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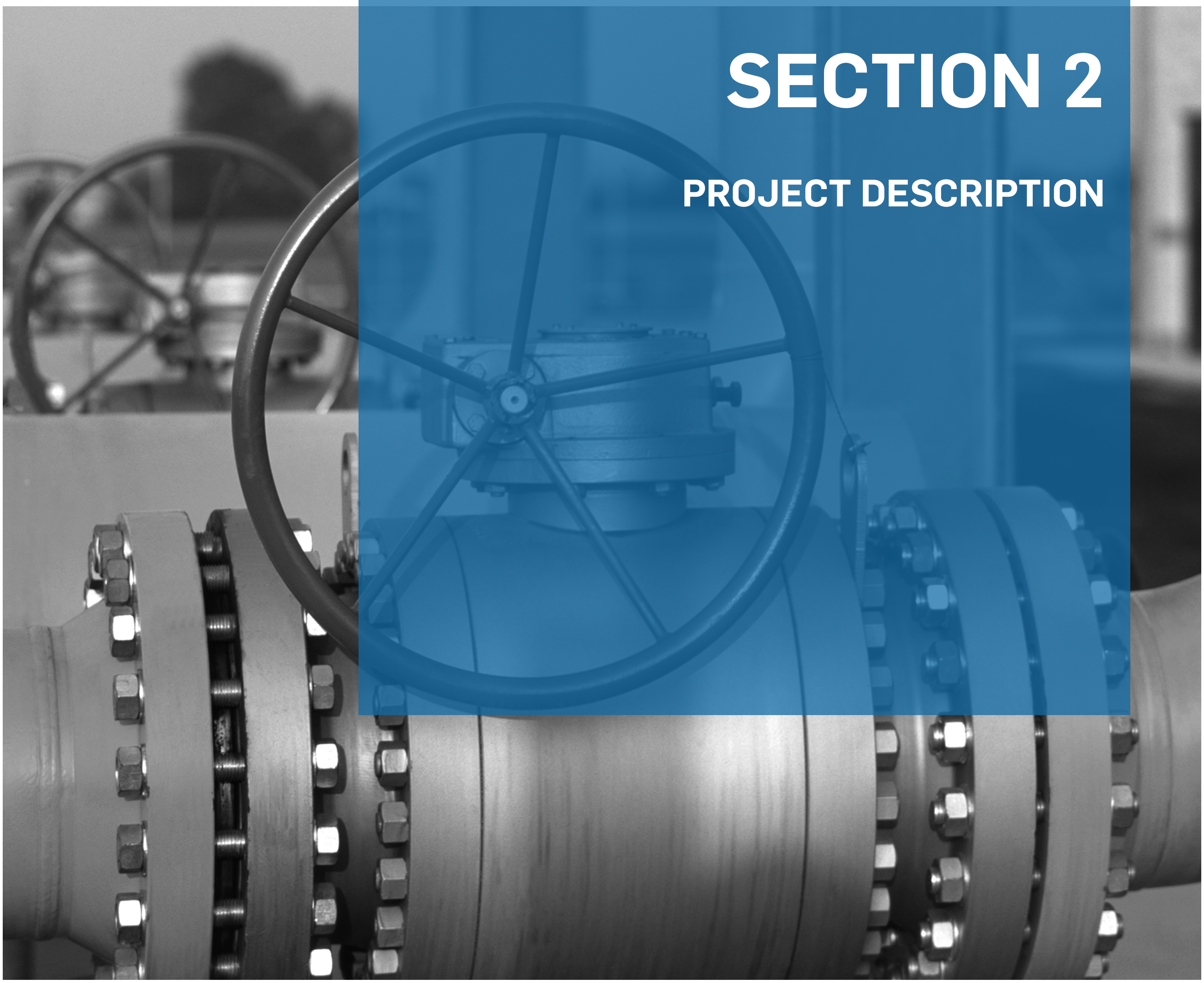
SECTION 2

PROJECT DESCRIPTION



Bear Head LNG

A subsidiary company of Liquefied Natural Gas Limited

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2 PROJECT DESCRIPTION

2.1 Project Overview

As indicated in Section 1.2, Bear Head LNG intends to utilize and build upon the existing infrastructure at Bear Head in the Point Tupper Industrial Park to construct an LNG export facility with a nominal production capacity of 8 mtpa capable of loading LNG vessels with a capacity up to 267,000 m^3. Feed gas will be received via a dedicated pipeline lateral. This feed gas will be liquefied, stored on site in LNG storage tanks, loaded onto LNG vessels and shipped to world markets. Table 2-1 summarizes the main project parameters.

The proposed plant will include four (4) LNG processing trains where feed gas will be treated, liquefied and sent to two LNG tanks, each with a capacity of approximately 180,000 m^3. Common utilities such as raw water facilities, refrigeration make-up storage and natural gas condensate storage will be provided to each of the four (4) LNG processing trains. Each train is a liquefaction system capable of producing 2 mtpa of LNG. Production capacity has the potential to increase as a result of various conditions including ambient climate and equipment performance. The proposed facility layout is shown in Figures 2-1 and 2-2.

2.2 Project Activities

2.2.1 Completed Works

Since most of the site preparation has been completed, including site clearing, grading and leveling, road construction, and the installation of two LNG tank foundations, the terrestrial footprint of the Project has been established. Additional site preparation will be undertaken to enable the installation of temporary facilities, fencing, parking, offices, staging and lay down areas; construction activities will require limited vegetation removal and grading to establish a gas metering station on the western portion of the site adjacent to the entrance gate and access road. Those areas that will require additional site preparation work are shown in the Figure 1-5.

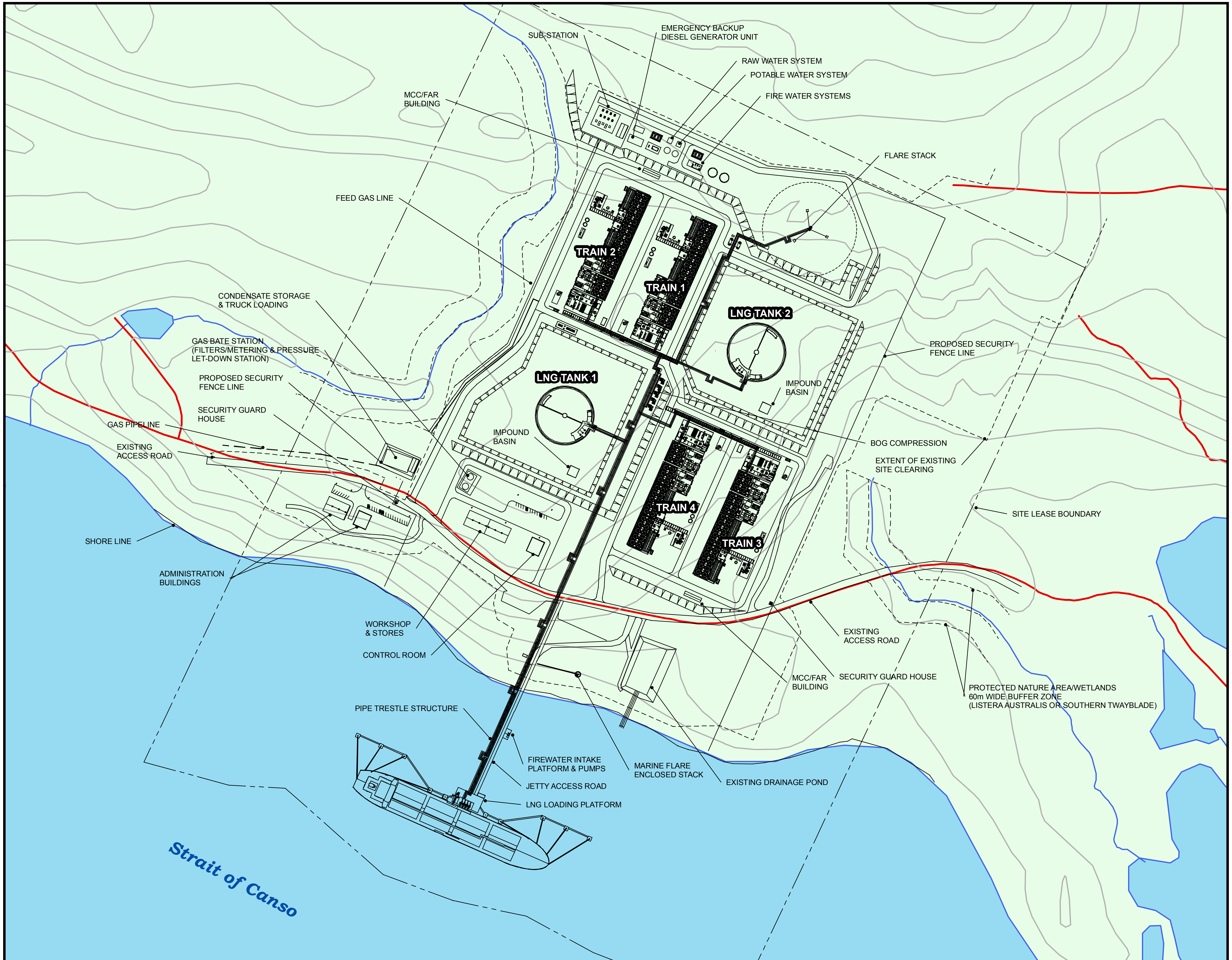

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Figure 2-1

Proposed Project Site Layout

Project Number: 622560
Date: April 1, 2015

Data Source:
-Canvec (2013) Digital National Topographic System (NTS) topographic dataset for Port Hawkesbury (011F11)
-Site Preparation As-builts, J & T Van Zutphen for Bear Head LNG Corp., April 7, 2006, PN 6143
-Plot Plan, LNG International Limited, March 5, 2015, BH-DG-00-002 Rev C1

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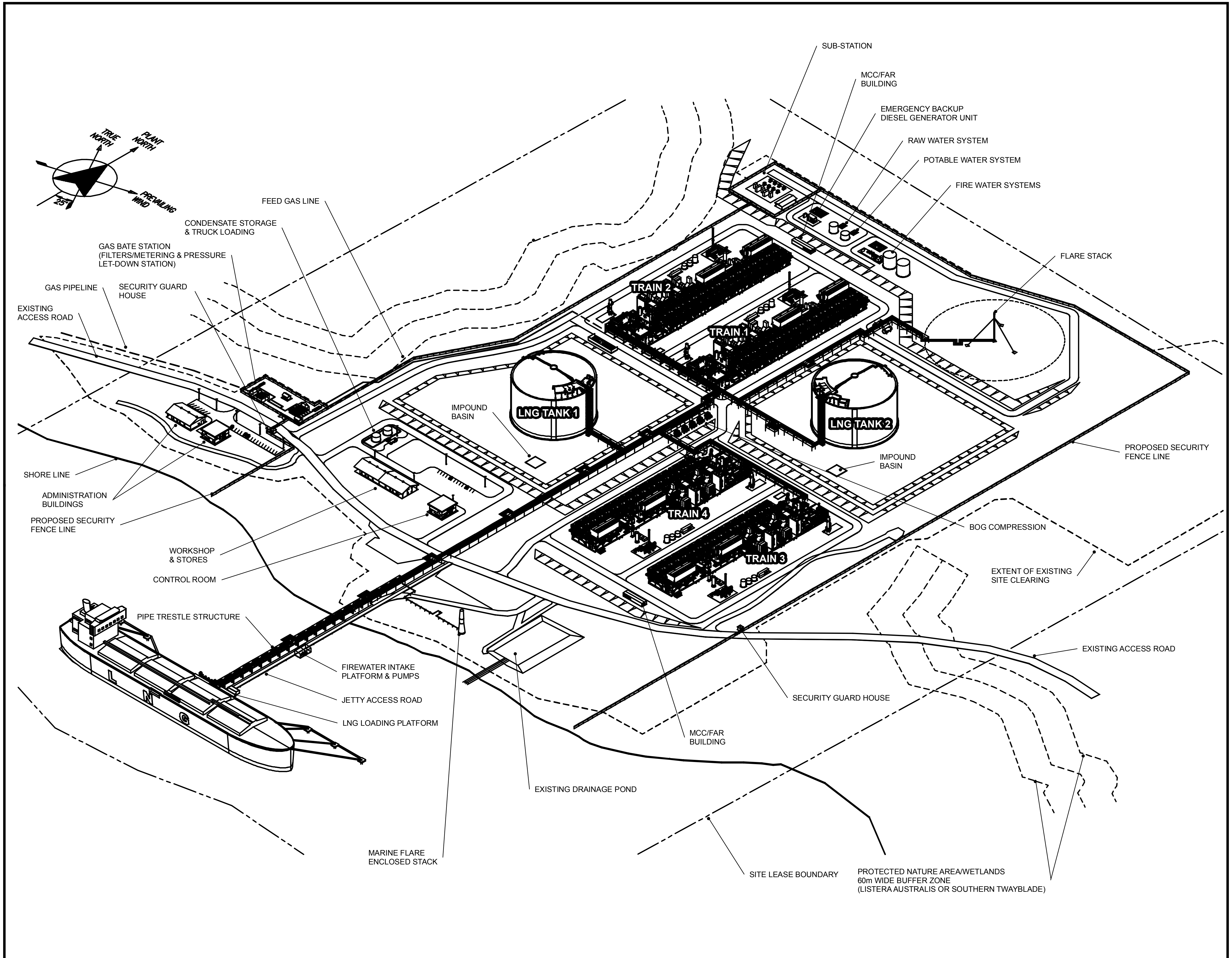

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Figure 2-2

Proposed Project Site Layout (3D)

Project Number: 622560
Date: April 1, 2015

Data Source:
-Site Preparation As-builts, J & T Van Zutphen for Bear Head LNG Corp., April 7, 2006, PN 6143
-Plot Plan, LNG International Limited, March 5, 2015, BH-DG-00-002 Rev C1

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Table 2-1: Overview of Bear Head LNG Project

Project Name:	Bear Head LNG
Project Developer:	Bear Head LNG Corporation
Project Location:	Point Tupper / Bear Head Industrial Park Cape Breton, Nova Scotia, Canada
Total Production Plant Nominal Capacity for 4 Trains:	8 mtpa
Gas Supply:	Approximately 300 MMscfd per Train
Gas Delivery:	Via a dedicated lateral pipeline to the Project site
Project Facilities:	♦ 4 x 2 mtpa processing trains each with gas pre-treatment and liquefaction ♦ 2 x approximately 180,000 m^3 single containment LNG storage tanks ♦ Condensate production rate: 65 to 295 barrels/day/train ♦ Condensate storage tanks and truck loading ♦ LNG vessel loading ♦ Utilities and buildings
LNG Vessel Capacity:	125,000 - 267,000 m^3
Shipping Frequency:	Expected Typical for 8 mtpa (nominal capacity): ♦ Approximately 80 – 130 vessels per year.
LNG Process:	Optimized Single Mixed Refrigerant (OSMR®)
OSMR® Process Licensor:	LNG Technology Pty Ltd

2.2.2 Continued Construction

The further construction of the Bear Head LNG facility will focus on equipment, infrastructure buildings and piping. Specifically, construction for the Project involves the following components:

- Construction of a temporary wharf and work surface;
- Fabrication and transportation of liquefaction processing trains and utility modules to the site;
- Onsite installation and hook-up of pre-fabricated process and utility modules;

- Construction of two (2) LNG storage tanks the base slabs for which are already in place;
- Construction of marine terminal facilities, including an LNG vessel loading platform, berthing and mooring dolphins, pipe trestle, jetty access road, walkways and electronic berthing systems;
- Construction of supporting infrastructure including, but not limited to, permanent buildings, roads, site access controls, permanent drainage, piping, flaring, spill containment berm walls, gas gate station, electrical sub-station, waste and materials handling, water supply, firewater systems, and waste systems; and
- Internal control, safety and security systems.

During fabrication and installation, quality assurance will be maintained by imposing controls such as:

- Specified qualifications for suppliers;
- Standards for welding, fabrication, non-destructive examination and auditing;
- Designer, fabricator and constructor competency requirements;
- LNG container construction, inspection and testing requirements;
- Qualifications for welders and quality assurance personnel; and
- Inspection and testing of piping.

In addition, communication with the relevant authorities will be adhered to for on-site inspection and approval in accordance with construction permit conditions.

2.2.3 Commissioning

In accordance with the LNG Code of Practice (2005), commissioning of Bear Head LNG will include, at a minimum:

- Cleaning and drying of equipment;
- Leak checking and hydrotesting;
- Function testing of instrumentation, controls and interlocks;
- Verification of software functionality; and
- Verification that all safety systems pertaining to process, control and fire safety philosophies are in place and functional.

Detailed commissioning procedures will be established through detailed design and will be submitted for review and approval by a Certifying Authority (Lloyd's Register) through the NSUARB approval process pursuant to the *Energy Resource Conservation Act.*

2.2.4 Operation

Following commissioning, routine operations at the facility will begin. Natural gas will be transported to site by pipeline, and will undergo processing on site in LNG liquefaction processing trains. Once liquefied, LNG will be stored in two (2) large tanks. LNG vessels will frequent the marine terminal to transport LNG to world markets. The marine terminal is designed to accommodate one (1) LNG vessel at a time. While an LNG vessel is at berth, it will be connected to the LNG lines with articulating loading arms and LNG will be pumped into the vessel. Further information related to the land based facilities, and marine terminal operations, is presented in the following sections.

2.2.5 Decommissioning

The Bear Head LNG facility will be designed for a lifespan of 20 years, with opportunities for lifespan extension with ongoing maintenance and scheduled improvements. Decommissioning of Bear Head LNG is expected to be similar to the construction phase and involve mobilization of equipment, offsite transport of LNG liquefaction train modules, and deconstruction of the supporting infrastructure including transport of LNG processing train instrumentation and tanks. A decommissioning plan will be developed prior to any decommissioning work and will take into account all applicable legislation, codes and standards in place at that time. Decommissioning planning is expected to include a review of pertinent baseline data and follow-up monitoring, ongoing record keeping, the documentation of factors influencing environmental conditions, and preparation of a site rehabilitation plan.

2.2.6 Project Schedule

The tentative schedule for the project is shown in Figure 2-3.

2.3 Land Based Facilities

As referenced above, the onshore liquefaction facility will consist of four (4) LNG liquefaction trains. Feed gas will be treated, liquefied and stored in two (2) LNG tanks of approximately 180,000 m^3 each. Utilities including flare systems, raw water facilities, material storage and condensate storage will be established. The nominal capacity of the facility will be eight (8) mtpa of LNG. The capacity is based on four (4) processing trains, with a production capacity of two (2) mtpa per train. Production capacity has the potential to increase as a result of various conditions including ambient climate and equipment performance.

The onshore facilities will include the gas supply connection (gas gate station), pre-treatment plant, liquefaction plant, heavy hydrocarbon liquid handling facilities, LNG tanks, boil-off gas system, auxiliary refrigeration plant, waste heat recovery (WHR) and steam plant and associated utilities. A simplified schematic of the process is shown below in Figure 2-4.

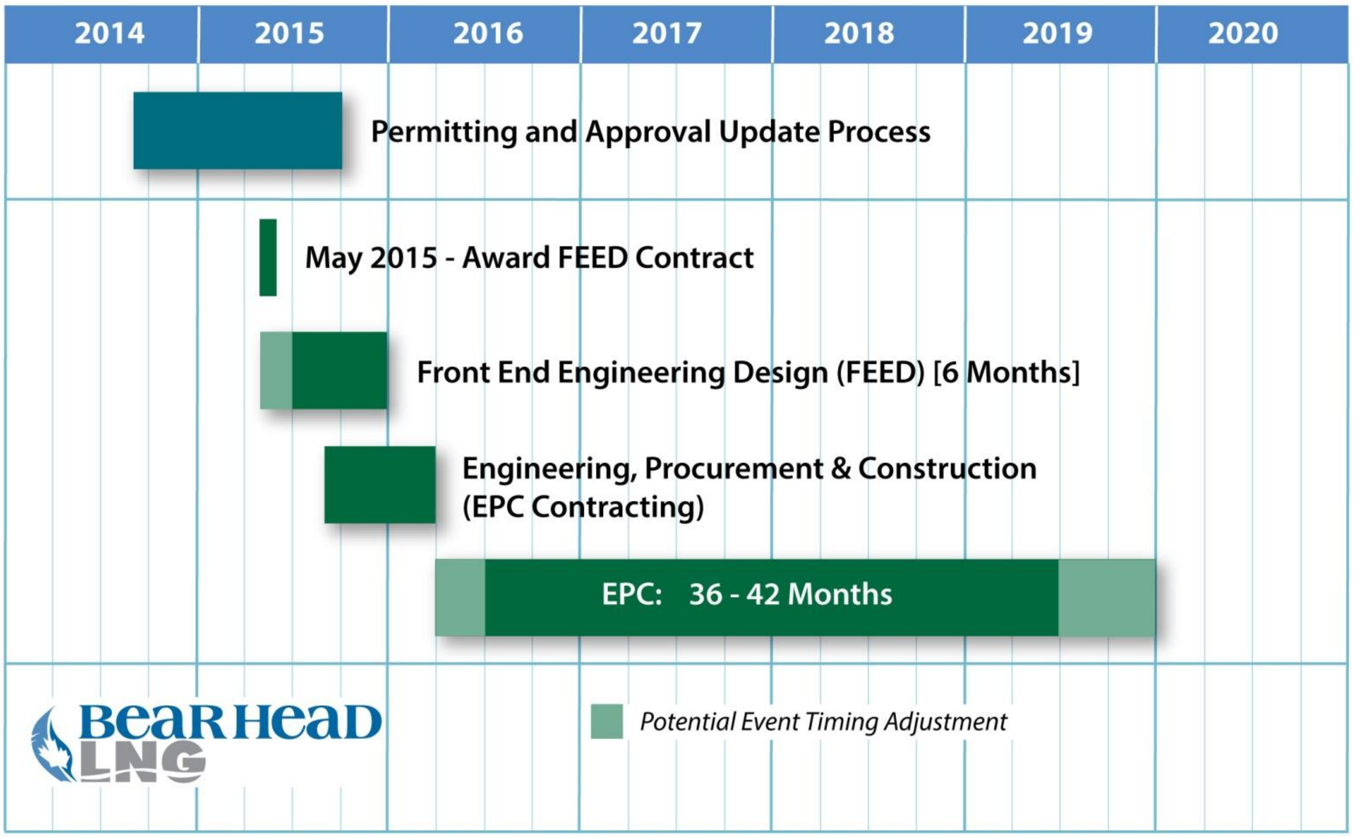

Figure 2-3: Project Schedule[1]

[1] Bear Head LNG has obtained nine of the 10 initial Canadian federal, provincial, and local regulatory approvals needed to construct a liquefied natural gas export facility on the Strait of Canso in Nova Scotia, including Permit to Construct (UARB), Transport Canada CEAA Screening (Federal Government), Navigable Waters Protection Act Authorizations (Federal Government), Fisheries and Oceans Canada CEAA Screening (Federal Government), Authorization for Works or Undertakings Affecting Fish Habitat (Federal Government), Environment Act Water Approval – Wetland Infill (Government of Nova Scotia), Breaking Soil of Highways Permit (Government of Nova Scotia), Development Permit (Municipality of Richmond County), and Beaches Act Clearance (Government of Nova Scotia). Bear Head expects the final of these initial permits (NSE approval) by the end of Q2, 2015.

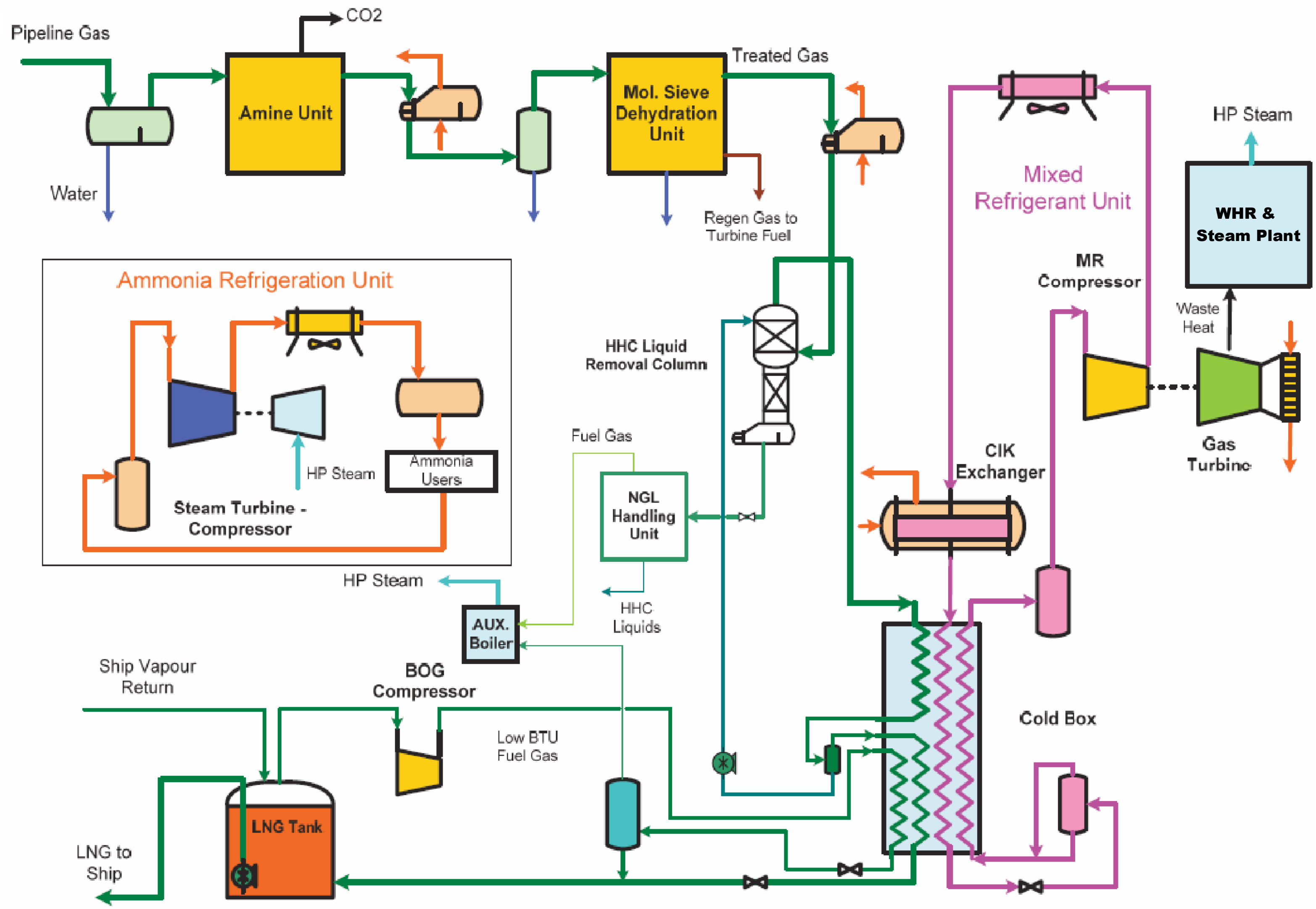

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Figure 2-4

Simplified OSMR® Schematic for the Bear Head LNG Project

Project Number: 622560
Date: April 1, 2015

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2.3.1 Gas Supply

A lateral pipeline is planned to transport feed gas to the Bear Head LNG facility. The pipeline is a separate project that will undergo its own review and permitting process, likely by a project proponent other than Bear Head LNG. The pipeline will be built to technical and environmental management standards approved for existing pipeline systems in the region. It will be laid in a trench, in a defined right-of-way, in overland areas and bottom laid across the Strait of Canso. It is expected that the pipeline will be installed in the existing right-of-way from Goldboro to the Strait of Canso, and will cross the Strait parallel to the existing gas pipeline. The exact routing of the pipeline for Bear Head LNG is currently unknown.

A gas gate station will be required at the entrance to the LNG facility; this will consist of an incoming pipeline, pig receiver, filter/separator, multiple custody transfer meters, pressure regulators, an emergency shutdown valve and a gas analyzer.

2.3.2 Pre-Treatment Plant

From the gas gate station, the feed gas will be routed to each train where it initially passes through an inlet filter coalescer that separates out any liquids prior to the gas entering an amine unit where carbon dioxide (CO_2) in the gas is removed in a contactor. Separated CO_2 is vented to the atmosphere. The water saturated gas is cooled using the auxiliary refrigeration system, passed via a knock-out separator to remove bulk water from the gas and then routed through the molecular sieve bed dryers to remove the remaining water. Condensed water and trace amounts of amine are recycled to the amine system as make-up water. The saturated gas is heated to meet the required dew point before entering the gas turbines as high pressure fuel gas. If a shortfall of fuel gas is experienced, the extra will be made up from the dry gas stream.

A mercury removal unit is provided after the molecular sieve dust filters to ensure that any mercury in the gas is removed prior to its entry into the liquefaction unit. The absorbent bed within the mercury removal unit will be replaced as warranted. Absorbent bed replacement will be completed by a qualified contractor and disposed in accordance with applicable waste disposal regulations. A treated gas filter downstream of the mercury removal unit will capture any lose particles from the mercury removal unit.

An average CO_2 content of 1.8% is expected in the feed gas. Bear Head LNG has proposed a design capacity for the amine system of up to 3 percent by volume (% vol) CO_2 in the natural gas stream. After regeneration, CO_2, after passing through a thermal oxidizer, would be vented to the atmosphere.

Hydrogen sulfide may also exist in the gas stream. The methyldiethanolamine (MDEA) used in the amine unit also captures hydrogen sulfur (H_2S). A maximum of 4 ppm_v H_2S has been considered for the design, but lower concentrations would be expected in the natural gas stream. The average feed gas composition on which the design is based is presented in Table 2-2.

Table 2-2: Average feed gas composition[2]

Main Feed Gas Constituent	Mixture Mole % (by volume)
Carbon Dioxide (CO_2)[3]	1.8%
Nitrogen (N_2)	0.4%
Methane (CH_4)	90.93%
Ethane (C_2H_6)	5.1%
Propane (C_3H_8)	1.4%
I-Butane	0.1%
N-Butane	0.1%
I-Pentane	0.05%
N-Pentane	0.05%
N-Hexane	0.02%
Benzene	0.005%
N-Heptane	0.005%
N-Octane	0.005%
Hydrogen Sulfur (H_2S)	0.0004%

2.3.3 Liquefaction Plant

The OSMR® liquefaction plant is based on a single mixed refrigerant (SMR) process comprising a simple vapour compression cycle using a mix of refrigerants. The refrigerant compressor is driven by highly fuel efficient low emissions aero-derivative gas turbines. Fuel for the gas turbines is provided by molecular sieve regeneration gas and by makeup feed gas. A description of the OSMR® process is included in Section 2.12.6.2.

Two (2) separate independent parallel refrigeration circuits are provided within each train, each comprising a mixed refrigerant (MR) compressor, MR air cooler, ammonia/MR pre- cooler, cold box and suction scrubber. The mixed refrigerant stream is comprised of methane, ethane, n- butane and nitrogen. Dry feed gas splits into two (2) feed lines and enters each cold box unit where it is cooled and passed via a liquid knockout separator to remove any heavy fractions that may freeze in the cold box. The gas is then returned to the cold box and continues to be cooled and liquefied. The liquefied gas is then flashed to low pressure and flows to the storage tanks.

2.3.4 Heavy Hydrocarbon Liquid Handling

Dry feed gas from the dehydration unit passes through a dry gas cooler (kettle type exchanger) before proceeding to a heavy hydrocarbon liquids removal column. Heavy hydrocarbon liquids recovered from the removal column are sent to the natural gas liquids handling unit where the liquids are distilled in a de-butanizer column to produce a saleable stabilized condensate product and recovered

[2] Gas composition is based on historical M&NP gas composition.
[3] 1.8% CO_2 is a conservative estimate of feed gas content.

C3-C4 liquids are pumped back to the main process with a partial reflux condenser.

2.3.5 LNG Tank and Marine Vessel Loading

LNG will be stored in two tanks, each with a capacity of approximately 180,000 m^3. Each tank will be a single containment type, with an inner wall constructed of low-temperature 9% nickel (Ni) steel and an outer wall constructed of carbon steel. The design specifications will meet National Fire Protection Association Standard (NFPA) 59A, as well as any other standards that may apply.

LNG will be transferred from the tanks to LNG vessels using submerged loading pumps. LNG will pass through a single cryogenic line and three (3) 16" loading arms on the marine terminal. Vapour generated on the vessel will be returned to the LNG tank and boil off gas (BOG) system by a vapour return arm and line. During periods when no vessel loading activity is taking place, a side stream of LNG from the cold box (just prior to the LNG tank) is used to re-circulate LNG through the vessel loading header pipeline in cases where pipelines are held at cryogenic temperatures. This assists in maintaining efficient cryogenic temperatures throughout the LNG vessel loading system by recirculating back to the LNG storage tank(s). From this same side stream of LNG, return BOG vapour from the vessel is cooled prior to entering the LNG storage tank(s). This is achieved by means of providing an LNG spray using an inline LNG vapour desuperheater.

2.3.6 Boil-off Gas System

The current design for the four (4) LNG trains allows for five (5) low pressure compressors and a simple re-liquefaction and nitrogen rejection system make up BOG system. This system is used to reject nitrogen from the LNG and BOG in order to meet the required nitrogen content in the LNG. Normally only one BOG compressor will be used per train, but during vessel loading, the fifth BOG compressor will be used to recover any additional BOG that is generated.

2.3.7 Auxiliary Ammonia Refrigeration Plant

The auxiliary ammonia refrigeration plant is used to cool the mixed refrigerant in the ammonia/MR pre-cooler, inlet air for the gas turbines, dry gas exiting the mercury bed and wet gas exiting the amine contactor. The refrigeration plant is comprised of two (2) ammonia compressors (driven by two (2) steam turbines which use steam generated from within the waste heat recovery (WHR) and steam plant), air cooled condensers, separator vessels, ammonia pumps, the interconnecting piping and control systems. The system greatly improves output and efficiency of the SMR process and stabilizes operation of the plant by dampening the impact of variations in the ambient air temperature.

2.3.8 Waste Heat Recovery and Steam Plant

The waste heat recovery and steam plant is comprised of two (2) gas turbines using once through steam generators (OTSG), two (2) steam turbines for the auxiliary refrigeration plant compressor drives, an auxiliary boiler, process and utility heating system, and air cooled condensers. Waste heat from the gas turbine exhaust and auxiliary boiler provide compression power and heat for the waste heat recovery and steam plant. The plant is sized to consume all the power that can be generated from waste heat and lean flash gas. Additional BOG generated during vessel loading results in additional low pressure fuel gas, which reduces the use of feed gas in the auxiliary boiler and alleviates the need for flaring of BOG during vessel loading. A schematic of the system is presented in Figure 2-5.

2.3.9 Electrical Power

The motors for the LNG loading pumps and BOG compressors, lighting, and other miscellaneous facility components will require electrical power from the Nova Scotia Power power grid. When at full capacity, it is anticipated that a base load of approximately 26 MW will be required during normal operating hours (twenty-four hours a day, seven days a week). While an LNG vessel is being loaded, an additional 5 MW will be needed. An average of one to two (1-2) vessels are expected per week.

The nearby Nova Scotia Power Inc. (NSPI) substation is capable of providing the power to a 138 kV or a 230 kV transmission line that would provide electrical power to the facility. A diesel generator will be available in cases where emergency power is required. No other electrical generation will occur on site.

2.3.10 Utilities

2.3.10.1 Flare Systems

The flare systems are comprised of three (3) flares: two (2) separate process flares, categorized as warm and cold flares, and a marine flare. The warm flare handles water wet relief vapour while the cold flare handles dry cryogenic vapour. This avoids any freezing in the process flare system. The marine flare relieves low pressure vapour from the LNG tanks and will be an enclosed flare. Enclosed flares provide a longer lifespan, reliable service, smaller plant footprints and have a smaller environmental impact. Flaring will not be required under normal operation due to the fact that BOG will be recovered for use as fuel.

2.3.10.2 General Site Utilities

Other process and utility systems include those for instrument air and nitrogen generation, utility water, firewater and safety systems. Buildings associated with general site utilities include the control room, the field auxiliary room, offices and workshop/store; shelters are planned for some process and utility equipment.

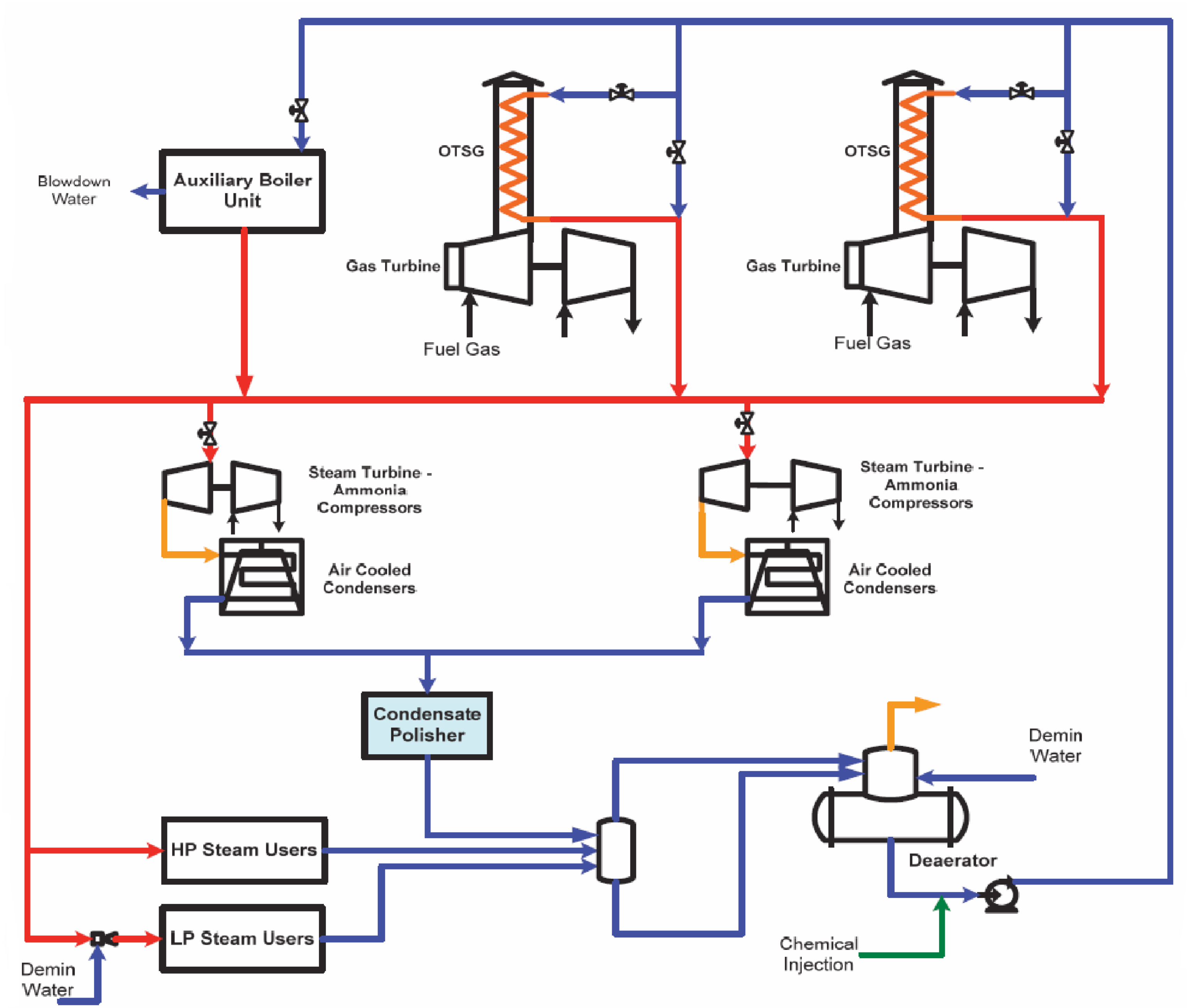

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Figure 2-5

Waste Heat Recovery and Steam Plant Schematic

Project Numer: 622560
Date: April 1, 2015

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2.3.10.3 Water Demand

Water will be used for certain process modules (steam and amine plants), fire suppression, safety (eye wash stations near chemical injection and storage sites), and for general site amenities. The water requirements for the facility will be sourced from both municipal supplies and on site groundwater wells.

A potable water package will be included as part of the overall water treatment plant. This will provide potable water which will be used for amenities and eyewash stations and safety showers. Potable water supply alternatives will be investigated during a future phase of project design (Bear Head LNG, 2014). It is recognized that water produced for human consumption must comply with provincial regulations and all necessary authorizations will be obtained.

Raw groundwater from on site wells will be treated and demineralized on site in the water treatment plant, then provided as process water to the steam and amine plants. Storage tanks and associated pumping systems will be installed for raw water and potable water.

Process water for the steam and amine plants will be demineralized. Waste streams from the demineralization process will be sent to the existing drainage pond (holding basin). Once this water quality meets acceptable levels, it will be discharged into the Strait of Canso.

Firewater for the site will come from on site groundwater wells. Well water will be stored in two (2) dedicated firewater storage tank reservoirs. Fire systems will include hydrants and hose reels, fixed and oscillating monitors, equipment deluge and water curtains, egress route sprinkler spray systems, high expansion foam generators etc. The tanks will have the capacity to provide fire protection for two (2) hours. In the event that additional fire suppression water is required, a secondary system will be in place that takes water from the Strait of Canso (salt water). A separate set of salt water pumps will be installed to pump this water through the fire suppression system (Bear Head LNG, 2014). During the EPC phase of the project, a Fire Protection Basis of Design and associated documentation will be further developed by a specialist fire systems consultant to ensure that the most up to date technologies and fire safety systems are implemented.

Other potential water sources exist and may be considered as detailed Project design is undertaken.

2.4 Marine Terminal

The marine terminal will include infrastructure for receiving LNG vessels and the loading of LNG. This will consist of an LNG vessel loading platform, an access jetty and trestle structure, mooring and berthing dolphins complete with interconnecting walkways, gangway, fire monitor towers, and with all necessary control and safety systems. The marine jetty will be a steel structure on tubular piles, with concrete decking. The access jetty from shore abutment to the LNG vessel loading platform will be approximately 143 m long. This will consist of reinforced concrete pile caps supported on tubular steel piles (driven down to bedrock), with a steel trestle frame structure in turn supporting pre-cast concrete decking. This provides support for the cryogenic piping, utilities steel support beams, and one lane of decking for light vehicle traffic. The tubular pile construction minimizes damage to the marine habitat. During construction of the marine facilities, turbidity curtains and other appropriate measures will be deployed, if logistically possible, to protect the marine environment.

The berth will include:

- A loading platform to support both the liquid product transfer lines and loading arms to transfer LNG on to the vessel;
- Four (4) breasting dolphins with quick-release hooks and fenders to assist in berthing and restrict longitudinal movement of the vessel; and
- Six (6) mooring dolphins to control potential transverse movement of the vessel.

Mooring dolphins will be accessible by walkways. A gangway will be established following berthing to transfer personnel to and from the vessel. Berthing will be supported by electronic controls.

During times when LNG is not being loaded on to a vessel, a 10-inch line will re-circulate LNG to the main header at the end of the pier. A total of four (4) marine loading arms will be installed on the platform, two (2) for liquid delivery to the vessel at berth, one (1) liquid or vapour (hybrid) arm, and one (1) for use in vapour return. The loading arms will be designed with swivel joints to provide the required range of movement between vessel and shore connections. Each arm will be fitted with powered emergency release coupling valves to protect the arm and avoid spillage. A hydraulic system and a counterbalance weight will be employed to reduce the deadweight of the arm on the shipside connection and to reduce the power required to maneuver the arm into position.

Examples of likely LNG vessels accommodated by the marine terminal design are shown in Table 2-3. Actual LNG vessel capacities have potential to vary between 125,000 m^3 and 267,000 m^3; dimensions which were previously approved for the Bear Head LNG facility. Given the natural depth of the Strait of Canso in the subject area, equal to 18 m at the proposed location of the jetty, it is not anticipated that dredging will be required to establish vessel access, or for construction of the marine facilities.

Table 2-3: Example Dimensions of LNG Vessels

	Existing Vessel Data	
	Minimum	**Maximum**
Liquid Capacity	134,318	266,000
Length Overall (LOA)	289	345
Beam	46	54
Loaded Draft (m)	12	12.2
Ballast Draft (m)	9.78	9.6
Loaded Displacement (mt)	101,151	163,922
Frontal wind area, ballast (m^2)	1,300	1,742
Lateral wind area, ballast (m^2)	6,250	9,552

2.5 Emissions and Waste Discharges

Bear Head LNG is committed to limiting waste generated by the proposed works and to meeting applicable regulations and standards. Table 2-4 outlines the various emissions generated over the life of the Project.

Table 2-4: Routine Project Emissions/Effluents

Type	Emissions and Effluents	Estimated Quantity	Characteristics	Applicable Standards/Regulation
Construction/Commissioning				
Atmospheric Emissions	Dust generation	Localized and temporary. Dust suppression techniques will be employed	Fine and Coarse Particulate Matter	NS Air Quality Regulations and Ambient Air Quality Regulations (CEPA)
	Emissions from equipment	Localized and temporary	CO_2, CO, NO_X, SO_X, PM	NS Air Quality Regulations and Ambient Air Quality Regulations (CEPA)
Wastewater Discharges	Hydrostatic testing	Testing of two approx. 180 000 m^3 tanks and necessary pipe sections	Seawater with small amounts of freshwater	After hydrostatic testing, wastewater will be tested and treated to meet provincial and federal regulations prior to discharge
	Sanitary and stormwater runoff	Portable sanitary units for workers; runoff based on rainfall amounts	Sanitary wastes, freshwater with possible particulate matter and hydrocarbon contamination	Any impacts from sanitary effluent and stormwater runoff will be addressed through the Environmental Protection Plan (EPP)
Noise Emissions	Increased noise levels	Construction noise will be temporary and intermittent	Increased noise	NSE Noise Criteria, Health Canada Noise Assessment Criteria, Richmond County Municipal By-Laws
Solid and Hazardous Waste	Solid and hazardous wastes generated during the construction phase of the Project	Dependent upon construction activities	Scrap metals, insulation waste, packing/crating materials, paints, oils, batteries, and sanitary waste	Solid wastes will be sorted into recyclable and non recyclable waste streams; waste management procedures will comply with provincial solid waste management regulations and municipal/ disposal facility requirements

Type	Emissions and Effluents	Estimated Quantity	Characteristics	Applicable Standards/Regulation
Operation				
Atmospheric Emissions	Combustion processes, fugitive or off-gassing emissions sources and flaring	Combustion will be ongoing throughout the Project; venting or off gassing is not expected to occur regularly; emissions will be	CO_2, CO, NO_X, SO_X, VOCs, N, and PM	NS Air Quality Regulations and Ambient Air Quality Regulations (CEPA)
Wastewater Discharges	Stormwater runoff	Dependent upon rainfall amounts	Possible particulate matter and hydrocarbon contamination	Any impacts will be addressed through proper collection and treatment measures, as detailed in the EPP
	Domestic effluent streams	Dependent upon total employees on site during operation	Sewage and wastewater from domestic usage	Sewage treatment systems will be developed in consultation with local government authorities and NSE
Noise Emissions	Increased noise levels	Noise levels at sensitive receptors have been modelled.	Increased noise	NSE Noise Criteria, Health Canada Noise Assessment Criteria, Richmond County Municipal By-Laws
Material and Hazardous Waste	Solid and hazardous wastes	Dependent upon operations	Scrap metals, insulation waste, packing/crating materials, paints, oils, batteries, and sanitary waste; material storage will include anhydrous ammonia, MR components (N, CH_4, ethane, N-butane) and diesel fuel	Solid wastes will be sorted into recyclable and non-recyclable wastes; waste management procedures will comply with provincial solid waste management regulations and disposal facility requirements

2.5.1 Air Emissions

Air emissions related to construction activities will include emissions from construction equipment and the generation of dust. Emissions from construction equipment will occur throughout the construction phase, but will be localized and temporary in nature. Routine inspection and maintenance will minimize exhaust fumes from equipment, and dust suppression techniques will be employed during all stages of construction.

Air emissions will also result from operation of the facility. Sources include combustion processes and fugitive emissions from equipment. Emissions from combustion processes include CO_2, Carbon Monoxide (CO), NO_x, SO_x, volatile organic compounds (VOCs) and particulate matter (PM). Fugitive or off gassing emission sources include nitrogen (N) and VOCs. Off-gassing is not expected to occur regularly; any resulting emissions will be intermittent. The need for flaring is expected to be minimal. As BOG is recovered for use as fuel, flaring will not be necessary under normal operating conditions.

2.5.1.1 Air Emissions Modelling

The anticipated air emissions were modelled to determine their potential impacts on air quality. Emission sources were identified as point sources using an emission inventory taking into account all equipment, heat input ratings and anticipated hours of operation. A summary of the ambient air quality data is presented in Section 4.2.6, and the complete results of the air modelling are presented in Section 6.1.4. As part of the air emissions modelling, the predicted air quality was compared to ambient conditions as well as air quality regulations.

2.5.2 Wastewater Discharges

The existing Bear Head LNG EPP will be updated prior to construction of the facility to minimize impacts to receptors as a result of erosion, sediment transport, stormwater runoff or wastewater used to clean concrete truck troughs. Wastewater discharges during construction are expected to be minimal and will be addressed by measures detailed in the EPP. The main source of wastewater discharge during construction will be the discharge of seawater used in the hydrostatic testing of the LNG tanks during commissioning. After hydrostatic testing, the used water will be tested, treated to meet regulations and then discharged to the sea. Pipe sections will be tested hydrostatically or pneumatically, depending on their type and function. Non-cryogenic pipes will be tested hydrostatically using clean water in accordance with American Society of Mechanical Engineers (ASME) standards.

Wastewater treatment systems will be developed to handle all wastewater produced by the facility, i.e. effluents from process, utilities, surface water streams and domestic effluents. The design of wastewater systems will be completed in consultation with local government authorities and any discharge will meet all applicable guidelines prior to release. Drainage, containment and effluent treatment systems will be installed as required and all streams will be treated to acceptable levels prior to discharge. Treatment measures may include, but will not necessarily be limited to the following:

- Site perimeter drains follow existing drainage flows discharging into the existing drainage pond. Storm water runoff from outside the plant process and utility area will be collected in this system prior to discharge into the Strait of Canso;
- Open drain system, with oily water interceptors for the five (5) process modules;
- Impoundment basins sized for LNG spill cases and potential spills of oil, chemicals and ammonia;
- A containment, open drain, separation sump and impoundment basin for the open amine plant area; and
- Containment, open drains, separation sump and impoundment basins for all LNG equipment.

Demineralized water is required for the steam plant and amine plant. The demineralized water plant will include prefiltering, reverse osmosis, electro-deionization, mixed resin bed and chemical treatment prior to storage. Reject water from the demineralized treatment plant would be drained to the existing drainage pond (holding basin) and diluted with stormwater runoff prior to discharge to the Strait of Canso.

2.5.3 Noise Emissions

Most of the site preparation has already been completed including site clearing, grading and leveling, road construction and the installation of two (2) LNG tank foundations. As a result, a large part of the Project footprint has already been established. Further construction activities will include the installation of foundations, equipment settings, ancillary equipment, piping and structures, as well as pile-driving associated with the construction of the marine facilities. The construction of the marine terminal will include the installation of an LNG vessel loading platform, an access jetty and trestle structure, mooring and berthing dolphins complete with interconnecting walkways and a temporary wharf for materials off-loading.

Project construction is projected to occur over a three (3) year time frame beginning in 2016 and running until 2019; this classifies as long term construction. Temporary and intermittent increases in ambient noise levels are anticipated. Construction hours will vary, but work will take place on site during certain stages twenty four hours a day, seven days a week.

During operation, noise will be generated from the process equipment as well as the LNG vessels. Equipment such as gas and steam turbine compressors, BOG compressors, air coolers, pumps, piping and utility equipment will generate noise, most of which will be continuous. Intermittent sources of noise such as flaring and venting are also anticipated.

The ambient noise levels at the Project site are characterized in Section 4.2.7. Noise modelling was performed to determine the impact of the Project and is presented in Section 6.1.5.

2.5.4 Lighting

Lighting is necessary for safety and security purposes. In particular, security cameras must be able to view the necessary connections, valves and vents on the LNG storage tanks. Plant lighting will be designed to meet lighting requirements in accordance with industry standards and safety regulations and will low intensity, shielded and directional, where feasible.

2.5.5 Material and Hazardous Waste

As indicated in Table 2-4, solid and hazardous wastes will be generated; these include:

- Scrap metals;
- Insulation waste;
- Packing and crating materials;
- Paints, oils, and batteries; and,
- Sanitary waste.

Solid wastes will be sorted into recyclable and non-recyclable waste streams. Where possible, every effort will be made to reduce, reuse, recycle and recover wastes at licensed facilities. Waste management procedures will comply with provincial solid waste management regulations and disposal facility requirements. Generated hazardous wastes will be stored on site in a separate and temporary hazardous waste storage area until removal by a licensed contractor for disposal.

2.6 Hazardous Materials

There will be hazardous materials on site, the majority of which will be used in the liquefaction process. Table 2-5 includes information on the hazardous materials that will be used at the facility including their source, transportation to the site, site storage (if applicable), and their use within the process. All staff working at the facility will be properly trained in the handling, storage and disposal of these materials as well as associated emergency procedures. The storage and handling of the chemicals involved will be undertaken in accordance with manufactures' recommendations and in accordance with federal and provincial regulations.

Table 2-5: Anticipated Hazardous Materials Present at the Plant

Material	Source	Transportation	Storage On Site	Use
LNG	Produced on site from feed gas	Export by LNG vessel	Two single containment storage tanks of approximately 180,000 m3 volume each	Produced on site to be shipped
Nitrogen	Low pressure fuel gas, nitrogen generator, and external	Will be generated on site. High purity nitrogen will be delivered to site as liquid in pressurized International Standards Organization (ISO) containers.	ISO containers for high purity nitrogen.	Component of mixed refrigerant
Methane	Dry feed gas, boil-off gas and low pressure fuel gas	None required; will be generated on site	None required; methane will be taken directly from the gas supply on site	Component of mixed refrigerant
Ethane	External	Delivery to site in high pressure cylinders contained in an ISO frame	High pressure cylinders; 10 tube skid cylinders, 2.5 tonne capacity	Component of mixed refrigerant
N-butane	External	Delivery to site as compressed liquid in ISO tanks	IMO 5 ISO container; 9.5 tonne capacity	Component of mixed refrigerant
Anhydrous Ammonia	External	Delivery to site by truck in HP ISO containers	Storage within liquefaction trains; no additional storage or supply required on site	Used to cool mixed refrigerant
Diesel	External	Delivery to site by fuel truck	Steel storage tanks with impoundment	Source of fuel for generator and various pumps on site

Material	Source	Transportation	Storage On Site	Use
Methyldiethanolamine (aMDEA)	External	Delivery to site in drums	One amine storage tank for each train	Used to remove carbon dioxide contained in natural gas feed
Heavy Hydrocarbon Liquid	On site Production from feed gas	Sent offsite by truck	Two tanks	Produced by Heavy Hydrocarbon Column used to remove aromatics from natural gas

Transportation and storage of hazardous materials will be completed in accordance with the Nova Scotia Dangerous Good Management Regulations as well as the *Transportation of Dangerous Goods Act* and Regulations. All hazardous materials stored on site will be properly labeled and Material Safety Data Sheets (MSDS) will be available to staff in designated areas. Risk mitigation measures will be in place to ensure the likelihood of a release is reduced. A site specific Spill Management Plan and Emergency Response and Contingency Plan will be developed to address the eventuality of a release of a hazardous material.

2.7 Technological Risk Assessment

As detailed in preceding sections, Bear Head LNG intends to resume development of the Bear Head site to export LNG. The Bear Head LNG facility will be built according to the requirements of the Canadian Standard, LNG: Production, storage and handling (CSA Z276-15), which specifies requirements related to production, storage and handling of LNG. This section provides further information on the properties of natural gas, LNG, and the refrigerant used in the liquefaction process, and provides reference to the Technological Risk Assessment. The complete Technological Risk Assessment is included in this report as Appendix B.

Natural gas is a naturally occurring flammable gas that, in its natural state, consists largely of methane and other hydrocarbons. It is a colourless, odourless, non-corrosive and non-toxic gas that is normally lighter than air due to its high methane gas make-up, unless released at its boiling point of 160^{0}C in which case it is dense. Natural gas has lower and upper flammability limits of 5% and 15% respectively. Explosions can occur only if the gas is at concentrations between these flammability limits and the gas is located within a confined space. Natural gas at the Bear Head LNG facility is expected to have the following approximate composition (base case): 90.93% methane, 5.12% ethane, 1.42% propane, 1.8%

carbon dioxide[4] and 0.4% nitrogen with the remaining 0.32% C4+.

LNG is natural gas in its liquid state that has gone through a cooling process using refrigerants to reduce temperatures to -162°C. LNG vapour at high concentrations can displace oxygen resulting in oxygen levels that are not safe for human exposure and potentially causing asphyxiation if a person were to enter a high concentration area. The low temperature of LNG causes condensation of water vapour in the air which forms a visible white cloud. The primary hazards of LNG result from its vapour dispersion characteristics, flammability and cryogenic temperatures which can cause frostbite under direct skin contact.

The liquefaction of natural gas at the Bear Head LNG facility will use a combination of anhydrous ammonia refrigerant and a MR cooling. The ammonia refrigerant is used as a liquefied or compressed gas to cool the mixed refrigerant in the ammonia and MR pre-cooler (CIK exchanger). Each LNG train will have a circulating inventory of approximately 50 tonnes of ammonia. Ammonia will be delivered to the site when required. If de-inventory is required, truck tankers will be mobilized to the site to transport ammonia off site. Ammonia in liquid form is colourless and very soluble in water. As a gas, ammonia is slightly flammable but difficult to ignite with a narrow range of flammability.

The MR is made up of four (4) components with the approximate composition as follows: 39% ethane, 33% methane, 16% nitrogen and 12% N-butane. The methane and nitrogen will be produced on site. Ethane and butane will be delivered in cylinders or ISO containers. The specific characteristics of MR components, such as toxicity and flammability, are discussed in detail within the appended Technical Risk Assessment Report (Appendix B).

2.7.1 Methodology and Analysis

The codes referenced within Section 4 of the appended Bear Head LNG Technological Risk Assessment (Appendix B) are CSA Z276-15 and the LNG Code of Practice. The CSA Z276-15 standard provides guidelines and requirements in order to provide for an acceptable level of safety for the population in the proximity of an LNG facility. The current version of this standard is incorporated by reference in the Gas Plant Facility Regulations in Nova Scotia. The LNG Code of Practice is adopted in accordance with the *Nova Scotia Energy Resources Conservation Act*. The LNG Code of Practice provides additional requirements and guidance for the design, construction, operation and abandonment of land-based LNG plants and the associated jetty and marine terminal to ensure the protection of the public. Section 4 of Appendix B discusses the compliance of the Bear Head LNG export facility with the identified code and standards. Specifically, plant siting provisions are discussed with relation to LNG storage tanks, LNG rundown and transfer areas, and minimum setbacks and separation distances. Also, thermal radiation and vapour dispersion exclusion zone requirements are modelled.

[4] 1.8% CO_2 is a conservative estimate of feed gas content.

Section 5 of the appended Technical Risk Assessment also refers specifically to Clause (e) of section 5.1.1 of CSA Z276-15, which states that the suitability of the LNG facility site must take into account the other factors applicable to the safety of plant personnel and the surrounding public. Section 5 of the Risk Assessment specifically outlines potential consequences of major accidents by referencing the Environmental Emergency Regulations which outline requirements for the preparation of emergency plans and reporting of accidental releases. Environment Canada recommends the following guidelines in application of the regulation:

- Council for Reducing Major Industrial Accidents, 2007. Risk Management Guide for Major Industrial Accidents
- Canadian Standards Association (CSA), 2003. Emergency Preparedness and Response. CAN/CSA Z731-03

Exclusions Zones

Following these regulations and guidelines, potential consequences of major accidents were analyzed in Section 5 of the Technological Risk Assessment. Specific scenarios include major accidental releases for MR and ammonia, major leaks in the LNG transfer lines and a major LNG spill from the storage tanks.

The LNG thermal radiation exclusion zones have been analyzed for the LNG storage tanks and for the liquefaction train and transfer lines impoundments. The CSA Z276-15 standard requires that provisions would be made to prevent radiant heat flux in case of a fire in an impounding area from exceeding the following limits:

- 5 kW/m^2 (1,600 Btu/h/ft^2) at a property line that can be built upon for ignition of a design spill;
- 5 kW/m^2 (1,600 Btu/h/ft^2) at the nearest point located outside the owner's property line that, at the time of plant siting, is used for outdoor assembly by groups of 50 or more persons for a fire over an impoundment;
- 9 kW/m^2 (3,000 Btu/h/ft^2) at the nearest point of the building or structure outside the owner's property line that is in existence at the time of plant siting and used for occupancies classified by NFPA 101 (Life Safety Code), as assembly, educational, health care, detention and correction or residential for a fire over an impounding area; and,
- 30 kW/m^2 (10,000 Btu/h/ft^2) at a property line that can be built upon for a fire over the impoundment.

Weather assumptions in accordance with the Standard were determined and three limits (5 kW/m^2, 9 kW/m^2, 30 kW/m^2) were modelled for the two LNG storage tanks on-site, the LNG rundown lines and liquefaction trains, and the LNG transfer lines and vessel loading area. Results are included in Map 1 and Map 2 of the appended report (Appendix B). The modelled scenario for 30 kW/m^2 for the LNG storage tanks (Appendix B, Map 1) extends slightly beyond the current property boundary. This scenario does not satisfy the Standard, as it is not contained within the current property boundaries. Land acquisition and additional mitigation measures will be employed during detailed design to assure that all applicable standards are met.

Vapour dispersion exclusion zones have also been analyzed for the site to ensure that the distance from an LNG tank impounding area to the nearest property line that can be built upon is sufficient to accommodate vapour cloud dispersion from the design spill such that an average concentration of methane in air of 50% of the Lower Flammability Limit (LFL) does not extend beyond the property line as per the CSA Z276-15 standard. Vapour dispersion exclusion zones were modelled for the LNG transfer lines and vessel loading area, as well as the LNG rundown lines and liquefaction trains. The results are included in Map 3 of the appended report (Appendix B). It was determined through modelling that the vapour cloud exclusion zones will remain within the current property boundary of the facility, in accordance with the CSA Z276 Standard requirements. Modelling was completed assuming that impoundments will be built with insulated concrete. This mitigation measure is in place to ensure the exclusion would not exceed the property limit.

Risk Assessment Scenarios

Mixed Refrigerant Release

Four (4) major accidental release scenarios were analyzed for MR stored or processed. Worst case release scenarios for MR (components) in storage would occur if a fill hose ruptured in ethane storage or butane storage. Worst case release scenarios for MR in process would occur if a rupture in the process pipe occurred before the cold box or if a rupture of a process pipe occurred before the compressor. Specific operating conditions such as pressure, temperature and release elevation were established for each scenario and are presented in Appendix B. Jet fire and flash fire can also occur from the release of a flammable refrigerant. A jet fire occurs when there is an immediate source of ignition while a flash fire occurs when a flammable cloud of MR meets an ignition source at a certain distance from the emission point. The resulting maximum distances in the case of a jet fire and the maximum distances in case of flash fires are presented in Appendix B. In neither case was a scenario identified that posed a risk to the public. A third possible outcome of a MR release is an explosion. This would occur if a flammable cloud of MR, which has a concentration between the lower and upper flammability limits, is located in a congested or confined area and meets an ignition source. The results of the explosion modelling scenarios are presented in Appendix B. None of the scenarios presented adversely impacted the public.

Ammonia Release

Dispersion modelling was undertaken for ammonia which will be used as a refrigerant at the facility. According to recommendations of the risk assessment guidelines and the definition of the worst case scenario:

- The selected scenario is related to the high pressure ammonia receiver, which is the process vessel with the maximum amount of ammonia;

- The scenario considers that the whole content is released in 10 minutes;
- Under normal operations, the vessel will contain 15 m^3 of ammonia.

A summary of the operating conditions of this scenario such as discharge time, operating temperature, operating pressure, and elevation are presented in Appendix B. Toxic cloud dispersion modelling was completed for this scenario; the results are included in Appendix B and summarized below.

For this scenario considering an ammonia receiver during normal operation, the resulting distances are shown in Table 17 and illustrated on Map 4 in Appendix B. Based on this scenario, which has a very low probability of occurrence by definition, and if the accident occurs with weather conditions not favorable to dispersion (low wind speed and high atmospheric stability), the following observations are made:

- There is no possibility of fatality for the surrounding residents;
- The population at Port Hawkesbury and Mulgrave could experience concentrations well below the AEGL2 value, meaning it could experience not disabling and temporary discomfort and irritation effects;
- Few residents scattered along Marine Drive (between Steep Creek and Melford Point), on the other side of the Canso Strait, could experience concentrations slightly over the AEGL2 value but below the AEGL3 value, meaning that they could experience irreversible or other serious, long-lasting adverse health effects if they are not protected.

For most frequent weather conditions (wind speed of 3.5 m/s and higher), there would be no consequences for the population. Because of the ocean proximity, low wind speed giving the largest distances is not frequent. Furthermore, populations are located upwind of the dominant winds coming from north-west, west and south-west. The few residents along Marine drive could be affected with specific low wind conditions (speed and direction, stability F) occurring about 1% of the time.

A potential design alternative would be to have two receivers instead of one, each of them containing 7.5m3 of ammonia during normal operation. In this case, the consequences of an ammonia release are shown in Table 18 and illustrated on Map 5 in Appendix B. With this alternate design, the residents along Marine Drive would always be exposed to concentrations below the AEGL2 value.

The above consequences are for worst-case scenarios only, which have a very low probability of occurrence. They were assessed with no mitigation measures in place. Especially when wind speed is low, the high upward air flow caused by the multiple air coolers within the trains would contribute to improve the dispersion of the ammonia and to reduce the maximum distances. This was not considered in the analysis.

The remote possibility of any adverse impact associated with an accidental event is taken seriously. Further analysis will be performed during detailed engineering to determine the design modifications, risk management measures and other mitigation measures required to ensure that ammonia concentrations remain within permissible limits in the improbable event of a major ammonia release. The mitigation measures could include the installation of additional facilities (such as water sprays), modifications to the facility and to equipment, and/or the implementation of more rigorous risk management programs, to ensure that no irreversible or serious long lasting impacts will occur.

Transfer Line Release

Two (2) worst case scenarios were assessed for the LNG rundown lines from the trains to the LNG storage tanks (liquefaction run down line) and for the LNG transfer line from the LNG storage tanks to the LNG vessels (marine loading line and area). The two worst case scenarios assessed were the occurrence of jetting or flashing due to a major leak in an LNG transfer line, and LNG conveyed to impoundment. Operating conditions of the main LNG lines are summarized in Appendix B; details include line size, operating temperature, operating pressure, operating flow rate and elevation. Maximum distances for jet fire and flammable cloud dispersion resulting from LNG jetting and flashing are summarized and presented in the appended report. Two (2) outcomes are possible for this scenario: a jet fire if there is an immediate ignition of the released LNG, or a flash fire if there is a delayed ignition of the flammable cloud formed by the flashing and the dispersion of released LNG. The analysis indicates that there will be no impact on the public for either scenario outcome. Depending on the prevailing conditions, the LNG releases can be partly conveyed to the impoundments. The two (2) possible outcomes of this scenario are a pool fire if there is an immediate ignition of the released LNG, or a flash fire if there is a delayed ignition of the flammable cloud formed by the LNG evaporated from the impoundment. These outcomes correspond to those used for the evaluation of the previously discussed exclusion zones. There will be no impact on the public for either scenario outcome.

Release from LNG Tanks

The final accident scenario presented in Appendix B assumed a major spill from one LNG tank. This scenario would result in LNG filling the bermed area and the outcome is a flash fire following the delayed ignition of a flammable cloud formed by evaporated LNG. The maximum distances for flammable cloud dispersion are presented in Appendix B and the modelling results are shown in Map 6 of that appendix. The results of this scenario do not take into account the active protection measures that can be used to mitigate the consequences. In the case of a major LNG spill in the bermed area, the application of high expansion foam would reduce the LNG evaporation rate and therefore reduce the extent of the flammable cloud.

Risk Assessment Conclusions

In conclusion, the following scenarios were modelled:

- LNG thermal radiation exclusion zones;

- Vapour dispersion exclusion zones;
- An accidental release of MR;
- An accidental release of Ammonia;
- A release from LNG transfer lines; and
- A major spill from one LNG tank.

Additional risk management planning and analysis will be performed during FEED to determine mitigation measures, assure that risk is limited to permissible limits and assure that the local population is not impacted in the improbable event of an accident scenario. These mitigation measures could include installation of additional facilities, modifications to details of plant equipment, or implementing more rigorous risk management programs.

2.8 Environmental and Safety Protection Systems

Natural gas in liquefied form, or LNG, is converted from gas to liquid using a variety of processes. Generally, the LNG is kept in this form by removing certain components, such as, heavy hydrocarbons, and condensing by cooling to a temperature of -162°C. The nature of LNG minimizes the potential environmental hazards as it vaporizes into a natural gas at standard temperature. Once in gaseous form, natural gas is lighter than air and disperses quickly. Methane, a major component of natural gas, is flammable. Although safety precautions must be taken for methane flammability, it is mostly non-reactive. There are no process releases of natural gas during normal operations.

Other potential contaminants, such as lube oil and diesel fuel will be kept on site for equipment operation and emergency power generation. Proper spill cleanup equipment and materials will be located and easily accessible on site in areas with potential for spills, such as the LNG terminal. To minimize the potential occurrence of spills, a Spill Management Plan and an Emergency Spill Response and Contingency Plan will be developed and implemented.

LNG facilities are regulated and comply with the most recent safety and operational standards. Design criteria, such as that identified in the CAN/CSA Z276-15 standard for Liquefied Natural Gas (LNG) Production, Storage and Handling, are used to minimize harm to the public and environment. Other design criteria will be applied to address the unlikely but potential negative effects of severe natural disasters and events, such as hurricanes, storm surges and other extreme weather events.

2.8.1 Equipment Inspection and Maintenance

The LNG industry bases facility and operation design on the following three (3) standards:

- CAN/CSA Z276-15 – Liquefied Natural Gas (LNG) Production, Storage, and Handling
- NFPA 59A – Standard for the Production, Storage, and Handling of Liquefied Natural Gas

(LNG)

- Nova Scotia LNG Code of Practice

The industry aims to attain the highest level of safe design and operating procedures to prevent spills and contamination, and to provide high standards of fire control and prevention systems. The reference standards are reviewed and updated regularly to ensure the strictest safety compliance. Inspection and preventative maintenance are significant components of safety operations at an LNG facility. Defined inspection and maintenance procedures for all equipment and components will be developed and potential hazards and response procedures will be listed and identified in the Emergency Response and Contingency Plan.

2.8.2 Hazard Mitigation and Fire Protection Measures

To ensure industry standard and up to date hazard prevention, mitigation, and protection systems are integral to the design of the Bear Head LNG facility. A detailed analysis of the hazards will be performed early in the design process, during the FEED.

CAN/CSA Z276-15 requires LNG operators to monitor for combustible gas concentrations at any area that has potential for leaks or pooling of combustible gas. Safety monitoring at the Bear Head LNG site will be performed using programmable logic controller (PLC) systems and components. To allow for the safe shutdown or isolation of process equipment (rotating, fired, or LNG storage), an independent Safety Instrument System (SIS) will be used.

2.8.2.1 Land Based Facilities

The Bear Head LNG facility will include passive and active engineering hazard mitigation. The active systems will include the following:

- Firewater storage tank(s), freshwater pump system complete with associated piping and deluge systems;
- Ammonia controls, such as water sprays[5] if required;
- Backup seawater pump systems;
- Fixed high-expansion foam and dry chemical systems;
- Audible and visual alarms;
- Fire extinguishers (dry chemical, CO_2); and
- Closed-Circuit Television (CCTV) security monitors.

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[5] Pending detailed design.

Automated instruments will monitor process parameters, such as pressure and temperature, to ensure normal operation. Fluctuations in process parameters can indicate hazardous conditions. This hazard detection system is designed to use visual monitoring, automatic detection, an alarm system, and an emergency shutdown system. If any of these conditions are detected, hazard controls and protocols are employed.

2.8.2.2 Marine Facilities

Marine loading facilities will be designed for the transfer of LNG from site to vessel, and strict berthing procedures will be followed to ensure safe transfer of LNG to the vessel. The Bear Head LNG marine loading facility will be designed to the following standards and regulations: the Oil Companies International Marine Forum (OCIMF), the Society of International Gas Tanker and Terminal Operators (SIGTTO), the International Convention for Safety of Life at Sea (SOLAS), and site specific navigation, passage, and berthing procedures as required by the Marine Communications and Traffic Services (MCTS) Eastern Canada Vessel Traffic Services Zone Regulations (ECREG).

LNG vessels supplied for the Project are expected to be double hulled construction and utilize spherical or membrane tank designs. By complying with the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (ICG Code) regulations, each Bear Head LNG vessel can withstand partial flooding (up to two compartments) without compromising stability. Each vessel is equipped with up-to-date cargo monitoring, specified control systems and the requisite navigation equipment. Each vessel will also be prepared to follow CCG and Eastern Canada Vessel Traffic Services Zone Regulations (ECREG) procedures for piloting and navigating the vessel to berth; these are described in Section 4.5.3.

2.8.2.3 Emergency Response and Contingency Plan

The Bear Head LNG facility will follow all provincial regulations pertaining to the storage and disposal of petroleum and lubrication products. An Emergency Response and Contingency Plan and a Spill Management Plan will be developed. The CAN/CSA Z731-03 Emergency Preparedness and Management Response protocols and criteria will be used in the development of these plans. The plans will include detail on:

- Scope of project and plan coverage;
- Facility and location;
- Initial response stage (i.e., discovery);
- Sustained action;
- Follow-up procedures;
- Notification;

- A defined response management system, including an evacuation plan;
- Monitoring program;
- Site requirements (i.e., medical, security, and communication);
- Documenting and report;
- Local fire protection and Emergency Health Services contacts;
- Training and prevention, i.e., Workplace Hazardous Materials Information System (WHMIS); and
- Required regulatory compliance.

2.8.3 GHG Management Plan

A key feature of the Bear Head LNG export Project is the intent to employ a new, highly efficient processing design developed from simple, low risk technology. The process is based on the standard single mixed refrigerant cycle, with significantly improved performance through the addition of conventional combined heat and power technology and conventional industrial refrigeration. Using OSMR® liquefaction technology, the Bear Head LNG export Project is expected to result in improved efficiency and lower Green House Gas (GHG) emissions than comparable liquefaction processes.

The primary innovation of this technology is that LNG plant design is simplified. Efficiencies in the process are optimized through energy recovery and pre-cooling. Key distinctions between OSMR® technology and traditional processes include:

- Waste heat is recovered and transformed into mechanical energy through steam production;
- Gas turbine inlet air is pre-cooled using anhydrous ammonia;
- The mixed refrigerant is pre-cooled using anhydrous ammonia; and
- OSMR® technology simplifies plant design and reduces equipment, operation and maintenance requirements.

The OSMR® process consumes less energy than traditional processes, thereby increasing the efficiency of the plant. The result is a plant which is anticipated to be more efficient than competing technologies, with substantially reduced emissions and improved project economics.

The proposed Project is also following a "Beyond No Regrets" approach by implementing Best Available Control Technologies (BACTs) to mitigate GHG emissions. Further mitigation measures may be defined by the provincial government, which is currently furthering their understanding of GHG emissions from LNG facilities within the framework of the 2007 *Environmental Goals and Sustainable Prosperity Act*. Bear Head LNG will collaborate with NSE in the development of GHG policies pertinent to the industry.

A detailed GHG management plan will be developed, including the following elements:

- Detailed inventory of the proposed Project's baseline GHG sources;
- Definition of annual GHG reporting requirements, including boundary definition, source identification and auditing requirements;
- Detailed flaring and venting management program;
- Fugitive management program incorporating the following best practices: A directed inspection and maintenance (DIM) that includes leak definition, detection and repair methods, component targeting and tagging (accounting for inaccessible components), monitoring frequencies, personnel training, equipment calibrations, record keeping, and performance objectives; and
- Identification of a facility energy efficiency program as the facility's engineering becomes more refined and once the facility is operational.

The GHG management plan will be developed in collaboration with the Provincial NSE regulators.

2.8.4 Flare Emissions Management

Flare systems are designed to dispose of streams released during start-up, shutdown, and plant upsets or emergency conditions. The Bear Head LNG site will be designed to avoid continuous flaring, and will be operated to avoid impacts to birds. This site will contain three (3) flaring systems: a warm flare, a cold flare and a marine flare. Common causes of pressure relief, or flaring systems, are described below:

- Electrical power failure;
- External fires;
- Instrument and equipment failure;
- Entrapment of cold liquid that could expand;
- Incorrect operating procedures; and
- Exchanger tube ruptures.

The cold system is designed for fluids lower than ambient temperature. This system includes a Cold Flare Knockout (KO) drum, where relief fluids are held before eventual vaporization to the flare. The warm system collects fluids from pre-treatment and other areas at ambient temperature. These fluids are collected in the Warm Flare KO drum, where they will eventually be pumped and trucked to a disposal facility.

Both systems would be continuously purged with fuel gas or with nitrogen. This ensures that positive pressure is maintained and prevents atmospheric air from entering the system after a hot release. The ammonia chilling plant and the steam system are equipped with separate pressure relief systems. Relief from these systems is sent to atmospheric vents located in a safe location.

A marine flare will be required for relieving low pressure vapour from LNG tanks, but flaring will not be required during normal operation as BOG is recovered and utilized as fuel. The marine flare will not require a KO drum as the low pressure vapour from the tank does not carry liquids. Thermal reliefs from the LNG line discharge into the LNG tank.

The final design capacity of the warm, cold and marine flare systems will be determined during final design. The allowable radiation level at the site boundary is 1.58 kW/m^2 under adverse wind and solar environments. The design will keep the radiation at the site boundary to acceptable levels.

2.9 Employment and Economic Considerations

Bear Head LNG prides itself on working closely with community stakeholders, and making contributions to local communities. The Project has the potential to provide significant economic benefits to the Strait of Canso area including:

- 45 to 70 permanent direct jobs;
- 175 permanent indirect jobs;
- 600 to 700 construction jobs;
- A major new addition to the property tax base in Richmond County; and,
- Company participation in the community as a committed corporate citizen.

The Bear Head LNG Project team is committed to working with government and community stakeholders, and the general public, who will help to determine the exact nature of additional contributions to local communities.

In 2015, a study was completed for Bear Head LNG Corporation by the Perryman Group to determine potential economic benefits resulting from the Project. For Canada, the study found that construction and preoperational spending would generate an increase in business activity of some $3.312 billion in gross product and 36,263 person-years of employment. Activity would be concentrated in Nova Scotia, where construction and preoperational spending for the Project would likely generate a gain in business activity of about $2.415 billion in gross product and 24,302 person-years of employment. Results of the study are summarized in Table 2-6.

Table 2-6: Anticipated Economic Impacts Resulting from Construction of Bear Head LNG[6]

Economic Effects	Canada	Nova Scotia
Total Expenditures	$9.06 billion	$6.55 billion
Gross Product	$4.20 billion	$3.06 billion
Personal Income	$2.79 billion	$1.94 billion
Retail Sales	$1.06 billion	$0.66 billion
Employment (Person-Years)	36,263	24,302
Fiscal Effects		
Local Governments	$0.15 billion	
Provincial Government	$0.35 billion	
Federal Government	$0.51 billion	

2.10 Health, Safety and Environmental Management

The development and execution of a detailed Health, Safety and Environment (HSE) Management system applicable to all facets of the construction and operation of the Bear Head LNG facility is central to its success. A fully detailed HSE management system will be completed and implemented in accordance with national and international standards for LNG facilities. Bear Head LNG is committed to HSE throughout all stages of design, operation and decommissioning phases. Environmental protection is an important part of the EHS management system.

A Risk Management Plan will be developed as a component of the overall system to identify potential risks, estimate impacts and define response procedures for all phases of the Project. This plan will detail operational protocols and mitigation measures. All staff working on the site will be educated and trained to execute operational protocols and other risk mitigation measures. These measures will be put in place to mitigate potential hazards and to ensure the health and safety of onsite staff and those living and working in the vicinity of the Bear Head LNG facility.

In accordance with industry standards, Bear Head LNG will also prepare an Emergency Response and Contingency Plan for the facility incorporating the following:

- Coordination with local emergency services and authorities, i.e., RCMP, Port Hawkesbury Volunteer Fire Department, Emergency Health Services (ambulances), Richmond County Fire Services, Richmond County and Port Hawkesbury Emergency Management Office (EMO) Coordinators, and Point Tupper Industrial Park Tenants Group;
- Emergency procedures to be implemented, and emergency equipment to be held, at the Bear Head LNG facility as the primary responsibility of Bear Head LNG;
- Established procedures for LNG release and other potential emergency response

[6] Source: Perryman Group, 2015. Monetary values presented in constant 2014 Canadian dollars March 31, 2015. Assumes that the engineering, procurement, and construction activity in Canada conforms to current expectations by Project sponsors.

requirements;

- Creation of an emergency manual (to be kept updated) and distributed to the appropriate emergency responders; and
- Description of the Process Safety Management System.

Establishing appropriate protocols and ensuring site staff are fully trained will help to prevent emergencies. These protocols will detail the actions required to minimize or prevent damage to the Bear Head LNG facilities and injury to the public, and mitigate or prevent environmental impact. The emergency plans and procedures pertinent to the LNG vessels take priority over any other document and will include established emergency procedures pertaining to the safety of the crew, the public, the environment and the vessel. This plan will include details pertaining to cargo release, fires, collisions, human injuries, groundings, spills, and mechanical and electrical failures.

Bear Head LNG will also develop and/or update the following environmental protection plans for the Bear Head LNG site:

- **Environmental Management Plan (EMP)**– Detailed management strategy including:
  - Corporate Environmental policy;
  - EMP Objectives;
  - Legal requirements;
  - Programs and procedures;
  - Training requirements;
  - Communication procedures;
  - Requirements for reporting and record keeping; and
  - EPP for all distinct project activities including construction of both the marine and terrestrial facilities and their subsequent operation.
- **Flare Management Plan** – Will include detailed procedures on overall flare operations and management, especially during adverse weather conditions, as well as detail on operating times.
- **Green House Gas Management Plan** – Will include a detailed inventory of GHG sources, definition of annual reporting requirements, a fugitive management program and identification of a facility energy efficiency program. It will also explain how the Project is employing the best-available technology for GHG mitigation.
- **Waste Management Plan -** Procedures for managing and minimizing waste generated on site, including appropriate disposal procedures and locations.
- **Spill Management Plan -** Procedures for cleaning up and preventing small to medium sized spills of hazardous materials.
- **Stormwater Management Plan -** Outlines plans for runoff, erosion control, sediment control,

and transport of hazardous material spills.

- **Archaeological Contingency Plan** - This plan will be developed in accordance with provincial standards for the potential discovery of unexpected archaeological information.
- **Traffic Management Plan** - This pertains to the traffic on land, safety efforts for traffic controls, and procedures for minimizing dust and noise.
- **LNG Navigation and Berthing** - Will be performed in accordance with Canadian Coast Guard requirements. All activity of Bear Head LNG vessels will be performed in accordance with the MCTS ECREG. Although not a regulatory instrument, the TERMPOL process will be used, in consultation with CCG, Transport Canada and MCTS.

2.11 A Description of Alternatives to the Project

This section outlines the alternatives and their associated benefits, and contrasts these with the benefits of the proposed Project. This discussion generally supports the need for the Project and emphasizes the appropriateness of its design. Section 2.11 examines other methods for carrying out the Project.

2.11.1 Project Does Not Proceed

The goal of the Project is to export LNG to world markets. This is being done to fill a demand for natural gas in these markets using the surplus currently being generated in North America. Previous plans to import LNG were shelved in response to changes in energy markets. Importing LNG into North America is not currently economically beneficial. Natural gas exploration and production are on the rise, with many development and production projects planned or already underway.

In the case that the Project does not proceed, environmental impacts associated with continued development of the Project would be avoided. Significant adverse environmental effects, however, are not expected. The site has been approved and substantially developed for the purpose of LNG facility construction. If the Project does not proceed, the many economic benefits associated with its development would not be realized; the opportunities for local communities to benefit from world energy markets, and the substantial work that has already gone into developing the Project and the Project Site, would be lost.

2.11.2 Alternative Locations

The Project Site is considered ideal and was selected over alternative locations for a number of reasons. It is located on the Strait of Canso, which is a natural ice free harbour that is extremely deep and accommodating to large marine vessels. It is already a major bulk port zoned for industrial/marine terminal use which accommodates approximately 68% of Nova Scotia's international and domestic cargo tonnage. The Strait of Canso is also central to international shipping routes, is close to offshore resources and is in close proximity to an existing natural gas pipeline (Strait of Canso Superport Corporation, n.d.).

The site is also suitable because of the amount of development and work done thus far. As part of previous works related to the Project, an environmental assessment was performed and approved. The extensive background research undertaken as part of that process provides substantive data on the site and its environment. Most importantly, as already indicated, construction was already started before the import Project was halted in 2007. The result is that a large part of the footprint of the project has been established, greatly limiting the future environmental impacts of the project.

Finally, the general public is generally familiar with the Project due to the previous environmental assessment, the consultations that have taken place, and the site work that has been undertaken. There is general optimism that the project's development would attract other investment in the region. All of these factors mean that the project location fully meets the needs of the Project, limits environmental impacts and provides positive benefits to the surrounding communities.

2.12 Other Methods for Carrying out the Project

Having ruled out any alternatives to the Project and settled on the existing Bear Head LNG site as the ideal location, the next step was to compare any other methods for carrying out the Project. These methods focus on design aspects and include the method of product transport, site layout, the liquefaction process and LNG storage, utilities and infrastructure.

2.12.1 Product Transport

The Project's potential market is worldwide and will likely be largely overseas. As such, the only viable option for product transport is by sea. Transport by roadway or rail can be eliminated and an undersea pipeline is not considered feasible at this time.

Shipping natural gas is conducted using large LNG vessels. LNG is the most efficient and economical method for shipping natural gas as the liquefaction process reduces the volume to 1/600th. This allows for cost efficient transport over large distances. LNG is also superior when compared to compressed natural gas (CNG) as the volumetric energy density is 2.4 times greater (Envocare Ltd., 2013). For these reasons the use of LNG vessels was selected as the best method by which to transport natural gas.

2.12.2 Site Layout

The site layout was chosen to best accommodate the needs of the facility and to limit impact to the environment. Site design took into account the best area for the marine terminal infrastructure (taking into account the turning radius of the carriers, harbour depth, berth pockets, the prevailing wind, current and wave directions, etc.), natural topography, site drainage, location of wetlands and species of concern and site access. The OSMR® trains are designed for modular construction which limits the facility footprint.

It should be noted that the footprint for the site layout is, for the most part, already in place. However, as detailed design continues, the site layout will be continuously review and identified beneficial changes incorporated. Recently, the orientation of the gas metering station was changed due to concerns that the original orientation might have an impact on a small 0.06 ha treed Black Spruce and Sphagnum slope/basin wet area that was identified during a site visit on December 22nd, 2014.

2.12.3 LNG Storage Tanks

Three main types of tanks are used to store LNG at atmospheric pressure: single containment tanks, double containment tanks or full containment tanks.

Materials to be used in equipment that comes into contact with LNG at cryogenic temperatures must be carefully selected to avoid brittleness and hardware failures. Steel with 9% nickel content and stainless steel are used for the internal storage tank, piping and other equipment that comes in contact with LNG.

After considering all the various possible solutions, single containment tanks have been selected for LNG storage. They were originally planned for the import facility and meet required industry standards. The tanks consist of an inner wall constructed of cryogenic 9% Ni steel and an outer wall of carbon steel; a bermed area will be constructed to provide secondary containment. The outer wall holds perlite insulation against the inner tank, preventing ingress heat into the tank that would boil more rapidly than LNG and providing for protection from fire, heat and projectiles.

2.12.4 Removal of Acid Gases (CO_2 and H_2S)

Natural gas must be treated before being liquefied. Removal of CO_2 and H_2S is achieved by a step called "natural gas sweetening" or "acid gas removal". Several methods can be used for this treatment; all are common practice in the oil and gas industry:

- Chemical absorption;
- Physical absorption;
- Physiochemical absorption; and
- Physical adsorption.

Other methods exist, but they only allow the removal of one of the two compounds, i.e. either CO_2 or H_2S.

2.12.4.1 Chemical Absorption

The chemical absorption position of the liquefaction process is based on contact between the gas treated and an aqueous solvent containing an amine. This allows it to react with CO_2 (acid). Chemical absorption takes place in an absorption tower equipped with trays or packing.

The solvent reacts with acid gases to form unstable salts. These chemical reactions are reversible: if heat is applied, the pressure and temperature conditions change, which frees the absorbed compounds and regenerates the solvent. Some amines tend to absorb heavy hydrocarbons, which must be avoided, or react with sulfur derivatives present in natural gas (carbonyl sulphide (COS) and carbon disulphide (CS_2)) to form stable and corrosive by-products, which means that an additional step of purification by distillation is required to regenerate the solvent. Table 2-7 compares the main amines that may be used in the chemical absorption process for a liquefaction unit.

2.12.4.2 Other Systems

Table 2-9 provides an overview of other systems available for natural gas sweetening.

2.12.4.3 Selected Option

Due to the characteristics of the natural gas and its composition with respect to acid gases, the chemical absorption process with tertiary amine (MDEA) was selected primarily due to its ability to remove CO_2 to very low levels and due to its lower foaming tendencies.

Table 2-7: Comparison of Amine Systems for the Chemical Absorption of Acid Gases

Amine	Monoethanolamine (MEA)	Diglycolamine (DGA)	Diethanolamine (DEA)	Methyldiethanolamine (MDEA)
Specifications	Primary amine Highly responsive to CO_2 and sulfur compounds	Primary amine. More concentrated than MEA; therefore the amine has a lower recirculation rate	Secondary amine Captures more acid gas per volume of circulated amine	Tertiary amine Selectively reacts with H_2S first, then with CO_2 (less reactive than MEA)
Special equipment	Addition of a distillation system	Smaller than MEA	-	-
Formation by-products	Reacts with COS and CS_2 to form stable and corrosive by-products	Reacts with COS and CS_2 as for MEA	Captures COS and CS_2 but does not form stable by-products	Captures COS and CS_2 but does not form stable by-products
Energy required for regeneration	Baseline scenario : higher than the other amines	Lower than MEA	Lower that MEA or DGA	Lower than all other amines
Degradation of the amine	Sensitive. Purification by distillation required	Sensitive. Purification by distillation required	Does not degrade	Does not degrade
Absorption of C3+ hydrocarbons	Low	Absorbs more C3+ than MEA Advantages	No	No

Amine	Monoethanolamine (MEA)	Diglycolamine (DGA)	Diethanolamine (DEA)	Methyldiethanolamine (MDEA)
Advantages	-	-	Less corrosive than MEA or DGA	Less corrosive than all other amines Lower foaming tendency
Disadvantages	Corrosive	Corrosive	-	-
Use	Barely used these days for liquefaction	Barely used these days for liquefaction	Most commonly used amine	Ideal choice depending on the sulfur and CO_2 content of the gas

Table 2-8: Other Methods Available for Acid Gas Removal

Parameter	Physical Absorption	Physicochemical Absorption	Physical Adsorption
Principle	Absorption by dissolution in a physical chemical without chemical reaction	Absorption by mixed solvents (chemical and physical); process similar to chemical absorption	Retention of the acid gases in a molecular sieve composed of crystals such as zeolite
Solvent or adsorbent material	Organic liquid such as : ♦ Methanol ♦ Propylene carbonate ♦ Morpholine derivatives	Association of a physical solvent such as sulfolane and an amine which makes it possible to capture mercaptans	Adsorbent as matter such as: ♦ Charcoal ♦ zeolite
Regeneration	Very economical: simple depressurization requiring little heat	The physical reduces the necessary regenerative energy	Several adsorbers in parallel with out of step adsorption/regeneration cycles
Performance	Higher at low-temperature and high partial pressure	Good absorption capacity for low partial pressures	Higher at low temperatures and high partial pressure
Application	Natural gas with high acid gas content	Natural gas with a high content of acid gases and a limited quantity of heavy hydrocarbons	Especially for natural gas with low acid gas content
Limitations	Cannot achieve the required low levels of CO_2 and H_2S		The diffusion of the gas in the solid and on the surface is significant
Absorption of C3+ hydrocarbons	Tends to absorb C3+	Tends to absorb C3+	Does not absorb C3+

2.12.5 Cooling System

The process cooling systems generally removes the heat of compression at various locations within the plant. The source of cooling can be water or air. Table 2-9 compares various possibilities: air-cooler, cooling tower and the open system (once-through cooling system).

Unlike the other water cooling systems, an air-cooler does not use chemicals for water treatment, and therefore does not discharge an effluent, and does not generate a vapour plume in winter. To take into account environmental sensitivities of the receiving environment, this technology has been successfully implemented for large LNG plants, and has therefore been selected for the Bear Head LNG Project.

Modular sections consisting of standard units allow greater availability of coolers. Fans with low-noise blades mitigate the noise impact of the installations if required. In addition, it should be noted that the construction of a new outfall or a new water intake could potentially affect fisheries and fish habitat and may therefore also require additional approvals.

Table 2-9: Cooling Methods Comparison

Cooling Method	Advantages	Disadvantages
Open System Once-through circulation of seawater in a cooling system	♦ Most economical system ♦ Low operation costs ♦ Low power consumption ♦ More efficient in terms of thermal performance ♦ Simple operation	♦ Requires a water intake and outfall (high costs) ♦ High environmental impact ♦ Requires a high water flow, especially in summer with possible fish entrainment and mortality ♦ Significant heat rejection ♦ Occasional discharge of chlorinated water for shock treatments
Cooling Tower Fluid in the system is cooled by partial evaporation into the atmosphere in a tower with natural or forced air circulation and a circulation of freshwater or seawater in a closed circuit	♦ Lower water flow and discharge temperature compared to the open system ♦ Moderate capital cost and power consumption	♦ Requires raw water and cooling water treatment ♦ Source of visual nuisance: vapour plume visible in winter ♦ Possible fog and icing of nearby roads in winter ♦ Potential source of noise ♦ Discharge of an effluent into the receiving watercourse
Air-Cooler Large diameter fans dissipate heat into the atmosphere through coils arranged in the manner of a conventional radiator	♦ Ideal choice if water is not available ♦ No water treatment and no liquid discharge ♦ No chemicals ♦ Distributed design based on standardized units	♦ Source of visual nuisance and noise ♦ Greater consumption of electricity than the other options ♦ Operation varies depending on weather conditions (less efficient in summer and more efficient in winter)

2.12.6 Refrigeration Circuit

There are several refrigeration cycle configurations that can be used to liquefy natural gas. Each cycle has its advantages and disadvantages. Some refrigeration cycles have high energy efficiency, but are technically complex and very expensive. Conversely, other refrigeration cycles are technically simpler and have a lower capital cost, but are less energy efficient. The OSMR® process that will be used for the Bear Head Project combines all the advantages sought for an LNG facility: simple, low cost, highly efficient, environmentally friendly, robust and low-risk.

As shown in Figure 2-6, the main natural gas liquefaction processes can be classified into three groups: cascade processes, processes with mixed refrigerants, and processes with compression/expansion. The following sections summarize the most common refrigeration cycles.

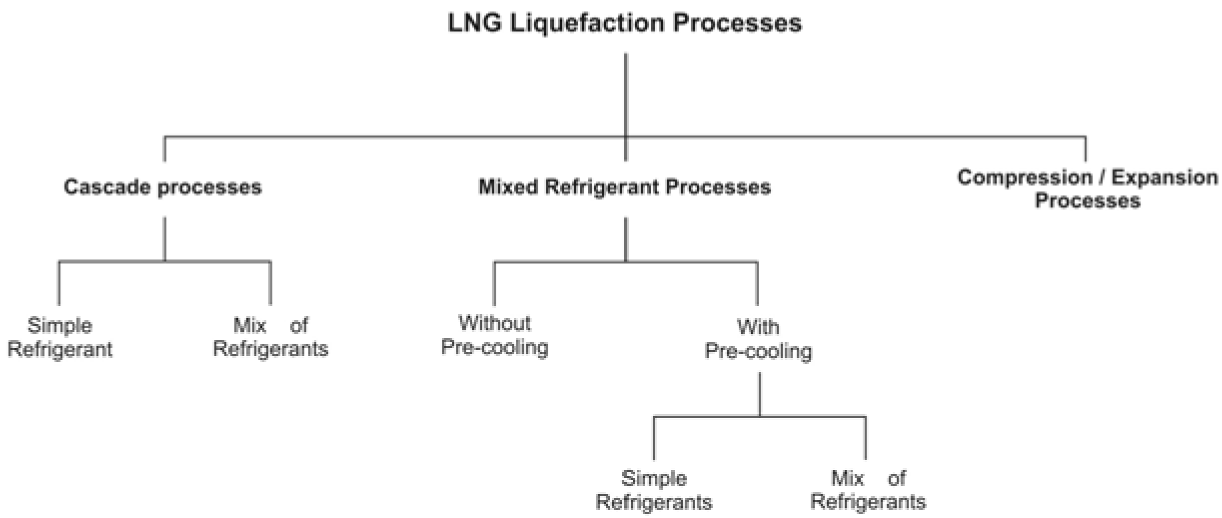

Figure 2-6: LNG Liquefaction Processes

2.12.6.1 Cascade Processes

The cascade process (Figure 2-7) is characterized by the use of a succession of three (3) increasingly cold cooling cycles: pre-cooling, liquefaction and sub-cooling. Cascade processes are used to follow the natural gas cooling curve, resulting in improved efficiency. Cooling is typically achieved with single refrigerants such as propane, ethylene and methane.

Processes with Single Refrigerants

The main advantage of this method lies in its simplicity of operation made possible by the single refrigerants, but its thermodynamic efficiency is lower than for processes using mixed refrigerants.

Process with Mixed Refrigerants - MFC (Mixed Fluid Cascade)

With the MFC process, three (3) refrigerant mixtures are used for pre-cooling, liquefaction and sub-cooling. The first cycle of pre-cooling uses a mixture of ethane and propane as refrigerants. As for the liquefaction and sub-cooling cycles, a mixture of methane, ethane, propane and nitrogen is used. Compared to the single refrigerant process, this process is characterized by reduced energy consumption and more flexibility at the operational level. This method is more suitable for medium capacity facilities.

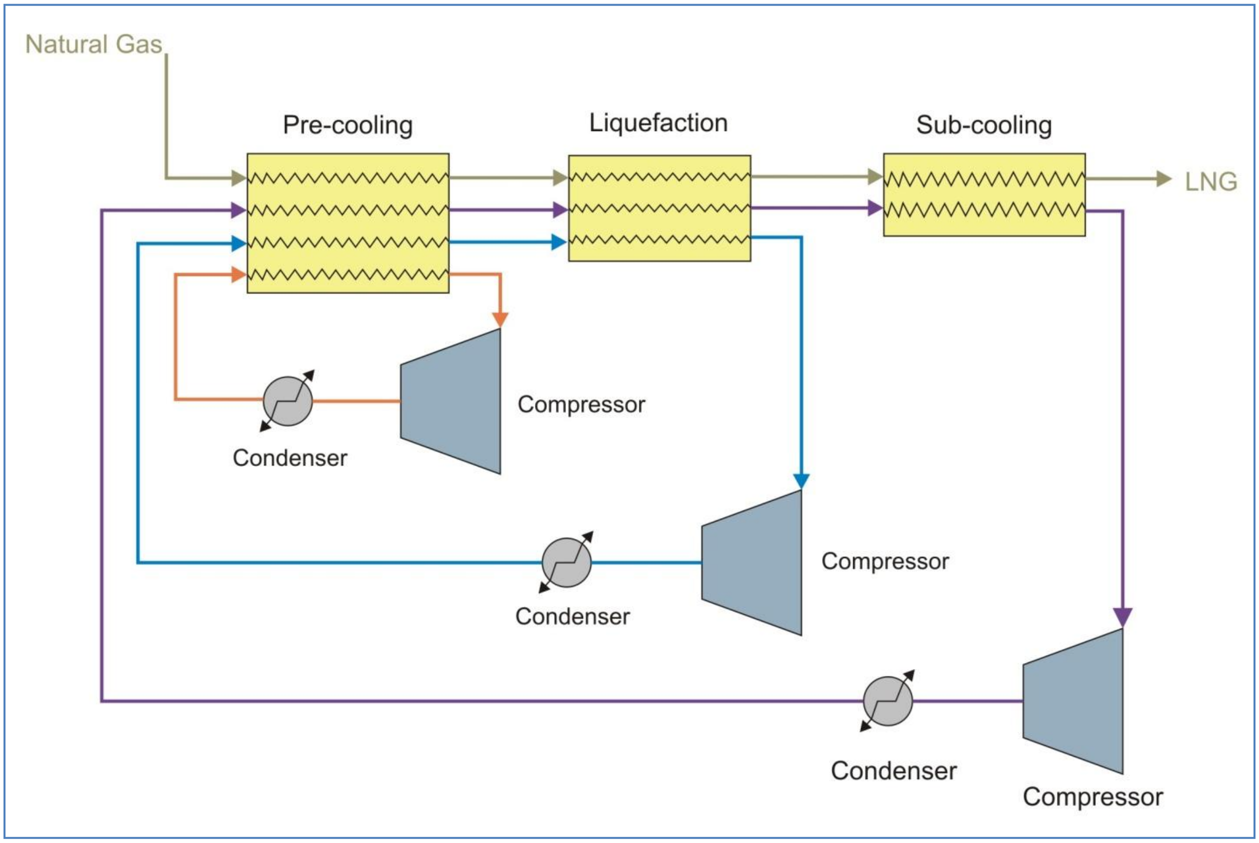

Figure 2-7: Simplified Cascade Process Diagram

2.12.6.2 Processes with Mixed Refrigerants

Mixed refrigerant processes are based on one (1) refrigeration cycle or on two (2) cycles when they include a pre-cooling cycle.

Single Mixed Refrigerant Process

This process consists in using a single flow of mixed refrigerants for pre-cooling, liquefaction and sub-cooling, which take place in a single cycle (see Figure 2-8). This process is characterized by its simplicity and a small number of equipment. The mixed refrigerant is composed of nitrogen and various hydrocarbons with a low boiling point.

This process has the advantage of requiring a smaller number of equipment items, but is less efficient than that of multi-cycle processes. It is not suitable for large capacity facilities.

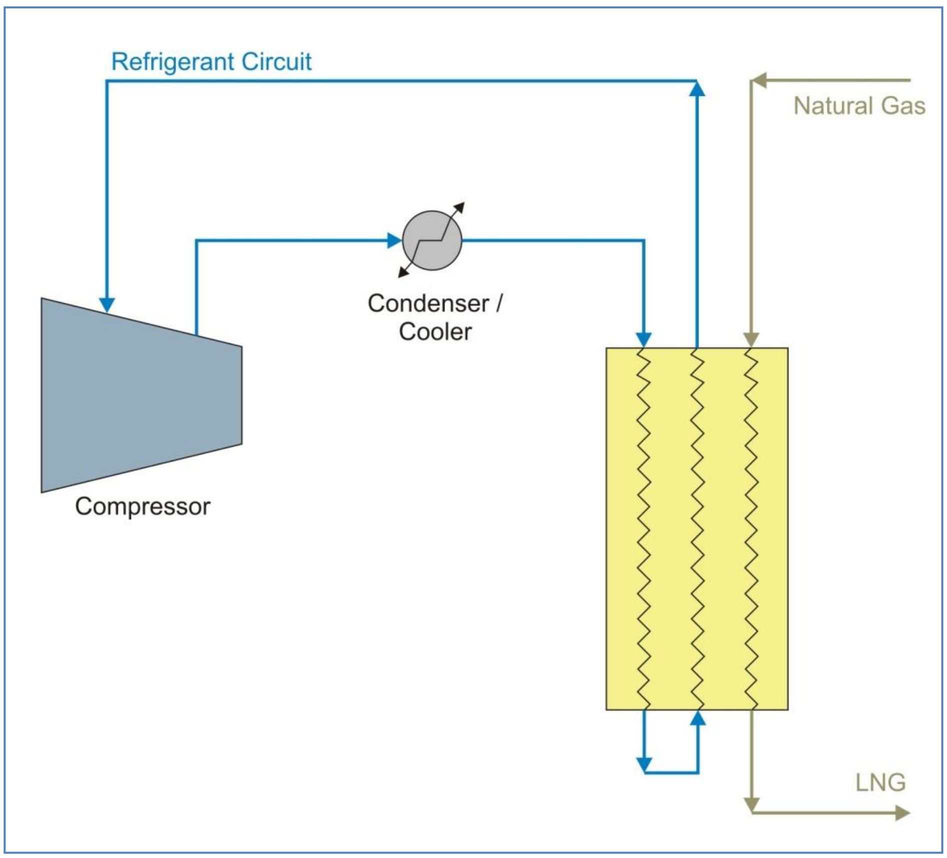

Figure 2-8: Schematic Diagram of a Single Mixed Refrigerant Process

Propane Mixed Refrigerant Processes

This process is based on two (2) refrigeration cycles: a pre-cooling cycle using propane as refrigerant and a liquefaction/sub-cooling cycle with a mixed refrigerant (see Figure 2-9). The liquefaction/sub-cooling cycle uses a mixed refrigerant consisting of propane, ethane and methane. This process combines the simplicity of the SMR process and the efficiency of the cascade processes. Most liquefaction plants currently in operation around the world are based on this technology.

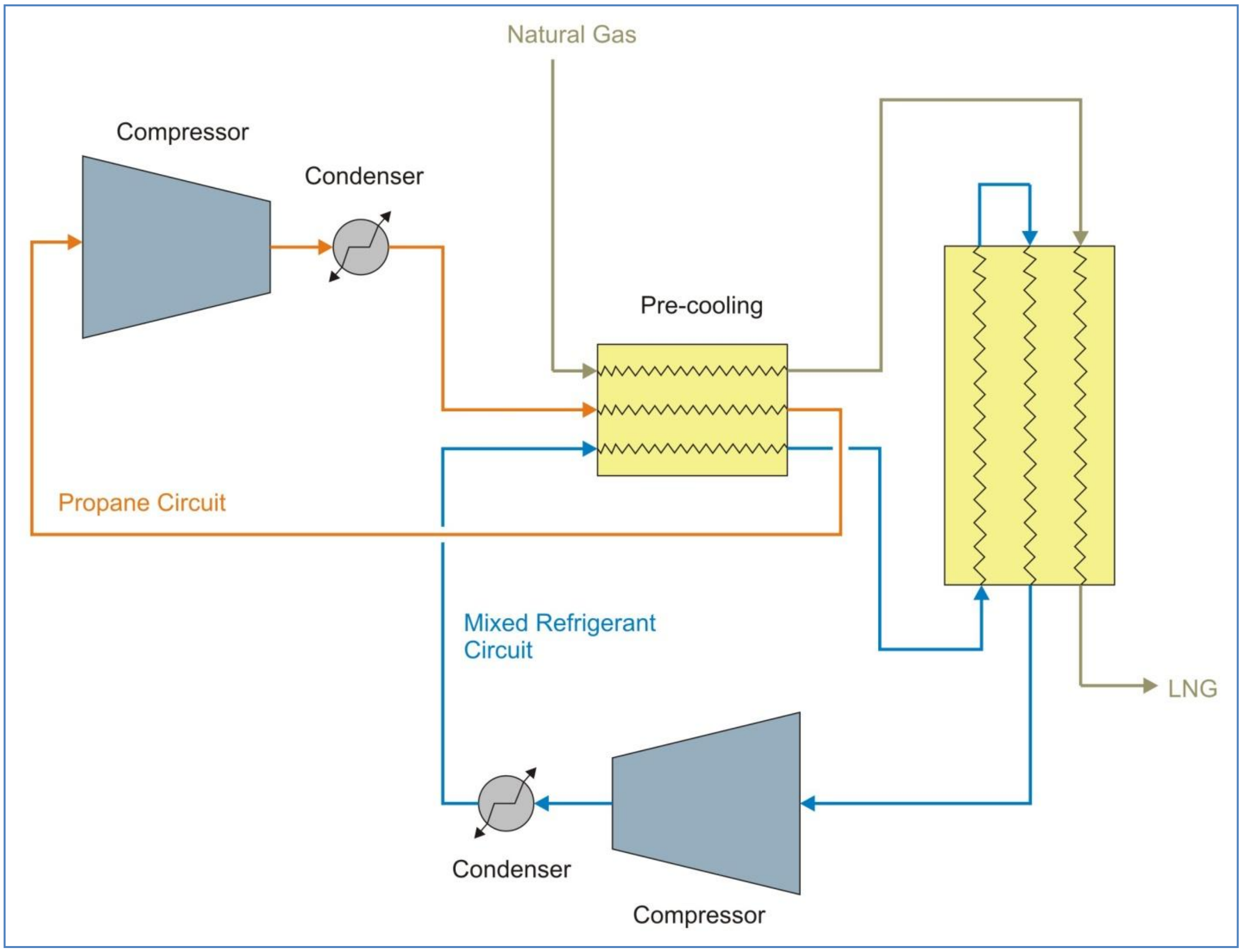

Figure 2-9: **Schematic Diagram of a Propane Mixed Refrigerant Process**

Double Mixed Refrigerant Systems

The main difference between the double mixed refrigerant systems and propane mixed refrigerant systems lies in the pre-cooling cycle. With the double mixed refrigerant process, the pre-cooling refrigerant is a mixture of ethane, propane, and small amounts of methane and butane. This process is more complex to operate than propane mixed refrigerant systems, but can be more energy efficient because the pre-cooling stage allows for a better use of compressors.

OSMR® Process (optimized single mixed refrigerant)

The OSMR® process integrates proven technologies, with a low equipment count and simple configuration. Similarly to a double mixed refrigerant process, a pre-cooling refrigerant is used with ammonia which has superior refrigeration properties to propane and allows for smaller condensers, exchangers and general plant size. Waste heat is recovered from gas turbines to generate steam driving a closed loop ammonia refrigeration circuit, which pre-cools the MR and directly cools inlet air to the gas turbines. This inlet air chilling ensures a consistent power output and avoids significant power loss at high ambient conditions.

The auxiliary ammonia refrigeration plant provides the cooling medium for the mixed refrigerant in the ammonia/MR pre-cooler, inlet air for the gas turbines, wet gas exiting the amine contractor and dry gas exiting the mercury guard bed. The auxiliary ammonia system greatly improves output and efficiency of the process and stabilizes operation of the plant by dampening the impact of variations in ambient air temperatures.

The MR composition, flow rate and pressures have been selected to provide a close match of the cooling curves as well as providing an economically sized exchanger and MR separator. The mixed refrigerant comprises methane, ethane, n-butane and nitrogen. The composition and pressure of the mixture can be adjusted to provide a close match on cooling curves during seasonal variations of ambient temperature and for plant turndown.

AP-X Method

The AP-X method uses three (3) refrigeration cycles: the first uses propane, the second uses a mixed refrigerant composed of methane, ethane and propane, and the third uses nitrogen. This recent process, which is designed for high capacity installations, combines the propane mixed refrigerant process with a nitrogen expansion cycle.

2.12.6.3 The Compression/Expansion Process

This process consists in compressing and expanding a fluid, typically nitrogen, in order to generate refrigeration. The fluid still remains in the gaseous phase. This process is very simple, requires a smaller number of equipment and is easier to operate because it uses fewer refrigerants. However, it is less efficient than the other methods, which makes it more suitable for small installations. Its efficiency can be increased by using multiple levels of expansion, but at the expense of greater complexity and higher cost. Finally, this process provides better inherent safety because it does not use a flammable refrigerant.

2.12.7 Comparison of Technologies

Several considerations must be taken into account during the selection of an appropriate liquefaction process, these include: efficiency, capacity requirements, capital and operational costs, and equipment reliability, flexibility and availability. Security, climate, natural gas composition and available space must also be considered. After consideration of these criteria, the OSMR® process was chosen because it is innovative, simple, low cost, highly efficient, environmentally friendly, robust and low risk technology. It has also been selected due to its suitability to be modularized and sited within a small, compact footprint compared to other LNG technologies, thus minimizing modifications to the existing completed earthworks. The simplicity of OSMR® technology results in a reliable LNG plant that is relatively simple to design, construct, operate and maintain.

Figure 2-10 compares the efficiency of various processes on a relative basis based on the ratio of fuel gas consumption per unit of LNG produced. The OSMR®, double mixed refrigerant and propane mixed refrigerant processes are the most effective, followed by cascade process (not shown), the single mixed refrigerant process, and nitrogen expansion processes.

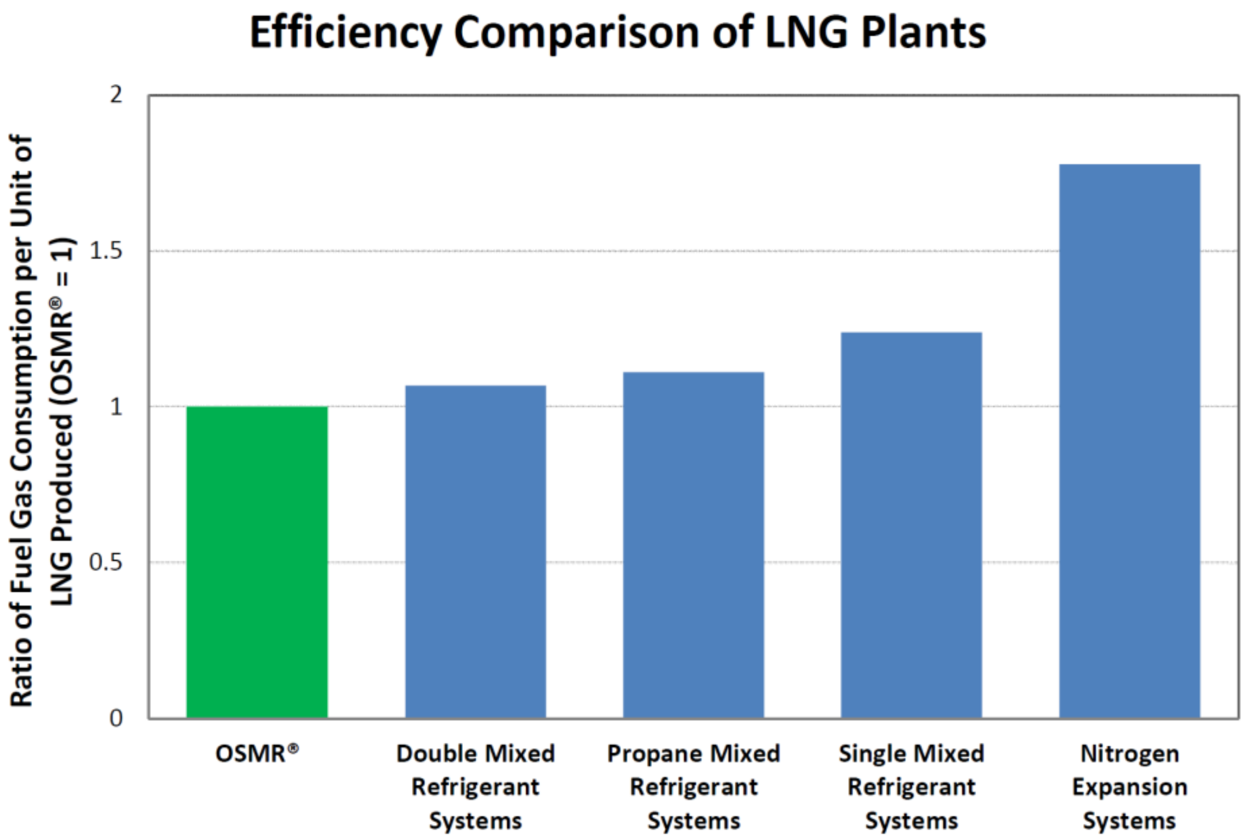

Figure 2-10: Relative Efficiencies of the Refrigeration Circuits

Required production capacity is, after efficiency, the second factor to be considered because each technology is preferably applicable in a specific range of production capacities. The plant capacity of OSMR® currently targets single LNG train capacities of 2 mtpa; however, it is scalable with single LNG train capacities from 0.5 mtpa to 4 mtpa or more.

2.12.8 Driving Compressors

The compressors used in the liquefaction process can be driven by gas turbines or by electric drive motors. The main benefit of electric drive motors is typically the avoidance of greenhouse gas emissions, depending on the energy source. This statement is valid only at the condition that electrical power is provided by a greener source than gas turbines. As the Nova Scotia power grid is supplied with coal power plants, use of electric drive motors would result in a higher global GHG emission for the province.

So far, electric motors used as the main drivers for LNG refrigeration compressors are currently in operation only on one LNG plant in Norway, and have not yet demonstrated the reliability necessary to sustain base load LNG production. Therefore, electric-driven compression would induce a financial risk for the project.

As mentioned in the precedent section, it should be noted the OSMR® process integrates aero-derivative gas turbines, waste heat recovery, ammonia refrigeration, and BOG recovery. In doing so, there is a considerable efficiency gain and corresponding reduction in GHG emissions when compared to the baseline process without these features.

2.12.9 Boil-Off Gas Recovery

During normal operation, LNG tanks are kept at a temperature of about -162°C and a low positive pressure of about 150 mbar (g) (i.e., 0.5 psi). At this temperature and pressure, the liquid in the tanks reaches its boiling point. Although the tank is insulated, there is an input of energy from the outside, which contributes to gradually evaporating the LNG. The boil-off gas must be continuously removed to maintain low or minimal pressure in the LNG storage tank.

There are two (2) ways of recovering formed boil-off gas:

1. By evaporation compressors and injection into the natural gas network to meet the natural gas requirements of a given industry. Since companies are prohibited by law to directly supply another industry without going through the natural gas distributor, this option cannot be selected.
2. It is primarily used as fuel at the plant for flare pilots. The excess boil-off gas is compressed using a multi-step compressor before being returned to feed the liquefaction units and re-liquefied. The system is designed to recover evaporated gas from LNG vessels during LNG

loading operations and to be operated as a no-flaring facility.

2.12.10 Utilities and Infrastructure

The FEED process will determine the optimal approach to deliver potable water, fire water, power, communications and road access to the Project Site. Considerations will be given to all options and the optimal design selected.

2.13 Summary

To summarize, Project design, including aspects such as product transport, site layout, and choice of technology have all been selected to best meet the needs of the Project while simultaneously meeting operational and safety standards, and reducing the environmental impact of the Project.