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Oregon Department of Energy – Energy Facility Siting Council
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RE: Jordan Cove Site Certificate Exemption Application Date: June 14th, 2018

Dear Mr. Cornett,

Please accept Jordan Cove Energy Project, LP's ("JCEP") application and fee for an exemption from a site certificate to the Energy Facility Siting Council ("EFSC") and the Oregon Department of Energy ("ODOE") as the supporting agency. Within this application JCEP demonstrates how the electrical power generating system at JCEP's proposed Liquefied Natural Gas ("LNG") Terminal in Coos Bay, Oregon meets the *high efficiency cogeneration facility* exemption definitions and criteria set forth in OAR 345-015-0360(5).

Pursuant to ORS 469.320(1), "no facility shall be constructed or expanded unless a [EFSC] site certificate has been issued for the site . . . ." A "facility" is defined as "an energy facility together with any related or supporting facilities." ORS 469.300(14). The definition of "energy facility" includes "[a]n electric power generating plant with a nominal electric generating capacity of 25 megawatts or more, including but not limited to: (i) Thermal power; (ii) Combustion turbine power plant; or (iii) Solar thermal power plant." ORS 469.300(11)(a)(A). There is a statutory exemption from the site certificate requirement for a "high efficiency cogeneration facility." ORS 469.320(2)(c); OAR 345-015-0350.

The electrical power generating system at the proposed LNG Terminal consists of three steam turbine generators ("STGs"). Each STG will generate electricity and will have a nominal electrical generating capacity of greater than 25 MW. Given the nominal electrical generating capacity of the STGs, the facility could be considered an "energy facility" under the statute. Without waiving any rights including jurisdiction over the proposed LNG Terminal, JCEP submits this application requesting a determination from EFSC that the proposed facility qualifies for an exemption from the site certificate requirement.

As shown in the application, the STGs have a nominal electric generating capacity of 50 megawatts ("MW") or more and the fuel chargeable to power heart rate value is not greater than 6000 Btu per kilowatt-hour. Therefore, the STGs meet the high efficiency cogeneration facility exemption definitions and criteria set forth in OAR 345-015-0360(5).

Pursuant to applicable rules we understand the following procedures for requesting an exemption apply. To claim an exemption from the requirement to obtain a site certificate, a party must request EFSC determine whether the proposed facility qualifies for the claimed exemption. ORS 469.320(4). EFSC's regulations set forth the required contents of the request. See OAR 345-015-0360(5).
Within 45 days after receipt of a request for exemption, ODOE shall review the request for completeness and provide the applicant with either: (1) a notice of filing of the request for exemption or

(2) a request for additional information. OAR 345-015-0370(1). When ODOE finds the request for exemption is complete, ODOE shall issue a notice of filing. *Id.* Within 60 days after issuing the notice of filing, ODOE shall review the request, prepare a proposed order for EFSC action and bring the matter before EFSC for action. *Id.* JCEP understands that EFSC's review of the proposed order does not trigger a contested proceeding under ORS 345-015-001.

JCEP's application includes trade secret information as defined under ORS 192.345. For ODOE's convenience, JCEP is submitting a public version of the application with the trade secret information redacted. JCEP requests that ODOE and EFSC maintain as confidential and not disclose the version that contains the trade secret information. JCEP has marked that version as:

Confidential Business Information
Exempt From Public Disclosure

JCEP appreciates EFSC's and ODOE's attention to this request and respectfully requests that EFSC grant the exemption per ORS 469.320(2)(c); OAR 345-015-0350.

Sincerely,

Tony Diocee
VP of LNG Projects,
Jordan Cove Energy Project, LP

Application Criteria. OAR 345-015-0360(5)

(5) In a request for an exemption based on a very efficient use of fuel (high efficiency cogeneration) under OAR 345-015-0350(3), the person shall provide the following information in support of the request:

(a) Detailed information on proposed fuel use, power plant design, steam or heat output to the thermal host and proposed electric output;

Response:

For the LNG Terminal, fuel gas is the principal source of energy from which all facility power is derived. Fuel gas is initially supplied directly from the pipeline, but once the facility is in normal operating mode, the primary source of fuel gas is derived from Boil-off Gas (BOG). BOG is produced when the LNG pressure from Liquefaction is let-down to near atmospheric pressure via the LNG Expander and pressure let-down valves, which produces 1.86 MW [1] of electrical power in the process, to the LNG Flash Drum in preparation for storage in the LNG Storage Tanks. BOG is also produced from heat in-leakage through the LNG Flash Drum and LNG Storage Tank insulation and through the run-down and keep-cool piping. The amount of BOG produced can be set by the amount of sub-cooling from the Liquefaction Process to best match facility fuel gas requirements, but once set, it is best, from an operations standpoint, to maintain the process in steady state. In addition to the LNG Expander, the Liquefaction process has five (5) Mixed Refrigerant expanders which contribute an additional 3.36 MW [1] of electrical power.

The main use of fuel gas at the LNG Terminal is to run the five (5) General Electric (GE) LM6000 PF+ Combustion Gas Turbines (CGTs) which provide the mechanical power to drive the refrigeration compressors. The hot exhaust gas from each LM6000 PF+ Gas Turbine Driver is routed through the HRSGs which produces High Pressure Steam from waste heat. Each gas turbine driver produces exhaust gas which each HRSG can convert to HP Steam. Each HRSG is equipped with a duct burner which can provide supplemental firing to produce approximately 10% of additional HP Steam with a maximum 19.7 MMBtu/hr of fuel gas (HHV) [1].

Most of the HP Steam produced is used to generate electrical power by pressure let-down through the facility Steam Turbine Generators (STGs). The maximum facility electrical power demand requirement is 49.5 MW [1] which occurs when the facility is in LNG Carrier Loading Mode. In order to provide sufficient margin, the design facility power requirement is raised by approximately 10% to 55.5 MW (calculated from 18.5 MW x 3 STGs) [1]. To meet the design power demand, two (2) x 30 MW STGs were selected. In addition, in order to meet the facility sparing requirements for an N+1 configuration, three (3) x 50% STGs are required. Therefore, the facility has specified 3 x 30 MW STGs to provide the electrical power for the LNG Terminal. An additional requirement is that the spare be a "rolling spare" so that in the event of a single STG trip, the remaining two STGs pick up the lost generating capacity as quickly as possible, therefore, all three STGs are normally operated at 18.5 MW [1] each, which requires 224,000 lb/hr [1] of HP Steam to produce, or 91% of the total generated. Of the remaining 9%, 70,300 lb/hr [1] of HP Steam is used intermittently to regenerate the Dehydration (Molecular Sieve) Beds, and the balance is sent to the steam dump condenser.

The LNG Terminal requires approximately 262,000 lb/hr [1] of LP Steam for the Feed Gas Inlet Heater, the Sulfur Scavenger Heater, the Defrost Gas Heater, the Fuel Gas Heater, the Amine Regenerator Reboiler, and the Deaerator. 262,000 lb/hr (approximately 38%) of the HP Steam to the STGs, is sequentially extracted upstream of the STGs low pressure section at 72.5 psig and 357˚F with the balance continuing through the low pressure section to the vacuum condenser to produce additional electrical power.

When the LNG Terminal is shutdown the single installed Auxiliary Boiler is capable of producing 189,100 lb/hr of HP Steam. This value has been revised to include some margin to 202,000 lb/hr of HP Steam and 296.2 MMBtu/hr [1] of fuel gas (HHV) per the Air Contaminant Discharge Permit Application (ACDP, filed with DEQ in October 2017) which allows for the unit to operate up to 876 hours per year.

References

1. Appendix A: Detailed LNG Facility Information – Trade Secret/Confidential Business Information

2. Appendix B: Detailed LNG Facility Information – Public Version

(b) Detailed information on the current facility, including fuel to be displaced, current steam or heat use and current electric output if any;

Response:

This criterion is not applicable because the LNG Terminal is not a current facility.

(c) A detailed engineering assessment of fuel efficiency, showing that the proposed facility is a high efficiency cogeneration facility under the definition in OAR 345-001-0010. The person shall provide calculations in sufficient detail to facilitate independent review by the Department. The person shall state c; and

Response:

The requirements to qualify for Exemption from an EFSC Site Certificate as a "high efficiency cogeneration facility" per ORS469.320(2)(c); OAR 345-015-0350 are:

> *A "high efficiency cogeneration facility" is an energy facility that sequentially produces electrical energy and useful thermal energy from the same fuel source and under average annual operating conditions:*
>
> *a) Has a nominal electric generating capacity of less than 50 megawatts and the fuel chargeable to power heat rate value is not greater than 5550 Btu per kilowatt-hour (higher heating value); or*
>
> *b) Has a nominal electric generating capacity of 50 megawatts or more and the fuel chargeable to power heat rate value is not greater than 6000 Btu per kilowatt-hour (higher heating value).*[1]

Where:

> ***Useful thermal energy*** *means "the verifiable thermal energy used in any viable industrial or commercial process, heating or cooling application." OAR 345-001-0010(66).*
>
> ***Nominal electric generating capacity*** *means "the maximum net electric power output of an energy facility based on the average temperature, barometric pressure and relative humidity at the site during the times of the year when the facility is intended to operate." ORS 469.300(17).*

Fuel chargeable to power heat rate *means "the net heat rate of electric power production during the first twelve months of commercial operation." OAR 345-001-0010(25). This rate "is calculated with all factors adjusted to the average temperature, barometric pressure and relative humidity at the site during the times of the year when the facility is intended to operate using the formula:*

FCP = (FI - FD)/ P*, where:*

a) ***FCP*** *= Fuel chargeable to power heat rate.*
b) ***FI*** *= Annual fuel input to the facility applicable to the cogeneration process in British thermal units (higher heating value).*
c) ***FD*** *= Annual fuel displaced in any industrial or commercial process, heating, or cooling application by supplying useful thermal energy from a cogeneration facility instead of from an alternate source, in British thermal units (higher heating value).*
d) ***P*** *= Annual net electric output of the cogeneration facility in kilowatt-hours.*

From the information above, it can be demonstrated that the STGs meet the requirements to qualify for the exemption from an EFSC Site Certificate.

The LNG Terminal is a *"high efficiency cogeneration facility"* because it utilizes amongst the most efficient aero-derivative gas turbine drivers available to drive the refrigeration compressors and then utilizes waste heat recovery to produce High Pressure Steam which is used to generate electrical power and as *"useful thermal energy"* to regenerate the Dehydration Unit Molecular Sieve Beds. The STGs are used to convert the High Pressure Steam to electrical power. Low Pressure Steam is sequentially extracted upstream of the Low Pressure Section of the STGs and is used as *"useful thermal energy"* for process heating in the Liquefaction Process.

In order to satisfy the equation:

FCP = (FI – FD)/P

Each component of the equation must be calculated from the process information provided above.

Annual Fuel Input (FI):

For the LNG Terminal, the *Annual Fuel Input (FI)* to the cogeneration process is the fuel gas used for the Duct Burners and the fuel gas used for the Auxiliary Boiler since both sources can provide High Pressure Steam to the cogeneration process. Per the ACDP application, the Duct Burners are permitted for 4,000 hours of operation per year and the Auxiliary Boiler is permitted for 876 hours of operation per year.

Note that the statute sets forth the applicable nominal electric generating capacity. However, the fuel chargeable to power heat rate values referenced in ORS 469.320(2)(c) are no longer controlling. In ORS 469.320(3), the Oregon Legislature granted EFSC the authority to review and revise the fuel chargeable to power heat rate values listed in the statute. EFSC altered these values. *See* OAR 315-015-0350(3) (referencing 345-001-0010).

The HRSG Duct Burners are sized to consume at most 19.7 MMBTU/hr (HHV) of fuel gas for each HRSG. Annual Duct Burner fuel gas usage is therefore:

- 19.7 MMBtu/hr x 5 HRSG Duct Burners = 98.5 MMBtu/hr

- 98.5 MMBtu/hr x 4000 hours/year = 394,000 MMBtu/year

The Auxiliary Boiler is sized to consume at most 296.2 MMBTU/hr (HHV). Annual Auxiliary fuel gas usage is therefore:

- 296.2 MMBtu/hr x 876 hours/year = 259,470 MMBtu/year

The Annual Fuel Input (FI) to the cogeneration process is therefore:

- **FI** = 394,000 MMBtu/year + 259,470 MMBtu/year = **<u>653,470 MMBtu/year</u>**

Annual Fuel Displaced (FD):

To calculate the *Annual Fuel Displaced (FD)*, it is assumed to be the fuel gas that would be required to produce the HP Steam and LP Steam used by the LNG Processes if it were generated by an *"alternate source."* In this case, the "alternate source" is assumed to be a Package Boiler with a similar heat rate to the current facility Auxiliary Boiler.

Based on the Facility Maximum HP Steam and LP Steam requirements:

- Process HP Steam Required: 70,300 lbs/hr
- Process LP Steam Required: 262,000 lbs/hr

The LP Steam for the LNG Process is normally produced by extraction from the STGs. If this system isn't available, then LP Steam is produced via pressure let-down and de-superheating of HP Steam.

From the International Association for the Properties of Water and Steam (IAPWS-97) Steam Tables, the enthalpy for Superheated Steam at:

- 727.8˚F and 753.5 psig is: 1,357.46 Btu/lbm
- 357.0˚F and 72.5 psig is: 1,206.89 Btu/lbm

And the enthalpy for Boiler Feed-water at:

- 249.0˚F and 72.5 psig is: 217.72 Btu/lbm

To produce the required quantity of LP Steam:

- Enthalpy HP Steam = HPS lb/hr x 1,357.46 BTU/lbm = h_{hps}
- Enthalpy BFW = (262,000 lb/hr - HPS lbm/hr) x 217.72 Btu/lbm = h_{bfw}
- Enthalpy LP Steam = 262,000 lbm/hr x 1,206.89 Btu/lbm = 316,204,807 Btu/hr = h_{lps}
- $h_{hps} + h_{bfw} = h_{lps}$
- HPS x 1357.46 + (262,000 – HPS) x 217.72 = 316,204,807
- (1357.46 – 217.72) x HPS + 57,043,714 = 316,204,807

Therefore:

- HPS = (316,204,807 – 57,043,714) ÷ (1357.46 – 217.72) = 227,387 lbs/hr, and
- BFW = (262,000 – 227,387) = 34,613 lbs/hr, required for de-superheating
- Total HP Steam is therefore: 227,387 lbs/hr + 70,300 lbs/hr = 297,687 lbs/hr

The LNG Terminal Auxiliary Boiler can produce up to 202,000 lbs/hr of HP Steam and requires a maximum of 296.2 MMBtu/hr (HHV) of fuel gas. Assuming a pair of boilers of similar heat rate to the Auxiliary Boiler, the fuel gas required to generate 297,687 lbs/hr of HP Steam is:

- 296.2 MMBTU/hr x 297,687 lbs/hr ÷ 202,000 lbs/hr = 436.5 MMBtu/hr (HHV)
- **FD** = 8760 hours/year x 436.6 MMBTU/hr = **<u>3,823,816 MMBtu/year (HHV)</u>**

The LNG Terminal requires 49.5 MW-hr of electrical power during LNG Carrier Loading Mode and the STGs are designed to provide approximately 10% margin for a total STG Power Generated of 55.5 MW. In addition, the LNG Expander and the MR Expanders provide an additional 1.86 MW and 3.36 MW, respectively. The maximum combined facility electrical power output is 60.72 MW.

The Annual Net Power Output of the Cogeneration Facility is therefore:

- **P** = 60.76 MW x 1000 kW/MW x 8760 hours/year = **<u>531,907,200 kW-hr</u>**

Plugging the above calculated values to equation FCP = (FI – FD) / P gives:

FI = 653,470 MMBtu/year (HHV)

FD = 3,823,816 MMBtu/year (HHV)

P = 531,907,200 kW-hr

FCP = (653,470 MMBtu – 3,823,816 MMBtu) x 10^6 ÷ 531,907,200 kW-hr

FCP = -<u>5,960 Btu/kW-hr</u>

The LNG Terminal combined heat and power system meets the above criteria and therefore is exempt from the EFSC Site Certificate requirement.

(d) A description of the facility, including the thermal host, the proposed energy facility, the location by address as well as township and range and any associated linear equipment needed.

Response:

1. PROJECT LOCATION AND DESCRIPTION OF FACILITIES

JCEP proposes to site, construct, and operate a new LNG export terminal on the bay side of the North Spit of Coos Bay in southwest Oregon (the Project). The proposed LNG Terminal will be located in unincorporated Coos County, Oregon, primarily within land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP, across two contiguous parcels (Ingram Yard and South Dunes) which are connected by an Access and Utility Corridor (shown on Figure 1.1-2). The primary site for the LNG Terminal is 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, more than 1 mile away from the nearest residence.

The proposed LNG Terminal will be located near the Pacific Ocean in the coastal lowlands ecozone. The primary site is a combination of brownfield decommissioned industrial facilities, an existing landfill requiring closure, and some open land covered by grasslands and brush (including some wetlands), as well as an area of forested dunes. Portions of the primary site have also previously been used for disposal of dredged material.

The LNG Terminal would be within Sections 4 and 5, Township (T.) 25 South (S.), Range (R.) 13 West (W.), shown on Coos County Assessor's map as tax lots 100/200/300.

2. LNG TERMINAL COMPONENTS AND FACILITIES

The LNG Terminal site is comprised of South Dunes, Ingram Yard, and the Access and Utility Corridor:

- South Dunes Site (includes construction and operational facilities, including the Workforce Housing Facility and SORSC)
- Ingram Yard (includes construction and operational facilities, including LNG tanks, liquefaction equipment and the slip and access channel)
- Access and Utility Corridor (includes construction and operational facilities, including the fire department)

These areas are shown on Figure 1.1-2. The LNG Terminal will receive a maximum of 1,200,000 Dth/d of natural gas from the Pipeline and produce a maximum of 7.8 mtpa of LNG for export. The LNG Terminal will receive natural gas from the Pipeline, process the gas, liquefy the gas into LNG, store the LNG, and load the LNG onto ocean-going LNG carriers at its marine dock. The main operational components of the LNG Terminal are shown on Figure 1.1-2 (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.

All LNG Terminal facilities and components will be constructed in accordance with governing regulations, including the regulations of the USCG for Liquefied Natural Gas Waterfront Facilities, 33 CFR Part 127; the U.S. Department of Transportation ("DOT") Federal Safety Standards for Liquefied Natural Gas Facilities, 49 CFR Part 193; and the National Fire Protection Association ("NFPA") Standard 59A for LNG facilities, and the codes and standards referenced therein.

2.0 GAS INLET FACILITIES AND GAS CONDITIONING

2.0.1 Gas Inlet Facilities and Metering

Pipeline quality feed gas will be supplied to JCEP via the Pipeline. The interface point between the Pipeline and LNG Terminal occurs at the flange immediately downstream of the metering skid located on the South Dunes Site.

Inlet pipeline metering facilities consist of a pipeline pig receiver, inlet filter/separator, and flow meter, which are in the PCGP scope. The pipe connecting the metering station to the liquefaction facilities will be buried from South Dunes through the Utility and Access Corridor, and then will resurface within the LNG Terminal facility at Ingram Yard.

A High Integrity Pressure Protection System (HIPPS) will be installed, in a 2 x 100 percent configuration, downstream of the metering station and upstream of any piping branches with the exception of the fuel supply for start-up and LNG storage tank vacuum breaker.

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 or units. A pressure reduction unit functions as an inlet pressure control station before the gas enters the gas conditioning unit.

2.0.2 Gas Conditioning Train

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

Mercury is first removed to prevent corrosion in downstream cryogenic aluminum equipment and minimize exposure of other equipment and vent streams to mercury contamination. The feed gas will then be treated by passing through the acid gas removal unit to remove CO_2 to prevent freezing in the liquefaction process. Trace amounts of hydrogen sulfide (H_2S) and other sulfur species will also be removed.

The amine solution of the acid gas removal process saturates the dry feed gas with water. The dehydration system removes the water content of the feed gas to prevent water freeze out in the liquefaction process.

2.0.3 Mercury Removal

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 be located downstream of the inlet filter/separator and upstream of the amine contactor, and will reduce the amount of mercury in the treated pipeline gas down to less than 0.01 micrograms per Normal cubic meter ($\mu g/Nm^3$).

The life of the mercury removal beds is designed to be three years, assuming a mercury concentration in the feed gas of 0.05 parts per billion by volume (ppbv). Spent catalyst from the mercury removal vessels will be removed periodically and sent off-site for disposal by a licensed hazardous waste management contractor.

2.0.4 Acid Gas Removal

Acid gas removal involves a closed-loop system that circulates a promoted methyl-diethanolamine 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 approximately 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 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.

2.0.5 Dehydration

The water removal 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 one 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-loaded 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 LIQUEFACTION FACILITIES

2.1.1 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) 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 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 turned into liquid by cooling it to approximately -260°F with the mixed refrigerant. The refrigerant exchanger consists of multiple brazed aluminum heat exchanger cores arranged in parallel inside a perlite insulated cold box. An aerial cooling system (fin-fan) rejects heat from the mixed refrigerant that is gained from the liquefaction of feed gas and compression. The cold box is purged with nitrogen gas to prevent moisture intrusion and eliminate the potential for a flammable atmosphere inside.

The refrigeration cycle is a closed-loop process that utilizes a single-body, two-stage refrigerant compressor. An aero-derivative combustion turbine directly provides the power to drive the refrigerant compressor. Exhaust-gas waste heat recovery in the form of steam generation maximizes the overall thermal efficiency of the LNG Terminal.

Heavy hydrocarbons (generally referred to as C5+ components) will be removed from the feed gas before the final liquefaction step to meet the LNG specification and prevent possible freezing at subcooled temperatures.

2.1.2 Heavies Removal

Heavy hydrocarbons or "heavies" will be removed from the feed gas before the final liquefaction step in order to meet the LNG specification and prevent possible freezing 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.

2.1.3 Refrigerant Makeup System

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 via ISO containers or qualified trucks and stored in pressurized vessels for intermittent makeup to the SMR circuit.

2.1.4 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 filling. Top filling 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 a fuel.

The two full-containment LNG storage tanks are each equipped with three fully submerged LNG in-tank pumps, each rated for approximately 2,400 cubic meters per hour (m^3/hr), and one spare well, fully piped and instrumented. LNG is pumped, using five of the six installed pumps, to the marine berth and into an LNG carrier at a normal loading rate of 12,000 m^3/h. 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.

LNG spills will be contained, and the bermed area around the LNG storage tanks will gravity drain to an LNG impoundment basin. An LNG spill containment trench will also collect any LNG from spills outside of the bermed area around the LNG storage tank area and gravity drain to the same LNG impoundment basin. A separate LNG trench and impoundment basin located near the marine loading system will also be provided to collect any LNG spills from the LNG transfer line or the recirculation line that would be located south of the liquefaction trains; this separate impoundment is required due to slope requirements to allow effective gravity drainage that cannot be achieved with a single impoundment basin. The LNG impoundment basins will include sump pumps to pump out rain water. In accordance with 49 CFR § 193.2173, the water removal system will have the capacity to remove water at a rate of 25 percent of the maximum predictable collection rate from a storm of ten-year frequency and one-hour duration. The discharged rainwater will be piped to the oily waste system.

2.2 MARINE FACILITIES

Overview

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 USCG. THE MOF will be constructed outside of the slip to deliver construction and maintenance components of the LNG Terminal that are too large or heavy to be delivered by road or rail.

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. The USCG Letter of Recommendation (LOR) and Waterway Suitability Report (WSR) currently allows LNG carriers up to 148,000 m^3 to dock at the LNG Terminal berth.

2.2.1 Access Channel

Access to the marine slip will be via a newly constructed access channel that will connect the slip to the Federal Navigation Channel at approximate Channel Mile 7.3 at the beginning of the confluence between the Jarvis Turn and the Upper Jarvis Range A. The access channel will flare from the narrowest portion at the mouth of the slip, with a minimum width of 780 feet, to the intersection with the Federal Navigation Channel with an approximate width of 2,200 feet. The proposed access channel will allow for the safe transit of vessels between the berth and the Federal Navigation Channel, and allow the safe turning of vessels during an inbound transit so that the LNG carrier can be backed into the slip and berthed bow out, according to industry best practice requirements.

The total access channel would cover approximately 22 acres below the Highest Measured Tide (HMT) elevation of 10.26 feet (NAVD88). The walls of the access channel would be sloped to meet the existing bottom contours at an angle of approximately 3 feet horizontal to 1 foot vertical (3:1). The marine slip and access channel will have a minimum depth of -45 feet below the mean lower low water (MLLW (-45.97 feet NAVD 88)) to ensure minimum under-keel clearance is achieved for the safe maneuvering and berthing of loaded LNG carriers. An allowance over and above the minimum depth will be made for advanced maintenance dredge and incidental over-dredge, in accordance with industry best practices. Dredging of the access channel would affect about 15 acres of currently existing deep subtidal area below -15.3 feet in depth below MLLW.

2.2.2 Marine Slip

The new marine slip will be constructed by excavating an existing upland area. The majority of the marine slip will be excavated from existing uplands owned by JCEP. Part of the marine slip would be constructed within state waters of Coos Bay to the MLLW line, for which the Port has obtained an easement from the ODSL.

The slip will be bounded on the east and west sides by sheet pile walls, creating a vertical face to support mooring structures. The northern side of the slip will be sloped to meet the existing bottom contours at an angle of 3 feet horizontal to one foot vertical (3:1). The inside dimensions at the toe of the slope of the slip will measure a minimum of 800 feet between the vertical sheet pile walls along the east/west axis, and approximately 1,500 feet and 1,200 feet along the western and eastern boundaries, respectively. The slip is sized to provide the flexibility needed to safely maneuver an LNG carrier from the access channel into the slip when another LNG carrier is already berthed on the east or west sides and for tugs to move a temporarily disabled LNG vessel away from the loading berth on the east side of the slip to the emergency lay berth on the west side of the slip if necessary.

2.2.3 LNG Carrier Berths

The marine facilities will include two LNG carrier berths, an Emergency Lay Berth and a Product Loading Berth. Each berth consists of a number of elements: the sheet pile wall, mooring structures and breasting structures. In general, the LNG loading berth will be about 1,280 feet long between the centers of the end mooring structures, and 312 feet long from the center of the northernmost breasting structure to the center of the southernmost breasting structure.

2.2.4 Sheet Pile Walls

The physical berth will be constructed of steel sheet piles to support surface structures (i.e., the loading area) or provide the foundation for the breasting and mooring structures. Under the loading facility, the wall will extend from the bottom of the slip at elevation -45.97 (minimum) to approximate elevation +34.5 (NAVD88). This face will extend north and south to capture the outermost breasting structures and then turn to the east, creating a setback wall for the remainder of the slip.

2.2.5 Mooring Structures

Mooring and breasting (see Section 1.3.6.4.3) structures will be provided at both the loading berth and the emergency lay berth for the safe breasting, berthing, and mooring of the LNG carriers docked at either berth.

Six mooring structures (three on each side of the LNG berth centerline) will be used to secure the LNG carrier at both the LNG loading berth and the emergency lay berth. The structures will be behind the sheet pile wall, set back approximately 145 feet from the face of each berth. These structures will have concrete platforms founded on steel pilings and will each have remote release mooring hooks with capstans, as well as all required equipment and instrumentation for safe mooring operations.

2.2.6 Breasting Structures

There will be four breasting structures located adjacent to the product loading facility (PLF); two will be located north of the PLF and two to the south. Like the mooring structures, each breasting structure will have a concrete platform founded on steel pilings and will have remote release mooring hooks with capstans, as well as all required equipment and instrumentation for safe mooring operations. Each breasting structure will also support a fender assembly sized to absorb and distribute berthing and mooring loads for the full range of LNG carriers that the LNG berth is designed for, thus preventing damage to the LNG carriers or the LNG berth. The fender system will allow the carriers to be moored a safe distance off the vertical face of the sheet pile wall. The emergency lay berth will have four breasting structures with fenders and capstans spaced equally about the mid-ship. There will be additional breasting fender structures, two to the north and two to the south of the main breasting structures, for a total of eight. The exact number, type, and location of the breasting structures for the emergency lay berth will be defined during detail design to meet OCIMF requirements for non-parallel vessel approach and the full range of vessel sizes.

2.2.7 Product Loading Facility

The PLF utilizes a pile-supported concrete slab that provides structural support to the marine loading arms, terminal gangway, and other ancillary equipment. The PLF is designed to support a number of elements that facilitate the safe transfer of LNG product between the LNG Terminal and the LNG carriers.

The PLF will be constructed on top of the sheet pile wall at approximate elevation +34.5, and will be about 130 feet long and 86 feet wide. The foundation will be reinforced concrete supported by steel pilings.

The transfer equipment consists of four marine loading arms and ancillary equipment. There will be two dedicated liquid loading arms, one hybrid arm, and one ship vapor return arm to meet the design loading rate of 12,000 m^3/h. The hybrid arm will be designed for dual service capable of transferring LNG to the LNG carriers or returning vapor from the LNG carriers to the BOG vapor management system. During normal operation the hybrid arm will be used in liquid service along with the two liquid arms, and the vapor return arm will be used to return vapor to the BOG vapor management system.

The loading arms are designed with swivel joints to provide the required range of movement between the LNG carrier and the shore connections. Each arm will be fitted with a hydraulically interlocked double ball valve and powered emergency release coupling to isolate the arm and the LNG carrier in the event of an emergency condition in which rapid disconnection of the connected arms is required. Each arm will be fully balanced in the empty condition by a counterweight system and maneuvered by hydraulic cylinder drives. A mezzanine-type elevated steel platform will be installed for maintenance of the triple-swivel assembly of the arms.

LNG spill containment will be accomplished by a concrete curbed and sloped area that will contain any LNG spillage and allow the spill to safely flow away from the loading area through the LNG spill collection trench to the marine area LNG impoundment basin.

Additional structures at the LNG loading berth will include an LNG carrier gangway, area lighting facilities, aids to navigation, firewater monitors, and a dry chemical firefighting system.

2.2.8 Emergency Lay Berth

An emergency lay berth on the west side of the slip will be provided with facilities to safely moor a temporarily disabled LNG carrier. Berthing facilities will be supported by the west side sheet pile wall with a top-of-wall elevation of approximately +20 feet (NAVD 88). The lay berth will have pile-supported breasting structures with fenders extending above the vertical sheet pile and mooring structures on the land side of the sheet pile. A grated platform with a gangway will be placed behind the berthing breasting structures to allow for safe access and egress from the disabled LNG carrier at berth. Support infrastructure will include an access road down from the area of the tug berth building, duct bank with cabling for powering the mooring hooks and capstans, and limited lighting of the ship access area.

Along the western property line, but on the Project side of the Henderson Property buffer zone, a tsunami flow control wall will be constructed. The flow control wall shall be of sufficient height and strength to prevent overtopping into Henderson Property and limit the drag due to the tsunami current loads on LNG carriers within the marine slip. The wall height shall be approximately 34.5 feet and determined in accordance with the design tsunami criteria. The wall will run from the southwest side of the LNG tank impoundment area down to the entrance to the slip.

2.2.9 Material Offloading Facility

The MOF will be constructed to deliver components of the LNG Terminal that are too large or heavy to be delivered by road or rail. The MOF will cover about 3 acres on the southeast side of the slip, adjacent to the RFP. The MOF will be constructed using the same sheet pile wall system as the LNG loading berth and the emergency lay berth. The top of the MOF will be at elevation approximately +13.0 feet (NAVD88), and the bottom of the exposed wall will be at the access channel elevation. The MOF will provide approximately 450 feet of dock face for the mooring and unloading of a variety of vessel types.

During construction of the LNG Terminal, in addition to receiving equipment and large modules (upwards of 6,000 short tons) by break bulk cargo carriers, roll on roll off cargo carriers, and barges, the MOF will allow other bulk materials to be delivered by sea to minimize impacts on the local road network. After project construction, the MOF will be retained as a permanent feature of the LNG Terminal to support maintenance and replacement for large equipment components that are too large to be transported by rail and road.

2.2.10 Tug Berth

The tug berth at the north side of the marine slip will accommodate four tugboats, as well as two sheriff's boats and six other visitor boats with similar characteristics as the sheriff's boats. For design purposes, the tugs are assumed to be 80-metric-ton bollard pull boats approximately 100 feet long with a beam of 40 feet. The basis for the sheriff's boat is the Willard USCG Long Range Interceptor. The tug dock will generally be about 470 feet long and 18 feet wide; in addition, there is 360 feet of 8-foot-wide floats for mooring and accessing the security vessels.

The tug dock will be concrete supported by steel piles. The security vessel docks will be precast concrete floats anchored by steel pile. The security boat dock will support two separate boat houses. The tug dock will be accessible from land by a pile-founded trestle, thus allowing vehicle and pedestrian access for service and support of operations. An onshore tug operations building will provide storage, meeting, and sanitary facilities for the crews of the tug and security boats.

2.2.11 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 Project's plans for the LNG carriers calling on the LNG Terminal and their transit route in Coos Bay, as described below, are primarily within the jurisdiction of the USCG. Because the USCG has authorized carriers of approximately 950 feet length, 150 feet beam, and loaded draft of 40 feet (nominal 148,000 m^3)[1] as the size of LNG carrier, the LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. The actual number of LNG carriers per year will be dependent on the capacity of the LNG carriers calling on the LNG Terminal and the actual output production of the LNG Terminal. The LNG loading berth is

[1] Depending upon the approved LNG containment system type, carriers with these approximate dimensions may range in LNG cargo capacity from 135,000 m^3 to 170,000 m^3 .

designed so that it could accommodate LNG carriers up to 217,000 m^3 if larger-sized carriers were to be authorized by the USCG in the future, resulting in a reduced number of LNG carrier calls each year.

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 1.5 hours 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 and transit of the Federal Navigation Channel.

An LNG ship traffic study conducted by Moffatt & Nichol International (M&N 2006) concluded that the additional LNG carrier traffic associated with the Project can be accommodated in the Port and the Federal Navigation Channel. The ship traffic conditions in the Port that existed when the LNG carrier traffic study was conducted have not changed.

Resources, such as high bollard pull tractor tugs and pilots, will be required to handle the planned number of LNG carriers. JCEP has committed to provide the following marine resources as identified by the USCG in the current version of the WSR:

- Four (three operation, one standby) 80-bollard-ton tractor tugs with Class 1, firefighting capability;
- A Port differential Global Positioning System navigation system for use by the Pilots and LNG carrier bridge team while transiting the channel en route to the Project;
- Physical Oceanographic Real Time System to provide real-time channel water level, current, and weather data;
- A Vessel Traffic Information System consisting of an Automatic Identification System receiver, 2 land-based radars, and 12 low light cameras (with zoom, pan, and tilt) to monitor the transit of the LNG carriers while in Coos Bay;
- Emergency response notification system;
- Installation of private navigation aids (e.g., channel centerline range markers); and
- Gas detection capability along the LNG carrier waterway transit route.

2.3 NAVIGATIONAL RELIABILITY IMPROVEMENTS

JCEP plans to excavate four submerged areas lying adjacent to the federally-authorized Channel. These minor enhancements will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window. This allows for greater navigational efficiency and reliability to enable JCEP to export the full capacity of the optimized design production of 7.8 mtpa from the LNG Terminal.

The total volume of capital dredge material from these excavations is approximately 700,000 cubic yards. Dredge material may be distributed between APCO 1 and APCO 2 upland disposal sites, or placed entirely at APCO 2 if shown to be feasible. The dredge areas are named Dredge Area 1 to 4 and located adjacent to the Channel roughly between River Mile (“RM”) 2 to RM 7 respectively.

Enhancement #1 – Coos Bay Inside Range channel and right turn to Coos Bay Range: Excavation at this site will reduce the constriction to vessel passage at the inbound entrance to Coos Bay Inside Range for any ship making the 95 degree turn from the Entrance Range through the Entrance Turn and Range. JCEP proposes to widen the Coos Bay Inside Range channel from the current 300 feet to 450 feet, thereby making it easier for all vessels transiting the area to make this turn. In addition, the total corner cutoff on the Coos Bay Range side will be lengthened from the current 850 feet to about 1,400 feet from the turn's apex.

Enhancement #2 – Turn from Coos Bay Range to Empire Range channels: The current corner cutoff distance from the apex of this turn is about 500 feet, making it difficult for vessels to begin turning sufficiently early to be able to make the turn and be properly positioned in the center of the next channel range. JCEP proposes to widen the turn area from the Coos Bay Range to the Empire Range from the current 400 feet to 600 feet at the apex of the turn and lengthen the total corner cutoff area from the current 1000 feet to about 3500 feet.

Enhancement #3 – Turn from the Empire Range to Lower Jarvis Range channels: JCEP proposes to add a corner cut on the west side in this area that will be about 1,150 feet, thereby providing additional room for vessels to make this turn.

Enhancement #4 – Turn from Lower Jarvis Range to Jarvis Turn Range channels: JCEP proposes to widen the turn area here from the current 500 feet to 600 feet at the apex of the turn and lengthen to total corner cutoff area of the turn from the current 1,125 feet to about 1,750 feet thereby allowing vessels to begin their turn in this area earlier.

Maintenance materials will be disposed of in the upland dredge disposal sites located on the APCO site 1 and APCO site 2 and management of the dredge areas would be the responsibility of Jordan Cove.

2.4 TERMINAL SUPPORT SYSTEMS

2.4.1 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 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 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.

Steam System

The LNG Terminal will use steam as a heat transfer fluid for process heating. High pressure steam is provided to the facility from Heat Recovery Steam Generators (HRSGs), which utilize waste heat from refrigerant compressor driver exhaust gases. High-pressure steam supplies the gas conditioning train and STGs, where the steam pressure is let down from 725 pounds per square inch gauge (“psig”) to produce low-pressure steam at 50 psig per gas conditioning needs and the balance is further dropped to a vacuum pressure and generates electricity for the plant. Any low-pressure steam requirement in excess of this can be made up by “de-superheating” a letdown of high-pressure steam. Process condensate is de-aerated and treated, and then returned to the cycle as boiler feed-water for the HRSGs. An auxiliary boiler is available to provide high-pressure steam to meet the requirements for one STG and any additional steam required for when the facility is not producing LNG.

2.4.2 Instrument Air

Instrument air will be provided through compression and drying packages. Air will be compressed in two 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 two 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 absorption mode while the other dryer regenerates. Instrument air will be used for pneumatic control of automated instrumentation, utility air, and supply for nitrogen generation.

2.4.3 Utility Air

Utility air will be used for normal maintenance activities (utility stations, control panel purges, building purges, etc.). Utility air will be dried with the instrument air but will be supplied throughout the facility from a separate header. The utility air header will be provided with a pressure regulator and on-off valve to shut off flow if the main header pressure drops to the minimum for proper functioning of actuators.

2.4.4 Nitrogen

Nitrogen will be provided through vaporization of liquid nitrogen and a pressure swing adsorption site generation package unit. Pressure swing adsorption units use swings in pressure to separate nitrogen from air; the pressure swing adsorption swings from high pressure, where nitrogen is adsorbed from air, to low pressure, where it is desorbed. Liquid nitrogen will be the only source of nitrogen used for refrigerant makeup, while the site-generated nitrogen will supply continuous utility users, such as compressor seals, cold box purges and LNG loading arm swivel joints, as well as intermittent users, such as LNG loading arm purges and utility stations. Nitrogen packages will be sized to fulfill peak demand and to handle the maximum expected instantaneous flow.

2.4.5 Utility and Potable Water System

An interconnect to the Coos Bay-North Bend Water Board (“CBNBWB”) potable water pipeline will be used for all normal operational water needs in the LNG Terminal, which includes fire water makeup, utility water used for such items as equipment and area cleaning, and potable water required to supply buildings and eyewash/safety shower stations.

Utility water is fed to the demineralized water package, but storage of utility water will be combined with fire water supply in the fire water tanks.

The CBNBWB raw water pipeline (in addition to the potable water pipeline) will be used for construction water, including LNG tank hydrotesting. The pipeline tap at the LNG Terminal site will remain connected after construction, but there are no normal operational uses anticipated for this raw water supply.

Resource Report 2 provides the estimated potable and raw water demand during the construction and operation of the LNG Terminal.

2.4.6 Fire Suppression System

Fire suppression and protection measures will be provided to ensure the safety of personnel and property. Fire water systems at the LNG Terminal including fire water supply storage tanks, stationary fire water pumps, fire hydrant mains, fixed water spray systems, automatic sprinkler extinguishing systems, high expansion foam system, and remotely controlled monitored spray systems will meet the requirements of 49 CFR Part 193, NFPA 59A, American Petroleum Institute ("API") 2510, API 2510A, and 33 CFR Part 127.

The function of the fire water system is to provide water under pressure to the fire hydrants, monitors, and fixed water suppression systems throughout the LNG Terminal. The fire water supply will also be used to provide water for on-site firefighting trucks. The fire suppression distribution piping network will comprise the following:

- Underground fire water mains;
- Aboveground fire water hydrant mains;
- Fixed fire water sprinkler and spray systems;
- Fixed high-expansion foam systems;
- Portable fire suppression equipment;
- Appurtenances, including all piping and valves connecting the pumps and water supply to the plant fire suppression systems; and
- Hydrants and monitors.

The main fire water supply for the LNG Terminal is provided by two x 100 percent capacity aboveground atmospheric storage tanks (located in the Access and Utility Corridor), which allow for redundancy if one of the tanks is unavailable. This redundancy is an acceptable precautionary measure for preparing for fire water tank repairs, in accordance with NFPA 22, and to perform regular maintenance and inspection of fire water tanks in accordance with NFPA 25. Water supply for the two fire water tanks is potable water from the local CBNBWB.

The fire water tanks are dual-service supply tanks and will provide the standpipe system to ensure dedicated fire water volume for fire protection systems. Each tank will hold a minimum usable capacity of 3,240,000 gal to supply four hours of fire water supply for the Maximum Probable Fire Water Demand, which is the demand for the largest fire scenario including 1,000 gpm hose stream allowance in accordance with NFPA 59A. Providing four hours of water supply is in accordance with API 2510 which exceeds the two hours of water supply required by NFPA 59A. The atmospheric tank design will follow API Standard 650 and NFPA 22.

The fire water distribution network will be supplied via four x 33 percent capacity fire water pumps. One fire pump will be electric motor driven while three will be diesel engine driven to ensure at least three pumps remain available in the event of power failure. Two x 100 percent electric-motor-driven jockey pumps will be provided to maintain pressure in the main fire water distribution system. The entire pump installation will be designed in accordance with NFPA 20 and the fire water distribution network will be designed in accordance with NFPA 24.

2.4.7 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 marine loading system. The “warm” relief loads are separated to ensure that wet fluids cannot freeze in the header if there were 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 enclosed ground flare, while the marine flare will be an enclosed cylindrical ground flare. A small pilot with electronic ignition is 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.

2.4.8 Stormwater and Wastewater Systems

The LNG Terminal and marine LNG loading area will include various drainage elements to manage segregated networks for contaminated and uncontaminated water from designated areas. Liquid effluent from the LNG Terminal and marine LNG loading area consists mainly of water from rainfall, protection of equipment with fire water, processing areas, storage areas, domestic areas, and utilities units. Water from all oil-filled equipment in LNG spill impounding basins will be pumped by submersible pumps to the oily water treatment system.

Stormwater from areas other than LNG spill impounding basins will be collected in a system of stormwater swales, a buried storm water system, infiltration basins, and other treatment facilities. Stormwater facility overflow outfalls will ultimately connect to Coos Bay. The initial runoff from all storms of a two-year return period and 24-hour duration or less will be infiltrated. Excess stormwater during storms of longer return periods will be allowed to overflow to the slip. Stormwater from some low elevation areas will be treated with cartridge filters and released to the slip.

Stormwater collected in areas that are potentially contaminated with oil or grease will be pumped or will flow to the oily water system. The oily water system will flow to the oily water separator package(s) before being treated and discharged to the IWWP.

The facility will be designed to provide drainage of surface water to designated areas for disposal in accordance with 49 CFR § 193.2159. Stormwater collection and treatment facilities will be designed to meet regulatory requirements from the National Marine Fisheries Service (“NMFS”) and ODEQ.

2.4.9 Sewage and Sanitary Waste Treatment

Sanitary waste from the northwest guard house and tug building will be directed to a holding tank. A sanitary waste contractor will remove the contents of the tank as necessary and dispose of the contents at authorized disposal sites through the sanitary waste contractor's permits. Sanitary waste from the remainder of buildings will be treated by a packaged treatment system. The effluent will be directed to the IWWP. Solids will be removed from the packaged treatment system periodically by a sanitary waste contractor and will be disposed of at authorized disposal sites through the sanitary waste contractor's permits.

2.4.10 Hazard Detection and Response

Safety controls, including hazard detection and response systems, are briefly summarized below. The Project will contain "passive" and "active" hazard prevention and mitigation systems and controls.

Passive systems will generally include those that do not require human intervention, such as spill drainage and collection systems, ignition source control, and fireproofing. Thermal proofing will be considered for application to support structures, components, and equipment, as required, to maintain structural stability in a fire hazard zone, cryogenic spill zone, or area where a failure could affect a safety-related system, provide additional fuel to a fire, or cause additional damage to the unit or facility.

Active systems normally are either automatic or require some action by an operator. Active fire control systems and equipment will consist of a looped, underground fire water distribution piping system serving hydrants, fire water monitors, hose reels, water-spray, or deluge and sprinkler systems. Active spill control systems will include fixed high-expansion foam and dry chemical systems. They will also include portable and wheeled fire extinguishers that employ dry chemicals and CO_2. Fire protection in buildings will generally consist of smoke detectors, flame detectors, portable fire extinguishers, sprinkler systems, and an emergency shutdown ("ESD") system.

Process instruments will routinely monitor for potentially hazardous conditions. Specialized automatic hazard detection and alarm notification devices will be installed to provide an early warning. The Project will also contain hazard detectors designed to sense a variety of conditions, including combustible gas, low temperatures (LNG spill), smoke, heat, and flame. Each of these detector systems will trigger visual and audible alarms at specific site locations and in the control room areas to facilitate effective and immediate response.

The safety of the LNG carriers while docked and loading is a major design consideration for hazard detection and response. Safety measures include ESD spill containment and provisions to protect piping from the effects of surges. In addition, JCEP will have a Fire Department with three pumping trucks, one ladder truck, and one hazardous materials truck that can be mobilized to attend to a fire in the facility in less than 4 minutes.

2.4.11 Process Control System

Operators will control and monitor the facility through a distributed control system ("DCS"). Vendor-supplied packaged units with local control panels and numerous field-mounted instruments will be connected to remote Input/Output ("I/O") cabinets located throughout the facility. These remote I/O cabinets interface with the DCS controllers through cabling run through the plant to the control room. The DCS also includes a local historian that historicizes all process data on-site. Overall plant process control and monitoring will be performed at consoles located in the central control room, with monitoring capabilities from the remote I/O rooms. Other machine monitoring and control systems such as those used for the refrigerant compressors will have local control panels but will also be linked to the DCS and central control room.

In addition to the DCS, independent Safety Instrumented Systems ("SIS") and Fire and Gas Systems ("FGS") will be employed to monitor hazardous conditions and provide emergency shutdown capability. The SIS will utilize separate, dedicated controllers to control safety functions such as those that are required for emergency shutdown safety functions. DCS controllers will monitor the present value of a designated process parameter and adjust actuated control valves to maintain the process setpoint. Limits will be defined to alert operators of deviation away from setpoint, and the SIS will take action if further deviation occurs. The FGS will permit activation of critical firefighting equipment from the control room and will utilize various flame, smoke, and temperature detectors as well as sirens, beacons, and manual alarm call points.

2.4.12 Electrical Systems

JCEP plans to obtain limited power from the regional electric grid for the SORSC and temporary construction activities as described in Section 1.9. 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 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 two standby diesel generators for the LNG Terminal and two for the SORSC. The facility will not be connected to the local grid, and will not import or export power. Two switchgear buses, in a main-tie-main configuration, will be connected to the STGs (minimum of one turbine to each bus). These switchgear buses will feed the plant distribution 13.8 kilovolt ("kV") switchgear, 6.9 kV switchgear and motor control center, and 480-volt switchgears and motor control center buses located throughout the plant. The plant distribution buses will contain two 6.9 kV essential power buses that power all of the essential plant loads. The LNG Terminal diesel generators have 100 percent redundancy and are connected to the 6.9 kV essential power buses.

2.4.13 Buildings

Buildings and structures required for the operation of the LNG Terminal `include:

- Administration building;
- SORSC building;
- Fire department;
- Operations building/control room/laboratory/first aid facility;
- Main gate guard house and security building;
- Secondary entrance security gate/terminal guard building;
- Plant warehouse/receiving building;
- Maintenance building;
- Tugboat, storage, and crew building;
- Lube oil, paint and compressed gas storage;

- Water treatment building;
- Inspection station shelter;
- Fire water pump buildings;
- Fire water valve houses;
- Marine control room building;
- Electrical powerhouses;
- Equipment shelters/buildings;
- Analyzer buildings;

The siting of occupied buildings will be evaluated for overpressure, toxic release, and fire hazards. Occupied buildings will be sited in accordance with industry standards. Loads, analysis, design, and construction will be in accordance with all statutory and regulatory requirements.

2.4.14 Lighting System

The lighting levels will be based on API standards. Lighting around equipment and facilities where routine maintenance activities could occur on a 24-hour basis would range from 1 to 20 foot-candles, with 20 foot-candle lighting levels within the compressor enclosures.

General process area lighting would be kept to a minimum, on the order of 2 foot-candles. Access and Utility Corridor lighting for the LNG Terminal would be 0.4 foot-candle. Perimeter security would be on the order of 1.3 foot-candles, using evenly spaced 400 watt floodlights. As a point of reference, 20 foot-candles is close to the indoor lighting in a typical home, 2 foot-candles is typical of that found in a store parking lot, and 0.4 foot-candle is typical of residential street lighting. The final lighting plan would be developed during detailed design.

Only lighting required for operation and maintenance, safety, security, and meeting Federal Aviation Administration requirements would be used on the LNG storage tanks. The light will be localized to minimize off-site effects.

2.4.15 Access and Utility Corridor, Haul Road, Access Roads, and Parking Lots

The Access and Utility Corridor will be constructed between Ingram Yard and the South Dunes Site. The corridor will be approximately 1 mile long. It will be located entirely on property owned by JCEP. The Access and Utility Corridor will cover about 26 acres.

The primary purpose of the Access and Utility Corridor is to provide a conduit for the underground feed gas supply to the LNG Terminal and a number of utility services required between the LNG Terminal and South Dunes. Utilities in the corridor will include underground power lines, fire water supply, communications lines, and metering skid control lines.

The full length of the corridor will be used during construction for the movement of equipment and materials. The road will be used to haul materials excavated from the Ingram Yard to the South Dunes Site and the Roseburg Forest Products (RFP) property. Use of the corridor for mass earth moving will reduce impacts to the Trans Pacific Parkway (TPP) and the existing RFP facility.

The western portion of the Access and Utility Corridor between the LNG Terminal and Jordan Cove Road will be paved and provide primary permanent access; it will include two lanes into the LNG Terminal and a single lane out. The remainder of the corridor, east of Jordan Cove Road, will be provided with a crushed rock track for infrequent maintenance access. Paved access between the South Dunes Site and the western portion of the Access and Utility Corridor will be provided by the existing Jordan Cove Road. A two-lane access road will be provided to the northwest of Ingram Yard to provide emergency, marine terminal, and occasional maintenance access from the TPP.

To the west of the Access and Utility Corridor and within the secured footprint of the LNG Terminal will be the guard house, security building, firefighting facility, operations building, warehouse building, maintenance building, and parking for operations personnel. Both the South Dunes Site and Ingram Yard will be provided with sufficient parking.

EFSC Plot Plan

Public

KBJ
JORDAN COVE LNG

Jordan Cove LNG℠

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0	14/JUN/18	ISSUED FOR LNTP1	HHS	HHS	-	JME	DMR
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JORDAN COVE LNG PROJECT

EFSC APPLICATION OVERALL PLOT PLAN

PROJECT: 189980-0000-DG2010 (DRAWING NUMBER) REV 0

JCLNG NUMBER: J1-000-TEC-PLT-KBJ-01010-01 REV 0

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Combined Heat and Power Block Flow Diagram

Confidential Business Information

Exempt from Public Disclosure

Appendix A

Detailed LNG Facility Information

Confidential Business Information

Exempt from Public Disclosure

Appendix B

Detailed LNG Facility Information

Public

Detailed LNG Facility Information

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Detailed LNG Facility Description

Detailed LNG Facility Description

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CONTENTS (Continued)

Detailed LNG Facility Description

CONTENTS (Continued)

TABLES

Detailed LNG Facility Description

ACRONYMS

$\mu g/Nm^3$	Microgram per Normal Cubic Meter
ºF	Degrees Fahrenheit
%-mol	Mole Percent
%-vol	Volume Percent
AC	Alternating Current
AGRU	Acid Gas Removal Unit
ANSI	American National Standards Institute
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials International
BMP	Best Management Practice
BMS	Burner Management System
BOG	Boil-Off Gas
BPCS	Basic Process Control System
BPVC	ASME Boiler and Pressure Vessel Code
BSCF	Billion Standard Cubic Feet
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
Btu	British Thermal Units
Btu/scf	British Thermal Units per Standard Cubic Foot
CBNBWB	Coos Bay North Bend Water Board
CCTV	Closed Circuit Television
CEMS	Continuous Emissions Monitoring Systems
CFD	Computational Fluid Dynamics
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
Commission	Federal Energy Regulatory Commission; also FERC
CR	Contractor Report
CS	Carbon Steel
dBA	A-weighted Decibels
DC	Direct Current
DCS	Distributed Control System
Dth/d	Dekatherms Per Day
EPC	Engineering, Procurement, and Construction
ERP	Emergency Response Plan
ESD	Emergency Shutdown System
ESDV	Emergency Shutdown Valve
F&G	Fire and Gas
FACP	Fire Alarm Control Panel
FCC	Federal Communications Commission
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission; also Commission
FGS	Fire and Gas System
FLACS	FLame ACceleration Simulator
fps	Feet Per Second

ACRONYMS (Continued)

ft	Feet
ft^2	Square Feet
ft^3	Cubic Feet
gal	Gallon
gpm	Gallons Per Minute
GTN	Gas Transmission Northwest LLC
H_2O	Water
H_2S	Hydrogen Sulfide
HAR	Hot Air Recirculation
HHV	Higher Heating Value
HIPPS	High Integrity Pressure Protection System
HMB	Heat and Material Balance
HMI	Human Machine Interface
HRSG	Heat Recovery Steam Generator
HTF	Heat Transfer Fluid
I&C	Instrumentation and Control
I/O	Input/Output
IBC	International Building Code
ICSS	Instrument Control and Safeguarding System
in WC	Inches of Water Column
inHg	Inches of Mercury
inHg/h	Inches of Mercury Per Hour
ISA	International Society of Automation
ISO	International Organization for Standardization
IWWP	Industrial Wastewater Pipeline
JCEP	Jordan Cove Energy Project, L.P.
JCSC	Jordan Cove Security Center
KBJ	Joint venture consisting of Kiewit, Black & Veatch, and JGC
KO	Knock-out
kV	Kilovolts
kVA	Kilovolts Ampere
lb/hr	Pounds Per Hour
LEL	Lower Explosive Limit
LEL-m	Lower Explosive Limit-Meters
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LTD	Level-Temperature-Density
LV	Low Voltage
m	Meters
m^3	Cubic Meters
m^3/h	Cubic Meters Per Hour
mA	Milliamperes
MAOP	Maximum Allowable Operating Pressure
MCC	Motor Control Center
MDEA	Methyl-Diethanolamine
mm	Millimeters
MMgal	Million Gallons
MMscf/d	Million Standard Cubic Feet Per Day

ACRONYMS (Continued)

MR	Mixed Refrigerant
mtpa	Million Metric Tons Per Annum
MW	Megawatts
N/A	Non-Applicable
N/mm^2	Newton Per Square Millimeter
N_2	Nitrogen
NCDC	National Climatic Data Center
NDT	Nondestructive Testing
NFIP	National Flood Insurance Program
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NGL	Natural Gas Liquids
NGVD29	National Geodetic Vertical Datum of 1929
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPSH	Net Positive Suction Head
NSHT	National Standard Hose Thread
NWS	National Weather Service
O&M	Operations and Maintenance
ODEQ	Oregon Department of Environmental Quality
ODF	Oregon Department of Forestry
ODOE	Oregon Department of Energy
OSHA	Occupational Safety and Health Administration
OSSC	Oregon Structural Specialty Code
P&ID	Piping and Instrumentation Diagram
PCGP	Pacific Connector Gas Pipeline, LP
PERC	Powered Emergency Release Coupling
PFD	Process Flow Diagram
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	Programmable Logic Controller
PLF	Product Loading Facility
ppbv	Parts Per Billion by Volume
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
psf	Pounds Per Square Foot
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Gauge
PSV	Pressure Safety Valve
RO	Reverse Osmosis
RP	Recommended Practice
RTD	Resistance Temperature Detectors
SAT	Site Acceptance Test
scf	Standard Cubic Feet
scfm	Standard Cubic Feet per Minute
SCR	Selective Catalytic Reduction
SIL	Safety Integrity Level

ACRONYMS (Continued)

SIS	Safety Instrumented System
sp. gr.	Specific Gravity
SS	Stainless Steel
STG	Steam Turbine Generator
TGS	Tank Gauging System
UFD	Utility Flow Diagram
U.S.	United States
V	Volts
VDC	Volts of Direct Current
yr	Years

JCEP LNG TERMINAL PROJECT

Detailed LNG Facility Description

1. INTRODUCTION

Jordan Cove Energy Project, L.P. ("JCEP") is seeking authorization from the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 3 of the Natural Gas Act ("NGA") to site, construct, and operate a natural gas liquefaction and liquefied natural gas ("LNG") export facility ("LNG Terminal"), located on the bay side of the North Spit of Coos Bay, Oregon. JCEP will design the LNG Terminal to receive a maximum of 1,171 Million Standard Cubic Feet Per Day ("MMscf/d") of natural gas and produce a maximum of 7.8 million metric tons per annum ("mtpa") of LNG for export. The LNG Terminal will turn natural gas into its liquid form via cooling to about -260°F, and in doing so it will reduce in volume to approximately 1/600th of its original volume, making it easier and more efficient to transport.

In order to supply the LNG Terminal with natural gas, Pacific Connector Gas Pipeline, LP ("PCGP") is proposing to contemporaneously construct and operate a new, approximately 229-mile-long, 36-inch-diameter natural gas transmission pipeline from a point of origin near the intersection of the Ruby Pipeline LLC ("Ruby") and Gas Transmission Northwest LLC ("GTN") systems to the LNG Terminal ("Pipeline," and collectively with the LNG Terminal, the "Project").

2. FACILITY DESCRIPTION

2.1 Project Location

JCEP is proposing to develop an LNG facility with a maximum capacity of 7.8 mtpa of LNG. The LNG Terminal would be capable of receiving natural gas from the PCGP, processing the gas, liquefying the gas into LNG, storing the LNG, and loading the LNG onto ocean-going carriers.

The proposed LNG Terminal will be located on the bay side of the North Spit of Coos Bay in southwest Oregon in unincorporated Coos County, Oregon, primarily within land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP, across two contiguous parcels (Ingram Yard and South Dunes) which are connected by an Access and Utility Corridor. The land is a combination of brownfield decommissioned industrial facilities, an existing landfill requiring closure, and some open land covered by grasslands and brush (including some wetlands), as well as an area of forested dunes. Portions of the proposed site have also previously been used for disposal of dredged material.

2.2 Project Facilities

The natural gas received from the Pipeline will be conditioned and liquefied to produce LNG. The LNG product will be stored in two LNG storage tanks until it is loaded into LNG carriers at the marine berth. The LNG Terminal consists of the Gas Conditioning Unit, natural gas Liquefaction Unit, and LNG Storage and Loading Unit.

The Gas Conditioning Unit is to be provided in one 100 percent train. The Gas Conditioning Unit will include a sulfur-impregnated activated carbon unit for mercury removal, a closed-loop amine solvent-based Acid Gas Removal Unit ("AGRU") for carbon dioxide ("CO_2") removal and molecular sieve beds for water removal (dehydration). Heavy hydrocarbons (generally referred to as C5+ components) will be removed from the feed gas before the final liquefaction step to meet the LNG specification and prevent possible freezing at subcooled temperatures.

The natural gas Liquefaction Unit will be composed of five parallel LNG trains required to produce a maximum of 7.8 mtpa of LNG to the LNG storage tanks, after deducting boil-off gas ("BOG") generated from LNG flashing and heat in-leakage to the LNG storage tanks and piping. The natural gas will be liquefied using the Black & Veatch proprietary PRICO® LNG technology.

LNG produced from the liquefaction trains will be let down to near atmospheric pressure and stored in two LNG storage tanks with 160,000 cubic meters ("m^3") working (net) capacity each. The flash vapor, combined with vapors from tank displacement and heat leak, flows to the BOG compressors for use in the fuel gas system.

The LNG storage tanks will be equipped with three in-tank pumps for each tank for pumping LNG to the marine berth and into LNG carriers. Two dedicated liquid LNG loading arms and one dual-service (hybrid) arm normally in liquid service will be used to load the LNG into the LNG carriers. One dedicated vapor return arm will return displacement and LNG carrier heat in-leakage vapors to the BOG compressors for subsequent use as fuel gas, and excess BOG will be recycled for re-liquefaction. The dual-service arm could be used in vapor service when the dedicated vapor return arm is out of service. An LNG recirculation line will continuously maintain the LNG loading piping system at operating temperature and ready for loading operations.

The LNG Terminal will include auxiliary and utility systems including flare and relief systems, fire water, stormwater management system, instrument and utility air, nitrogen, potable and utility water, steam system, and other systems required for safe and continuous operation.

2.3 Feed Gas Facilities and Gas Conditioning

2.3.1 Feed Gas Facilities Design

The LNG Terminal will be designed to liquefy natural gas from the Pipeline for export to international markets. The operating envelope for liquefaction has been developed to encompass a variety of expected feed gas conditions and compositions.

The feed gas conditions at the battery limit of the LNG Terminal are based on three scenarios: design temperature, low temperature, and high temperature. The gas is throttled down immediately past the inlet facilities to match the pressure at the other conditions for all downstream unit operations. The feed gas composition is classified into three categories: lean, design, and rich. Equipment and piping will be sized for the design case composition. Rich and lean rating cases are used to establish liquefaction operating capacities and LNG quality in the LNG storage tanks.

2.3.1.1 Feed Gas Battery Limit Operating and Design Flow Rate Capacities

The range of design and operating feed gas flow rates at the battery limit is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Flow (MMscf/d)	115	1,064	1,171

2.3.1.2 Feed Gas Battery Limit Operating and Design Pressures

The range of design and operating feed gas pressures at the battery limit is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Pressure (psig)	845	1,125	1,600

2.3.1.3 Feed Gas Battery Limit Operating and Design Temperatures

The range of design and operating feed gas temperatures at the battery limit is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Temperature (ºF)	40	50	95

2.3.1.4 Feed Gas Startup, Operation and Shutdown

The battery limits of the LNG Terminal are delineated at the insulating flange downstream of the pipeline metering station. Upstream of the pipeline metering station, PCGP will provide a pipeline pig receiver and an inlet filter/separator. The feed inlet heater is included to prevent the formation of hydrates if the incoming gas temperature is low coincident with a high arrival pressure. The low temperature case includes a coincident higher pressure to investigate potential hydrocarbon hydrate formation. The heater is sized using the low temperature design case and uses steam as the heating medium.

During initial start-up or after system depressurization, re-pressurization bypass valves are located throughout the pretreatment system to equalize the pressure on both sides of the isolation valves.

The feed gas supply can be isolated through operator intervention through the DCS or automatically through SIS intervention.

2.3.1.1 Feed Gas Metering

Pipeline quality feed gas will be supplied to JCEP via the PCGP 36-inch-diameter natural gas transmission pipeline. The interface point between the PCGP and JCEP facilities occurs at the insulating flange immediately downstream of the pipeline metering station located on the South Dunes Site.

Feed gas metering, provided by the PCGP metering station, is outside the scope of the LNG Terminal.

2.3.1.2 Feed Gas High Integrity Pressure Protection Systems ("HIPPS")

The HIPPS is a special purpose safety system to be used in high pressure safety applications at the facility. There will be a HIPPS system, independent of the DCS/SIS, to prevent over-pressurization of process piping and equipment, installed in a 2x100% configuration, to allow for required maintenance and testing. The HIPPS is a instrumented system rated Safety Integrity Level ("SIL") 3 that will use three pressure transmitters (voting two out of three), two on-off shutdown valves (voting one out of two) in-series, and a logic solver. The HIPPS transmitters and valves will be installed between the pipeline interface and pressure letdown station upstream of the Gas Conditioning Unit.

2.4 Gas Conditioning

Gas conditioning consists of three distinct processes: mercury removal via sulfur-impregnated activated carbon, CO_2 and other acid gas removal via an amine system, and dehydration via a molecular sieve absorbent system. The LNG Terminal will include a single gas conditioning train.

2.4.1 Mercury Removal Design

A mercury removal unit will be provided to remove mercury from the feed gas upstream of the amine system to prevent cold box corrosion during gas liquefaction, and minimize exposure of other equipment and vent streams to potential mercury contamination. Mercury removal is accomplished using a sulfur-impregnated activated carbon adsorption bed in three mercury removal vessels. Mercury is removed from the feed gas stream down to 0.001 parts per billion by volume ("ppbv") (0.01 microgram per normal cubic meter ("$\mu g/Nm^3$")) (dry basis).

2.4.1.1 Mercury Removal Disposal

Spent catalyst from the mercury removal vessels will be removed periodically and sent off-site for disposal by a specialist. The bed life will be a minimum of three years.

2.4.2 Acid Gas Removal Design

The amine unit provided for acid gas removal will be designed for a maximum of 2 mol% CO_2 in the feed gas. CO_2 in the feed gas is removed to less than 50 parts per million by volume ("ppmv") (dry basis) to prevent freezing in the liquefaction process using a promoted methyl-diethanolamine ("MDEA") solution. Sulfur species are removed in the acid gas removal process to prevent downstream operational problems and corrosion potential, as well as to meet LNG and fuel gas specifications.

2.4.2.1 Hydrogen Sulfide Removal/Disposal

H_2S and other sulfur components are removed from the acid gas disposal stream in the sulfur scavenger package before entering the thermal oxidizer. The sulfur scavenger package will remove at least 98 percent of H_2S and 65 percent of all mercaptans. Periodically, fully saturated beds in the sulfur removal vessels will be removed and sent off-site for off-site disposal by a specialist.

2.4.2.2 Carbon Dioxide Removal/Disposal

Carbon dioxide is vented to atmosphere through the thermal oxidizer stack.

2.4.3 Water Removal (Dehydration) Design

A dehydration unit will be provided to remove water from the feed gas to prevent freezing during the liquefaction process. Dehydration is to be accomplished via molecular sieve adsorption beds, with the basic design package to remove water down to less than 0.1 ppmv. Hot regeneration (regen) gas is sent through the dehydrator in regen (heating) mode followed by a cooler and knock-out drum to condense water. A Regeneration Gas Compressor is used to overcome friction losses in the system to recycle the cooled regen gas back upstream.

2.4.3.1 Dehydration and Regeneration – Other Safety Features

The regeneration gas heating is done using superheated steam. This methodology is inherently safer than others, because the high pressure steam temperature and pressure are selected to match the requirements of the dehydration regeneration system rather than using a heating medium, which could overheat the regeneration gas.

2.5 Liquefaction Facilities

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) 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 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 turned into liquid by cooling it to approximately -260°F with the mixed refrigerant. The refrigerant exchanger consists of multiple brazed aluminum heat exchanger cores arranged in parallel inside a perlite insulated cold box. An aerial cooling system (fin-fan) rejects heat from the mixed refrigerant that is gained from the liquefaction of feed gas and compression. The cold box is purged with nitrogen gas to prevent moisture intrusion and eliminate the potential for a flammable atmosphere inside.

The refrigeration cycle is a closed-loop process that utilizes a single-body, two-stage refrigerant compressor. An aero-derivative combustion turbine directly provides the power to drive the refrigerant compressor. Exhaust-gas waste heat recovery in the form of steam generation maximizes the overall thermal efficiency of the LNG Terminal.

Heavy hydrocarbons (generally referred to as C5+ components) will be removed from the feed gas before the final liquefaction step to meet the LNG specification and prevent possible freezing at subcooled temperatures.

2.5.1 Liquefaction Design

2.5.1.1 Feed Gas Precooling System

Feed gas is not precooled before entering the liquefaction cold box. The first section of the cold box adequately cools the feed gas to remove heavier components in the deethanizer.

2.5.1.2 Main Refrigerant Heat Exchangers and Cold Boxes

For each train, multiple brazed aluminum heat exchanger cores are contained within a single cold box. The cold box is purged with nitrogen gas to prevent moisture intrusion and eliminate the potential for a flammable atmosphere inside. [redacted]

After liquefaction, the LNG product from each train combines and goes through the LNG expander, which produces electrical power (rated for 2500 HP/1.86 MW) while minimizing BOG production via flashing as the LNG pressure is dropped. The pressure of the LNG expander outlet is controlled to prevent vapor from forming within the expander. After a final pressure letdown that creates flash gas, the two phases are separated in the LNG flash drum. Vapor from the drum flows to the BOG compressors and the sub-cooled liquid product is sent to the LNG storage tanks by the LNG rundown pumps. Slip streams of the liquid are used for the "keep cool" circulation loop to maintain a cold state in the loading line as well as to quench the BOG compressor suction, if necessary.

2.5.1.3 Refrigerant Compressors and Drivers

Each train has a single two-stage, centrifugal refrigerant compressor driven by aero-derivative combustion gas turbine drivers with exhaust gas waste heat recovery. Inlet air is chilled through the turbine inlet air chilling package to increase turbine power output.

[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]

[redacted]

2.5.1.4 Liquefaction Cooling System Source and Type

The cooling for the liquefaction process is accomplished through the use of induced-draft aerial coolers.

2.5.1.5 Liquefaction Operating and Design Flow Rate Capacities

The range of operating and design liquefaction flow rate capacities per LNG Train is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Flow Rate (MMscf/d)	115	210	233

2.5.2 Natural Gas Liquids ("NGL") Removal, Storage, and Disposition

Heavy hydrocarbons (generally referred to as C5+ components) will be removed from the feed gas before the final liquefaction step to meet the LNG specification and prevent possible freezing 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 possible into the gas going to the final liquefaction step. Condensate will be blended with BOG and consumed in the facility as fuel gas.

2.5.2.1 Heavies/Condensates Removal Design

The total volume of heavies removed across the range of feed compositions will be blended into the fuel gas stream, so no tankage or disposal logistics need to be considered.

2.5.2.2 Heavies/Condensates Removal Type

[redacted]

2.5.2.3 Heavies/Condensates Disposition Design

Heavy hydrocarbon liquids from each liquefaction train are pumped downstream of the BOG compressor discharge coolers by the heavies pump and subsequently used as fuel gas for the facility.

2.5.3 Refrigerant Storage and Makeup System

The liquefaction unit of the plant uses a proprietary mix of refrigerant to condense and sub-cool the treated natural gas. During operation, there is a need for intermittent refrigerant make-up into the liquefaction trains because of the slow loss of components through compressor seal gas leakage or small openings, or after draining sections for occasional maintenance (*e.g.*, spare pumps). [redacted]

2.5.3.1 Source of Refrigerants

[redacted] Liquid refrigerants will be provided by trucks as needed to maintain inventory levels. Methane will be sourced from the treated feed gas.

2.5.3.2 Refrigerant Transfer/Makeup System

[redacted]

2.5.4 Refrigerant Storage Design

The refrigerant storage is designed to receive refrigerants, and store and deliver them to the refrigerant loops of each of the liquefaction trains.

[redacted]

[redacted]

2.5.4.1 Refrigerant Storage Operating and Design Capacities

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			

2.5.4.2 Refrigerant Storage Tanks Impoundment

The refrigerant make-up drums are located in a curbed area graded towards the refrigerant storage impoundment basin. The basin and tank foundations are constructed from concrete and can withstand cryogenic temperatures. The basin has a capacity of 11,600 cubic feet ("ft^3") and a firewall located on the north side of the basin to protect the vessels from radiation in the event of a fire in the impoundment basin.

2.6 LNG Storage Tanks

2.6.1 LNG Storage Tank Design

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 m^3 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.

The two full-containment LNG storage tanks are each equipped with three fully submerged LNG in-tank pumps, each rated for approximately 2,400 m^3/hr, and one spare well fully piped and instrumented. LNG is pumped, using five of the six installed pumps, to the marine berth and into an LNG carrier at a normal loading rate of 12,000 m^3/h. 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.

2.6.1.1 LNG Storage Tank Foundation Type

Shallow mat foundations will be used to support the LNG tanks on the ground surface. A base isolation friction pendulum bearing system is planned for the LNG tanks, with the isolators installed on top of plinths extending up from the shallow mat foundation. The tank slabs will be installed on the isolators, and will support the outer tank and inner tank.

2.6.1.2 LNG Storage Tank Insulation Systems

Cellular glass will be applied to the bottom insulation and secondary bottom. A glass wool blanket will be installed on the inner tank. The remainder of the annular space between the outer tank and inner tank will be filled with expanded perlite. Insulation on the suspended deck will consist of glass fiber blankets or perlite.

2.6.1.3 LNG Storage Tanks Operating and Design Capacities

The range of operating and design capacities for each LNG storage tank is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Capacity (m^3)	6,188	160,000	173,340

2.6.1.4 LNG Storage Tanks Operating and Design Pressures/Vacuums

The range of operating and design LNG storage tank pressures is detailed below.

Parameter	Minimum Design	Normal Operating	Maximum Design
Pressure (psig)	-0.14 (-3.88 inH_2O)	1.1	4.21

2.6.1.5 LNG Storage Tanks Operating and Design Temperatures

The range of operating and design LNG storage tank temperatures is detailed below.

Parameter		Minimum Design	Normal Operating	Maximum Design
Temperature (°F)		-275	-257.3	N/A

2.6.1.6 LNG Storage Tank Cooldown Sensors

The LNG storage tanks will be equipped with cooldown sensors. The inner tank shell and bottom will be monitored to indicate the temperature profile during the cooldown process and operation. Each temperature sensor will be a dual-element resistance temperature detector ("RTD") with full-length SS sheaths, routed and wired to a junction box at the tank battery limits. A minimum of thirteen temperature sensors will be equally spaced along a vertical line on the inner tank shell. Eleven temperature sensors will be distributed strategically along diagonal lines on the inner tank bottom. Piping cooldown RTDs will be provided and routed back to the control room DCS for monitoring purposes.

2.6.1.7 LNG Storage Tank Level Control

LNG tank instrumentation will include two servo-type level gauges equipped to provide remote reading and level alarm signals to the control room. Each gauge will be equipped with a transmitter and contacts set at Low-Low Liquid Level, Low Liquid Level, High Liquid Level, and High-High Liquid Level. A third independent level instrument (radar-type level switch) will be provided to signal High-High Liquid Level to the control room.

2.6.1.8 LNG Storage Tank Pressure Control

The LNG flash drum and LNG storage tanks vapor lines are connected so that pressure is equalized between the two. The LNG flash drum and LNG storage tanks pressure is automatically controlled by the load on the BOG compressor(s).

2.6.1.9 LNG Storage Tank Density/Rollover Control

LNG tank instrumentation will include an independent, servo-type, level-temperature-density ("LTD") system monitor with density difference alarm. Additionally, the bottom inlets to the tanks will be designed such that the mixing of the product is optimized to minimize the potential for rollover.

2.6.1.10 LNG Storage Tank Safety Instrumented Systems

In the event of an SIS-triggering event, the SIS system will trigger isolation valves on the LNG rundown and sendout lines, and will shut down the LNG in-tank pumps. SIS triggers include high and low pressure, high and low level, and tank tilt protection.

2.6.1.11 LNG Storage Tank Overfill Protection

LNG storage tank level control will protect against overfill.

2.6.1.12 LNG Storage Tank Overpressure Protection

If the BOG compressors cannot process enough vapor to stop pressure rise in the LNG storage tanks, a pressure control valve will relieve vapors to the marine flare.

Additionally, each tank will be provided with pilot-operated pressure relief valves. The valves will relieve from the inner tank vapor space where, if overfill were to occur, LNG would not block the pressure relief inlet pipes. Pressure-relief valve outlet pipes will discharge vertically, at sufficient height so that no fire water protection is required on the roof, in the event of a pressure-relief valve fire. The outlet will have a rain flapper and drain. Each pressure-relief valve will have a nitrogen connection for purging against ice formation and for snuffing. One spare pressure-relief valve will be provided.

Each tank will also be provided with vacuum-relief valves. One spare vacuum-relief valve will be provided.

2.6.1.13 LNG Storage Tank Relief Valves and Discharge

Pressure relief valves and vacuum relief valves are provided to maintain tank integrity. Pressure protection will be sized by the tank vendor based on the controlling case and be relieved to a safe location.

2.6.1.14 LNG Storage Tank Containment

The full-containment LNG storage tanks are designed to contain an LNG spill in accordance with NFPA 59A. According to NFPA 59A, the secondary containment volume required for an LNG tank spill equals 110 percent of the liquid volume of the inner tank, which is accomplished by the outer concrete shell. Berms at an elevation of 19 feet greater than grade at the LNG tank foundation level will provide protection from a tsunami event but are not required for LNG containment.

2.6.1.15 LNG Storage Tank Roof Spill Containment and Protection

Liquid spilled on the roof will be directed, with the use of a SS drip pan on the roof, to a SS downcomer pipe running all the way down the shell of the tank. The SS downcomer pipe will direct the spilled LNG transfer liquid to the spill containment slab at the base of the tank for direction to the spill containment trench and ultimately to the LNG impoundment basin – process area located west of the LNG storage tanks

2.6.1.16 LNG Storage Tank Leak Detection Instrumentation

To continuously monitor the annular space for potential accumulation of LNG between the inner and outer tank walls, each tank will be equipped with a leak detection system. The leak detection system will, at a minimum, include four equally spaced dual-element RTDs at the bottom of the annular space, and three dual-element RTDs will be installed on the inside of the outer tank wall and will be equally spaced vertically to indicate leak depth. Each RTD will be installed in SS sheaths, and routed and wired to a junction box at the battery limits.

The monitoring system will provide an alarm in the control room when LNG spillage is detected. The monitoring system will also provide a system alarm if it malfunctions.

2.6.1.17 Foundation Frost Heave Mitigation

The LNG storage tanks do not require foundation temperature detection and foundation heaters to prevent frost heave, because the tanks are set on base isolators above the foundation and ground line.

2.6.2 LNG Pumps

Each LNG storage tank contains three LNG in-tank pumps However, a fourth in-tank pump well will be installed in case a well or pump becomes inoperable.

2.6.2.1 LNG Pump Recirculation to Marine Transfer

A minimum flow of LNG is supplied from the LNG rundown header downstream of LNG rundown pumps for "keep cool" operation. The keep cool loop consists of a line to the loading area and returns to the LNG storage tanks through the main loading line. This process keeps the LNG loading system cool to avoid excess boil-off losses and potential damage due to thermal cycling of piping between carrier arrivals.

2.7 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 USCG. The MOF will be constructed outside of the slip to deliver construction and maintenance components of the LNG Terminal that are too large or heavy to be delivered by road or rail.

The LNG carrier loading berth will be capable of accommodating LNG carriers with a cargo capacity range of 89,000 m3 to 217,000 m3. The USCG Letter of Recommendation (LOR) and Waterway Suitability Report (WSR) currently allows LNG carriers up to 148,000 m3 to dock at the LNG Terminal berth.

2.7.1 Shipping Channel

The LNG carrier loading berth is located on the south side of the Ingram Yard area in the marine slip. Access to the marine slip will be via a newly-constructed terminal access channel that will connect the slip to the Federal Navigation Channel at approximate Channel Mile 7.3 at the beginning of the confluence between the Jarvis Turn Range and the Upper Jarvis Range A.

2.7.1.1 Channel Width

The access channel will flare from narrowest portion at the mouth of the slip, with a minimum width of 800 feet, to the intersection with the Federal Navigation Channel, with an approximate width of 2,200 feet. The proposed access channel will allow for the safe transit of vessels between the berth and the Federal Navigation Channel, and allow the safe turning of vessels during an inbound transit so that the LNG carrier can be backed into the slip and berthed bow out, according to industry best practice requirements.

The present Federal Navigation Channel begins outside the existing rock jetty breakwaters, enters the river mouth, and continues in a northerly direction for approximately 6 miles. It then turns east where it is transected by a railroad bridge and a highway bridge (US 101), and then turns south. The JCEP terminal site is located at the northern point along the transit route and would currently be the first ship dock encountered along the Federal Navigation Channel by ships entering from the Pacific Ocean.

The Coos Bay entrance and Federal Navigation Channel up to the project location is approximately 8.4 miles in length, and has a minimum 37' depth at Mean Lower Low Water ("MLLW") and a 300-800' channel width depending upon the location.

The NOAA nautical chart No. 18587 is the primary navigation tool for Coos Bay. The chart is the only one published for the entire Coos Bay harbor (scale 1:20,000). Table 2.7-1 provides the below summary dimensions for the Coos Bay Channel to the JCEP terminal site.

Table 2.7-1
Federal Navigation Channel Characteristics

Name of Channel Leg	Width (ft)	Length (nm)	Depth (ft)
Entrance Range	>1,500 – 300 (by measurement)	1.9	50-37
Entrance Range and Turn	300	0.8	37
Coos Bay Inside Range	300	0.8	37
Coos Bay Range	300	0.9	37
Empire Range	300-800	2.3	37
Lower Jarvis Range	300-800	1.1	37
Jarvis Turn Range	300	0.6	37

Table 2.7-1 Federal Navigation Channel Characteristics			
Name of Channel Leg	**Width (ft)**	**Length (nm)**	**Depth (ft)**
Source: NOAA chart & USACOE Data			

2.7.2 Marine Product Loading Facility Design

The marine Product Loading Facility (PLF) comprises a pile-supported concrete slab and steel structure supporting the LNG loading arms, terminal gangway, and other ancillary equipment. The PLF is designed to support a number of elements that facilitate the safe transfer of LNG product between the LNG plant and the LNG carriers.

The PLF is considered a Seismic Category II structure and will be designed to remain functional with repairable damage during a DE event.

2.7.2.1 Marine PLF Location and Spacing

The berth layout is based on the assumption that the LNG carriers will normally dock port (left) side to the berth with the bows to the south, as recommended by industry best practices. This arrangement reduces turning basin dredge requirements and optimizes mooring structure locations. The slip is designed for stern-in mooring for product transfer. Although some vessels might fit in the loading envelope for mooring in either direction, it is expected that some vessels will only be able to berth stern-in.

The ship/terminal compatibility studies will be completed during the detailed design phase in order to optimize the berth for the full range of vessels expected at the LNG Terminal site.

The following minimum clearances are provided when the LNG carrier is moored:

- 80 feet between the stern and toe of the slope on the northern side of the marine basin;
- 750 feet between the bow and the defined northern (closest) edge of the Federal Navigation Channel;
- 125 feet from the stern to the nearest marine structure to the north; and

609 feet from the side of the shell of the largest vessel (52 meter beam) and the closest marine structure on the west side of the slip.

2.7.2.2 Number and Design of Berths

The slip will have a full product loading berth on the east side, an emergency lay berth on the west side, a tug dock and security vessel berth on the north side of the slip, and a MOF berth outside of the slip. The east berth will include one LNG loading berth consisting of the PLF, six mooring structures, and four breasting structures.

Due to the lack of a safe anchorage at the Port of Coos Bay, 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 USCG. This will include a safe means for embarking and disembarking the vessel while at the emergency lay berth.

The tug berth on the north side of the slip will be designed to safely accommodate and support four tugs and two Coos County Sherriff's security vessels and other small visiting USCG vessels.

2.7.2.3 Water Depth at Berth and in Approach Channel

The access channel connects the marine slip to the Federal Navigation Channel. For navigation, the datum used for determining minimum depths is MLLW. The marine slip and access channel will have a minimum depth of -45 feet at MLLW (-45.97 feet NAVD 88) to ensure minimum under-keel clearance is achieved for the safe maneuvering and berthing of loaded LNG carriers. The Federal Navigation Channel will have a minimum controlled depth of –37 feet at MLLW. To ensure minimum under-keel clearance is achieved for safe navigation, all loaded LNG carriers will depart the berth and terminal slip only at higher tidal levels.

2.7.2.4 Number and Design of Hooks

Mooring and breasting structures will be provided at both the loading berth and the emergency lay berth for the safe breasting, berthing, and mooring of the LNG carriers docked at either berth.

A preliminary mooring analysis indicates that four breasting structures and six mooring structures will be required to safely moor the range of vessels expected at the LNG Terminal. Each of the structures will have a minimum of three quick release hooks with an integrated capstan winch. The exact number and layout of quick release hooks will be determined during the detailed design phase.

2.7.2.5 Arrangement, Number, and Design of Mooring Structures

Six mooring structures (three on each side of the LNG berth centerline) will be used to secure the LNG carrier at both the LNG loading berth and the emergency lay berth.

2.7.2.6 Arrangement, Number, and Design of Breasting Structures

Four breasting structures with attached fenders (two on either side of the PLF) will be used to secure the LNG carrier at the LNG loading berth. The emergency lay berth will have four breasting structures with fenders and capstans spaced equally about the mid-ship. There will be additional fender structures, two to the north and two to the south of the breasting structures, for a total of eight. The exact type and location is under evaluation for off-angle approach and the range of vessels.

2.7.2.7 Number and Design of Fenders

The LNG loading berth will include four fender assemblies, one on each of the breasting structures. The emergency lay berth will include four fender assemblies with capstans and four additional fender assemblies, for a total of eight fender assemblies.

2.7.2.8 Number and Design of Capstans

The LNG loading berth will include ten powered capstans in total, one at each mooring and breasting structure. The electric capstan must consist of a vertically-mounted, in-line, direct-coupled, geared squirrel-cage motor assembly, with the capstan head keyed to the output shaft. The gearbox must be oil-filled for life. The emergency lay berth will include ten powered capstans in total.

2.7.2.9 Tension Monitors

Display of load data for each mooring hook will be measured and made available to the mooring crew at the hook units, appearing on a display panel in the marine control room building and on a portable display panel that is given to the LNG carrier while it is moored at the berth. Display of loads will be in real time and automatic in operation. Current and average load will be displayed for each hook in turn. The mooring tension monitoring system will have programmable alarm set points for each mooring hook for both high and low tension parameters.

2.7.3 Material Offloading Facility

The MOF will be constructed to deliver components of the LNG Terminal that are too large or heavy to be delivered by road or rail. The MOF will cover about 3 acres on the southeast side of the slip, adjacent to the RFP. The MOF will be constructed using the same sheet pile wall system as the LNG loading berth and the emergency lay berth. The top of the MOF will be at elevation approximately +13.0 feet (NAVD88), and the bottom of the exposed wall will be at the access channel elevation. The MOF will provide approximately 450 feet of dock face for the mooring and unloading of a variety of vessel types.

During construction of the LNG Terminal, in addition to receiving equipment and large modules (upwards of 6,000 short tons) by break bulk cargo carriers, roll on roll off cargo carriers, and barges, the MOF will allow other bulk materials to be delivered by sea to minimize impacts on the local road network. After project construction, the MOF will be retained as a permanent feature of the LNG Terminal to support maintenance and replacement for large equipment components that are too large to be transported by rail and road.

2.7.4 Tug Berth

The tug berth at the north side of the marine slip will accommodate four tugboats, as well as two sheriff's boats and six other visitor boats with similar characteristics as the sheriff's boats. For design purposes, the tugs are assumed to be 80-metric-ton bollard pull boats approximately 100 feet long with a beam of 40 feet. The basis for the sheriff's boat is the Willard USCG Long Range Interceptor. The tug dock will generally be about 470 feet long and 18 feet wide; in addition, there is 360 feet of 8-foot-wide floats for mooring and accessing the security vessels.

The tug dock will be concrete supported by steel piles. The security vessel docks will be precast concrete floats anchored by steel pile. The security boat dock will support two separate boat houses. The tug dock will be accessible from land by a pile-founded trestle, thus allowing vehicle and pedestrian access for service and support of operations. An onshore tug operations building will provide storage, meeting, and sanitary facilities for the crews of the tug and security boats.

2.7.5 LNG Vessels

The LNG berth will be designed to safely berth, moor, and load LNG carriers with a base vessel range from 89,000 m3 to 217,000 m3. It will accommodate LNG carriers with moss spherical, membrane, and other types of approved cargo containment systems, taking due account of the varying vessel hull geometries, drafts, freeboards, positions of cargo manifolds, etc.

The maximum LNG transfer rate to an LNG carrier is 12,000 m^3/h. The normal operating pressure at the loading arm flange is between 5.6 and 30 psig.

2.7.5.1 LNG Vessel Size

The LNG berth will be designed to safely berth, moor, and load LNG carriers with a base vessel range from 89,000 m^3 to 217,000 m^3. It will accommodate LNG carriers with moss spherical, membrane, and other types of approved cargo containment systems, taking due account of the varying vessel hull geometries, drafts, freeboards, positions of cargo manifolds, etc. Table 2.7-2 provides a summary of the key LNG carrier dimensions considered for the design of the LNG berth.

Table 2.7-2 LNG Carrier Design Data								
Capacity	**Carrier Type**	**Length Overall**	**Length Between Perpendiculars ("LBP")**	**Beam**	**Molded Depth**	**Draft – Loaded**	**Draft – Ballast**	**Displacement**
m^3		m	m	m	m	m	m	m^3
89,880	Self-supporting Prismatic Type B	239	226	40	26.8	11	10	72,524
122,000	Membrane	274.42	262	42	26.14	11.2	9	99,130
125,000	Membrane	289	276	41.2	25	11	9.3	99,770
125,000	Spherical	285.3	273.39	43.7	25	11.02	10	97,800
130,000	Membrane	280.7	266	41.6	27.6	11	10.1	97,600
133,000	Membrane	286.9	275	41.8	28	11.2	10.1	99,489
135,496	Spherical	293	280	45.75	25.5	11.25	9	105,000
136,000	Spherical	290	276	46	25.5	10.8	9.5	98,770
136,000	Spherical	297.5	283	45.8	25.5	10.9	9	102,200
137,245	Spherical	288.8	274	48.2	26.5	12	11.3	114,419
145,000	Membrane	283	270	43.4	26	12	9.6	102,600
145,000	Spherical	289.5	277	49	27	11.4	9.5	105,000
154,200	Membrane	289.9	276	44.7	26	11.37	9.35	112,200
160,000	Membrane	288	276	45	27	12	10	N/A
217,000	Membrane	315	303	52	27	12.5	10	142,000

2.7.6 Shipping Route within U.S. Waters

LNG carriers would access the LNG Terminal through a waterway for LNG marine traffic, which is defined by the U.S. Coast Guard ("USCG") for the LNG Terminal 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 transit route has been broken down into five distinct legs for the purpose of describing the navigation of vessels into Coos Bay. Each leg has a specific transit element that is briefly described below.

2.7.6.1 Transit Leg One

The transit route of LNG carriers on an international voyage would begin by entry into the voluntary traffic lanes 25 to 50 miles offshore. The West Coast Offshore Vessel Traffic Risk Management Project Workgroup recommends that, where no other management measure such as Areas to Be Avoided ("ATBAs"), Traffic Separation Schemes ("TSSs"), or recommended tracks already exists, vessels 300 gross tons or larger transiting coastwise anywhere between Cook Inlet and San Diego should voluntarily stay a minimum distance of 25 nautical miles offshore.

From the entry towards the sea buoy, the vessel should already have contacted the Pilots with exact arrival times and should have discussed weather parameters. If the weather is unacceptable, the vessel would remain approximately 50 miles offshore until all required clearances are obtained. Then the LNG carrier will commence its inbound transit to arrive at the Pilot boarding area at the appropriate time of entry.

Pilots normally board inbound vessels well outside the sea buoy. For all LNG carriers, it has been agreed with USCG that Pilots will board the vessel approximately 5 miles west of the jetty entrance to the Port of Coos Bay. Generally, the waters in the Pilot boarding area are about 85 feet deep, providing plenty of water, and the swell is almost always from behind the ship.

After the Pilot boards the vessel, and when the Pilot and ship captain have the Master-Pilot exchange meeting and both are in agreement that all is in order to proceed with the inbound transit, the vessel heads towards the channel and past the sea buoy. During this time, the Pilot determines what speed and course correction is necessary in order to maintain the primary heading in the channel (116 degrees inbound). If the ship can hold the course, the Pilot continues through the entire 1.72 miles of the leg. The last point to turn the ship around and abort the passage is Buoy #1 (which is left to port), where the water is approximately 50 feet deep. There are lighted range lights with day boards for the entrance channel that are maintained by the USCG, which guide the Pilot and the LNG carrier bridge team in ensuring that the vessel remains in the center of the entrance channel.

2.7.6.1.1 Transit Leg Two

Transit Leg Two begins at the Demarcation Line, or the end of the breakwater, and continues through the turn to port in the Entrance Turn and Range, a total distance of 1.81 miles. The vessel at this point is not impacted by the coastal current. The vessel is traveling at a speed of 6- to 8 knots as it passes the entrance, and the Pilot takes steps to slow the vessel speed as it enters the Entrance Turn. The Pilot keeps the vessel's speed as slow as possible depending upon the coastal current and the speed necessary to transit safely into the breakwater area.

2.7.6.1.2 Transit Leg Three

Transit Leg Three is up to the Coos Bay Range, a total of 1.6 miles. The range includes USCG maintained range markers with day board and lights on course.

The Pilot would have vessels transit this area at approximately 4 knots speed to a maximum speed of 5 knots. The exact speed would be determined by the steerage of the vessel and the wind conditions.

The channel does have a small turning basin for smaller vessels halfway up the Coos Bay Range. Pilots report that the turning basin is not used for larger vessels that have Pilots.

2.7.6.1.3 Transit Leg Four

Transit Leg Four is the Empire Range, which continues in a northerly direction on course 025 degrees and then into the Lower Jarvis Range on course 009 degrees. The entire leg is only 2.1 miles in length.

Both the Empire Range and Lower Jarvis Range are served by USCG-maintained range markers.

2.7.6.1.4 Transit Leg Five

Transit Leg Five is the final section before the vessel would dock at the proposed facility. Leg Five is only 0.8 nautical miles in length and follows the Jarvis Range on course 079 degrees. The Jarvis Range is a lighted range with day markers.

2.7.6.2 Ship Traffic

The LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. Moffatt & Nichol conducted a ship traffic simulation of vessel movements in the Federal Navigation Channel, two simulations were conducted: a base case with just the existing vessels and a case involving both the existing vessels and the LNG ships. The simulations were conducted for a period of 25 years, and the traffic delays for both inbound and outbound vessels were determined. The simulation recorded delays due to unfavorable weather conditions (wind, tide, and waves), and waiting for available berth. These delays were considered statistically equivalent for both the "with" and "without" LNG ship traffic cases. The following navigation rules were incorporated into the simulations:

- Pilots and tugs were not considered to be limiting resources;
- The traffic density used for the study was 113 LNG ships per year;
- The channel is one-way to all vessels in the channel and a first-come, first-served system applies;
- Vessel traffic in the same direction will be allowed to follow in a convoy fashion but must obey a safety and security zone of a 1/2 nautical mile ("nm") gap between vessels other than LNG ships, and for LNG ships, 2 nm ahead and 1 nm astern (current traffic levels do not require convoying);
- Visibility must be at least 2 miles for the estimated duration of the vessel's transit;
- Wind speed must be less than 30 knots for the estimated duration of the vessel's transit;
- Wave height outside buoy "K" must be less than 16 feet for safe pilot boarding or disembarking;
- All vessels must enter and exit at high tide; and
- The USCG allows 24-hour port operations (day and night transits).

Overall, the traffic model simulation results show that the integration of LNG ships into the traffic of Coos Bay has very limited effects on other Coos Bay marine traffic operations even when taking into consideration the in-channel maneuvering and turning of LNG ships. Without any additional LNG ship traffic, vessels transiting the Federal Navigation Channel currently experience some delay due to the one-way traffic system in place and the gaps required by consecutive vessels for the safety and security zone of 1/2 nm ahead and 1/2 nm astern. More than 96% of all inbound vessels experience no delay and 4% experience some traffic delay up to 3.4 hours. With the addition of LNG ships, approximately 85% of all inbound vessels will experience no traffic delays, about 10% will experience delays up to 1 hour, and the remaining 5% will experience delays from 1 hour up to 3.4 hours.

The maximum traffic delay for all existing vessels transiting up the one-way Federal Navigation Channel is predicted to slightly increase by 0.7 hour, and the maximum delay for all exiting vessels is predicted to slightly increase by 0.7 hour as well. The average delay for all vessels transiting up the Federal Navigation Channel would slightly increase by 0.11 hour, and the average delay for all vessels transiting down the channel would slightly increase by 0.16 hour. This is due primarily to the one-way traffic system and the increased LNG traffic volume. A vessel must wait for the channel to be clear of traffic in the opposite direction before it can start its transit. The increased LNG ship traffic will increase the waiting time of other vessels coming in the opposite direction.

While fishing and recreational vessels are typically shallow-draft vessels that can maneuver out of the channel when required, they were not included in the traffic analysis. Recreational vessels typically can and will use the navigable waters outside of the delineated channel. However, the impacts on these vessels can be qualitatively assessed as follows: fishing and recreational vessels based in Charleston use the entrance channel, entrance channel and turn, and the inside range (reaches 1 and 2) to enter or exit Coos Bay. The fishing and recreational vessels that are present in these reaches must maneuver out of the channel (if not already located outside the limits of the channel) and wait for the deep-draft vessel to pass. The entire length of these reaches is about 3.5 nm, and it can take 20 to 30 minutes for an LNG ship or other deep-draft vessel to complete the transit of these reaches. Therefore, in a worst case scenario, a fishing or recreational vessel could have to wait 20 to 30 minutes at a maximum. It should be noted that this maximum delay would occur with all deep-draft vessels, not just LNG ships.

The average number of barge calls to the Port are approximately 100 per year. Similar to the fishing and recreational vessels, barges are shallow-draft vessels that can maneuver out of the channel to avoid deep-draft vessels. Due to the safety and security zone around the LNG carrier, the maximum time delay for a barge will be 20 to 30 minutes while it waits for the LNG carrier to pass. The maximum delay time is expected when a barge is preparing to enter or exit Coos Bay at the same time as the LNG carrier, because there is little to no out-of-channel space at the jetties. In the upstream reaches (beyond the entrance channel, entrance channel and turn, and inside range), there is ample room on both sides of the channel for a barge to maneuver safely. Considering the low calling frequency of barges (100 per year), the probability of a barge encountering an LNG carrier is lower than that for the fishing and recreational vessels.

2.7.6.3 Aids to Navigation

The LNG Terminal will include a variety of different private navigation aids. These may include, but are not limited to, lights or beacons denoting the limits of marine features and range markers at the back of the slip to assist the Pilots in backing the LNG carriers safely into the slip, including day boards and directional lighting.

Navigation aids will comply with USCG requirements regarding their locations, size, shape, and material quantities. Specific details of the private navigation aids will be determined through the USCG Private Aids to Navigation ("PATON") Permit process.

2.7.6.4 Vessel Approach Velocity Monitors

The LNG Terminal will have an approach and berthing aid system, which is used to measure and track the velocity, distance, and angle of an approaching vessel over the last 500 feet until the vessel comes to rest against the fenders. This system will consist of a portable display unit that the Pilots will have with them, which will provide a visual display of vessel location and approach speed from the project-specific digital global positioning system ("GPS") vessel position tracking system, which will be installed as part of the LNG Terminal. During berth approach, the graphic display will show the distance from the vessel to the berthing line and the speed of approach. The approach and berthing aid system will include a second display board in the marine control room that will display the bow and stern distance and bow and stern velocity. The system will record the entire vessel transit, including the slip entry and berthing maneuver, for future playback and review.

2.7.6.5 Current Monitors

An acoustic Doppler-type current monitor will be installed on a buoy in the Lower Jarvis Turn channel range to provide current speed and direction in the Federal Navigation Channel. The current in the slip will be negligible, because the slip is a dead-end body of water.

2.7.7 Navigational Reliability Improvements

JCEP plans to excavate four submerged areas lying adjacent to the federally-authorized Channel. These minor enhancements will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window. This allows for greater navigational efficiency and reliability to enable JCEP to export the full capacity of the optimized design production of 7.8 mtpa from the LNG Terminal.

The total volume of capital dredge material from these excavations is approximately 700,000 cubic yards. Dredge material may be distributed between APCO 1 and APCO 2 upland disposal sites, or placed entirely at APCO 2 if shown to be feasible. The dredge areas are named Dredge Area 1 to 4 and located adjacent to the Channel roughly between River Mile ("RM") 2 to RM 7 respectively.

Enhancement #1 – Coos Bay Inside Range channel and right turn to Coos Bay Range: Excavation at this site will reduce the constriction to vessel passage at the inbound entrance to Coos Bay Inside Range for any ship making the 95 degree turn from the Entrance Range through the Entrance Turn and Range. JCEP proposes to widen the Coos Bay Inside Range channel from the current 300 feet to 450 feet, thereby making it easier for all vessels transiting the area to make this turn. In addition, the total corner cutoff on the Coos Bay Range side will be lengthened from the current 850 feet to about 1,400 feet from the turn's apex.

Enhancement #2 – Turn from Coos Bay Range to Empire Range channels: The current corner cutoff distance from the apex of this turn is about 500 feet, making it difficult for vessels to begin turning sufficiently early to be able to make the turn and be properly positioned in the center of the next channel range. JCEP proposes to widen the turn area from the Coos Bay Range to the Empire Range from the current 400 feet to 600 feet at the apex of the turn and lengthen the total corner cutoff area from the current 1000 feet to about 3500 feet.

Enhancement #3 – Turn from the Empire Range to Lower Jarvis Range channels: JCEP proposes to add a corner cut on the west side in this area that will be about 1,150 feet, thereby providing additional room for vessels to make this turn.

Enhancement #4 – Turn from Lower Jarvis Range to Jarvis Turn Range channels: JCEP proposes to widen the turn area here from the current 500 feet to 600 feet at the apex of the turn and lengthen to total corner cutoff area of the turn from the current 1,125 feet to about 1,750 feet thereby allowing vessels to begin their turn in this area earlier.

Maintenance materials will be disposed of in the upland dredge disposal sites located on the APCO site 1 and APCO site 2 and management of the dredge areas would be the responsibility of Jordan Cove.

3. TERMINAL SUPPORT SYSTEMS

3.1 Vapor Handling Design

The BOG stream is the vapor generated from the LNG storage and loading system. The BOG stream is from various sources. The main sources are 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 stream flows to the BOG suction drum. From the BOG suction drum, the cold gas flows to the BOG compressors, which are controlled to maintain LNG storage tank pressure. [redacted]

3.1.1 BOG High Pressure Compression

Two BOG compressor trains are available to compress the vapor from the LNG storage tank pressure to fuel gas pressure; one will be operating continuously to handle holding mode, while the second will be needed only during loading mode or during an off-design condition resulting in increased BOG generation. The BOG compressors will be designed to start from a warm condition and immediately handle cryogenic vapor, so startup and ramp-up to normal operation will occur in only a matter of seconds.

The BOG stream flows to the BOG suction drum. Because the first stage of the BOG compressor is cryogenic, the inlet temperature is controlled using LNG injection, if needed. LNG is injected into the BOG suction drum and contacts the flowing stream in packing to ensure the suction to the compressor stays at the proper cool temperature. If liquids begin to accumulate in the suction drum, a recycle line from downstream of the BOG interstage cooler can be opened to flow through the bottom and vaporize the liquid.

From the BOG suction drum, the cold gas flows to the BOG compressor, which is controlled to maintain LNG storage tank pressure. The BOG then goes through the interstage cooler, the second stage of the compressor, and the discharge cooler. The gas is compressed to 850 psig and becomes the fuel gas supply for the facility.

No provisions will be provided for BOG compression back to the pipeline.

3.1.2 BOG High Pressure Compressors

The BOG compressors are two-stage centrifugal type compressors.

The range of operating and design parameters per unit for the BOG compressors is provided in **Error! Reference source not found.**.

Table 3.1-1 BOG Compressor Design Parameters per Compressor			
Section Parameter	**Minimum Design**	**Normal Operating**	**Maximum Design**
No of HP BOG Compressor	2, one will be operating continuously to handle Holding mode, the second will be needed only during Loading mode or during an off-design condition resulting in increased BOG generation		
Inlet Flow (lb/hr) per compressor	58,552	95,696 (Holding) 71,932 (Loading)	109,708
Suction Pressure (psig)	0.1	0.6	2.5
Suction Temperature (°F)	-250	-224	-200
Discharge Pressure (psig)	N/A	850	N/A
Discharge Temperature (°F)	197	235	271

3.2 Fuel Gas System

The primary source of fuel gas is the BOG from LNG flash drum and LNG storage tanks.

The fuel gas system is supplied by BOG, heavies, and feed gas from the Pipeline. During Holding Mode, the system is designed for approximately 10%, or 272.1 MMBtu/hr (HHV) of the fuel gas required to be supplied from the pipeline. This helps to maintain fuel gas system stability because the amount of feed gas from the pipeline supplied can be modulated to match actual facility fuel gas needs. Compressed BOG and heavies combine and pass through the fuel gas superheater to fully vaporize the stream, if necessary, and to provide adequate superheat for gas turbine usage. The gas passes through the HP Fuel Gas Mixing Drum to knock out any remaining liquids and to limit the Wobbe Index rate of change. If the BOG/heavies mixture results in excess fuel for the demand, it can be recycled upstream of the amine unit and go through the liquefaction process again.

3.2.1.1 Fuel Gas Specifications

The fuel gas specification is provided below for the design holding and loading cases.

Table 3.2-1 Fuel Gas Conditions		
Case	**Holding**	**Loading**
Components	**mol%**	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 3.2-1 Fuel Gas Conditions		
Case	Holding	Loading
Components	mol%	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		

3.2.1.2 Fuel Gas Distribution List and Requirement by Equipment

The fuel gas distribution list is provided in Table 3.2-2.

Table 3.2-2 Fuel Gas User List		
Fuel Gas Supply (LP/HP)	Equipment	Flow Rate (MMBtu/hr) (HHV) Expected / Max Consumption
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

3.2.1.3 Fuel Gas Operating and Design Flow Rate Capacities

The range of operating and design flow rate capacities of fuel gas is detailed below.

Fuel Gas System	Parameter	Minimum Design	Normal Operating	Maximum Design
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.2.1.4 Fuel Gas Operating and Design Pressures

The range of operating and design pressure of fuel gas is detailed below.

Fuel Gas System	Parameter	Minimum Design	Normal Operating	Maximum Design
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.2.1.5 Fuel Gas Operating and Design Temperatures

The range of operating and design temperature of fuel gas is detailed below.

Fuel Gas System	Parameter	Minimum Design	Normal Operating	Maximum Design
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.2.1.6 Fuel Gas Operating and Design Densities

The range of operating and design densities of fuel gas is detailed below.

Fuel Gas System	Parameter	Minimum Design	Normal Operating	Maximum Design
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.3 Heat Transfer Fluid (HTF) Systems

The LNG Terminal will use steam as a heat transfer fluid ("HTF") for process heating. High pressure steam is provided to the facility from the Heat Recovery Steam Generators ("HRSGs"). Low pressure steam is primarily provided from extraction out of the Steam Turbine Generators ("STGs"), which let down the pressure from 725 psig to the 50 psig header at an intermediate stage in the turbines for extraction then the balance is letdown to vacuum pressure and condensed; any low pressure steam requirement in excess of this can be made up by desuperheating a letdown of high pressure steam. In addition, one auxiliary boiler will be provided to supply the high pressure steam (rated for 202,000 lb/hr) required for turndown operation or facility startups.

3.3.1 HTF distribution list and usage requirement by equipment

Steam users and their demand are provided in Table 3.3-1.

Table 3.3-1
HTF Distribution List and Usage

Consumers	Normal Usage (Holding), lb/hr	Normal Usage (Loading), lb/hr	Maximum Usage, lb/hr
High Pressure ("HP") Steam consumers			
STG	[redacted]	[redacted]	[redacted]
Regeneration Gas Heater	[redacted]	[redacted]	[redacted]
Letdown for LP Steam Header	[redacted]	[redacted]	[redacted]
Low Pressure ("LP") Steam consumers			
Amine Reboilers	[redacted]	[redacted]	[redacted]
Fuel Gas Superheater	[redacted]	[redacted]	[redacted]
Feed Inlet Heater	[redacted]	[redacted]	[redacted]

Sulfur Scavenger Inlet Heater	[redacted]	[redacted]	[redacted]
Deaerator	[redacted]	[redacted]	[redacted]
Utility Stations	[redacted]	[redacted]	[redacted]

3.3.2 Heating Source

[redacted]

3.3.3 HTF Heaters Type

High pressure steam is produced from the HRSG using exhaust gases from the refrigerant compressor driver. Duct burners fueled by natural gas in the HRSGs allow for production of additional steam when steam production is reduced due to HRSG outages (*i.e.*, when fewer than four LNG trains are in operation). Low pressure steam is produced by letting down high pressure steam through the STGs at an intermediate stage or directly from the high pressure steam header with desuperheating.

3.3.4 Number of HTF Heaters, Operating and Spare

There are five HRSGs for the entire LNG Terminal, one per train, and one common auxiliary boiler (25-PK-0001). Duct burners fueled by natural gas in the HRSGs allow for production of additional steam when fewer than four LNG trains are in operation.

3.3.5 HTF Heaters Operating and Design Heat Duty/Rate

The range of operating and design heat duty/rates for the HTF heaters is detailed below for the lower heating value, or LHV, of the design fuel gas.

Heater	Parameter	Minimum Design	Normal Operating	Maximum Design
HRSG	Heat Rate (MMBtu/h HHV) - Duct Burners only	[redacted]	[redacted]	[redacted]
Auxiliary Boiler	Heat Rate (MMBtu/h HHV)	[redacted]	[redacted]	[redacted]

3.3.6 HTF Heaters Operating and Design Pressures

The range of operating and design pressures for the HTF heaters is detailed below.

Heater	Parameter	Minimum Design	Normal Operating	Maximum Design
HRSG	Pressure (psig)	[redacted]	[redacted]	[redacted]
Auxiliary Boiler	Pressure (psig)	[redacted]	[redacted]	[redacted]

3.3.7 HTF Heaters Operating and Design Inlet Temperatures

The range of operating and design inlet temperatures for the HTF heaters is detailed below.

Heater	Parameter	Minimum Design	Normal Operating	Maximum Design
HRSG	Temperature (°F)	[redacted]	[redacted]	[redacted]
Auxiliary Boiler	Temperature (°F)	[redacted]	[redacted]	[redacted]

3.3.8 HTF Heaters Operating and Design Outlet Temperatures

The range of operating and design outlet temperatures for the HTF heaters is detailed below.

Heater	Parameter	Minimum Design	Normal Operating	Maximum Design
HRSG	Temperature (°F)	[redacted]	[redacted]	[redacted]
Auxiliary Boiler	Temperature (°F)	[redacted]	[redacted]	[redacted]

3.4 Instrument and Plant/Utility Air

Instrument air will be provided through compression and drying packages. It will be used for pneumatic control of automated instrumentation, utility air, and supply for nitrogen generation. Utility air will be used for normal maintenance activities.

3.4.1 Instrument Air Specifications, Dew Point, and Particulates

The instrument air specifications and design parameters are provided in Table 3.4-1.

Table 3.4-1
Instrument Air Design Parameters

Parameter	Instrument Air
Source	Plant Air
Dew Point (°F)	-40°F at operating pressure
Minimum Pressure (psig)	60
Header Operating Pressure (psig)	100
Header Operating Temperature	Ambient
Header Mechanical Design Pressure (psig)	250
Header Mechanical Design Temperature (°F)	150
Quality	Oil Free
Particulate size (μm)	<1
Instrument Air Receivers	15 min residence time

3.4.2 Instrument Air Compressors

There are two integrally geared centrifugal compressors—one operating and one spare. There is one additional oil-flooded screw compressor to provide essential instrument air duty.

The air compressors are integrally geared centrifugal compressors. The back-up air compressor is an oil-flooded screw compressor.

3.4.3 Instrument Air Drying System

There is one air dryer package. The package consists of total of four air dryers and each will be designed for full, continuous operation. The air dryers have a 2 x 100% sparing configuration. One dryer will be in adsorption mode while the other dryer is regenerating. The air dryer package will consist of a regenerable desiccant to remove moisture from the instrument air.

There is also one back-up air dryer package consisting of two back-up air dryers (72-V-0006A/B), and each will be designed for operation only with the back-up air compressor. One dryer will be in adsorption mode while the other dryer is regenerating.

3.4.4 Instrument Air Receivers

There are two wet air receivers (72-V-0001 A/B) associated with the two air compressors. The back-up air compressor has the back-up air receiver. There are two operating instrument air receivers for the LNG Terminal, and one operating Instrument air receiver – marine area for the marine area.

3.4.5 Plant/Utility Air Design

Utility air will be dried with the instrument air but will be supplied throughout the plant from a separate header with shutoff capability on low pressure.

3.1 Nitrogen

Nitrogen is used for inert purging of lines and equipment in the LNG Terminal.

3.1.1 Nitrogen Design

Nitrogen ("N_2") will be provided through vaporization of liquid nitrogen and through generation with a pressure swing adsorption unit. Liquid nitrogen will be the only source of nitrogen used for refrigerant make-up, while the site-generated nitrogen will supply continuous users (*i.e.*, compressor seals, cold box purges, LNG loading arm swivel joints, etc.) and intermittent users (*i.e.*, LNG loading arm purges, utility stations, etc.).

Pressure swing adsorption units use swings in pressure to separate nitrogen from air; the pressure swing adsorption swings from high pressure, where nitrogen is adsorbed from air, to low pressure, where it is desorbed. Pressure swing adsorption nitrogen generators consist of two towers with adsorbent material (usually a carbon molecular sieve). While one tower is in active nitrogen production, the other tower is in regeneration (similar to the concept of a desiccant air dryer for the production of instrument air). One pressure swing adsorption nitrogen generation unit consists of the two towers, piping, skid, paint, instrumentation, controls, dew point sensor(s), oxygen sensor(s), and filters (as required and specified). The nitrogen generation package is rated for a production rate of 609.4 standard cubic feet per minute ("scfm"). The liquid nitrogen storage vessel with a storage capacity of 9,500 gal.

There is one nitrogen vaporization package with two vaporizer units—one operating and one spare (2 x 100%).

There are three operating nitrogen receivers—nitrogen receiver, nitrogen generation unit receiver tank, and nitrogen receiver – marine area.

3.2 Utility Water and Other Utilities

The LNG Terminal will have utility water, tempered water, demineralized water, reverse osmosis ("RO") water, steam, and firewater on-site.

3.2.1 Utility Water Sources

Utility and potable water will be supplied from the CBNBWB Potable Water Pipeline.

3.2.2 Utility Water Operating and Design Storage Capacities

The utility water storage capacity is provided below. The fire water tanks are dual-service supply tanks and will provide utility water from a standpipe to ensure dedicated fire water volume for fire protection systems.

Unit	Parameter	Design
Demineralized Water Tank	Capacity (gal)	25,000
RO Product Tank	Capacity (gal)	12,500
Tempered Water Tank	Capacity (gal)	850
Fire Water Tank (each)	Capacity (gal)	3,280,320 (total) 3,240,00 (reserved for fire water) 40,320 (for utility water usage)

3.3 Fire Water System

The fire water systems for the LNG Terminal will provide necessary fire protection measures for life and property safety. These systems will be designed in accordance with applicable codes and standards.

3.3.1 Fire Suppression System

Fire water systems include water storage tanks, stationary fire water pumps, fire hydrants and main, fixed water spray systems, automatic sprinkler extinguishing systems, high expansion foam system, and remotely controlled monitored spray systems. These fire water systems will be designed to meet the requirements of 49 CFR Part 193, NFPA 59A, API 2510, API 2510A, 33 CFR Part 127, and applicable codes.

Fire scenarios for designing the fire water systems are based on the consideration of fires in high-fire-risk areas and necessary cooling required for surrounding areas to mitigate fire damage and bring fires under control. Areas of the plant that are tightly packed with fire potential equipment require larger volumes of water because greater amounts of surrounding equipment require cooling; conversely, areas of the plant that are well separated require relatively limited fire water, because the amount of surrounding equipment that might be impacted is minimized. The siting and arrangement of plant equipment will be optimized, to the extent possible, to limit the required fire water to control the single largest fire.

3.3.2 Fire Water Philosophy

The primary purpose of the fire water systems in the process areas is to prevent the escalation of a fire event by providing exposure protection until the fuel supply to the fire is shut off and the fire burns itself out. Therefore, fire water is used primarily to cool the surrounding equipment in the event of a fire. Water spray systems will generally be used to provide supplementary cooling of surrounding structures and equipment, whereas flammable liquid spills will be drained and impounded remotely. Special attention will be given to pressure vessels that store flammable liquids and gases that are in proximity to potential pool fire risks, because heating due to fire exposure can lead to over pressurization of the vessels and BLEVE conditions, which have the potential to cause widespread damage to surrounding areas. Actuation of the fire water systems can also aid in the dispersal of hazardous vapors and gases in non-fire situations.

3.3.3 Main Fire Water Supply and Back-up Supply

The fire water supply for the facility is provided by two x 100 percent capacity aboveground atmospheric storage tanks, which allow for redundancy if one of the tanks is unavailable. This redundancy is an acceptable precautionary measure for preparing for fire water tank repairs, in accordance with Section 14.1.5 of NFPA 22, and to perform regular maintenance and inspection of fire water tanks in accordance with NFPA 25. The fire water tanks are dual-service supply tanks and will provide the standpipe system to ensure dedicated fire water volume for fire protection systems. Each tank holds a minimum usable capacity to supply four hours of water supply for the Maximum Probable Fire Water Demand, which is the demand for the largest fire scenario including a 1,000 gpm hose stream allowance in accordance with NFPA 59A. Providing four hours of water supply is in accordance with API 2510 and is greater than the two hours of water supply required by NFPA 59A.

Water supply for the two fire water tanks is potable water from the local CBNBWB. Potable water pumps deliver this make-up water to the tanks, or a larger flow, if needed, from the CBNBWB potable water line and/or raw water line may be provided with a larger line and bypass valve around the potable water pumps.

3.3.4 Fire Water Pumps and Driver Type

Three x 33 percent capacity pumps will supply the fire water to fire water systems, and an additional fourth pump of 33 percent capacity will be provided as back-up. The main fire water pump set includes three diesel main pumps and one electric main pump. The additional diesel back-up pump is provided in case one of the main pumps fails to operate or is out of service for maintenance. In addition to the main pumps, two electric-motor-driven jockey pumps will be provided to maintain pressure in the main fire water distribution system. One jockey pump is on automatic start to maintain the system pressure, while the other pump is manually turned off during normal operating conditions. The entire pump installation will be designed in accordance with NFPA 20.

The main fire water pumps will automatically start upon a pressure drop if the jockey pump cannot maintain pressure, or if a remote start command is received from the F&G control panel, located in the central control room. The main fire pump start set pressures are arranged to start additional pumps sequentially, as required to maintain discharge pressure. The main fire water pumps do not have a stop pressure and must be shut off manually at the local fire pump controller.

3.3.5 Fire Water Piping Design and Layout

The fire water system consists of multiple looped fire water mains encompassing the main process area, refrigerant make-up, marine terminal, gas conditioning, and LNG storage tanks. The fire water main is designed to ensure that adequate pressure is available for each of the various fire water systems. The minimum pressure required for each fire water system, while flowing at the design rate, will be either 75 psig at the water spray system valve header, 20 psig at each hydrant outlet, or 75 psig at each monitor spray nozzle. The entire fire water system is designed so that if a pipe break were to occur, the section of underground distribution piping that is rendered inoperable would be taken out of service using underground post-indicating isolation valves. If a section of the underground main needs to be taken out of service using the isolation valves, the fire water system would still able to support the pressure and flow demands of the fire protection systems due to the multiple flow paths provided. The fire water distribution network will be designed in accordance with NFPA 24.

Fire water distribution network piping is sized to limit the maximum water velocity in accordance with NFPA codes and standards.

3.3.6 Freeze Protection

The fire water distribution network is laid underground below the freeze depth layer to provide protection against freezing under normal and emergency conditions. Aboveground piping will be provided with electric heat tracing to maintain fire water temperature above 42 °F. Fire water storage tanks do not require a provision for heat as they are classified under NFPA 22 (2013) Section 16.2.2.1. Fire water supply to the fixed fire water systems, such as water spray systems, elevated monitor spray system, sprinkler system, foam system, etc., will be brought above ground within heated enclosures; thus, no electric heat tracing will be provided for aboveground water supply risers and valve assembly. All fire hydrants will be dry barrel type, which are suitable for freezing temperatures experienced during winter season. Hydrant-mounted monitors will be protected against water freezing using automatic drain valves at the base of hydrants, below the freeze depth, to automatically drain water from the monitor and/or hydrant connection after use.

3.3.7 Fire Water Hydrants Design and Layout

Fire water hydrants will be located 150 feet apart in the process areas, 300 feet apart in non-process areas, and up to 500 feet apart for remote areas of the LNG facility in accordance with NFPA 24 and API 2510 recommendations. Hydrant-mounted monitor spray coverage will be 125 feet for 500 gpm flow rate to cool adjacent equipment. Hydrants will be located no closer than 40 feet to any buildings or structures, where possible, to allow access during a fire condition.

The marine transfer area for the facility will have an international shore connection in accordance with the American Society for Testing and Materials International ("ASTM") F1121, a 2.5-inch fire hydrant, and a 2.5-inch fire hose of sufficient length to connect the fire hydrant to the international shore connection on the marine vessel. A hydrant with a 4-inch bumper connection will be provided near the tug boat berth area.

3.3.8 Fire Water Monitors Design and Layout

Fire water monitors are placed based on the following factors: potential fire sources, reduction of potential heat flux to nearby process equipment and structures using monitor spray coverage, and provision of monitor water streams from multiple directions to minimize effects of wind and provide redundant coverage. Monitors will be strategically located in high-risk areas to aid in fire control and exposure protection for various pieces of equipment that are hard to reach using manual hose streams or that pose a life safety risk to emergency response personnel. These high-risk areas include liquefaction process trains, refrigerant make-up area, gas conditioning area, and the LNG marine terminal. Monitors can be either hydrant-mounted or stand-alone devices. Monitors at elevated locations are operated automatically via deluge valves that oscillate to protect a preset area. Where possible, a group of monitors is activated with a single deluge valve to provide coverage on multiple pieces of equipment. The LNG Terminal marine transfer area will contain two remotely controlled elevated monitors, one on each side of the transfer area, to spray water streams to each part of the LNG transfer piping and connections, including LNG loading arms.

3.3.9 Hose Reel Design and Layout

Outside hose stations are provided strategically around the LNG Terminal in accordance with NFPA 24.

Hydrants will be furnished with a 6-inch, ANSI Class 125 flange inlet connection. Outlet connections will consist of two 2.5-inch hose nozzles and one 4-inch pumper nozzle. Outlet connection threads will be in accordance with the requirements of the local fire department. The hydrants will have 5.25 inches compression-type main valve openings. Each hydrant will be equipped with an automatic drain to keep the barrel dry when the compression valve is closed.

The compression valve will open with the counterclockwise turning of the operating nut. The hydrants will be designed for a working pressure of 200 psig and a hydrostatic pressure of 350 psig. Fire hydrant hose houses will be provided throughout the facility at strategic locations to provide ready access to firefighting equipment during an emergency condition. Each fire hydrant hose house will include the following accessory equipment:

- 100-foot sections of 2.5- inch fire hose, 100 percent polyester single-jacket rubber-lined—2.1 Newton per square millimeter ("N/mm^2") test, FM Global ("FM") approved hose with hard-coat anodized lightweight aluminum alloy rocker lug, and National Standard Hose Thread ("NSHT") connection coupling;
- 100-foot sections of 1.5-inch fire hose, 100 percent polyester single-jacket rubber-lined—2.1 N/mm^2 test FM-approved hose with hard-coat anodized lightweight aluminum alloy rocker lug, NSHT connection coupling;
- Hard-coat anodized lightweight aluminum alloy with approved combination spray, solid stream, ball, or twist shutoff nozzles for 2.5-inch hose;
- Hard-coat anodized lightweight aluminum alloy with approved combination spray, solid stream, ball, or twist shutoff nozzles for 1.5-inch hose;
- One adjustable hydrant wrench;
- Universal type spanner wrenches;
- One hard-coat anodized lightweight aluminum alloy gated 2.5 inch by 1.5 inch by 1.5 inch NSHT wye; and
- One 2.5-inch to 1.5-inch adapter fitting.

None of the LNG Terminal buildings require an indoor hose reel system (standpipe system) in accordance with OSSC, and thus no standpipe system will be provided. All LNG Terminal buildings will be provided with fire hydrant coverage in accordance with Oregon Fire Code for manual firefighting operations during an emergency condition.

3.3.10 Water Screens and Deluge Systems Design and Layout

Spray systems using directional spray nozzles are designed to provide fire control and cooling for equipment in outdoor areas. The water supply is held back from the spray nozzles by a deluge valve, which is automatically actuated by the operation of the fire detection system or through manual means. Upon alarm of the fire detector, the local fire panel will actuate the appropriate deluge valve. This allows water to flow through the open spray nozzles attached to deluge valve piping. Water discharges from all of the open spray nozzles simultaneously to protect the equipment from fire damage. Deluge spray systems are designed in accordance with NFPA 15.

3.3.11 Expansion Foam Philosophy

High expansion foam is provided at the process and marine LNG impoundment basins. The high expansion foam is designed primarily to form an insulating blanket of foam on top of LNG, thus suppressing flammable liquid spill fires and reducing the rate of LNG vaporization within the basins. Actuation of the fixed high expansion foam system will be possible manually or automatically from area fire detectors monitored by the plant FGS. If fire is detected, deluge valves will open and provide a foam water solution to high expansion foam generators located at surrounding LNG impoundment basins. The foam concentrate is proportioned automatically into the water supply at the foam mixing skid. High expansion foam systems are designed in accordance with NFPA 11.

3.3.12 Expansion Foam System Design Cases, Demands, Calculations, and Basis of Sizing

The design parameters for foam system are to provide primary protection for LNG spill basins such as the process LNG basin and the marine LNG basin. The industry's current safety practice is to mitigate and to control LNG vapor and fires until the LNG is completely vaporized or consumed by the fire. Therefore, the high expansion foam system is designed to have foam produced and discharged within the LNG impoundment basin after system actuation. Systems will be sized to achieve a controlled LNG burn while maintaining reduction in thermal radiation to the surrounding area until the fire consumes the spill and to control the vapor plume until the LNG is completely vaporized. The following parameters are used for designing the high expansion foam system:

1. Foam concentrate will be suitable for use with freshwater or sea water;
2. Foam solution will have the optimal expansion ratio range between 350:1 and 500:1;
3. Foam concentrate will provide high water retention characteristics and will be UL-listed;
4. Foam generators will be UL-approved;
5. The foam system will produce a minimum expanded foam depth of 3 to 5 feet within one minute of activation;
6. The initial foam application will achieve and maintain a minimum depth of 3 feet to 5 feet for the first three minutes of activation;
7. The foam system will be fitted with a detection system capable of initiating the foam system in the event of an incident;
8. Foam system concentrate storage tanks will be fitted with low-level shutdown switches to prevent raw water from being applied to fuel. Alarms will also be provided to alert operators of low-level conditions; and
9. The foam liquid capacity should be sufficient to operate all generators covering the largest hazard for the amount of time in accordance with NFPA 11.

3.4 Relief Valve and Flare/Vent Systems

3.4.1 Relief Valves and Flare/Vent Systems Design

The LNG Terminal will have three separate flare systems for pressure relief conditions: one for warm (wet) reliefs, one for cold, cryogenic (dry) reliefs, and one for low-pressure cryogenic reliefs from the BOG and marine loading system. The "warm" relief loads are separated to ensure that wet fluids cannot freeze in the header if there were 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.

All flare systems will be ground flares. For the warm (wet) and cold (dry) flares, multi-point ground flares combined into a shared field have been selected, and a totally enclosed ground flare has been selected for the marine flare. This eliminates flame visibility from grade and allows a much shorter stack, because heat radiation at grade is negligible.

The flare system will be used during emergency scenarios, maintenance activities, off-design loading scenarios (*e.g.*, warm or contaminated ship), and initial commissioning/startup.

To protect the facility from overpressure events (such as a fire, control valve failures, and unplanned equipment shutdowns), PSVs will be installed in appropriate locations to ensure that all piping and equipment are protected. Discharges from these PSVs will collect in the flare headers and be combusted in the appropriate flare system.

Fuel gas will be connected to the end of each flare sub-header to ensure continuous positive pressure through the sub-headers, headers, and flare stacks. This fuel gas purge prevents air (oxygen) ingress into the flare system from the flare tips. Air ingress could possibly lead to explosive hydrocarbon mixtures within the header.

Relief valve discharge pipes, flare sub-headers, and flare headers are sloped, or at least level, to allow liquids to freely drain to the flare KO drums. This arrangement ensures that relieved liquids cannot get trapped in low sections of piping, allowing a free, open, and unrestricted pathway for future releases.

Reliefs from the steam system will not be routed to the warm flare. Steam is not flammable, and not hazardous as long as the relief discharge is routed to a safe location that will ensure personnel cannot come into contact with the hot steam.

3.4.2 Relief Valve Philosophy

All valves used will be suitable for installation in outdoor, unprotected locations and be adequately protected from the corrosion likely to occur because of exposure to adverse weather conditions. Valves selected will be able to withstand exposure to wind-driven dust, saline damp air, and high ambient temperatures.

The valves selected will be capable of operating automatically and require minimum maintenance. All materials selected will be suitable for service in the process temperature and pressure range stated in the data sheet.

Valves selected will be of a proven design and have demonstrated leak-tight shutoff.

Conventional safety relief valves will be used on all services for liquid, gas, or vapor service if the total back pressure is less than 10 percent of the set pressure. The bonnet will be internally vented to the discharge side of the valve.

Balanced bellows will be used for applications where the maximum superimposed back pressure and built-up back pressure is greater than 10 percent of the set pressure. The valves will have a bonnet vented to the atmosphere.

Pilot-operated relief valves will be used when operating pressure is above 90 percent of set pressure or where total back pressure may exceed 30 percent of set pressure or as required by process conditions.

Safety relief valves will be sized in accordance with API RP 520 and ASME Section VIII. Reaction force calculated will be based on API RP 520.

Noise level at 98 feet (30 meters) will be calculated in accordance with API RP 521.

Each valve will be sized using criteria and data and the valve design conditions indicated on the technical data sheets. The orifice selected will match the calculated area. If the area calculated is not a standard, then the next larger standard orifice size will be used.

Valves will be designed for safe and reliable operation under the conditions specified on the technical data sheets. Valves will have port and body flow areas adequate to pass the service fluid capacity specified on the process data sheets. Pressure accumulation will not be greater than 10 percent of the valve set pressure except for a fire case, for which 21 percent accumulation is allowed. Capacity ratings will be certified in accordance with ASME Boiler and Pressure Vessel Code ("BPVC"), Section VIII.

Valve sizing will take into consideration the maximum relieving pressure and permissible accumulation, as well as the superimposed and built-up back pressure as stated on the data sheet.

Inlet and outlet connection sizes indicated on the technical data sheet are those suitable for installation in the associated piping system and are the minimum acceptable sizes. If the specified capacity can be achieved with a smaller body size, specified body size will be furnished with a smaller orifice size. If the valve with the indicated inlet and outlet connection size cannot pass the required flow at the specified conditions, a larger valve will be furnished.

3.4.3 Vent Stack Philosophy

The LNG Terminal will be provided with one vent stack. The vent stack will run parallel to the thermal oxidizer for use when the thermal oxidizer trips or is down for maintenance. The vent stack outlet will be located 130 feet above grade in the gas conditioning section and will have no impact to personnel or off-site.

3.4.3.1 Vent Sources

After sulfur scavenging, the sweetened stream is sent to the thermal oxidizer, which combines fuel and air in the system in order to oxidize the remaining sulfur species and combust the other hydrocarbons, potentially including BTEX, to minimize volatile organic compound ("VOC") and other hazardous emissions. This sweetened stream is vented in case of a trip or planned maintenance of the thermal oxidizer.

3.4.4 Flare Philosophy

The facility will have three separate flare systems: one for warm (wet) reliefs; one for cold, cryogenic (dry) reliefs; and one for low-pressure cryogenic reliefs. The "warm" relief loads are separated to ensure that wet fluids cannot freeze in the header in the event of 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 in the event that an unrelated release is occurring.

All flare systems are ground flares. For the warm (wet) and cold (dry) flares, multi-point ground flares combined into a shared field have been selected, and for the marine flare, a totally enclosed ground flare has been selected. This approach eliminates flame visibility from grade and allows a much shorter stack, since heat radiation at grade is negligible.

3.4.4.1 Flare Sources

The feed gas from the PCGP contains some water and gets saturated by the amine system upstream of dehydration. These wet reliefs from the inlet facilities will be collected in the low-temperature carbon steel warm flare system. This system includes a header, KO drum, pump to remove accumulated liquids, and the warm flare.

All cold and/or dry reliefs from the liquefaction, refrigerant make-up, and BOG systems are collected in a SS cryogenic flare system. This system includes a header, KO drum, and the cold flare. Defrost gas will be provided through a sparger to vaporize any liquids that might accumulate in the cold flare knockout drum. A blowcase will also be provided to remove any nonvolatile liquid heel to the slop drum.

The marine flare is designed to protect the LNG storage tanks and LNG carrier from overpressure if a BOG Compressor trips, or to dispose of warm or off-spec vapor during cargo cooldown operations and/or if an LNG carrier arrives inerted. The vapor return from the LNG carrier can be sent to the marine flare isolated from the main vapor header. The main BOG header can be vented to the marine flare header automatically on high pressure to prevent the LNG storage tanks and LNG carrier relief valves from opening. The marine flare system is independent from the cold flare system to ensure that the flare header back pressure will not prevent the relief of very low-pressure (near atmospheric pressure) vapor.

3.4.4.2 Flare Operating and Design Radiant Heat

There is no radiant heat at grade from ground flares, because the walls and enclosures shield the flame from personnel. The flares will be located so that any radiation at any height will not occur where personnel might be present, and flare field wall or enclosure heights will be finalized during the detailed design phase to ensure this condition.

3.5 Stormwater Management System

The design includes various stormwater management systems that are sized to handle rain events at the LNG Terminal site. Runoff from rain events will be separated into two major stormwater systems: the stormwater system and the oily waste system. Runoff for both these systems will be concentrated into below-grade piping networks that will transport water from the surface of the LNG Terminal site to locations to be treated using best management practices ("BMPs"). For the stormwater system, stormwater above the design storm event that is not infiltrated by BMPs will be discharged at outfall locations in the slip or in Jordan Cove. Also, treated effluent from cartridge-filter-type BMPs will discharge directly to outfall locations in the slip or in Coos Bay. The oily waste system will transport the potentially oily water to a buried oil/water separator. The effluent from the oil/water separator will be discharged to the Industrial Wastewater Pipeline ("IWWP").

3.5.1 Overview of Stormwater Management Systems

Stormwater pollution control measures for the JCEP Project Area consist of both structural and non-structural control measures. Structural controls include exposure minimization BMPs and stormwater containment and discharge reduction BMPs. Non-structural controls will include operations and maintenance ("O&M") manuals, good housekeeping measures, preventative maintenance, spill and leak prevention, materials handling and waste management, erosion and sediment controls, training programs, and quality assurance and record keeping.

3.5.1.1 Runoff Transport Systems

Runoff from rain or wash-down will be separated into two major systems: the stormwater system and the oily waste system. The stormwater system refers to the system that does not include runoff potentially contaminated with oil or grease. The oily waste system refers to the system that includes runoff from the plant that is potentially contaminated with oil or grease.

3.5.1.2 Structural BMPs

Table 3.5-1 provides a summary of the potential pollutants that might be found at the JCEP Project Area site; the likely sources and locations of these pollutants; and the selected BMPs to prevent, reduce, and treat these pollutants.

Table 3.5-1 **Summary of Structural BMPs**				
Primary Pollutant	**Constituent Pollutants**	**Pollutant Sources**	**Areas of Site**	**BMPs**
Suspended Solids	Sediment Gravel and tire particles Exhaust gas particulates Heavy Metals	Trucks and vehicles Soil erosion	Parking lots Laydown areas Concrete surfaces Gravel surfaces	Buried infiltration chamber Open graded gravel infiltration basin Vegetated infiltration basin Cartridge filtration Vegetated side slopes Stabilized surfaces Geotextile separation of subgrade Periodic cleaning of catch basins Commercial street sweepers
Oil, Grease, and Hydrocarbons	Automotive fluids Gas and diesel Oil and grease Transformer oil Wash-down water Amine	Trucks and vehicles Leaks and spills Equipment (pumps, etc.) Transformers Diesel fueling Heavy equipment Oil or diesel storage Equipment maintenance	Process areas Equipment Vehicles Laydown areas	Secondary containment Drip pans for spills, leaks Curbed hydrocarbon areas Storm water pre-treatment manholes Oil/water separator Preventative maintenance
Liquid Chemicals	Process chemicals	Chemical tanks Loading and unloading of chemicals	Process areas	Secondary containment Containment curbs
Bacteria and Viruses	Pathogens	Broken sanitary sewer lines	General areas	PV pipe with watertight joints
Nutrients	Nitrogen Phosphorous	Fertilizers Landscape materials Soil erosion	Vegetated areas	Using proper fertilization techniques Stabilized surfaces
Solid Waste	Paper Garbage Debris	Loading and unloading of materials Littering	Buildings Parking lots Outdoor trash receptacles	Good housekeeping Routine waste removal Routine inspections

3.6 Sewage and Sanitary Waste Treatment

Sanitary waste from the northwest guard house and tug building will be directed to a holding tank. A sanitary waste contractor will remove the contents of the tank as necessary and dispose of the contents at authorized disposal sites through the sanitary waste contractor's permits. Sanitary waste from the remainder of buildings will be treated by a packaged treatment system. The effluent will be directed to the IWWP. Solids will be removed from the packaged treatment system periodically by a sanitary waste contractor and will be disposed of at authorized disposal sites through the sanitary waste contractor's permits.

3.7 Hazard Detection Systems

3.7.1 Hazard Detection System Design

A Hazard Detection and Mitigation System ("HDMS"), also called the Fire and Gas System or FGS, will be an independent, stand-alone, high-integrity system, and will continuously monitor and alert operating personnel to LNG and refrigerant spills, fires or flammable gas leaks.

The purpose of fire, spill, and gas detection and an alarm system is to provide an early warning of a fire, spill, or gas leak situation, which will allow for an orderly shutdown of the affected plant area and the initiation of ERPs.

The FGS will communicate with the ICSS, which consists of the DCS, SIS, HIPPS, and all other associated control systems and monitoring.

The FGS will receive inputs from various fire and gas detection devices and manual call points installed throughout the plant, as well as from stand-alone FACPs installed inside buildings and, if applicable, from other dedicated fire and gas systems (*e.g.*, vendor-supplied FGS).

The FGS will comprise the following types of equipment:

- Combustible gas detectors (point type);
- Combustible gas detectors (open path type);
- H_2S gas detectors;
- Ammonia detectors;
- Ultraviolet/infrared ("UV/IR") and triple infrared ("IR") fire detectors; and
- Fiber optic temperature detection.

3.7.2 Hazard Detection Philosophies

3.7.2.1 Selection

A selection of combustible gas detectors will be utilized for areas/zones where escaped hydrocarbons could be present. Point-type detectors should be used in combination with open path detectors when environmental conditions could make the open path detector unavailable or not fit for the purpose. The open path gas detectors will be used for perimeter monitoring since there is a possibility that for high-pressure leaks, the jet streams might pass the point IR detector and form a gas cloud outside the detection zone of the point IR detector. This is to prevent the migration of flammable gases into non-hazardous areas.

For densely packed areas, where there are a large number of potential leak sources, spacing between detectors will be taken into account to cover all areas within the enclosed space. If open path gas detectors are used, both the transmitter and receiver of each device will be cabled on the same route. Both the transmitter and receiver must be located within the same fire zone/area.

Toxic (H_2S) detectors will be located around equipment where the concentration of H_2S in the process is expected to present a possible health hazard.

Ammonia detectors will be provided in the liquefaction trains area near the aqueous ammonia vaporization skids and inlet piping to the HRSG SCR bed, and around the ammonia storage drum. These ammonia detectors will be intelligent toxic gas sensors calibrated to measure ammonia concentrations between 0 and 60 parts per million ("ppm").

UV/IR or multi-spectrum, triple IR flame detectors will be provided throughout the plant area. A means of automatically detecting fire, as well as a subsequent shutdown signal for the process unit/area/plant, will be provided.

Manual alarm call ("MAC") points will be located at selected locations within the process area. There will be MACs to manually initiate alarms as well as a MAC for emergency process shutdowns. These MAC points in buildings will be of the "break glass, auto release" type and will be protected from accidental activation. For MACs in the process and outside areas in the facility, mushroom pull-to-activate buttons will be used. The pull-to-activate design will prevent accidental activation.

3.7.2.2 Layout

The F&G logic controller processors use a zoning approach for the design. The F&G field instruments that will be used are combustible gas area monitors using point and open path technologies, UV/IR or multi-spectrum triple IR flame detectors, H_2S gas detectors, ammonia detectors, local MAC stations, horns, and beacons/strobes.

The occupied buildings will each have its own local FACP with fire and smoke detectors and suppression in accordance with Oregon fire code. These local panels will interface with the main F&G detection system.

Locations for MAC points will be shown in F&G layout drawings and will be finalized during the detailed design phase. The typical considerations for MAC locations are as follows:

- Along main escape routes;
- At the entrances to main safety/fire areas;
- At each building's exit door including the SORSC Building; and
- In local control rooms.

The F&G detection areas will generally follow the boundaries of the fire areas, which will also be the basis for the zoning of fire water coverage areas. The process unit areas will be divided into F&G zones, with multiple sensors provided in each zone to detect a dangerous environment before shutdowns are required to be initiated.

3.7.2.3 Alarm

Audible and visual alarms will be sounded by the FGS in the ICSS operator interface consoles.

Audible alarms (horns) located in hazardous areas will be activated upon fire or gas detection or activation of a MAC device.

Local audible alarms (horns) will be rated for continuous use and have a minimum sound pressure level of 85 dBA, adjustable to 110 dBA, measured at a distance of 10 feet. The format of the audible signal will be selectable as continuous, intermittent, or whoop/sweep, with adjustable volume and frequency. The horns will be suitable for surface or pole mounting.

Visual alarms (beacons) will be of the strobe type and will accompany horns to give visual placement to the audible alarms. Each fire zone will have at least one beacon and one horn.

3.7.2.4 Activation

The process area will be partitioned into F&G zones that are equivalent to the process modules. At least two detectors of the same type (gas/gas or fire/fire) must reach the shutdown set point before a process shutdown action is called for. The extent of shutdown action is determined by shutdown logic when an F&G shutdown signal is received from a particular zone. Single zones or multiple zones may be shut down and isolated depending on the shutdown logic.

Alarms include general alarms for the entire process area, as well as zone-specific alarms to indicate the particular zone in which the hazard has been detected.

Zone-specific alarms will incorporate a two-level alarm signal beacon with the following features:

- Off (normal);
- Flashing amber (one high gas alarm detected in the zone);
- Flashing amber plus horn (one high-high gas alarm or one fire alarm detected in the zone);
- Flashing red plus horn (two high-high combustible gas, two high-high H_2S gas, two fire alarms detected); and
- Flashing white for fire alarms according to NFPA 72.

All process zones will have at least two alarm beacons each, and horns and beacons will be powered and activated by the FGS.

3.7.2.5 Alarm Set Points

F&G detectors will be electronic solid state types utilizing a standard 4-20 milliampere ("mA") electrical signal with the additional "smart" HART™ digital communication superimposed on the 4-20 mA signal.

The system will be based on a fault-tolerant design. Any single fault will not degrade system safety or functionality or impact operation of the process. Any fault occurring in the system must be alarmed and include an indication of the exact location of the faulty component.

An open path gas detector utilized for detection of combustible gas in the open area measuring range is between 0 and 5 lower explosive limit-meters ("LEL-m"); hence it will initiate alarm levels measured in LEL-m as follows:

- High gas alarm set at 2 LEL-m; and
- High-high gas alarm set at 3 LEL-m.

A point-type gas detector utilized for detection of combustible gas in the open area measuring range is between 0 and 100 percent LEL, and will initiate alarm levels measured in LEL as follows:

- High gas alarm set at 10 percent LEL; and
- High-high gas alarm set at 50 percent LEL.

Confirmed toxic gas alarm set at two (or more) detectors and the FGS will initiate alarm and shutdown set point as follows:

- H_2S gas pre-alarm set point at 10 ppm, high alarm/shutdown set point at 50 ppm; and

- Ammonia gas alarm set point at 10 ppm, high alarm/shutdown set point at 50 ppm.

3.7.2.6 Voting Logic, Voting Degradation Logic

Detectors (sensors) will require a minimum of two different-type or two same-type sensors in a particular fire zone to detect a hazard that requires shutdown. There will be voting between multiple detectors in an area to minimize any unintentional shutdown caused by malfunction or inadvertent operation. The voting will normally be as follows:

- 1ooN detectors to reach alarm limit when N<= 2.
- 2ooN detectors to reach alarm limit when N>= 3.

MACs will be installed throughout strategic locations in plant areas, the control room building, the warehouse area, and corridor facilities.

3.7.2.7 Hazard Detection Design and Performance Criteria

Gas detectors will be installed in critical locations throughout the plant and in all building air handling unit inlets to detect the presence of combustible gas. Gas detectors will be located close to potential gas leak sources (*e.g.*, pump and compressor seals) and located to suit the density of the gas released. Flammable gas detectors will be provided at HVAC inlets, in analyzer shelters, and inside and outside of doors to rooms that are in flammable service.

Where the potential gas leak is heavier than air (such as H_2S), point-type gas detectors will be mounted at a lower level, between 1 and 3 feet above grade. Where the potential gas leak is lighter than air (combustible gases such as methane), point-type gas detectors will be mounted above the potential leak source. Open path combustible gas detectors will be located on the edge of individual process areas and will be mounted between 6 and 10 feet above grade. Field-mounted instruments will generally be mounted on a 2-inch-diameter corrosion-resistant pipe support designed for steel column or fixed grating (not removable grating) mounting on the modules.

Fire detectors will be placed in the vicinity of the most likely fire sources. Attention will be given to avoiding interferences and to considering the cone of detection of the particular device.

All detectors will be supplied with splash guards to prevent water or wind from affecting the sensors.

Fire detection systems will be installed where it is considered that the development of fire could constitute a serious risk to the plant or operators, or where required in accordance with the codes and standards. Response time will be as fast as possible and will not exceed 3 seconds at 49.2 feet (15 meters). Areas requiring fire detection will include, but not be limited to, occupied buildings and enclosed buildings containing hydrocarbon-handling equipment or high voltage electrical equipment.

3.7.2.8 Low-temperature Detectors

An adequate number of cold detectors (*i.e.*, temperature sensors) for monitoring leakage of LNG and cryogenic refrigerants will be provided on the tank roof near the vicinity of nozzles, within the outer tank annular space, and in the LNG trench running under the main piping throughout the plant.

The LNG leak detection system will be specifically designed for cryogenic leak detection. It will continuously monitor the temperature along the fiber-optic cable, which will be installed in the LNG spill trenches from the berth to the marine impoundment basin. It will incorporate fiber-optic distributed temperature sensing ("DTS") technology.

The LNG leak detection system will be applied for LNG rundown and LNG loading. The LNG vapor return line will not require leak detection.

3.7.2.9 Oxygen Deficiency Detectors

Oxygen deficiency detectors will be located in the buildings that are not continuously occupied and have hydrocarbon or other gas sources in the building. Examples are analyzer shelters, UPS battery rooms, and continuous emissions monitoring systems ("CEMS"). Oxygen deficiency will also be monitored around the liquid nitrogen storage area in case of potential leaks.

3.7.2.10 Toxic Gas Detectors

Toxic gas detection will be installed if the potential for toxic gas accumulation exists, in accordance with fluid service. Toxic gas leaks may be associated with the following equipment: rotating equipment, compressors, and pump seals. Releases of toxic gas will be monitored with toxic gas detectors and located close to potential leak sources.

Pipe flanges and pipe walls/vessels usually are not required for monitoring toxic releases; however, manifolds with large numbers of valves and flanges may be locally monitored when the toxic gas concentration potential is high.

Toxic detectors will be able to perform in accordance with the specifications prescribed in Underwriters Laboratories ("UL") 920001.

The detectors will consist of two elements: one being active and sensitive to the gas to be detected, and the other effectively being passive and acting as an environmental compensator. The devices will be capable of calibration within a range that is in accordance with respective toxic gas effect level in ppm.

3.7.2.11 Flammable/Combustible Gas Detectors

The early detection of flammable gas is important in preventing explosions or potentially hazardous conditions. The plant design will ensure that non-catastrophic leakages of flammable gases and vapors will normally be dispersed to below the LEL of the material before encountering an ignition source, which is achieved by keeping ignition sources outside of the hazardous areas and by using equipment certified for use in a hazardous area. It is possible, however, that leaks larger than accounted for in the classification of hazardous zones may occasionally occur; therefore, flammable gas detection should be provided.

Open path gas detectors will be located in conjunction with point-type gas detectors in areas of high gas leak potential, primarily in the process and storage areas. The open path gas detectors will be used for perimeter monitoring, because there is a possibility that for high-pressure leaks, the jet streams may pass the point IR detector and form a gas cloud outside the detection zone of the point IR detector. This is to prevent the migration of flammable gases into nonhazardous areas.

Combustible gas detectors will be able to perform to the temperature, humidity, air velocity, and vibration specifications prescribed in ISA 60079-29-1.

The detectors will consist of two elements, one being active and sensitive to the gas to be detected, and the other effectively being passive and acting as an environmental compensator.

3.7.2.12 Flame Detectors

The flame detection system will be designed using UV/IR or multi-spectrum, triple IR flame detectors. Flame detectors will be used for alarm purposes and automatic activation (where required) of the associated fire protection system. The sensitivity to a fire condition will not be affected by arc welding, lightning, sunlight, artificial light, x-rays, or heated objects. The detector will be capable of detecting a fire through surface-level lens contamination (*e.g.*, dust, oil, or water spray).

The cone of vision will be approximate 90-degree horizontal and 75-degree vertical planes. The detector viewing range will have a nominal conical vision of 120 degrees with the highest sensitivity at the central axis.

The detector will have a periodic self-checking facility every 1 or 2 seconds for detecting malfunctions in the optical surfaces and circuit components (optical integrity). If a malfunction is detected, the output current will rise to the fault level and a fault relay will be energized.

The output signal will be composed of an alarm signal and malfunction signal that would result from a dirty window, short circuit, or circuit disconnected.

3.7.2.13 Heat Detectors

Where ambient conditions prohibit installation of automatic smoke detection, automatic heat detection will be permitted. The heat detector will be dynamically supervised and uniquely identified by the fire alarming and detection system. The heat detectors are defined by:

- Sensor type – Rate compensated/fixed temperature;
- Temperature set – per NFPA 72; and
- Rate of temperature rise – per NFPA 72.

Heat detectors would be used independently or in conjunction with flame detectors in areas such as compressor shelters and UPS battery rooms.

3.7.2.14 Smoke/Products of Combustion Detectors

In areas that are not continuously occupied, automatic smoke detection will be provided at the location of each fire alarm control panel to provide notification of a fire at that location.

Smoke detection will be installed in electrical substations, the main control room, marine area control building, rack rooms, and locations where power cables are run in voids, as well as all buildings where sprinkler systems are not installed.

3.7.2.15 Manual Pull Stations

All MACs installed in buildings will be of the "break glass, auto release" type and will be protected from accidental activation. For MACs in the process and outside areas of the facility, mushroom pull-to-activate buttons will be used. The pull-to-activate design will prevent accidental activation. The units will be provided with contacts that are supervised as normally closed under healthy conditions and opening to alarm. In plant areas, MACs located outdoors will be certified for use in hazardous areas. MACs will be robust, suitable for an industrial environment, and corrosion-resistant.

3.7.2.16 Audible and Visual Notification Systems for Field, Control Room, Plant-wide, and Off-site

Audible and visual notification devices for gas alarms will be a different sound and beacon color from the plant "fire" alarm. Audible alarms will be at least 110 dBA above the environmental noise of the plant areas in which they are located, with certification use in hazardous areas and powered with 24 volts of direct current ("VDC") for activation through FGS. Beacons will be the strobe type and will accompany horns to give visual placement to the audible alarms.

3.7.2.17 **Other Hazard Detectors *e.g.***

Acoustic leak detection would be used to monitor the gas pipeline from the PGCP metering station to the LNG Terminal gas treating section.

Fiber-optic-based temperature detection technology will be used in the bottom of the LNG trenches and impoundment basins. The sensors will detect both the actual temperature and the rate of change of the temperature in order to identify LNG spills flowing into the LNG trenches.

No CCTV will be used for detection services. However, the CCTVs will be used by the operations and security teams to rapidly locate and assess the responses required to mitigate hazardous events.

Buildings will all be equipped with smoke, fire, and carbon monoxide detectors as required to protect the occupants in accordance with NFPA code.

3.8 Hazard Control Systems

The hazard control systems protect facility equipment and structures from fire damage and personnel from fire, smoke, hazardous liquid, and gas exposure. The systems include fire extinguishers, bulk dry chemical systems, and clean agent systems. Hazard control systems are designed to control or suppress the fire in accordance with applicable NFPA standards.

3.8.1 Hazard Control Philosophies

3.8.1.1 Selection

All hazard control equipment will be selected to meet applicable NFPA requirements and be listed for fire suppression use when applicable. All equipment will meet applicable authority having jurisdiction ("AHJ") requirements for the intended function. Hazard control equipment material will be selected based on its compatibility with ambient environmental conditions and potential hazards encountered.

3.8.1.2 Layout

Handheld fire extinguishers will be provided throughout the facility, including indoor and outdoor locations. These will be located in appropriate places near the utility stations, egress pathways, and/or in other areas to allow easy access in the event of a fire emergency.

Dry chemical suppression systems will be provided for the marine terminal at the LNG loading shipping berth in accordance with NFPA 59A and 33 CFR Part 127. Four dry chemical systems, two turret and two hose reel systems, based on potassium bicarbonate agent, will be provided on pre-engineered skids.

Clean agent fire suppression systems will be provided in buildings that house critical electrical and control equipment for the operation of the LNG Terminal. This includes buildings such as the control room, I/O cabinet room, DCS engineering room, power distribution equipment rooms, and powerhouses.

3.8.1.3 Activation

Manual firefighting operations are necessary to extinguish any incipient fires that might occur, in accordance with the approved ERP. Fixed hazard control system actuation will provide alarm signals at the local fire panels and main fire alarm control panel in the control room to notify operators of potential emergency conditions. Early response by emergency control personnel and fire protection system will minimize damage to life and property. Activation of the fixed dry chemical turret system will be possible manually or automatically from area fire detectors monitored by the plant FGS. Activation of the clean agent fire suppression system will be possible manually or automatically from area fire detectors monitored by the plant FGS.

3.8.1.4 Performance Criteria

Hazard control equipment will meet the performance requirements of applicable NFPA and API standards and their listing limitations. All of the equipment will be rated for the system design pressures and environmental conditions. All fixed hazard control equipment (except the fire suppression piping) will be listed, in accordance with applicable codes and standards, by a recognized laboratory or agency acceptable to AHJ at Coos Bay.

Four dry chemical systems, based on potassium bicarbonate agent, will be provided on pre-engineered skids. These systems include two fixed dry chemical turret systems and two hose reel systems, with shutoff capability, located within the shipping berth area. A dry chemical system with a pre-aimed turret will discharge the dry chemical agent to the area surrounding the LNG loading arms. The systems will be charged and ready to operate using manual actuators mounted on the skid. Each system will have a minimum dry chemical capacity to supply the agent for 45 seconds. Dry chemical systems will be designed and installed in accordance with NFPA 17. Actuation of the fixed dry chemical turret system will be possible manually or automatically from area fire detectors monitored by the plant FGS.

The clean agent system will be a total flooding fire suppression system with automatic detection and automatic or manual system release capability. The system will be a skid-mounted package, complete with clean agent tank(s), manifold, release mechanism, controls, and instrumentation. All components and accessories will be listed and approved for use with the clean agent systems for their intended purpose.

The clean agent fire suppression system will be designed and installed in accordance with NFPA 2001. The system will be designed to achieve a minimum design concentration to meet the NFPA 2001 requirement within ten seconds in all protected areas. Each compartment will be protected as a separate risk area if spaced sufficiently apart or if individual protection is most economical. The discharge of the extinguishing agent into one compartment will not affect other compartments not protected by the same system. Appropriate safeguards will be provided to ensure that the protected area is sealed properly to maintain the necessary concentration levels for the required duration in accordance with NFPA 2001.

Piping and tanks will be securely supported, taking into account the forces generated during discharge or during seismic activity. Liquid level indicators will be installed on all tanks for verification of agent quantity. Strainers will be provided with the necessary piping, and piping lengths will be kept to a minimum.

3.8.1.5 Portable Fire Extinguishers Design and Layout

Portable and wheeled type fire extinguishers will be supplied and placed at key locations in accordance with the requirements of applicable codes and standards such as the Oregon fire code, NFPA 10, NFPA 59A, CFR regulations, and industry standards. The extinguishing agent will be either a dry chemical powder or carbon dioxide. The agent used will be selected based on the fire hazards encountered in the immediate area.

3.8.1.6 Fixed Dry Chemical Systems Design and Layout

Dry chemical suppression systems include two fixed dry chemical turret systems and two hose reel systems, with shutoff capability, located adjacent to the LNG loading platform. A dry chemical system with pre-aimed turret will discharge the dry chemical agent to the area surrounding the LNG loading arms. The systems will be charged and ready to operate using manual actuators mounted on the skid or remotely at the local fire alarm panel. Dry chemical systems will be designed and installed in accordance with the standards of NFPA 17.

3.8.1.7 Clean Agent Systems Design and Layout

Clean agent systems will be designed in accordance with NFPA 2001 standards to extinguish fire from electrical and combustible hazards within the protected areas. The systems will be designed for total flooding application to suppress the fire and limit the potential fire damage to a minimum.

3.8.1.8 Carbon Dioxide Systems Design and Layout

The combustion gas turbine enclosure fire protection system will be provided by the equipment manufacturer. The details of this system will be finalized during the detailed design phase. Carbon dioxide fire extinguishing systems will not be provided for areas with human occupancy. If a CO_2 fire extinguishing system is provided, the system will be designed in accordance with NFPA 12 standard.

3.8.1.9 Other Hazard Control Systems Design and Layout

The ground flare will include nitrogen to be used as back-up supply for line sweeping/purging. Nitrogen will be used for snuffing and deicing of the relief valve outlets of the LNG storage tanks.

All LNG process-related buildings that handle hazardous materials will be ventilated in accordance with Oregon Fire Code and OSSC requirements to mitigate fire and explosion hazards. The NFPA 497 standard was used as guide to design the HVAC system for those locations where flammable gases or vapors, flammable liquids, or combustible liquids are processed or handled, and where their release into the atmosphere could result in their ignition by electrical systems or equipment.

LNG Terminal non-process buildings will be designed to meet the OSSC safety requirements.

3.9 Spill Containment

3.9.1 Spill Containment System Design

The LNG Terminal is subject to the siting requirements of 49 CFR Part 193, Subpart B, and NFPA 59A, which the USDOT incorporated within 49 CFR Part 193 on April 9, 2004:

- NFPA 59A requires impoundment areas to be installed at the terminal to serve LNG, refrigerant, and heavy hydrocarbon processing equipment and transfer areas. The water removal system for impoundment areas will be in accordance with 49 CFR Part 193.2173.
- NFPA 59A requires impoundment areas for containers with over-the-top fill connections, with no penetrations below the liquid level, and spill containment able to hold the largest flow from the failure of any single pipeline that could be pumped into the impounding area, with the container withdrawal pump or pumps delivering the full rated capacity for a duration of ten minutes.
- NFPA 30 defines the spill criteria for remote refrigerant impoundment basins to be the capacity of the largest tank that can drain into it.

3.9.2 Spill Containment Philosophy

The spill containment systems are intended to prevent the following:

- Spread of cryogenic liquid from the immediate spill area to other plant areas or public areas outside the LNG facility and waters.
- Spread of flammable vapor concentrations from process equipment spills to outside the facility boundary.
- Ignition of any LNG or gas under uncontrolled conditions.

- Sustained pool fire from accumulated flammable hydrocarbon liquids.

The accidental spillage of LNG and other flammable liquid hydrocarbons will be directed to and contained within impoundment basins to prevent their spreading to other areas of the facility and to minimize the vapor cloud dispersion. This drainage system will be built with sloped concrete surfaces beneath the equipment that contains the LNG or flammable liquid hydrocarbon and main valve stations, with collecting trenches directing the spillage away from equipment or piping into a separate area. The trenches and impoundment basins will be designed to contain a design spill from a failure in the vessel or piping determined in accordance with NFPA 59A and additional guidance from the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). If ignition of accidentally released gas or liquid occurs despite safety precautions, the collecting areas will serve to minimize the fire size to reduce heat fluxes to the surroundings, localize the need for fire protection, and minimize the size of fire protection equipment required for fire control.

3.10 Passive Protection Systems

Passive protection systems require no human or energy input in order to provide prevention and mitigation measures for managing risks at the LNG Terminal.

3.10.1 Passive Protection Design

According to NFPA 59A, all hazards that can affect the safety of the public or plant personnel are to be considered in the design. In addition to LNG, other hazards associated with flammable gases, flammable refrigerants, flammable or combustible liquids, or acutely toxic materials are considered. If present at the LNG plant, hazards, including vapor dispersion from liquid pools, vapor dispersion from jetting and flashing phenomena, thermal radiation from pool fires, thermal radiation from fires involving jetting and flashing phenomena (jet fires), overpressure from vapor cloud ignitions, toxic gas dispersion, and boiling liquid expanding vapor explosions ("BLEVEs") involving pressurized storage vessels, are included in the LNG Terminal's hazard evaluation. Passive protection measures are considered in order to protect against these scenarios.

3.10.2 Passive Protection Philosophy

Passive protection is an essential component of the safety basis of design that aids in achieving the following safety objectives in the LNG Terminal:

- Equipment and asset protection;
- Personnel protection;
- Spillage and environmental protection;
- Minimizing the potential for hazardous occurrences; and
- Design process necessary to ensure the previous objectives.

Thermal proofing is considered for application to support structures, components, and equipment, as required, to maintain structural stability in a fire hazard zone, a cryogenic spill zone, or an area where a failure could affect a safety-related system, provide additional fuel to a fire, or cause additional damage to the unit or to the LNG Terminal.

3.10.3 Cryogenic Structural Protection

Equipment and all main structural steel supporting process equipment and pipes that could be affected by an LNG or other cryogenic spill are protected against cold shocks. The effect of low-temperature fluid spills on equipment and structural steels are assessed, and measures are taken to prevent accident escalation through selection of suitable materials of construction or by embrittlement protection.

3.10.4 Vapor Barriers

Vapor barriers are included in the design in order to control the dispersion of the flammable vapor clouds from the identified release scenarios. Vapor dispersion and deflagration calculations performed using GexCon's computational fluid dynamics ("CFD") modeling software FLame ACceleration Simulator ("FLACS").

3.10.5 Equipment Layout Setbacks and Separation

The LNG Terminal will handle flammable vapors and liquids, which if ignited following a release could have the potential to cause a major fire or explosion. The site layout aims to contain an accident at the source to prevent escalation.

Inherently safer plant layout is achieved by measures including, but not limited to, the following:

- Identification and segregation of systems/units risk;
- Equipment/unit safety distances that reduce the potential for escalation of hazards and provide adequate accessibility for easy escape in case of accidental discharge;
- Minimization of the risks of ignition of possible gas clouds by ensuring adequate distances are available to uncontrolled sources of ignitions;
- Facility orientation and layout to maximize natural ventilation and to minimize confinement and congestion;
- Operability and maintainability; and
- Access for emergency services.

3.10.6 Blast Walls, Hardened Structures, and Blast-resistant Design

The basic blast-resistant design principle is that all the occupied or critical buildings will be located in safe areas as far as practicable. If such a building were in a hazardous area or in the line of sight and range of a potential explosion, it would be designed as a blast-resistant construction.

The following criteria will be applied:

- Doors will be located, as far as is practicable, on the opposite side to the most likely source of blast overpressure or jet fire;
- No windows are allowed in the occupied building at its exterior portions within the overpressure zone;
- The building will be designed to withstand all load cases and its technical systems, such as HVAC, power supply, etc., for its operability in extreme conditions;
- Storage of objects above head height within the buildings will be minimized; and
- Storage of flammable materials inside the buildings will be minimized.

3.10.7 Fireproofing, Firewalls, and Radiant Heat Shields Design

The objective of fireproofing is to:

- Minimize the possibility of a collapse of steelwork supporting equipment containing flammable or toxic materials, whose material release would increase the intensity of a fire and lead to fire escalation;
- Protect vital safety equipment (and associated power and signal cables) for a period sufficient to permit them to fulfill their function;

- Provide the most cost-effective measure to minimize the support steelwork probability of collapse in the event of fire and prevent fire in one fire area from escalating into adjacent locations;
- Maintain integrity of critical systems and equipment whose function must be guaranteed in case of fire or other emergencies; and
- Prevent loss of containment due to thermal weakening of the means of containment.

All steelwork within a fireproofing zone will be passively protected for a minimum of two hours duration up to the highest steel that supports a piece of equipment or 25 feet, whichever governs. Bracing design to support the structural gravity load in a high temperature environment will also be fireproofed.

Pneumatic valves whose function is to limit the extent of a hazard or mitigate the effect of a hazard will generally be located outside of fire-exposed envelopes. When this is not practical, the valves will be fire-rated and will function effectively during a fire by means of the fireproofing protection of the actuator and the tubing.

Cable entrance to buildings in fire hazard areas at low level feeding critical equipment or alarms will be flame-retardant, using an approved system/material. Main cable trays outside of hazardous areas, or at a high level, need not be fireproofed, but all critical alarm or SIS/F&G cables will be reasonably protected from damage with flame-retardant specification as necessary.

A fire-rated wall will be placed between the refrigerant make-up drums and the refrigerant spill impoundment basin to protect against a basin fire from impacting the refrigerant make-up drums. In addition, the drums and saddles will be insulated with fire-resistant insulation.

Fire walls will be provided to separate hazardous areas/equipment from adjacent hazards. The OSSC, Oregon Fire Code, and NFPA requirements will be implemented in the design of building exterior and interior walls to separate the occupancy hazards or to meet the distance requirements for fire separation.

3.10.8 Other Passive Protection

Other passive protection considered for this LNG Terminal includes ventilation and ignition control.

Ventilation will be achieved by the following measures:

- Locating hazardous units/process in open air;
- Minimizing congestion and dead areas around likely leak sources;
- Preventing storage of items that impact ventilation;
- Locating control buildings, administration buildings, warehouse, or workshop outside of hazardous areas; and
- Maintaining continuous positive pressure ventilation in the electrical and instrumentation rooms of the buildings if it is necessary to locate within a hazardous area.

Ignition control will be employed to reduce the likelihood of ignition in the event of a flammable material release. Ignition control is achieved through the following features for the LNG Terminal and marine LNG loading area:

- Minimization of the number of potential ignition sources;
- Use of inherently safe equipment;

- Equipment design to reduce the likelihood of ignition in areas where leaks of flammable substances could occur;
- Segregation of ignition sources from flammable inventories; and

Location of intakes and exhausts for combustion equipment outside of hazardous areas.

3.11 Process Control and Safety Instrumented Systems

3.11.1 Basic Process Control System Design

The basic process control system ("BPCS"), also known as the DCS, is a computerized system that will control and monitor the facility. The BPCS will be provided with the vendor's customary software packages for building process applications and displays, data archiving and retrieval, report generation, system security, alarm monitoring, etc. The DCS will communicate with microprocessor-/PLC-based control systems that will be provided as packaged controls on mechanical equipment. In addition, sub-systems that will be interfaced to the DCS will include SIS, F&G detection systems, and other external networks.

3.11.1.1 BPCS Philosophy

The facility will be controlled, monitored, and protected by the ICSS, as well as by a third-party PLC by the package equipment supplier. The ICSS, which consists of the DCS/SIS/F&G processors, data highway, power supplies, and remote I/O communication equipment, will be designed so that a single-point failure does not disable any control functions or prevent operator control actions, indications, or alarms. Redundancy will be maintained for all control components supporting equipment for safe shutdown.

3.11.1.2 Control Power Sources, Operating and Backup

The DCS equipment will be supplied power by a redundant UPS, each of which will be connected to two separate AC circuits.

3.11.2 Safety Instrumented Systems

3.11.2.1 Safety Instrumented System (SIS) Design

The SIS is a completely independent, stand-alone, high integrity system that will be designed to implement process safety-related interlocks. The SIS will be designed in accordance with the ANSI/ International Society of Automation ("ISA") S84.01 standards regarding management of functional safety of the overall process. The SIS will be based on the same equipment platform as the DCS.

3.11.2.2 SIS, Fire and Gas System, ESD, and Depressurization Philosophies

The SIS and fire and gas system ("FGS") each will have its own separate hardware and software, and all will be a part of the ICSS. The SIS will be structured such that it can operate at different levels to determine the appropriate extent of response required to predefined emergency scenarios. This hierarchical order of the SIS ensures that an orderly shutdown of the systems can be accomplished. The shutdown hierarchy levels include: process shutdown, ESD, and emergency depressuring.

The FGS will receive inputs from various fire and gas detection devices and manual call points installed throughout the plant, as well as from stand-alone fire alarm control panels ("FACPs") installed inside buildings and, if applicable, from other dedicated fire and gas systems (*e.g.*, vendor-supplied FGS). The FGS will implement logic functions and determine the required actions, which could be an alarm, a fire extinguishing system activation, signals to the Heating, Ventilation, and Air Conditioning ("HVAC") system to close inlet air dampers and shut down fans, or a trip signal to other systems such as the DCS and/or SIS. The F&G hardware will be separated from all other control systems and will not require the correct operation of any other system to fulfil its own functions. The plant FGS will be implemented on a fault-tolerant programmable electronic system having high reliability, high availability, self-testing, and self-diagnostic capabilities.

The LNG Terminal will be designed to implement safe and dependable emergency depressurization of applicable process equipment under upset conditions. After the initiation of emergency shutdown through the SIS, the isolation valves close in order to isolate the respective segments for which emergency depressuring can be initiated manually by the operator from the control room. The system inventories can then be depressurized via dedicated depressurization valves in each segment, initiated by an operator.

3.12 Electrical

3.12.1 Power Requirements

The total power requirements for the LNG Terminal are 39.2 megawatts ("MW") (holding) and 49.5 MW (loading).

3.12.2 Main Power Supply, Utility/Generated

The main power supply will be generated, on-site, by STGs. Each STG nominally produces 13.1 MW (holding mode), 16.5 MW (loading mode), 18.5 MW (design), and are rated for 30 MW.

3.12.3 Main Power Generators Type

The main power generators are STGs driven by steam generated by HRSG units located at each liquefaction train by an auxiliary boiler during black-start, or by a combination of HRSGs and auxiliary boiler when two or more HRSGs are offline for maintenance.

3.12.4 Number of Main Power Generators, including Black-start Generators

The LNG Terminal electrical system will be primarily supplied from three by 50 percent, 30 MW STGs. Two back-up diesel generators (includes N+1 redundancy) support the black-start of the auxiliary boiler, one STG, the back-up air compressor, control building essential loads, and miscellaneous electrical load for enclosures, buildings, and miscellaneous process loads.

3.12.5 Main Power Supply Voltage

For the main power supply, each STG will produce electricity at 13.8 kilovolts ("kV.")

3.12.6 Main Power Supply Capacity

The main power supply capacity for the normal operating load under the holding case is 43,679 kilovolts ampere ("kVA") and for the normal load under the loading case is 54,603 kVA.

3.12.7 Emergency Power Supply, Utility/Generated

Plant emergency loads will be powered through redundant uninterruptible power supply ("UPS") or direct current ("DC") systems. No emergency power generator will be provided.

3.12.8 Number of Transformers

A total of 54 transformers are currently allocated for the LNG Terminal.

3.12.9 Electrical Distribution System

The power distribution system will include: a 13.8 kV electrical system for the plant main supply, a 6.9 kV electrical system to supply the plant's MV loads, a 480 V/motor control center ("MCC") electrical system to supply the plant's LV loads, a UPS system, and DC battery systems.

3.12.10 Uninterruptible Power Supply and Battery Backup Systems

UPS systems dedicated to process control and process safety will contain two DC-to-alternating current ("AC") inverters, a bypass transformer, static transfer switches, and an AC power panel. Both inverters will be fed from common battery bank with a battery monitoring system. This design will provide a consistent power supply for critical control during normal operation and for limited duration to restore power supply upon loss of the normal AC source. This UPS system will be sized to provide 60 minutes of back-up power. The Fire and Gas ("F&G") system will have a dedicated battery bank and chargers, and battery monitoring. The battery sizing for the F&G system is based on NFPA 72 requirements.

3.12.11 Hazard Area Classifications

The hazardous area classification will be in accordance with NFPA 59A and NFPA 497, and API Recommended Practice ("RP") 500 requirements.

3.12.12 Ignition Control Setbacks and Separations

Ignition control will be employed to reduce the likelihood of ignition in the event of a flammable material release. Ignition control is achieved through the following features for the LNG Terminal:

- Minimization of the number of potential ignition sources;
- Use of inherently safe equipment;
- Equipment design to reduce the likelihood of ignition in areas where leaks of flammable substances could occur;
- Segregation of ignition sources from flammable inventories; and
- Location of intakes and exhausts for combustion equipment outside hazardous areas.

3.13 Buildings and Structures

Buildings and structures required for the operation of the LNG Terminal include:

- Administration building;
- SORSC building;
- Fire department;
- Operations building/control room/laboratory/first aid facility;
- Main gate guard house and security building;
- Secondary entrance security gate/terminal guard building;
- Plant warehouse/receiving building;
- Maintenance building;
- Tugboat, storage, and crew building;
- Lube oil, paint and compressed gas storage;
- Water treatment building;
- Inspection station shelter;
- Fire water pump buildings;
- Fire water valve houses;
- Marine control room building;
- Electrical powerhouses;
- Equipment shelters/buildings;
- Analyzer buildings;

The siting of occupied buildings will be evaluated for overpressure, toxic release, and fire hazards. Occupied buildings will be sited in accordance with industry standards. Loads, analysis, design, and construction will be in accordance with all statutory and regulatory requirements.

3.14 Lighting System

The lighting levels will be based on API standards. Lighting around equipment and facilities where routine maintenance activities could occur on a 24-hour basis would range from 1 to 20 foot-candles, with 20 foot-candle lighting levels within the compressor enclosures.

General process area lighting would be kept to a minimum, on the order of 2 foot-candles. Access and Utility Corridor lighting for the LNG Terminal would be 0.4 foot-candle. Perimeter security would be on the order of 1.3 foot-candles, using evenly spaced 400 watt floodlights. As a point of reference, 20 foot-candles is close to the indoor lighting in a typical home, 2 foot-candles is typical of that found in a store parking lot, and 0.4 foot-candle is typical of residential street lighting. The final lighting plan would be developed during detailed design.

Only lighting required for operation and maintenance, safety, security, and meeting Federal Aviation Administration requirements would be used on the LNG storage tanks. The light will be localized to minimize off-site effects.