5
	VES20	393010.5	4801474.0	0.0	40.0	408.2	34.5	1.5
	VES21	393096.2	4801655.0	0.0	40.0	408.2	34.5	1.5
	VES22	393182.0	4801836.0	0.0	40.0	408.2	34.5	1.5
	VES23	393267.7	4802017.0	0.0	40.0	408.2	34.5	1.5
	VES24	393381.2	4802176.5	0.0	40.0	408.2	34.5	1.5
	VES25	393522.3	4802318.5	0.0	40.0	408.2	34.5	1.5
	VES26	393663.4	4802460.5	0.0	40.0	408.2	34.5	1.5
	VES27	393804.4	4802602.5	0.0	40.0	408.2	34.5	1.5
	VES28	393945.5	4802744.5	0.0	40.0	408.2	34.5	1.5
	VES29	394086.6	4802886.5	0.0	40.0	408.2	34.5	1.5
	VES30	394227.6	4803028.5	0.0	40.0	408.2	34.5	1.5
	VES31	394368.7	4803170.5	0.0	40.0	408.2	34.5	1.5
	VES32	394509.7	4803312.5	0.0	40.0	408.2	34.5	1.5
	VES33	394650.8	4803454.5	0.0	40.0	408.2	34.5	1.5
	VES34	394791.9	4803596.5	0.0	40.0	408.2	34.5	1.5
	VES35	394932.9	4803738.5	0.0	40.0	408.2	34.5	1.5
	VES36	395074.0	4803880.5	0.0	40.0	408.2	34.5	1.5
	VES37	395215.1	4804022.5	0.0	40.0	408.2	34.5	1.5
	VES38	395356.0	4804161.0	0.0	40.0	408.2	34.5	1.5
	VES39	395438.1	4804335.0	0.0	40.0	408.2	34.5	1.5
	VES40	395520.2	4804509.1	0.0	40.0	408.2	34.5	1.5
	VES41	395602.4	4804683.1	0.0	40.0	408.2	34.5	1.5
	VES42	395684.5	4804857.1	0.0	40.0	408.2	34.5	1.5
	VES43	395766.6	4805031.1	0.0	40.0	408.2	34.5	1.5
	VES44	395848.7	4805205.1	0.0	40.0	408.2	34.5	1.5
	VES45	395930.9	4805379.1	0.0	40.0	408.2	34.5	1.5
	VES46	396013.0	4805553.1	0.0	40.0	408.2	34.5	1.5
	VES47	396095.1	4805727.1	0.0	40.0	408.2	34.5	1.5
	VES48	396177.2	4805901.1	0.0	40.0	408.2	34.5	1.5
	VES49	396259.4	4806075.1	0.0	40.0	408.2	34.5	1.5
	VES50	396341.5	4806249.1	0.0	40.0	408.2	34.5	1.5
	VES51	396423.9	4806421.6	0.0	40.0	408.2	34.5	1.5
	VES52	396453.3	4806604.6	0.0	40.0	408.2	34.5	1.5
	VES53	396482.6	4806787.6	0.0	40.0	408.2	34.5	1.5
	VES54	396512.0	4806970.6	0.0	40.0	408.2	34.5	1.5
	VES55	396541.4	4807153.6	0.0	40.0	408.2	34.5	1.5
	VES56	396570.8	4807336.6	0.0	40.0	408.2	34.5	1.5
	VES57	396600.1	4807519.6	0.0	40.0	408.2	34.5	1.5
	VES58	396629.7	4807705.6	0.0	40.0	408.2	34.5	1.5
	VES59	396732.8	4807876.6	0.0	40.0	408.2	34.5	1.5
	VES60	396848.9	4808023.6	0.0	40.0	408.2	34.5	1.5
	VES61	396978.0	4808145.6	0.0	40.0	408.2	34.5	1.5
	VES62	397107.1	4808267.6	0.0	40.0	408.2	34.5	1.5
	VES63	397236.2	4808389.6	0.0	40.0	408.2	34.5	1.5
	VES64	397365.3	4808512.6	0.0	40.0	408.2	34.5	1.5
	VES65	397560.9	4808554.1	0.0	40.0	408.2	34.5	1.5
	VES66	397561.4	4808721.1	0.0	40.0	408.2	34.5	1.5
	VES67	397561.9	4808888.1	0.0	40.0	408.2	34.5	1.5
	VES68	397562.5	4809054.1	0.0	40.0	408.2	34.5	1.5

Table G-10. Locations and Stack Parameters for Steam Turbine Ships Operating on Gas

Activity	AERMOD Source ID	Stack Location			Stack Parameters			
		UTM E (m)	UTM N (m)	Elevation (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)
Berthed Not Carrying Out Cargo Transfer	GSTHTL1	397540.7	4809097.7	0.0	40.0	408.2	7.1	1.5
Berthed carrying out cargo transfer	GSTHTL4	397540.7	4809097.7	0.0	40.0	408.2	6.1	1.5
Tugboat	TUGS01	397485.0	4809200.0	0.0	10.7	801.0	61.8	0.3
	TUGS02	397485.0	4809100.0	0.0	10.7	801.0	61.8	0.3
	TUGS03	397485.0	4809000.0	0.0	10.7	801.0	61.8	0.3
	TUGS04	397485.0	4808900.0	0.0	10.7	801.0	61.8	0.3
Arrival to Berth at 4-5 knots	GLNG01	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Berthing Vessel	GLNG02	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Vessel warm up and unberthing	GLNG08	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Transit Berth to Pilot Station	GLNG09	397540.7	4809097.7	0.0	40.0	408.2	34.5	1.5
Transit in Channel/Near Shore	GVES1	389899.8	4801854.5	0.0	40.0	408.2	34.5	1.5
	GVES2	390078.0	4801763.5	0.0	40.0	408.2	34.5	1.5
	GVES3	390256.2	4801672.5	0.0	40.0	408.2	34.5	1.5
	GVES4	390434.4	4801581.5	0.0	40.0	408.2	34.5	1.5
	GVES5	390612.5	4801490.5	0.0	40.0	408.2	34.5	1.5
	GVES6	390790.7	4801399.5	0.0	40.0	408.2	34.5	1.5
	GVES7	390968.9	4801308.5	0.0	40.0	408.2	34.5	1.5
	GVES8	391147.1	4801217.5	0.0	40.0	408.2	34.5	1.5
	GVES9	391325.3	4801126.5	0.0	40.0	408.2	34.5	1.5
	GVES10	391503.5	4801035.5	0.0	40.0	408.2	34.5	1.5
	GVES11	391681.7	4800944.5	0.0	40.0	408.2	34.5	1.5
	GVES12	391859.9	4800853.5	0.0	40.0	408.2	34.5	1.5
	GVES13	392038.2	4800765.0	0.0	40.0	408.2	34.5	1.5
	GVES14	392206.6	4800822.0	0.0	40.0	408.2	34.5	1.5
	GVES15	392375.1	4800879.0	0.0	40.0	408.2	34.5	1.5
	GVES16	392543.4	4800936.0	0.0	40.0	408.2	34.5	1.5
	GVES17	392711.8	4800993.0	0.0	40.0	408.2	34.5	1.5
	GVES18	392839.0	4801112.0	0.0	40.0	408.2	34.5	1.5
	GVES19	392924.7	4801293.0	0.0	40.0	408.2	34.5	1.5
	GVES20	393010.5	4801474.0	0.0	40.0	408.2	34.5	1.5
	GVES21	393096.2	4801655.0	0.0	40.0	408.2	34.5	1.5
	GVES22	393182.0	4801836.0	0.0	40.0	408.2	34.5	1.5
	GVES23	393267.7	4802017.0	0.0	40.0	408.2	34.5	1.5
	GVES24	393381.2	4802176.5	0.0	40.0	408.2	34.5	1.5
	GVES25	393522.3	4802318.5	0.0	40.0	408.2	34.5	1.5
	GVES26	393663.4	4802460.5	0.0	40.0	408.2	34.5	1.5
	GVES27	393804.4	4802602.5	0.0	40.0	408.2	34.5	1.5
	GVES28	393945.5	4802744.5	0.0	40.0	408.2	34.5	1.5
	GVES29	394086.6	4802886.5	0.0	40.0	408.2	34.5	1.5
	GVES30	394227.6	4803028.5	0.0	40.0	408.2	34.5	1.5
	GVES31	394368.7	4803170.5	0.0	40.0	408.2	34.5	1.5
	GVES32	394509.7	4803312.5	0.0	40.0	408.2	34.5	1.5
	GVES33	394650.8	4803454.5	0.0	40.0	408.2	34.5	1.5
	GVES34	394791.9	4803596.5	0.0	40.0	408.2	34.5	1.5
	GVES35	394932.9	4803738.5	0.0	40.0	408.2	34.5	1.5
	GVES36	395074.0	4803880.5	0.0	40.0	408.2	34.5	1.5
	GVES37	395215.1	4804022.5	0.0	40.0	408.2	34.5	1.5
	GVES38	395356.0	4804161.0	0.0	40.0	408.2	34.5	1.5
	GVES39	395438.1	4804335.0	0.0	40.0	408.2	34.5	1.5
	GVES40	395520.2	4804509.1	0.0	40.0	408.2	34.5	1.5
	GVES41	395602.4	4804683.1	0.0	40.0	408.2	34.5	1.5
	GVES42	395684.5	4804857.1	0.0	40.0	408.2	34.5	1.5
	GVES43	395766.6	4805031.1	0.0	40.0	408.2	34.5	1.5
	GVES44	395848.7	4805205.1	0.0	40.0	408.2	34.5	1.5
	GVES45	395930.9	4805379.1	0.0	40.0	408.2	34.5	1.5
	GVES46	396013.0	4805553.1	0.0	40.0	408.2	34.5	1.5
	GVES47	396095.1	4805727.1	0.0	40.0	408.2	34.5	1.5
	GVES48	396177.2	4805901.1	0.0	40.0	408.2	34.5	1.5
	GVES49	396259.4	4806075.1	0.0	40.0	408.2	34.5	1.5
	GVES50	396341.5	4806249.1	0.0	40.0	408.2	34.5	1.5
	GVES51	396423.9	4806421.6	0.0	40.0	408.2	34.5	1.5
	GVES52	396453.3	4806604.6	0.0	40.0	408.2	34.5	1.5
	GVES53	396482.6	4806787.6	0.0	40.0	408.2	34.5	1.5
	GVES54	396512.0	4806970.6	0.0	40.0	408.2	34.5	1.5
	GVES55	396541.4	4807153.6	0.0	40.0	408.2	34.5	1.5
	GVES56	396570.8	4807336.6	0.0	40.0	408.2	34.5	1.5
	GVES57	396600.1	4807519.6	0.0	40.0	408.2	34.5	1.5
	GVES58	396629.7	4807705.6	0.0	40.0	408.2	34.5	1.5
	GVES59	396732.8	4807876.6	0.0	40.0	408.2	34.5	1.5
	GVES60	396848.9	4808023.6	0.0	40.0	408.2	34.5	1.5
	GVES61	396978.0	4808145.6	0.0	40.0	408.2	34.5	1.5
	GVES62	397107.1	4808267.6	0.0	40.0	408.2	34.5	1.5
	GVES63	397236.2	4808389.6	0.0	40.0	408.2	34.5	1.5
	GVES64	397365.3	4808512.6	0.0	40.0	408.2	34.5	1.5
	GVES65	397560.9	4808554.1	0.0	40.0	408.2	34.5	1.5
	GVES66	397561.4	4808721.1	0.0	40.0	408.2	34.5	1.5
	GVES67	397561.9	4808888.1	0.0	40.0	408.2	34.5	1.5
	GVES68	397562.5	4809054.1	0.0	40.0	408.2	34.5	1.5

Table G-11. Locations and Stack Parameters for DFDE Ships

Activity	AERMOD Source ID	Stack Location			Stack Parameters			
		UTM E (m)	UTM N (m)	Elevation (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)
Berthed Not Carrying Out Cargo Transfer	DFDEHTL1	397540.7	4809097.7	0.0	40.0	623.2	5.6	1.5
Berthed carrying out cargo transfer	DFDEHTL4	397540.7	4809097.7	0.0	40.0	623.2	4.8	1.5
Tugboat	TUGS01	397485.0	4809200.0	0.0	10.7	801.0	61.8	0.3
	TUGS02	397485.0	4809100.0	0.0	10.7	801.0	61.8	0.3
	TUGS03	397485.0	4809000.0	0.0	10.7	801.0	61.8	0.3
	TUGS04	397485.0	4808900.0	0.0	10.7	801.0	61.8	0.3
Arrival to Berth at 4-5 knots	DFDLNG01	397540.7	4809097.7	0.0	40.0	623.2	35.5	1.5
Berthing Vessel	DFDLNG02	397540.7	4809097.7	0.0	40.0	623.2	8.7	1.5
Vessel warm up and unberthing	DFDLNG08	397540.7	4809097.7	0.0	40.0	623.2	8.7	1.5
Transit Berth to Pilot Station	DFDLNG09	397540.7	4809097.7	0.0	40.0	623.2	35.5	1.5
Transit in Channel/Near Shore	DFDVES1	389899.8	4801854.5	0.0	40.0	623.2	35.5	1.5
	DFDVES2	390078.0	4801763.5	0.0	40.0	623.2	35.5	1.5
	DFDVES3	390256.2	4801672.5	0.0	40.0	623.2	35.5	1.5
	DFDVES4	390434.4	4801581.5	0.0	40.0	623.2	35.5	1.5
	DFDVES5	390612.5	4801490.5	0.0	40.0	623.2	35.5	1.5
	DFDVES6	390790.7	4801399.5	0.0	40.0	623.2	35.5	1.5
	DFDVES7	390968.9	4801308.5	0.0	40.0	623.2	35.5	1.5
	DFDVES8	391147.1	4801217.5	0.0	40.0	623.2	35.5	1.5
	DFDVES9	391325.3	4801126.5	0.0	40.0	623.2	35.5	1.5
	DFDVES10	391503.5	4801035.5	0.0	40.0	623.2	35.5	1.5
	DFDVES11	391681.7	4800944.5	0.0	40.0	623.2	35.5	1.5
	DFDVES12	391859.9	4800853.5	0.0	40.0	623.2	35.5	1.5
	DFDVES13	392038.2	4800765.0	0.0	40.0	623.2	35.5	1.5
	DFDVES14	392206.6	4800822.0	0.0	40.0	623.2	35.5	1.5
	DFDVES15	392375.1	4800879.0	0.0	40.0	623.2	35.5	1.5
	DFDVES16	392543.4	4800936.0	0.0	40.0	623.2	35.5	1.5
	DFDVES17	392711.8	4800993.0	0.0	40.0	623.2	35.5	1.5
	DFDVES18	392839.0	4801112.0	0.0	40.0	623.2	35.5	1.5
	DFDVES19	392924.7	4801293.0	0.0	40.0	623.2	35.5	1.5
	DFDVES20	393010.5	4801474.0	0.0	40.0	623.2	35.5	1.5
	DFDVES21	393096.2	4801655.0	0.0	40.0	623.2	35.5	1.5
	DFDVES22	393182.0	4801836.0	0.0	40.0	623.2	35.5	1.5
	DFDVES23	393267.7	4802017.0	0.0	40.0	623.2	35.5	1.5
	DFDVES24	393381.2	4802176.5	0.0	40.0	623.2	35.5	1.5
	DFDVES25	393522.3	4802318.5	0.0	40.0	623.2	35.5	1.5
	DFDVES26	393663.4	4802460.5	0.0	40.0	623.2	35.5	1.5
	DFDVES27	393804.4	4802602.5	0.0	40.0	623.2	35.5	1.5
	DFDVES28	393945.5	4802744.5	0.0	40.0	623.2	35.5	1.5
	DFDVES29	394086.6	4802886.5	0.0	40.0	623.2	35.5	1.5
	DFDVES30	394227.6	4803028.5	0.0	40.0	623.2	35.5	1.5
	DFDVES31	394368.7	4803170.5	0.0	40.0	623.2	35.5	1.5
	DFDVES32	394509.7	4803312.5	0.0	40.0	623.2	35.5	1.5
	DFDVES33	394650.8	4803454.5	0.0	40.0	623.2	35.5	1.5
	DFDVES34	394791.9	4803596.5	0.0	40.0	623.2	35.5	1.5
	DFDVES35	394932.9	4803738.5	0.0	40.0	623.2	35.5	1.5
	DFDVES36	395074.0	4803880.5	0.0	40.0	623.2	35.5	1.5
	DFDVES37	395215.1	4804022.5	0.0	40.0	623.2	35.5	1.5
	DFDVES38	395356.0	4804161.0	0.0	40.0	623.2	35.5	1.5
	DFDVES39	395438.1	4804335.0	0.0	40.0	623.2	35.5	1.5
	DFDVES40	395520.2	4804509.1	0.0	40.0	623.2	35.5	1.5
	DFDVES41	395602.4	4804683.1	0.0	40.0	623.2	35.5	1.5
	DFDVES42	395684.5	4804857.1	0.0	40.0	623.2	35.5	1.5
	DFDVES43	395766.6	4805031.1	0.0	40.0	623.2	35.5	1.5
	DFDVES44	395848.7	4805205.1	0.0	40.0	623.2	35.5	1.5
	DFDVES45	395930.9	4805379.1	0.0	40.0	623.2	35.5	1.5
	DFDVES46	396013.0	4805553.1	0.0	40.0	623.2	35.5	1.5
	DFDVES47	396095.1	4805727.1	0.0	40.0	623.2	35.5	1.5
	DFDVES48	396177.2	4805901.1	0.0	40.0	623.2	35.5	1.5
	DFDVES49	396259.4	4806075.1	0.0	40.0	623.2	35.5	1.5
	DFDVES50	396341.5	4806249.1	0.0	40.0	623.2	35.5	1.5
	DFDVES51	396423.9	4806421.6	0.0	40.0	623.2	35.5	1.5
	DFDVES52	396453.3	4806604.6	0.0	40.0	623.2	35.5	1.5
	DFDVES53	396482.6	4806787.6	0.0	40.0	623.2	35.5	1.5
	DFDVES54	396512.0	4806970.6	0.0	40.0	623.2	35.5	1.5
	DFDVES55	396541.4	4807153.6	0.0	40.0	623.2	35.5	1.5
	DFDVES56	396570.8	4807336.6	0.0	40.0	623.2	35.5	1.5
	DFDVES57	396600.1	4807519.6	0.0	40.0	623.2	35.5	1.5
	DFDVES58	396629.7	4807705.6	0.0	40.0	623.2	35.5	1.5
	DFDVES59	396732.8	4807876.6	0.0	40.0	623.2	35.5	1.5
	DFDVES60	396848.9	4808023.6	0.0	40.0	623.2	35.5	1.5
	DFDVES61	396978.0	4808145.6	0.0	40.0	623.2	35.5	1.5
	DFDVES62	397107.1	4808267.6	0.0	40.0	623.2	35.5	1.5
	DFDVES63	397236.2	4808389.6	0.0	40.0	623.2	35.5	1.5
	DFDVES64	397365.3	4808512.6	0.0	40.0	623.2	35.5	1.5
	DFDVES65	397560.9	4808554.1	0.0	40.0	623.2	35.5	1.5
	DFDVES66	397561.4	4808721.1	0.0	40.0	623.2	35.5	1.5
	DFDVES67	397561.9	4808888.1	0.0	40.0	623.2	35.5	1.5
	DFDVES68	397562.5	4809054.1	0.0	40.0	623.2	35.5	1.5

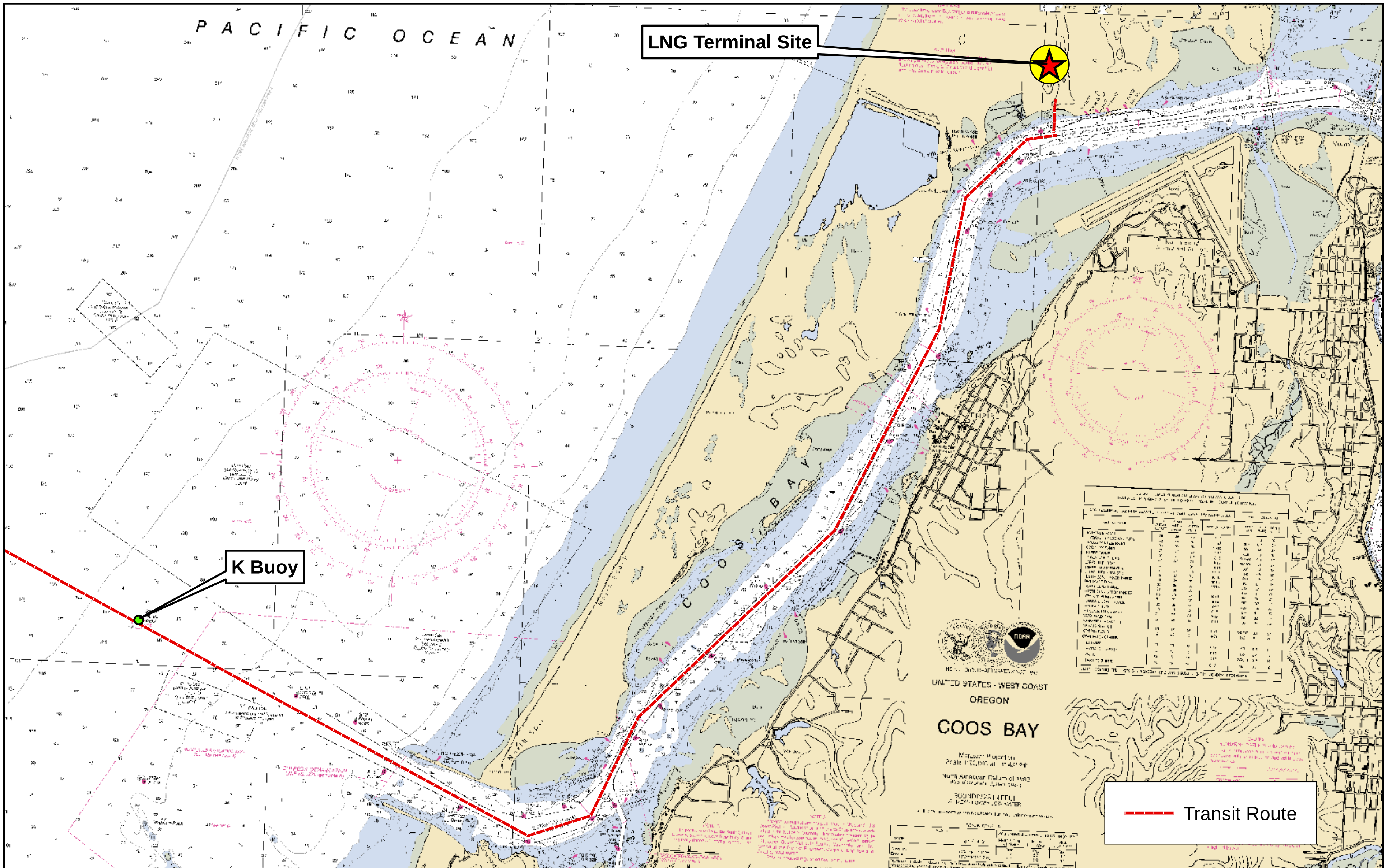
Table G-12. Tugboat Emissions Information(1)							
Pollutant	Emission Factor (g/kWh)	Tug Emissions per Port Call (kg)	Emission Factors for Modeling (per surrogate source, g/s)(1)				
			1-hour	3-hour	8-hour	24-hour	Annual
NO_x(2)	1.80E+00	72	2.38E-01	N/A	N/A	N/A	5.70E-04
CO(3)	3.35E+00	134	4.42E-01	N/A	4.42E-01	N/A	N/A
PM(2)	6.00E-02	2	N/A	N/A	N/A	7.93E-03	1.90E-05
SO_2(3)	4.92E-01	20	6.50E-02	6.50E-02	N/A	6.50E-02	1.56E-04
VOC(2)	1.90E-01	8	N/A	N/A	N/A	N/A	N/A
CO_2(3)	7.06E+02	28183	N/A	N/A	N/A	N/A	N/A

Notes:
(1) Tug is represented as four surrogate sources to account for manuevering about the berthed ship.
(2) NOx, PM, and VOC emissions are EPA Marine Tier 4 standards (40 CFR Section 1042.1, Table 3)
(3) CO, SO2, and CO2 emission factors from AP42 Table 3.4-1. Sulfur content of fuel assumed 0.1%.
(4) Emissions per call calculated by multiplying emisison factor by 39942 kWh, the total energy expended per ship call. Rates determined by dividing total emissions by 1260 minutes operation per ship call. Emission rate for each surrogate source is one-quarter of the overall emission rate. Annual emissions based on 120 ship calls per year.

Tug Activities and Operating Times per Ship Call

Activity	Time (min)	Kw	Kw-Hour
Maneuvering Around Ship	1200	1902	38040
Maneuvering Around Ship/Easy Push	60	1902	1902
Total Tug Activity per LNG Ship Call	1260	1902	39942

Table F-13. Tugboat Stack and Location Information(1)						
Location			Stack Parameters			
UTM E (m)	UTM N (m)	Elevation (m)	Height (m)	Temp (K)	Velocity (m/s)	Diameter (m)
397485.0	4809200.0	0.0	10.7	801.0	61.8	0.3
397485.0	4809100.0	0.0	10.7	801.0	61.8	0.3
397485.0	4809000.0	0.0	10.7	801.0	61.8	0.3
397485.0	4808900.0	0.0	10.7	801.0	61.8	0.3



Jordan Cove Energy Project, L.P.

N

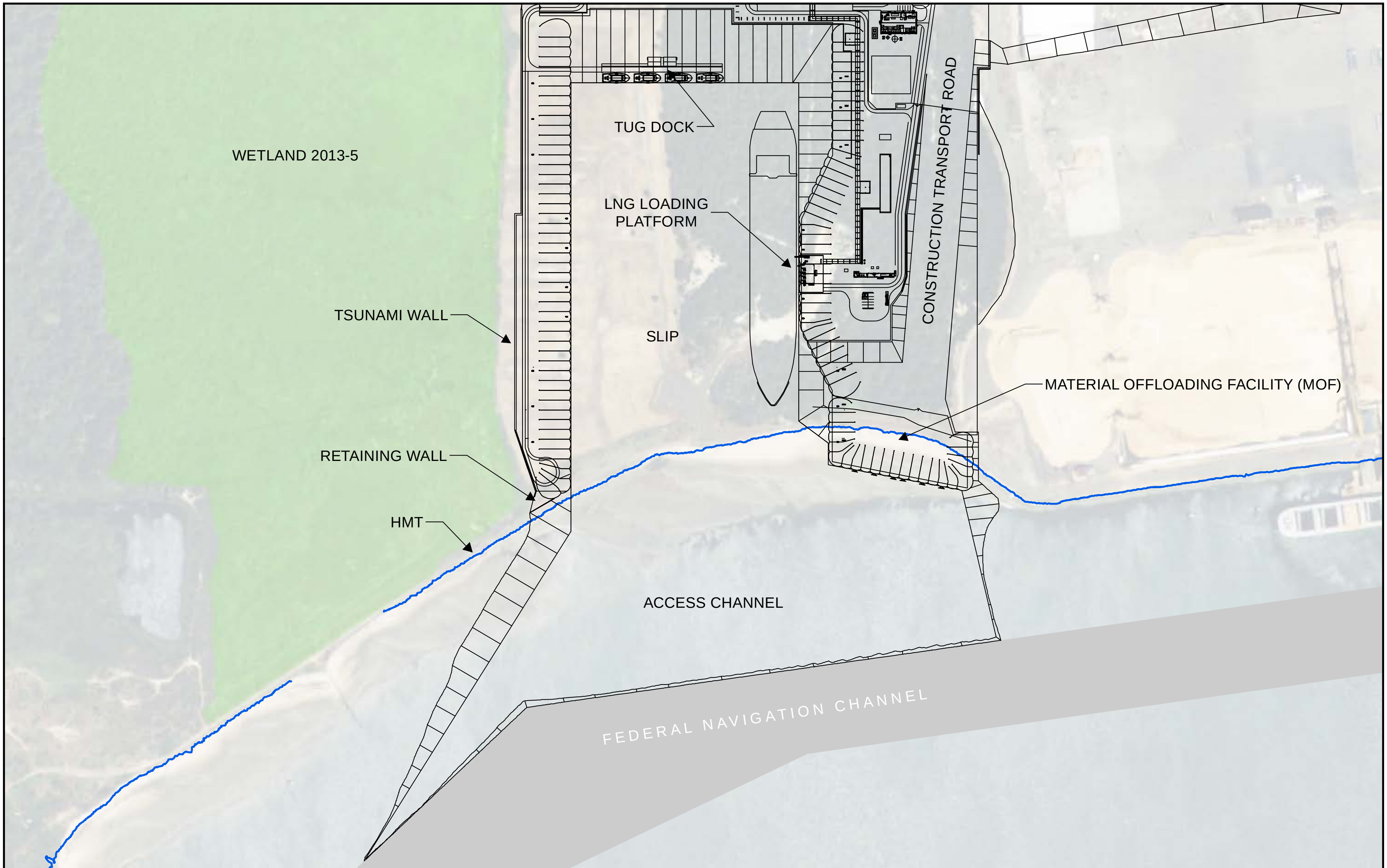
0 0.5 1 Mile

Data Sources: NOAA/NOS/Office of Coast Survey, Oregon GEO, USACE

Jordan Cove Energy Project

Figure G-1

LNG Ship Transit Route



Jordan Cove Energy Project, L.P.

N

0 250 500 Feet

Federal Navigation Channel
Highest Measured Tide (HMT) (10.26 ft NAVD88)
Delineated Wetland

Jordan Cove Energy Project

Figure G-2

Plot Plan of Marine Facilities

GAS FORM C

DESCRIPTION OF THE VESSEL

METHANE JULIA LOUISE
SHI – HULL 1745

1	**GENERAL**	
	Hull Number	1745
	Builder and Yard	Samsung Heavy Industries Co. Ltd. Korea
	Year Built	2010
	Flag	Bermuda
	Classification Society	American Bureau of Shipping
	Classification Notations	HA1 E, Liquefied gas carrier, Ship type 2G (Membrane tank, Maximum pressure 25 kPaG and Minimum Temperature -163ºC, Specific Gravity 500 kg/m^3), SH, FL(40), SH-DLA, SHCM, SFA(40), HM2+R, HAMS, NIBS, HACCU, UWILD, PMS including CMS, R2 without dual centralized fresh water cooling systems.
	Call Sign	ZCEB2
2	**PERFORMANCE STANDARDS**	
	Guaranteed Deadweight	80,700 metric tonnes at design draft of 11.5 meters
	Guaranteed Speed	19.75 knots at a draft of 11.5 meters and at propulsion shaft power of 20, 840 kW
	Guaranteed LNG Cargo Carrying Capacity	168,162.306 cubic meters at maximum allowable cargo tank fill ratio of 98.5% and reference temperature according to IGC Code 15.1.2-4
	Guaranteed Fuel Consumption	Maximum Continuous Rating (MCR): Approx 25,400kW X 86 RPM. Gas Operation: Specific energy consumption at MCR with main generation driven pumps of 7,410 kJ/kWh, with 1.0 g/kWh for pilot fuel Back Up Fuel Operation: Specific energy consumption at MCR with main generation driven pumps of 189 g/kWh Daily Fuel Oil Consumption of 124.9 metric tons per day of DO at MCR Daily fuel consumption of reliq plant 11.4 metric tons of DO per day Fuel Consumption shall be measured according to ISO 3046/1-1995, with lower calorific value of 42,700 kJ/kg of diesel oil.
	Guaranteed Boil-off Rate	0.15 per cent by volume per laden day.
	Cargo containment system type	Gaztransport & Technigaz (MARK III) Membrane

3	**DIMENSIONS**	
	Length Overall	291.066 meters
	Length between perpendiculars	279.000 meters
	Breadth (moulded)	45.000 meters
	Depth to upper deck (moulded)	26.000 meters
	Design Draft, moulded (in seawater of specific gravity of 1.025) :	11.500 meters
	Scantling Draft, moulded (in seawater of specific gravity of 1.025)	12.500 meters
	Air Draft	54.338 meters Ballast draught 9.72m
4	**TONNAGE**	
	Dead-weight tonnage on LNG loaded draught: (11.73m)	84,000 metric tonnes (at full cargo with density 470 kg/m3 plus 5050 m/t bunker, FW, lubs, etc).
	Light ship displacement	32,968.9 metric tonnes
	Displacement	119,094.1 metric tonnes (summer)
	Gross Tonnage	109,004 tons
	Net Tonnage	32,701 tons
	Suez Canal Gross Tonnage	113,005.56
	Suez Canal New Tonnage	101,642.68
5	**MACHINERY**	
	Main Propulsion Plant:	Dual Fuel Diesel Electric, Twin Shaft
	Electric Propulsion Motor Make and Type	Converteam, N3HXC 1000. Squirrel Cage Induction Motor x 2 Sets
	Horsepower (at MCR)	25,400 kW (12,700 kW x 2 sets)
	Normal Service Rating	20,840 kW
	Main Electrical Generating Plant:	
	Dual Fuel Generator Engines Make and Type	Wartsila 12V50DF x 3 sets Wartsila 6L50DF x 1 set
	Generators Make and Type	Converteam M4HXD 253-71 x 3 Sets Converteam M4HXD 253-58 x 1 Set
	Maximum Output	11,400 kW x 3 Sets 5,700 kW x 1 Set
	Auxiliary Boilers:	
	Make	Aalborg
	Type	Mission OS 5000
	Maximum Evaporation	5000 kg/h
	Number	2 Sets

6	**CARGO TANKS**	
	Number of Cargo Tanks	4
	Total Capacity 100% full	170,723.372 m^3
	Type of construction	GTT Mark III system (Membrane)
	Type of insulation	Rigid polyurethane foam with reinforcing glass fibre.
	Minimum Temperature	Minus 163 degrees Celsius
	Loading/filling restrictions	98.5% maximum filling limit
	100%Capacity at 25 ℃ of:	
	• No. 1 tank	26,995.4 m^3
	• No. 2 tank	47,904.6 m^3
	• No. 3 tank	47,906.1 m^3
	• No. 4 tank	47,917.3 m^3
	The Vessel's cargo tanks can be cooled down from ambient temperature to the loading condition (minus 130 degree Celsius mean temperature of cargo tanks) within ten hours.	
	Relief valve settings	25kPa gauge
	Loaded boil-off design rate	0.15 per cent by volume per laden day
7	**FRESH WATER**	
	Capacity of F.W. generators	30 Tonnes per Day x 2sets
	Capacity of Tanks:	
	Boiler Feed (Distilled Water)	63.6 m^3
	Fresh Water	495.5 m^3
	Drinking Water	Not applicable
8	**BUNKER CAPACITY**	
	Diesel Oil (100%)	824.0 m^3 (Storage and Service Tanks in Machinery Space)
	Fuel Oil (100%)	5,259.5 m^3 (Storage, Settling and Low Sulphur Tanks)
9	**WATER BALLAST**	
	Tank Capacity (100%)	62,933.4 m^3 (including peak tanks)
	Number and Capacity of water ballast pumps	3000 m^3/hr each X 3 sets
	The vessel is capable of loading/discharging ballast concurrent with cargo operations	Yes
10	**CARGO PUMPS**	
	Number	8 sets
	Type and Make	Single stage centrifugal submerged, Ebara International Corporation
	Rated Capacity of each Pump	1750 m^3/hr 160 MLC (specific gravity 0.5)
11	**SPRAY PUMPS**	
	Number	4 sets
	Type and Make	Single stage centrifugal submerged, Ebara International Corporation
	Rated capacity of each Pump	50 m^3/hr 145 MLC (specific gravity 0.5)

12	**FUEL GAS PUMPS**	
	Number	2 sets
	Type and Make	Single stage centrifugal submerged, Ebara International Corporation
	Rated capacity of each Pump	15 m^3/hr 215 MLC (specific gravity 0.5)
13	**CARGO INSTRUMENTATION**	
	Liquid Level Gauge	
	Primary:	
	Maker and Type	SAAB Marine Electronics AB, Radar Ullage Measurement
		1 set
	Number per Tank	± 7.5 mm
	Accuracy	0.026m to 26.52m
	Measuring Range	
	Secondary:	Whessoe Total Automation, Float Type Ullage Measurement
	Type and Maker	1 set
		± 7.5mm
	Number per Tank	0 to 54 m.
	Accuracy	
	Measuring Range	
	Temperature Sensor	
	Type	Resistance temperature detectors
	Number per Tank	5 pairs
	Accuracy	± 0.2 ℃ (between - 165℃ and - 145℃) Rising to + 1.5 ℃ at +50 ℃
	Measuring range	From - 165 ℃ to + 50 ℃
	Pressure Sensor System	
	Number per Tank	1 set
	Accuracy	± 1 % of span with deck temperature ranging between – 30^{0}C and +60^{0}C
	Measuring range	800 - 1,400 mbar
14	**RE-LIQUEFACTION PLANT**	
	System Maker and Type	Hamworthy Gas Systems, Moss RS^{TM} Mark I re-liquefaction system
	System Capacity	2500 kg/hr (including 500kg/hr flash gas)
	BOG Compressors	
	Type and Make	Cryostar, CM2-200
		Horizontal, two stage centrifugal.
	Number and Capacity	Two sets, 6,699 m^3/h each
	Discharge Pressure	6.5 barA
	Suction Press. and Temperature	1.03 barA / -120 ℃
	Compander	
		Atlas Copco, Model GT026N3D0+ET1135MS
	Make and Type	Three stage integral gear compressor with a single stage radial turbine.
	Cold Box	
	Make and Type	Fives Cryogenic, Counter-Flow Heat Exchanger
	Capacity	2,500 kg/hr

15	**INERT GAS GENERATION**	
	Make and Type	Smit Gas Systems BV, Oil burning type with cooling and drying unit,
	Capacity	14000 Nm^3/hour
	Quality of Gas	O_2 - max 1% by volume CO_2 - max approx 14% by volume CO- max 100 ppm SO_x - max 1 ppm N_2 - balance Soot - complete absence (0 on Bacharach scale) Dew Point not more than -45 ℃
16	**NITROGEN GENERATION**	
	Make and Type	Air Products AS, NC1.1-1816-WXP-130970 Ext.cab Membrane Separation Type.
	Capacity	130 Nm^3/h @ 97% N_2 x 2 sets
	Pressure Tank	32 m^3 x 10 bar g x 1 set
17	**GAS COMPRESSORS**	
	High Duty:	
	Make and Type	Cryostar, CM 400/55 Horizontal, single stage, centrifugal.
	Number and Capacity	Two sets 28,000 m^3/h each
	Discharge Pressure	2.0 barA,
	Suction Press. and Temp.	1.03 barA -140 ℃
18	**CARGO VAPOURISERS**	
	Forcing Vapouriser Make, Type and Capacity	Cryostar, 34-UT-25/21-3.6, 5,500 kg/hr
	LNG Vapouriser Make, Type and Capacity	Cryostar, 65-UT-3838/34-5.6, 25,000 kg/hr
19	**DECK MACHINERY**	
	Winches: Number, Position, Type	Upper deck forward Combine Anchor Windlass and Mooring winch 2 sets x 30 Metric Tonnes x 15 m/min (winch) or x 57 Metric Tonnes x 9 m/min (windlass) for 110 meters chain in the water Total drums: 9 Mooring Winches 2 sets x 30 Metric Tonnes x 15 m/min Upper deck Aft Mooring Winches 5 sets x 30 Metric Tonnes x 15 m/min Total drums: 11
	Holding Power of Brakes	99.7 Metric Tonnes Type: Split Compact Electro Hydraulic Winch.
	Mooring Ropes Make and Type	Samson, Amsteel Blue

	Size and min. B.S. of Wires	40 mmΦ x 200 m, ISO/BS EN 919 MBS 128mt
	Whether Fitted with Tails, State Length, Material, Min. B.S.	Samson P-7 Grommet Mooring Line Pendant 56mmΦ x 11 m, 100% Polyester ISO/BS EN919 MBS 164mt
	Derrick, Cranes, etc.: Type and Capacity	Midships Hose Handling cranes : MacGregor x 2 Sets, Slewing single jib type, 5.0 metric tonnes SWL, minimum outreach 5.2 m, maximum outreach 26m Cargo Machinery crane: DMC x 1 set, slewing single jib type, SW L 6.0 tonnes, out reach min. 3,4 m max. 12 m. Provision cranes Stbd side – MacGregor,1 set, slewing single jib type, 10.0 metric tonnes SWL, minimum outreach 3.7m, maximum outreach 18.3m, hook travel 54m Port Side-MacGregor,1 set, slewing single jib type, 5.0 metric tonnes SWL, minimum outreach 3.7m, maximum outreach 18.3m, hook travel 54m
20	**NAVIGATION AND RADIO**	
	Navigation Aids	Make: Furuno Electric Co Ltd. Two sets X-band radar with Arpa One set S-band radar with Arpa Two sets Differential Global Positioning System navigator equipment One set Electronic Chart Display and Information System.
	Radio Equipment	Make: Furuno Electric Co Ltd One set GMDSS (area 3) Radio Equipment, One set radio station comprising 1 set MF/HF transmitter/receiver with radio telephone and DSC control unit , 1 set MH/HF DSC watch receiver, and I set remote distress message controller. One set Inmarsat C MES equipment One set Inmarsat F MES equipment
21	**OTHERS**	
	Bilge Oily Water Monitor	Make: Smart Cell– Bilge Type; Detection of light scatter across oily water sample. .
	Incinerator	Make Hyundai -Atlas Type: Forced draught package type, 500,000 kcal per hour
	Sewage Treatment Plant	Make: DVZ-Services GmBH. Type: DVZ-SKA-30 “BIOMASTER” Bio reaction and aeration system Capacity 3,450 ltr per day.

PROFORMA FORM C

DESCRIPTION OF THE VESSEL

SHI – HULL 1553-54-55-85-86-87-88

1.	**GENERAL**			
	1.1	Vessel Name and Hull Number	:	*To be named* Hull Number 1553-54-55-85-86-87-88
	1.2	Builder and Yard	:	Samsung Heavy Industries Geoje Island, Korea
	1.3	Year Built / delivered	:	2006-2008
	1.4	Containment System	:	Membrane Type GTT Mark 3
	1.5	Country of Registry	:	Bermuda
	1.6	Port of registration	:	Hamilton
	1.7	Classification Society	:	American Bureau of Shipping A1E, Liquefied gas carrier, ship type 2G (Membrane tank, Maximum pressure 25 kPaG and Minimum Temperature - 163ºC, Specific Gravity 500 kg/m^3), SH, FL(40), SH-DLA, SHCM, SFA(40), HM2+R, AMS, NIBS, ACCU, UWILD, PMS including CMS.
2.	**DIMENSIONS, TONNAGE**			
	2.1	Length Overall	:	approx. 283 metres
	2.2	Length between Perpendiculars	:	270.0 metres
	2.3	Beam (moulded)	:	43.4 metres
	2.4	Depth to upper deck, moulded	:	26.0 metres
	2.5	Scantling Draft, moulded (in seawater of specific gravity of 1.025)	:	12.4 metres
	2.6	Design Draft, moulded (in seawater of specific gravity of 1.025)	:	11.4 metres
	2.7	Summer Draft (moulded)	:	Apprx. 12.0 metres
	2.8	Air Draft	:	max. 50.00 A/B with radar mast in lowered position and about 56.00m A/B with radar mast in raised position.
3.	**TONNAGE**			
	3.1	Deadweight at Design Draft, extreme	:	Apprx. 71,450 metric tonnes
		at Summer Draft, extreme	:	Apprx. 77,450 metric tonnes
	3.2	Lightweight	:	-
	3.3	Displacement at Summer Draft	:	-
	3.4	Gross Tonnage (International)	:	Apprx. 97,100 metric tonnes
	3.5	Net Register Tonnage	:	-
	3.6	Suez Canal Gross Tonnage	:	-
	3.7	Suez Canal Net Tonnage	:	-
4.	**MACHINERY**			
	4.1	Propelling Machinery,		

	Type and Make	:	Steam Turbine, Reversible Geared, Cross Compound, Steam Driven / Kawasaki Heavy Industries Limited
	Maximum Continuous Rating	:	39,500 PS @ 90 RPM
	Normal Service Rating	:	33,550 PS @ 86.9 RPM
4.2	Main Boilers		
	Type, Make and Number	:	Two Water tube, forced draft, marine boiler, Kawasaki Heavy Industries Limited
	Maximum Evaporation	:	Total 65 Te/h, each (incl. 4 Te/h desuperheated steam)
4.3	Electrical Generating Plan		
	Type, Maximum Output per	:	Two (2) sets of turbo generator, 4,312.5 kVA (3,450 kW), 6,600 VAC, 60 Hz, 3 Phase / Mitsubishi Heavy Industries Limited One (1) sets of diesel generator, 4,312.5 kVA (3,450 kW), 6,600 VAC, 60 Hz, 3 Phase / Wärtsilä One (1) set of emergency diesel generator, 1,062 kVA (850 kW), 450V AC, 60Hz, 3 Phase / STX--Cummins
4.4	Bow Thruster	:	Controllable Pitch Propeller (C.P.P.)
	Electric motor	:	2,500 kW, 6,600V
	No of blades	:	Four (4) (Ni-Al-Bronze)

5. OWNER GUARANTEE SPEEDS

The guarantee speed at the designed draft of 11.4m on even keel shall be not less than 20.2 knots with the main propulsion machinery running at an output of 30,910 PS under weather conditions not exceeding Beaufort 4.

6. FUEL CONSUMPTION RATE

At NCR : 182.2 metric tonnes per day

Consumption rate based upon using fuel classified as RMH55 in accordance with ISO8217 (1996) and having a higher calorific value of 43 MJ/kg (10,280 kcal/kg).

7. CARGO TANKS

7.1	Total Capacity 98.5% full	:	142,950 cubic metres at maximum allowable cargo tank fill ratio of 98.5% and reference temperature according to IGC Code 15.1.2-4
7.2	Number of Cargo Tanks	:	4
7.3	Maximum S.G.	:	470 kg/m^3
7.4	Minimum Temperature	:	-163ºC
7.5	Normal Tank Operating Pressure	:	106 kPa absolute
7.6	Relief Valve Settings	:	25 kPa gauge
7.7	Capacity at -163°C 100% full	:	Apprx.145,130 m^3

No. 1 tank	:	22,040 m^3	No. 2 tank	:	42,760 m^3
No. 3 tank	:	42,,760 m^3	No. 4 tank	:	37,570 m^3

7.8 The Vessel's cargo tanks can be cooled down from ambient temperature to the loading condition in less than 10 hours (-130°C , mean temp. of cargo tanks).

8 CARGO LOADING AND DISCHARGE PERFORMANCE

(a) The ship shall be able to load the bulk of the cargo (exluding slow starting and topping off) through two (2) liquid manifolds in ***approximately 12 hours at pressure of 240 kPa(G)*** inboard of the manifold strainer.

(b) The ship shall be able to discharge the bulk cargo through three (3) liquid manifolds in approximately 12 hours (excluding slow starting and topping off) against a backpressure of 100 MLC measured inboard of the manifold strainer with cargo tanks at mid-level.

9. BOIL-OFF RATE

9.1	Guarantee Boil-off Rate	:	Not to exceed 0.15% per day

10. FRESH WATER

10.1	Capacity of F.W. generators	:	Two 60 T/d / Alfa-Laval
10.2	Capacity of Tanks		
	Boiler Feed	:	Apprx. 400 m^3
	Fresh Water	:	Apprx. 350 m^3

11. BUNKER CAPACITY

11.1	Fuel Oil (100%)	:	Apprx. 7,400 m^3
11.2	Gas Oil (100%)	:	Apprx. 100 m^3
11.3	Diesel Oil (100%)	:	Apprx. 300 m^3
		:	

12. WATER BALLAST

12.1	Tank Capacity (100%)	:	Apprx. 55,500 m^3
12.2	Number and Capacity of water ballast pumps	:	3 X 3,000 m^3/h at 30 mwc
12.3	The vessel is capable of loading/discharging ballast concurrent with cargo operations	:	Yes

13. CARGO PUMP

13.1	Number	:	8
13.2	Type and Make	:	Centrifugal, single stage, submerged / Ebara
13.3	Rated Capacity of each Pump	:	1,700 m^3/h at 155 mlc (S.G. 0.5)

14. SPRAY PUMP

14.1	Number	:	4
14.2	Type and Make	:	Centrifugal, submerged / Ebara
14.3	Rated Capacity of each Pump	:	50 m^3/h at 145 mlc (S.G. 0.5)

15. EMERGENCY CARGO PUMP

15.1	Number	:	1
15.2	Type and Make	:	Centrifugal, single stage, removable type / Ebara
15.3	Rated Capacity	:	550 m^3/h at 155 mlc (S.G. 0.5)

16. CARGO INSTRUMENTATION

16.1	Liquid Level Gauge		
	<u>Primary</u>		
	Type	:	Radar / Saab
	Number per Tank	:	1
	Accuracy	:	7.5 mm
	Measuring range	:	26.52 m

	Secondary		
	Type	:	Float / Whessoe
	Number per Tank	:	1
	Accuracy	:	7.5 mm
	Measuring range	:	26.52 m
16.2	Temperature Sensor		
	Type	:	High Accuracy
	Number per Tank	:	5 pair
	Accuracy	:	+0.2°C between -165°C and -145°C, rising to +1.5°C at +50°C
	Measuring range	:	-165°C to +50°C
16.3	Pressure Sensor System		
	Number per Tank	:	1
	Accuracy	:	+ 1% of span with deck temperature ranging between -30°C and +60°C
	Measuring range	:	800 - 1,400 mbar
16.4	Ship shore communication system	:	Fibre optic, intrinsically safe and pneumatic types

17. NITROGEN GENERATION

17.1	Type and Make	:	Membrane permeation type / Air Product AS
17.2	Capacity	:	2 off 100 Nm^3/h
17.3	Pressure Tank	:	6.5 bar g

18. INERT GAS GENERATION

18.1	Type and Make	:	Stoichiometric combustion of fuel oil / Smit Gas System
18.2	Capacity	:	14,000 Nm3/h inert gas or dry air
18.3	Quality of Gas	:	Dew point -45°C at 760 mmHg

O_2	: max. 1.0% by vol.
CO	: max. 100 ppm
SOx	: max. 10 ppm
NOx	: max. 100 ppm
Soot	: Bacharach 0
HC	: 0%
CO_2	: max. 14% by volume
Remainder	: N_2 , H_2 , Ar

19. GAS COMPRESSORS

19.1	High Duty		
	Type and Make	:	Horizontal, single stage centrifugal / Cyrostar
	Number and Capacity		2 off 26,000 m^3/h
	Discharge Pressure		200 kPa A
	Suction Press and Temp		-140°C, 103 kPa A
19.2	Low Duty		
	Type and Make	:	Horizontal, single stage centrifugal / Cyrostar
	Number and Capacity	:	2 off 8,000 m^3/h
	Discharge Pressure	:	200 kPa A
	Suction Press and Temp	:	-40°C, 106 kPa A

20. FORCING VAPORIZER

20.1	Capacity	:	7,000 kg/h from -163°C to -40°C / Cyrostar

21. DECK MACHINERY

21.1	Winches Number, Position, Type (incl. windlass)	:	4 for'd (2 combined with windlass) 5 aft, Electro-hydraulic self contained power pack, non auto-tension type mooring winches & windlasses / Kochs
21.2	Holding Power of Brake	:	80% of mooring line MBL (design) set at 60%
21.4	Size of Wires and whether fitted with Tails State Length, Material	:	Twenty-two (22) sets including two (2) spares, each 200 m long and 44 mm diameter of spectra rope or equivalent with each 11 m long nylon tail and a Tonsberg mooring link.
21.5	Derrick, cranes, etc. Type and Capacity	:	Electro-hydraulic driven single jib crane One (1) x 5.0 Te SWL at port aft and one (1) x 10.0 Te SWL at starboard aft. One (1) x 6.0 Te SWL for cargo machinery room Two (2) x 5.0 Te SWL at P&S manifold

22. NAVIGATION AND RADIO

22.1	Navigation Aids and Radio Equipment	:	VHF radio telephones GMDSS distress message controller Display units for radars (X and S-bands), ECDIS and conning display Auto pilot operating unit CCTV control station for mooring area camera and night vision camera UHF base station DGPS navigator Echo sounder recorder Master electric clock DGPS navigator Speed log main unit Navtex receiver Signal light control panel Loran-C receiver VHF radio telephone Inmarsat-B Inmarsat-C

23. OTHER

23.1	Bilge Oily Water Monitor	:	1 X 5 m^3/h (15 ppm)
23.2	Incinerator	:	1 X 500,000 kcal/h for solid garbage waste and sludge oil having flash point above 60°C
23.3	Sewage Treatment Plant	:	One (1) biological type for 45 persons

23.4 CCTV system with 11 cameras and monitors in wheelhouse, engine control room and cargo control room;
23.5 Loading computer including damage stability calculations;
23.6 Shipboard management system
23.7 Public address system
23.8 Master clock system
23.9 UHF onboard radio communication with 2 base stations, 1 base repeater station and twelve portable sets

APPENDIX H

CLASS I SCREENING AND Q/D ANALYSIS

Type B State New Source Review Application

Jordan Cove LNG Terminal
Jordan Cove Energy Project, LP
125 Central Avenue, Suite 380
Coos Bay, Oregon 97240

September 2017

Table H-1: Crater Lake Results and Significant Impact Levels (μg/m^3)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area	Class I SILs[(1)]
SO_2	3-hr	0.129	N/A	1
	24-hr	0.029	N/A	0.2
	Annual	0.002	N/A	0.1
NO_2	Annual	0.004	N/A	0.1
PM_{10}	24-hr	0.072	N/A	0.3
	Annual	0.003	N/A	0.2
$PM_{2.5}$	24-hr	0.072	5.93E-06	0.07
	Annual	0.003	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

Table H-2: Diamond Peak Results and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area	Class I SILs[1]
SO_2	3-hr	0.118	N/A	1
	24-hr	0.025	N/A	0.2
	Annual	0.001	N/A	0.1
NO_2	Annual	0.004	N/A	0.1
PM_{10}	24-hr	0.059	N/A	0.3
	Annual	0.003	N/A	0.2
$PM_{2.5}$	24-hr	0.059	N/A	0.07
	Annual	0.003	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

Table H-3: Kalmiopsis Results and Significant Impact Levels (µg/m^3)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area	Class I SILs(1)
SO_2	3-hr	1.331	0.24	1
	24-hr	0.354	0.023	0.2
	Annual	0.012	N/A	0.1
NO_2	Annual	0.032	N/A	0.1
PM_{10}	24-hr	0.854	0.061	0.3
	Annual	0.026	N/A	0.2
$PM_{2.5}$	24-hr	0.854	0.061	0.07
	Annual	0.026	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

Table H-4: Redwood Results and Significant Impact Levels (μg/m^3)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area	Class I SILs[1]
SO_2	3-hr	1.331	0.049	1
	24-hr	0.354	0.002	0.2
	Annual	0.012	N/A	0.1
NO_2	Annual	0.032	N/A	0.1
PM_{10}	24-hr	0.854	0.004	0.3
	Annual	0.026	N/A	0.2
$PM_{2.5}$	24-hr	0.854	0.004	0.07
	Annual	0.026	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

Table H-5: Three Sisters Results and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Period	Maximum Concentration at 50 km	Maximum Concentration at Class I Area	Class I SILs[(1)]
SO_2	3-hr	0.691	N/A	1
	24-hr	0.117	N/A	0.2
	Annual	0.003	N/A	0.1
NO_2	Annual	0.007	N/A	0.1
PM_{10}	24-hr	0.28	N/A	0.3
	Annual	0.006	N/A	0.2
$PM_{2.5}$	24-hr	0.28	0.003	0.07
	Annual	0.006	N/A	0.06

(1) OAR 340-200-0020(163). All SILs are based on the first highest concentration at any one location.

Table 1: Refined Q Calculations for Jordan Cove Energy Project

Source	Pound per Hour				Duration	Pounds per Day				Tons per Year			
	PM	SO_2	NO_x	H_2SO_4	(hours/day)	PM	SO_2	NO_x	H_2SO_4	PM	SO_2	NO_x	H_2SO_4
Turbine 1													
Normal Operation	5.40	1.64	3.80	1.10	23.85	128.79	39.11	90.63	26.24	24.1	7.2	17.2	4.8
Worst-Case Startup or Shutdown	22.00	0.46	24.67	0.00	0.15	3.30	0.07	3.70	0.00				
Turbine 2													
Normal Operation	5.40	1.64	3.80	1.10	23.85	128.79	39.11	90.63	26.24	24.1	7.2	17.2	4.8
Worst-Case Startup or Shutdown	22.00	0.46	24.67	0.00	0.15	3.30	0.07	3.70	0.00				
Turbine 3													
Normal Operation	5.40	1.640	3.80	1.10	23.85	128.79	39.11	90.63	26.24	24.1	7.2	17.2	4.8
Worst-Case Startup or Shutdown	22.00	0.46	24.67	0.00	0.15	3.30	0.07	3.70	0.00				
Turbine 4													
Normal Operation	5.40	1.64	3.80	1.10	23.85	128.79	39.11	90.63	26.24	24.1	7.2	17.2	4.8
Worst-Case Startup or Shutdown	22.00	0.46	24.67	0.00	0.15	3.30	0.07	3.70	0.00				
Turbine 5													
Normal Operation	5.40	1.640	3.80	1.10	23.85	128.79	39.11	90.63	26.24	24.1	7.2	17.2	4.8
Worst-Case Startup or Shutdown	22.00	0.46	24.67	0.00	0.15	3.30	0.07	3.70	0.00				
Oxidizer	0.82	4.53	14.44	0.00	24.00	19.67	108.72	346.56	0.00	3.6	19.8	63.2	0.0
Auxiliary Boiler	5.63	0.83	2.18	0.56	24.00	135.08	19.90	52.38	13.40	24.7	3.6	9.6	2.4
Fire Water Pump 1	0.30	0.01	5.31	0.00	1.00	0.30	0.01	5.31	0.00	0.1	0.0	1.0	0.0
Fire Water Pump 2	0.30	0.01	5.31	0.00	1.00	0.30	0.01	5.31	0.00	0.1	0.0	1.0	0.0
Fire Water Pump 3	0.30	0.01	5.31	0.00	1.00	0.30	0.01	5.31	0.00	0.1	0.0	1.0	0.0
Backup Generator 1	0.19	0.01	16.63	0.00	1.00	0.19	0.01	16.63	0.00	0.0	0.0	3.0	0.0
Backup Generator 2	0.19	0.01	16.63	0.00	1.00	0.19	0.01	16.63	0.00	0.0	0.0	3.0	0.0
Black Start Generator 1	0.23	0.04	7.43	0.00	1.00	0.23	0.04	7.43	0.00	0.0	0.0	1.4	0.0
Black Start Generator 2	0.23	0.04	7.43	0.00	1.00	0.23	0.04	7.43	0.00	0.0	0.0	1.4	0.0
Ground Flare	0.07	0.01	0.14	0.00	24.00	1.56	0.16	3.48	0.01	0.3	0.0	0.6	0.0
Marine Flare	0.02	0.00	0.04	0.00	24.00	0.40	0.04	0.89	0.00	0.1	0.0	0.2	0.0
Gas Up (From Marine Flare)	33.43	4.89	62.31	0.37	24.00	802.34	117.29	1495.47	8.98	146.4	21.4	272.9	1.6

Total (tpy)	295.9	80.7	444.3	28.0
Q	849			

Table 2: Refined Q/D Calculations for Jordan Cove Energy Project

Class I Area	State	Q (tpy)	Distance (km)	Q/D
Crater Lake NP	OR	849	165	5.1
Diamond Peak Wilderness	OR	849	177	4.8
Kalmiopsis Wildnerness	OR	849	110	7.7
Redwood NP	CA	849	165	5.1
Three Sisters Wilderness	OR	849	178	4.8

Jason Reed

From: ALLEN Philip <philip.allen@state.or.us>
Sent: August 07, 2017 9:52 AM
To: Jason Reed; Jessica Stark; EISELE Michael
Cc: 'Miller, James - FS'; Graw, Rick -FS
Subject: NPS Class I Area Determination

All,

Here is the determination by Don Shepherd of the NPS that Jordan Cove will not have a significant impact on AQRVs for the NPS Class I areas. The USFS has not yet made their determination.

Phil

From: Shepherd, Don [mailto:don_shepherd@nps.gov]
Sent: Monday, August 07, 2017 8:32 AM
To: ALLEN Philip
Cc: Tonnie Cummings
Subject: Re: FW: Additional information request

Hi Phil,

Based upon the new information provided by the applicant, we conclude that it is unlikely that the Jordan Cove Energy Project would have a significant impact upon Air Quality Related Values in any of our Class I areas.

We would appreciate it if OR DEQ would provide electronic copies of the complete/final permit application, staff analysis, draft permit, and public notice.

thanks,

On Sun, Aug 6, 2017 at 6:21 PM, ALLEN Philip <philip.allen@state.or.us> wrote:

Don,

Here is the response from SLR regarding their revised Q/d calculation for Crater Lake NP and Redwood NP. If you have additional concerns, please let me know. Thanks.

Phil

Philip Allen

Air Quality Program

Oregon DEQ

Portland

503.229.6904

allen.philip@deq.state.or.us

From: Jason Reed [mailto:jreed@slrconsulting.com]
Sent: Saturday, August 05, 2017 1:10 PM
To: ALLEN Philip
Cc: DAVIS Claudia; CAMARATA Mary; 'meagan.masten@vereseninc.com'; EISELE Michael; Andrew Jackson; Jessica Stark
Subject: RE: Additional information request

Hi Phil, please see below for our response to Don Shepherd's request. Please let me know if there are any additional questions.

SLR has recalculated the Q value for the Jordan Cove Energy Project based on a worst-case 24 hour emission scenario for project emissions of PM, SO_2, NOx, and H_2SO_4 (see attached). Following FLAG 2010 guidance, the worst-case 24 hour emissions were assumed to persist for the entire year and then summed in order to calculate the ton per year emissions (Q). The worst-case daily emissions scenario includes the following assumptions:

- Each turbine undergoing a startup/shutdown with normal operation (with duct burners) thereafter;
- Continuous operation of the thermal oxidizer;
- Continuous operation of the auxiliary boiler;
- One hour of operation of each of the three fire water pumps;
- One hour of operation of each of the two backup generators;
- One hour of operation of each of the two black start generators;
- Continuous operation of the ground flare and the marine flare pilot and purge gas; and
- Continuous emissions from gas up (flaring of gas vented from incoming LNG tankers).

Based on this worst-case daily emissions scenario, the calculated Q value is 849 tons per year. Both Crater Lake National Park (NP) and Redwood NP are approximately 165 km from the facility, **resulting in a Q/D value of 5.1**. In the development of the worst-case scenario, it is noted that several of the sources are intermittent (e.g., startup/shutdowns, auxiliary boiler, firewater pumps, backup generators, black start generators, and gas up emissions), thus concurrent operation of these sources in the same day is extremely unlikely.

It should also be noted that the Q value quoted in the Jordan Cove Energy Project modeling protocol was provided for informational purposes only for the Type B state New Source Review application, since AQRV analyses are not required.

SLR

Jason Reed, CCM
Senior Scientist

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SLR International Corporation
1612 Specht Point Road, Suite 119, Fort Collins, CO, 80525

From: ALLEN Philip [mailto:philip.allen@state.or.us]
Sent: August 02, 2017 1:44 PM
To: Jessica Stark; Jason Reed
Cc: DAVIS Claudia; CAMARATA Mary; 'meagan.masten@vereseninc.com'; EISELE Michael
Subject: Additional information request

Hi Jason,

See below for email from Don Shepherd of the NPS requesting additional information for the Q/d calculation for Class I Area impacts. Please respond to me, and I will forward the revised information to both the NPS and USFS.

On a separate note, the inventory of competing sources will be sent later today by separate email.

Please contact me if you have questions. Thanks.

Phil

Philip Allen

Air Quality Program

Oregon DEQ

Portland

503.229.6904

allen.philip@deq.state.or.us

From: Shepherd, Don [mailto:don_shepherd@nps.gov]
Sent: Wednesday, August 02, 2017 8:05 AM
To: philip.allen@state.or.us
Cc: Tonnie Cummings; d King
Subject: Jordan Cove Modeling Protocol and Q/d

Hello Phil,

Tonnie Cummings has asked me to respond to your request for comments on the modeling protocol for the Jordan Cove Energy Project.

Before i can give you a decision, i need clarification of how the "Q" value in the Q/d calculation was derived. Here is what the applicant says on page 21 of the application:

Using the emissions summarized in Table 2-1 for the visibility impairing pollutants of NOx, SO2, PM, and H2SO4 the calculated Q value is 327.6. Using the shortest distance, D, from Table 4-1 above, the Q/D value is calculated to be 2.98, which is below the threshold value of 10.

My concern regards Table 2.1 on page 3. According to the applicant:

The potential annual emission rates for each criteria air pollutant from each source are shown in Table 2-1. The EPC contractor, KBJ, has completed the pre-FEED design stage of the project and is currently developing the detailed facility design.

Instead of using annual average emissions, Q should be calculated based upon the maximum 24-emission rates of NOx, SO2, PM, and H2SO4, including start-ups and shut-downs. The maximum 24-hour emission rate should then annualized to yield a tpy value for Q. It is also important that the applicant provide its calculations and assumptions in deriving these emission rates.

Please feel free to contact me with any questions.

thanks,

Don Shepherd

National Park Service

Air Resources Division

12795 W. Alameda Pkwy.

Lakewood, CO 80228

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"the man who really counts in the world is the doer, not the mere critic" TR 1891

Jason Reed

From:	ALLEN Philip <philip.allen@state.or.us>
Sent:	August 07, 2017 11:08 AM
To:	Jason Reed; Jessica Stark; EISELE Michael
Subject:	USFS Class I Area Determination

Hi All,

The USFS agrees with the NPS that Jordan Cove will not have a significant AQRV impact on USFS Class I areas. See below.

Thanks.

Phil

From: Miller, James - FS [mailto:jamesmiller2@fs.fed.us]
Sent: Monday, August 07, 2017 9:41 AM
To: ALLEN Philip
Subject: RE: NPS Class I Area Determination

Hi Phil,

Given that the revised Q/D for Kalmiopsis – the closest Class I unit – is still < 10, Rick and I do not think Jordan Cove will have a significant impact for USFS Class I areas. Thank you for providing the feedback from Tonnie, Don, and others.

Best,

Jim