ACCESS NORTHEAST PROJECT

RESOURCE REPORT 13

Engineering and Design Material

FERC Docket No. PF16-1-000

Pre-Filing Draft

May 2016

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RESOURCE REPORT 13—ENGINEERING AND DESIGN MATERIAL	
Filing Requirement	**Location in Environmental Report**
☒ Provide all the listed detailed engineering materials. (§ 380.12(o)) These include: (1) Provide a detailed plot plan showing the location of all major components to be installed, including compression, pretreatment, liquefaction, storage, transfer piping, vaporization, truck loading/unloading, vent stacks, pumps, and auxiliary or appurtenant service facilities.	Appendix A.2, A.3, U.1
(2) Provide a detailed layout of the fire protection system showing the location of fire water pumps, piping, hydrants, hose reels, dry chemical systems, high expansion foam systems, and auxiliary or appurtenant service facilities.	Appendix U.8
(3) Provide a layout of the hazard detection system showing the location of combustible-gas detectors, fire detectors, heat detectors, smoke or combustion product detectors, and low temperature detectors. Identify those detectors that activate automatic shutdowns and the equipment that would shut down. Include all safety provisions incorporated in the plant design, including automatic and manually activated emergency shutdown systems.	Appendix U.7
(4) Provide a detailed layout of the spill containment system showing the location of impoundments, sumps, subdikes, channels, and water removal systems.	Appendix Q.3
(5) Provide manufacturer's specifications, drawings, and literature on the fail-safe shut-off valve for each loading area at a marine terminal (if applicable).	Appendix S.1
(6) Provide a detailed layout of the fuel gas system showing all taps with process components.	Appendix U.4
(7) Provide copies of company, engineering firm, or consultant studies of a conceptual nature that show the engineering planning or design approach to the construction of new facilities or plants.	Appendix R
(8) Provide engineering information on major process components related to the first six items above, which include (as applicable) function, capacity, type, manufacturer, drive system (horsepower, voltage), operating pressure, and temperature.	Appendix U.4, M.1, M.3
(9) Provide manuals and construction drawings for LNG storage tank(s).	Appendix L
(10) Provide up-to-date piping and instrumentation diagrams. Include a description of the instrumentation and control philosophy, type of instrumentation (pneumatic, electronic), use of computer technology, and control room display and operation. Also, provide an overall schematic diagram of the entire process flow system, including maps, materials, and energy balances.	Appendix U.4
(11) Provide engineering information on the plant's electrical power generation system, distribution system, emergency power system, uninterruptible power system, and battery backup system.	Appendix O
(12) Identify all codes and standards under which the plant (and marine terminal, if applicable) will be designed, and any special considerations or safety provisions that were applied to the design of plant components.	Appendix D

RESOURCE REPORT 13—ENGINEERING AND DESIGN MATERIAL	
Filing Requirement	**Location in Environmental Report**
(13) Provide a list of all permits or approvals from local, state, Federal, or Native American groups or Indian agencies required prior to and during construction of the plant, and the status of each, including the date filed, the date issued, and any known obstacles to approval. Include a description of data records required for submission to such agencies and transcripts of any public hearings by such agencies. Also provide copies of any correspondence relating to the actions by all, or any, of these agencies regarding all required approvals.	Appendix E
(14) Identify how each applicable requirement will comply with 49 CFR part 193 and the National Fire Protection Association 59A LNG Standards. For new facilities, the siting requirements of 49 CFR part 193, subpart B, must be given special attention. If applicable, vapor dispersion calculations from LNG spills over water should also be presented to ensure compliance with the U.S. Coast Guard's LNG regulations in 33 CFR part 127.	Appendix F
(15) Provide seismic information specified in Data Requirements for the Seismic Review of LNG facilities (NBSIR 84-2833, available from FERC staff) for facilities that would be located in zone 2, 3, or 4 of the Uniform Building Code Seismic Map of the United States.	Appendix I

RESOURCE REPORT 13— ENGINEERING AND DESIGN MATERIAL Information Outstanding for Draft Resource Report 13		
Information	**Resource Report Location**	**Anticipated Submittal Date**
EPC Contractor Selection	Section 13.1.1	To be awarded Second Quarter 2017.
Design of sendout metering skid.	Section 13.5.11	To be filed with Algonquin’s Certificate application in November 2016.

ACRONYMS AND ABBREVIATIONS

°F	Degrees Fahrenheit
ACI	American Concrete Institute
Algonquin	Algonquin Gas Transmission, LLC
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
bbl	barrel
BOG	boiloff gas
bscf	billion standard cubic feet
CCTV	Closed Circuit Television
CFR	Code of Federal Regulations
CO_2	carbon dioxide
DCS	Distributed Control System
DOT PHMSA	U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration
EPC	engineering, procurement, and construction
ERP	Emergency Response Plan
ESD	Emergency Shutdown
Eversource	Eversource Energy
LNG Facility	Access Northeast LNG Facility
FEED	Front End Engineering Design
FERC or Commission	Federal Energy Regulatory Commission
FM	Factory Mutual
ft^3	Cubic feet
gpm	gallons per minute
H&MB	heat & material balance
HDMS	Hazard Detection and Mitigation System
HHC	heavy hydrocarbon
HHV	higher heating value
HHC	Heavy Hydrocarbon
Hi-Ex	high expansion
HMI	Human-machine Interface
HP	high pressure
hr	hour
IEC	International Electrotechnical Commission
I/O	Input/Output
kV	kilovolt
kVA	kilovolt ampere
lb/hr	pounds per hour
LHV	lower heating value
LNG	liquefied natural gas
LP	low pressure
m^3	cubic meter
m^3/hr	cubic meters per hour
mA	milliampere
MCC	motor control console
MMscfd	million standard cubic feet per day
Mol%	mol percent

mph	Miles Per Hour
MW	megawatt(s)
NFPA 59A	*NFPA 59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*
NFPA	National Fire Protection Association
Ni	Nickel
NMLL	Normal Maximum Liquid Level
O&M	Operations & Maintenance
OBE	Operating Base Earthquake
P&ID	Piping and Instrumentation Diagram/Drawings
PA/GA	Public Address/General Announcement
PIV	Post Indicating Valve
PLC	programmable logic controller
Project	Access Northeast Project
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
QMR	Quadruple Modular Redundant
RTD	resistance temperature detector
scfh	standard cubic feet per hour
SIL	Safety Integrity Level
SIS	Safety Instrumented System
SRSS	Square Root Sum of the Squares
SSE	Safe Shutdown Earthquake
SSI	Soil Structure Interaction
TCP/IP	Transmission Control Protocol/Internet Protocol
TMR	Triple Modular Redundant
Tscf	trillion standard cubic feet
UL	Underwriters Laboratories
UPS	un-interruptible power supply
V	volt
(v)	volume

13.0 RESOURCE REPORT 13 – ENGINEERING AND DESIGN MATERIAL

Algonquin Gas Transmission, LLC ("Algonquin") is seeking a certificate of public convenience and necessity ("Certificate") from the Federal Energy Regulatory Commission ("FERC" or the "Commission") pursuant to Section 7(c) of the Natural Gas Act[1] to construct, install, own, operate and maintain the Access Northeast Project[2] ("Access Northeast" or the "Project"). Algonquin also seeks authorization to abandon certain facilities under Section 7(b) of the Natural Gas Act[3]. As part of this Project, Algonquin will upgrade and expand the existing Algonquin pipeline system and construct a liquefied natural gas ("LNG") storage facility in New England to deliver, on peak days, up to an additional 925,000 dekatherms per day of natural gas. The Project is designed to meet the capacity needs of natural gas-fired electric generating units as coal and nuclear electric generating units retire. Access Northeast will be implemented in phases, with the initial phase currently projected to be in-service by November 1, 2018. Phasing Project construction over several years will allow New England's natural gas-fired generators to begin acquiring firm transportation capacity as soon as possible while phasing in the full project capacity and associated costs over a longer period.

The Project includes the construction of approximately 123.22 miles of pipeline facilities, modifications at seven existing compressor stations[4], the construction of one new compressor station, associated pipeline facilities including metering and regulating stations and the construction of an LNG liquefaction, storage, and vaporization facility ("Access Northeast LNG Facility" or "LNG Facility"). These proposed Project facilities will be located in New Jersey, New York, Connecticut, Rhode Island, and Massachusetts. A more detailed description of the Project is set forth in Draft Resource Report 1.

This Pre-Filing Draft Resource Report 13 provides site-specific design information produced in the course of developing the design of the Access Northeast LNG Facility. A checklist showing the FERC filing requirements for Resource Report 13 is included following the table of contents of this Resource Report.

13.1 Facility Description

The proposed Access Northeast LNG Facility will be located on a 210 acre site owned by Eversource Gas Transmission LLC ("Eversource Energy") in Acushnet, Massachusetts, that is adjacent to an existing Eversource-owned LNG facility. The proposed LNG Facility will provide no-notice supply service to meet an estimated 410 thousand dekatherms per day of power plant peaking/backstop demand that is a critical component of the Access Northeast Project proposed service offering. The new LNG Facility will be interconnected to Algonquin's G System via the proposed Acushnet 24-inch Connector through which gas will be sent out during times of peak demand and sent in to fill the tanks during low demand periods. The proposed LNG Facility will not be connected to, replace or modify the existing Eversource LNG facility located adjacent to the proposed location of the Access Northeast LNG Facility. Components of the proposed Access Northeast LNG Facility include:

1 15 U.S.C. § 717f(c) (2012).
2 The Access Northeast Project is being developed by Algonquin, whose members are Spectra Algonquin Holdings, LLC, Eversource Gas Transmission LLC and National Grid Algonquin LLC.
3 15 U.S.C. § 717f(b) (2012).
4 The Weymouth Compressor Station in Norfolk County, Massachusetts, which will be constructed and operational as part of the Atlantic Bridge Project under CP16-9-000, will be modified as part of the Access Northeast Project.

- Two LNG storage tanks with a total combined capacity of 6.8 billion standard cubic feet ("bscf") (6.5 bscf net);
- Liquefaction and regasification capability;
- A new access road off of Peckham Road to serve both construction and operation of the LNG Facility;
- Electrical service facilities to support LNG operations;
- Ground flare; and
- Other ancillary on-site structures and equipment, as required to support the operation and maintenance of the proposed LNG Facility.

13.1.1 Owner, Operator and Principal Contractors

Algonquin will own the LNG Facility and Eversource LNG Service Company will operate and maintain the LNG Facility.

CH·IV International ("CH·IV") has been contracted to develop the front end engineering design ("FEED") for the LNG Facility and will serve as the Owner's Engineer throughout the engineer, procurement, and construction ("EPC") phase of the Project.

At the time of this filing, the EPC Contractor has not yet been determined.

13.1.2 Location and Site Information

The proposed LNG Facility will be located on a 210 acre site owned by Eversource in Acushnet, Massachusetts, which is adjacent to an existing Eversource-owned LNG facility. An area plot plan is included in Appendix A.2.

13.1.3 LNG Terminal: Source and Market for Product

Not applicable.

13.1.4 LNG Terminal; Storage, Import and Sendout Capacities and Conditions

Not applicable.

13.1.5 Liquefaction; Source of Feed Gas and Market for Product

Not applicable.

13.1.6 Base Load Liquefaction; Capacities of Feed Gas, Pretreatment, Liquefaction, Fractionation Products

Not applicable.

13.1.7 Base Load Liquefaction; Storage, Product Shipping and Sendout Capacities and Conditions

Not applicable.

13.1.8 Peak Shaving; Source of Feed Gas and Market for Product

Approximately 60 million standard cubic feet per day ("MMscfd") of natural gas will be contracted for transportation to the LNG Facility site. Gas will be sourced from Algonquin's G System and travel to the site via the proposed Acushnet 24-inch Connector. The Acushnet 24-inch Connector consists of approximately 2.70 miles of new 24-inch diameter pipeline in the towns of Freetown and Acushnet in Bristol County, Massachusetts. The Acushnet 24-inch Connector will begin (MP 0.00) in the Town of Freetown at the intersection of the Algonquin Line G-8 pipeline. From this starting point, the proposed Acushnet 24-inch Connector extends south over a greenfield route for approximately 1.26 miles, then continues in a west and then southerly direction along Dr. Braley and Keene Roads to MP 1.80. The pipeline continues along Nestles Lane, across the Freetown/Acushnet border at MP 2.17, to MP 2.58 where it heads southeast 0.12 miles within the Access Northeast LNG Facility off Peckham Road in Acushnet and terminating at MP 2.70.

The LNG Facility will be designed to handle a range of feed gas components specified by the Project. The feed gas composition to the LNG Facility is shown in Table 13.1-1:

Table 13.1-1

Design Feed Gas Specification

Contaminants	
Nitrogen	< 0.6 mol%
Carbon Dioxide	< 0.61 mol%
Oxygen	< 1.7 ppm
Hydrogen Sulfide	< 0.4 ppm
Total Sulfur	< 11.8 ppm
Water	< 3.4 lb/MMscf
Heating Value	
Wobbe Index (upper)	< 1382
Wobbe Index (lower)	> 1361
Conditions	
Pressure	< 819 psig
Temperature	< 95^{o}F

The Project will provide up to 400 MMscfd of natural gas for electric generation to serve the New England energy markets. Natural gas reserves in the United States are sufficient to meet domestic demand for decades. In November 2015, the Energy Information Administration released updated information on United States dry natural gas reserves showing that proved reserves, as of December 31, 2014, reached 388 trillion standard cubic feet ("Tscf") (U.S. Energy Information Administration, 2015). This updated information supports the conclusion that domestic natural gas supply as measured by proved natural gas reserves has been increasing and that a growing supply of natural gas is available under existing economic and operating conditions (U.S. Department of Energy, 2013).

The Project is being developed to receive this abundant domestically produced natural gas in order to produce LNG for electric generation needs in the New England area. This will present several significant economic and environmental benefits as summarized in Section 1.2, Purpose and Need, of Resource Report 1.

13.1.9 Peak Shaving; Capacities of Feed Gas Pretreatment and Liquefaction

The LNG Facility is designed to pretreat and liquefy natural gas such that 54 MMscfd is measured as liquid into the LNG storage tanks. To achieve this, approximately 60 MMscfd of pipeline feed gas will be taken into the LNG Facility and pretreated with an amine pretreatment technology to remove impurities to provide a clean natural gas stream for liquefaction. The pretreatment system includes the following components:

- Gas sweetening (carbon dioxide [“CO_2”] and Sulfur removal)
    - Amine absorber, filters, separators, heat exchangers, pumps, amine stripper, reflux condenser, amine stripper reboiler
    - Thermal oxidizer
    - Treated gas cooler and coalescer
- Gas dehydration (H_2O removal)
    - Dehydrator beds
- Dust filter
- Mercury guard bed
- Regeneration gas heaters and compressors

In liquefaction, heavy hydrocarbons (“HHC”) are removed as a side product and the resulting liquid stream entering the tank results in 54 MMscfd measured as liquid in the LNG storage tanks. The liquefaction system is a 2 x 50 percent system with two parallel units each producing 27 MMscfd. The liquefaction system includes the following components:

- Natural Gas Demethanization
    - Demethanizer Precooler
    - Demethanizer Reboiler
    - Demethanizer Column
- Natural Gas Liquefaction
    - Liquefier Exchanger
- Nitrogen Refrigeration
    - Nitrogen Compressor and coolers
    - Cold and warm compressor-expanders
    - Nitrogen Heat Exchanger

13.1.10 Peak Shaving; Storage, Vaporization, Sendout Capacities and Conditions

Two full containment LNG storage tanks, each with a gross capacity of 160,000 cubic meter (m^3), will store the LNG product from the liquefaction units. The LNG storage tanks will be full containment type with double-wall construction, with an inner wall being of low-temperature 9 percent Nickel (“Ni”) steel and the outer wall of reinforced post-tensioned concrete. The LNG storage tanks are designed to meet the requirements of National Fire Protection Association (“NFPA:) 59A, regulations of the Department of Transportation (“DOT”) Pipeline and Hazardous Materials Safety Administration (“PHMSA”) at 49 Code of Federal Regulations (“CFR”) Part 193 and other applicable standards.

Each LNG storage tank will have the following features:

- Inner wall: 9 percent Ni steel containment;
- Outer wall: Reinforced post-tensioned concrete with a steel liner;

- Reinforced concrete domed roof, supporting insulated deck, LNG pumps and tank top LNG and vapor pipework;
- An insulated deck over the inner containment suspended from the outer containment roof;
- Submerged motor pumps located in vertical pump caissons and supported by a structure attached to the roof and walls;
- Base heating system;
- Pressure, level and temperature instrumentation, including monitoring of tank cool-down;
- Pressure and vacuum relief systems;
- Nozzles and internal pipework including two-phase inlet (top and bottom fill), top cool-down spray;
- All nozzle penetrations are through the roof;
- Nitrogen purge and gas detection system for wall and floor insulation space;
- Roof platforms, crane, walkways and pipe supports; and
- External stairways, ladder and pipe supports.

The LNG storage tanks are designed and will be constructed so that the self-supporting primary containment and the secondary containment are capable of independently containing the LNG. The primary containment will contain the LNG under normal operating conditions. The secondary containment is designed to be capable of containing 110 percent of the capacity of the inner tank. To provide an additional layer of safety, a stormwater pond will provide tertiary containment and will have a minimum containment capacity greater than the gross volume of one LNG storage tank, which is 160,000 cubic meter (“m^3“)

The sendout system is designed to send out up to 400 MMscfd of natural gas into the pipeline. LNG from the LNG storage tanks is first transferred to the high pressure (“HP”) pump drum via the LNG storage tanks’ in-tank pumps, which are each rated for 100 MMscfd. LNG from the HP pump drum is then pumped to pipeline pressure via HP sendout pumps which are each rated for 100 MMscfd. LNG is then passed through shell and tube vaporizers, which are each rated for 100 MMscfd where it is vaporized, and sent to a metering system before entering the pipeline. Nominally, four in tank pumps will work with four HP pumps and four shell and tube vaporizers to obtain the design sendout rate of 400 MMscfd.

13.1.11 Satellite; Source of LNG and Market for Sendout

Not applicable

13.1.12 Satellite; Storage, Vaporization, Sendout Capacities and Conditions

Not applicable

13.1.13 LNG Trucking Facilities

The LNG Facility will include support facilities for trucking. The trucking facilities are designed to load LNG onto trucks in the event of a mutual aid request from other LNG facilities in the Northeast or to otherwise support emergency loading/unloading operations. The trucking facilities will also be capable of supporting LNG loading and delivery for distribution in the Northeast, should commercial arrangement for such deliveries be entered into at a future point. The trucking facilities are also designed to support operational, maintenance, and material delivery requirements (including liquid nitrogen for purging and refrigerant makeup).

The capacity of the LNG trucks will be up to 12,000 gallons with a loading flow rate of approximately 343 gallons per minute ("gpm"). LNG will be supplied to the truck loading station via the LNG storage tank's in-tank pumps. The truck loading station is a dual bay design and each truck will be loaded one at a time. The LNG truck loading facility will include the following components:

- Cryogenic pipework (loading and vapor return) from LNG storage tank(s) to the LNG truck loading facility;
- Flexible cryogenic hoses (loading and vapor return) for filling;
- Emergency Shut-off Control panel;
- Communication to Control Room;
- Truck weigh scales; and
- Driver Shelter.

13.1.14 List of Major Systems and Components

The LNG Facility will include the following major systems and components:

Tag Number:	Title:
D-102	Booster Compressor Drum
C-103	Booster Compressor
E-104	Booster Compressor Aftercooler
DF-110	Amine Prefilter Coalescer
D-112	Amine Absorber
E-113	Treated Gas Cooler
DF-114	Treated Gas Coalescer
D-120	Amine Gas Separator
DF-121	Rich Amine Filter
E-122A/B	Rich/Lean Amine Exchanger
D-123	Amine Stripper
P-124A/B	Lean Amine Booster Pump
T-125	Amine Drain Tank
P-126A/B	Amine Drain Tank Pump
DF-127	Amine Charcoal Prefilter
DF-128	Amine Charcoal Filter
DF-129	Amine Charcoal Afterfilter
E-130	Lean Amine Cooler
P-131A/B	Amine Reflux Booster Pump
L-132	Anti-Foam Injection Package
T-135	Amine Storage Tank
P-136A/B	Amine Transfer Pump
E-140	Reflux Condenser
D-141	Reflux Accumulator
P-142A/B	Amine Reflux Pump
L-143	Thermal Oxidizer
E-144	Amine Stripper Reboiler
DF-150	Dehydrator Inlet Filter Coalescer
D-151A/B/C	Dehydrator
DF-152	Dehydrator Dust Filter
D-153	Mercury Guard Bed
DF-154	Mercury Bed Dust Filter
E-155	Regeneration Gas Heater
E-156	Regeneration Gas Cooler
D-157	Regeneration Gas KO Drum
C-158	Regeneration Gas Compressor
E-200A/B	Liquefier Exchanger
D-211A/B	Demethanizer Column
E-212A/B	Demethanizer Precooler
E-213A/B	Demethanizer Reboiler
T-220A/B	LNG Storage Tank
P-221AA/BC	LP Pump
D-300A/B	N2 Compressor Drum

Tag Number:	Title:
C-301A/B	N2 Compressor
E-302A/B	N2 Compressor 1st Intercooler
E-303A/B	N2 Compressor 2nd Intercooler
E-304A/B	N2 Compressor Aftercooler
C-310A/B	Cold N2 Compressor
CE-310A/B	Cold N2 Expander
C-320A/B	Warm N2 Compressor
CE-320A/B	Warm N2 Expander
E-321A/B	N2 Compander Aftercooler
E-330A/B	N2 Heat Exchanger
D-400	HP Pump Drum
P-401A/E	HP Pump
E-402A/E	LNG Vaporizer
(By Pipeline Contractor)	Metering System
D-410	BOG Drum
C-411A/C	BOG Compressor
E-412A/C	BOG 1st Intercooler
E-413A/C	BOG 2nd Intercooler
E-414A/C	BOG Aftercooler
L-430A/B	LNG Truck Loading Station
L-440	Ground Flare Package
E-500	HP Fuel Gas Heater
D-501	HP Fuel Gas Drum
E-510	LP Fuel Gas Heater
D-511	LP Fuel Gas Drum
D-520	Hot Oil Surge Drum
P-521A/B	Hot Oil Pump
B-522	Hot Oil Heater
D-530	WEG Surge Drum
P-531A/E	WEG Pump
B-533A/E	WEG Heater
DF-535	WEG Filter
L-540A/B	Gas Turbine Driver Package
T-600	Firewater Tank
P-601	Electric Firewater Pump
P-602	Diesel Firewater Pump
P-603	Firewater Jockey Pump
T-611	Foam Concentrate Storage Tank
P-612A/B	Foam Concentrate Pump
L-613	Foam Generator
L-801A/B	Air Compressor Package
D-802A/B	Instrument Air Receiver
T-810	Demineralized Water Tank
P-811A/B	Demineralized Water Pump
P-821A/B	Service Water Pump
S-830	Process Impoundment Basin
P-831A/B	Process Impoundment Sump Pump
S-832	Trucking Impoundment Basin
P-833A/B	Trucking Impoundment Sump Pump
S-842	Compressor Shelter Sump
P-843A/B	Compressor Shelter Sump Pump
S-845	Amine Drain Tank Sump
P-846A/B	Amine Drain Sump Pump
L-848	Oily Water Treatment Package
L-850A/B/C	Backup Generator
L-855	Black Start Diesel Generator
L-860	LIN Storage Package
T-870	Diesel Storage Tank
A-901	Admin Bldg. / Control Room
A-902	Warehouse / Maintenance Bldg.
A-904	Truck Loading Bldg.
A-910	Compressor Shelter
A-915	Booster Compressor Shelter
A-920	HP Pump House
A-925	BOG Compressor Shelter

Tag Number:	Title:
A-930	WEG Shelter
A-960	Firewater Pump House
A-980	Demin Water Pump House
A-990	Electric Switchgear Bldg.
A-925	BOG Compressor Shelter
A-930	WEG Shelter
A-960	Firewater Pump House
A-980	Demin Water Pump House
A-990	Electric Switchgear Bldg.

13.1.15 Design Features

Pretreatment:

The pretreatment system comprises gas sweetening and dehydration that remove components (principally CO_2, sulfur compounds and water) in the pipeline gas which would otherwise freeze solid and block the liquefaction exchangers at cryogenic temperatures.

The purpose of the amine pretreatment system is to remove $CO_2$from the gas stream as this would otherwise freeze in the liquefaction exchangers. The CO_2 content is typically 0.2-0.65 mol”) however the amine plant is designed to remove up to 2 mol% of CO_2 down to 50 parts per million (“ppm”)(v) to prevent CO_2 from solidifying and blocking the liquefaction exchangers.

A commercially available amine solvent will be utilized to remove CO_2 to acceptable levels. Though the amine solvent is non-corrosive, the primary contaminant captured, CO_2, is corrosive in aqueous solutions at high temperatures. Therefore, stainless steel material is used for those items in corrosive service and adequate corrosion allowance would be specified where required.

Water must be removed from the gas stream to less than 1.0 ppm prior to liquefaction to avoid freezing in the liquefaction exchangers. This is achieved using three molecular sieve dehydrator vessels. Three vessels have been selected to accommodate the plant throughput required during capacity ramp-up so that the minimum required regeneration velocity through the sieve bed is met. Two beds will operate in adsorption mode with the third vessel in regeneration or standby mode. Each bed cycles consecutively through adsorption, heating, cooling and standby under control of a valve switching system. A side stream of dry gas is used for regeneration. This side stream is heated to approximately 500 Degrees Fahrenheit (“ºF”) before flowing upwards through the bed for regeneration. The expected bed life is approximately 4 years, and replacement will coincide with other scheduled plant maintenance.

A non-regenerative mercury guard bed will be provided to remove mercury down to < 1 ppb(v). This protects the aluminum heat exchangers used for liquefaction from corrosion.

The pretreatment system will be built by an EPC Contractor based on design information from the selected pretreatment system vendor. The pretreatment system vendor provides necessary guarantees for the performance of the system. The vendor will provide process simulations, equipment design data and process schematic under a Licensing Agreement.

Liquefaction:

The liquefaction system comprises natural gas liquefaction and heavy hydrocarbon removal and produces LNG at a rate of 54 MMscfd measured in the LNG storage tank.

Natural gas will be liquefied using two Nitrogen Expander Cycles sized for 27 MMscfd production each. The Nitrogen Expander cycle is a relatively simple refrigerant cycle used primarily in small-scale liquefaction applications. There is also an inherent safety benefit in using only a non-flammable compound (nitrogen) as the refrigerant. The nitrogen expander process has been in use at LNG peak-shaving facilities for over 30 years.

The nitrogen flows in a closed-loop cycle. Ambient, low pressure nitrogen vapor exits the coldbox and is then compressed by the Nitrogen Compressor boosting the pressure of the nitrogen. Each stage of compressor is cooled by forced draft air coolers. The nitrogen is further compressed by a warm and cold compressor and subsequently cooled by a forced draft air cooler.

The high pressure nitrogen stream then enters the Nitrogen Expander leaving at cryogenic temperatures and lower pressure. The heat from natural gas entering the Liquefier Exchanger is extracted by the cryogenic, low pressure nitrogen.

The removal of HHC is accomplished by partially liquefying the incoming natural gas in the Liquefier Exchanger. Heavier hydrocarbons liquefy at a higher temperature than methane, the principal constituent of natural gas. The HHCs drop out of the feed gas stream and are removed in the Demethanizer Column prior to the final liquid product entering the LNG storage tank. This HHC stream is then consumed as fuel gas.

LNG Storage:

The two LNG storage tanks will be identical, full-containment type tanks with a primary inner containment and a secondary outer containment. The tanks are designed and will be constructed so that the self-supporting primary containment and the secondary containment will be capable of independently containing the full volume of LNG. The primary containment (inner containment) will contain the LNG under normal operating conditions. The secondary containment (outer containment) is designed to be capable of containing the LNG (110 percent capacity of the primary containment contents) and controlling the vapor resulting from the highly unlikely failure of the primary containment. Each insulated tank is designed to store a gross volume of 160,000 m^3 of LNG at a design temperature of -270°F and a maximum internal pressure of 4.2 pounds per square inch gauge ("psig").

Each full containment tank will consist of:

- A 9 percent Ni steel open-top inner containment;
- A pre-stressed concrete outer containment wall;
- A reinforced concrete dome roof;
- A reinforced concrete outer containment bottom; and
- An insulated deck over the inner containment suspended from the outer containment roof.

The aluminum support deck is designed to be insulated on its top surface with fiberglass blanket insulation material. The fiberglass blanket is chosen to minimize the potential of in-leakage of Perlite® insulation into the inner containment. The small amount of vapor pressure generated from boiloff of the LNG is designed to be equalized through ports in the suspended deck with the boiloff gas ("BOG") contained by the outer containment. The internal design pressure of the outer containment roof is 4.2 psig. The space between the inner containment and the outer containment is insulated to allow the LNG to be stored at a minimum design temperature of -270°F while maintaining the outer containment at near ambient temperature. The insulation beneath the inner containment is cellular glass, load-bearing insulation that will support the weight of the inner containment tank, associated structures (including the bottom fill standpipe column) and the LNG. The space between the sidewalls of the inner and outer containments is filled with expanded Perlite® insulation that will be compacted to reduce long-term settling of the insulation. The outer containment is lined on the inside with carbon steel plates. This carbon steel liner serves as a barrier to moisture migration from the atmosphere reaching the insulation inside the outer concrete wall. This liner also provides a barrier to prevent vapor escaping from inside the tank in normal operation.

There will be no penetrations through the inner containment or outer containment sidewall or bottom. All piping into and out of the inner or outer containments enters from the top of the tank. The inner containment is designed and will be constructed in accordance with the requirements of American Petroleum Institute ("API") Standard 620 Appendix Q. The tank system meets the requirements of NFPA 59A (2001 edition will be used as the basis except where the 2006 edition is required) and 49 CFR Part 193.

Each tank is protected against over-pressure and under-pressure by the provision of pressure and vacuum relief valves. Instrumentation installed on the tank will monitor level, temperature and density for detection of situations that could result in rollover. Stratification is mitigated by internal recirculation via the LNG storage tank in-tank pumps.

In-Tank Low Pressure Pumps:

Each of the LNG storage tanks will have three low pressure ("LP") pumps. Each LP pump will be mounted inside its own column and will be located inside the column near the bottom of the LNG storage tank. Each pump will be provided with an individual minimum flow recycle line and flow control to protect the pump from insufficient cooling and bearing lubrication at low flow rates. The pumps will have remotely monitored pressure, flow, vibration and motor amperage signals and will include features to isolate and safely maintain a single pump without requiring other pumps to be removed from service. The LP pumps will be removable for maintenance while maintaining an operating level in the LNG storage tank.

Sendout System:

The LP pumps will supply LNG to the HP pumps via the HP pump drum.

Each HP pump will be provided with an individual minimum flow recycle line and flow control to protect the pump from insufficient cooling and bearing lubrication at low flow rates. The recycle flow will be routed to the LNG storage tanks through the tank top fill lines. The pumps will have remotely monitored pressure, flow, vibration and motor amperage signals and will include features to isolate and safely maintain a single pump without requiring other pumps to be removed from service.

The HP pumps will supply LNG vaporizers, which are shell and tube heat exchangers. Heat for vaporization will be via a solution of ethylene glycol and water that will be heated in fired heaters.

Vapor Handling System:

The Vapor Handling System includes the BOG Header, LNG storage tank vapor space, BOG compressors and overpressure relief line to flare.

The BOG is generated from the following sources:

- Heat leak into the LNG storage tank through the insulation systems;

- Displaced vapor due to the LNG volumes entering into the storage tanks from the liquefiers;
- LNG flash gas from LNG entering the storage tank;
- Heat generated by LNG in-tank (loading) pumps; and
- Heat leak into LNG piping, including transfer pipeline recirculation.

The composition of the BOG is predominantly a function of the mole percent of nitrogen in the LNG stream as it enters the LNG Storage Tank.

The LNG Facility will be designed to minimize fugitive emissions with no flaring during all normal operations using a Closed Vent/Drain System. All LNG and natural gas relief valves (excluding LNG storage tank, fuel gas drum and the LNG vaporizer process relief valves) will be vented into a closed vent flare system that is common within the LNG storage tank vapor spaces.

All release in the liquefaction system during an operation upset or start-up will be sent to a closed flare system. The following is the basis of the flare design:

- Initial dryout and cooldown of liquefaction system; and
- Maximum emergency release during operation of the liquefaction system.

13.1.16 Utilities and Services

Instrument Air System:

Air compressors produce compressed air for the instrument air and service air systems for use at the LNG Facility. Process air is used to power tools and equipment that will be used in the maintenance of the LNG Facility. Dry instrument air is used for the instrumentation and control system installed at the LNG Facility. Instrument air takes priority over process air if there is any reduction in compressed air supply.

Nitrogen System:

Liquid nitrogen will be stored at the LNG Facility in vertical storage tanks with a total storage capacity of 39,990 gallons and will be vaporized as needed to meet demand. Vaporization will be performed in a vendor-supplied skid using ambient air through which vaporized nitrogen will flow to various locations through a piping distribution system. Nitrogen will be used to purge pipelines and equipment in preparation for maintenance and in preparation for return to service.

Electric Power Transmission and Control System:

Power from the local grid will be required to run motors for LNG and BOG compressors, lighting, and other items. At full liquefaction or sendout operations, the LNG Facility is expected to import a base load of less than 15 megawatt (“MW”).

NSTAR Electric will supply power via 13.2 kilovolt (“kV”) underground distribution feeders located on Peckham Road.

Three standby power generators will be provided that will be capable of supplying enough power for 400 MMscfd of natural gas sendout, facility emergency lighting (including security lighting), security monitoring and warning systems, emergency communications systems, control systems, instrument air compression, and other necessary auxiliary systems. A blackstart diesel generator will be provided to provide the necessary power to start the first generator and bring it online.

Potable and Service Water:

Potable and service water will be provided from the Town of Acushnet municipal water system. Potable water will be used for domestic consumption and sanitary purposes throughout the LNG Facility, while service water will be used for maintenance activities.

No storage of potable water will be provided on the site. Potable water will be supplied directly from the town main at local pressure.

Service water will be drawn from the top of Firewater Tank T-601 through a standpipe in the tank. Service water flow will be pumped throughout the distribution system by one of two service water pumps in parallel. Service water main pressure will be maintained at a nominal pressure of 90 psig.

Stormwater Systems:

Stormwater falling in the pretreatment area and trucking area will drain to local sumps and flow through an oily water treatment package before being discharged into a stormwater management pond for infiltration. All other stormwater falling within curbed areas, bermed areas, and the LNG spill containment system will flow to local low points or sumps and drain to the stormwater management pond.

13.1.17 Safety Features for Containment

The LNG Facility is subject to the siting requirements of 49 CFR Part 193 Subpart B and NFPA 59A 2001 edition, (which DOT PHMSA incorporated by reference into 49 CFR Part 193 on April 9, 2004). Parts 193.2057 and 193.2059 of 49 CFR require the establishment of thermal and flammable vapor exclusion zones. Section 2.2.3.2 of NFPA 59A specifies thermal exclusion zones based on the design spill and the impounding area. NFPA 59A Sections 2.2.3.3 and 2.2.3.4 specify a flammable vapor exclusion zone for the design spill, which is determined in accordance with Section 2.2.3.5 of NFPA 59A.

In accordance with 49 CFR Part 193.2181, the impoundment system serving a single LNG storage tank must have a volumetric capacity of 110 percent of the LNG storage tank's maximum liquid capacity. The LNG storage tanks are each of full containment design consisting of a primary inner containment and a secondary outer containment meeting this requirement.

In accordance with NFPA 59A Section 2.2.2.2 impounding areas will be installed at the LNG Facility to serve LNG and heavy hydrocarbon process equipment and transfer areas.

For impoundment areas for containers with over-the-top fill connections, NFPA 59A (2001 edition) Section 2.2.3.5 requires that spill containment be designed to hold the largest flow from the failure of any single pipeline that could be pumped into the impounding area with the container withdrawal pump(s) considered to be delivering the full rated capacity for a duration of 10 minutes.

The Process Area Impoundment Basin has been sized to contain the greatest flow capacity from a single pipe for 10 minutes in the local area. This flow was determined to be a release from the LNG sendout pipeline. The design flow rate of the LNG sendout pipeline is 408 MMscfd via four (4) LNG pumps delivering LNG at a rate of 102 MMscfd per pump. Based on pump curves, the maximum continuous flow at the pump's rated impeller is 1,225 gpm. For four (4) LNG pumps, the maximum sendout flow rate would therefore be 4,900 gpm. A 10 minute spill would therefore result in a volume of 49,000 gallons (6,550 cubic feet ["ft^3"]).

The Truck Loading Area Impoundment Basin has been sized to contain the greatest flow capacity from a single pipe for 10 minutes in the local area. This flow was determined to be a release from the LNG truck loading line. Based on the heat and material balance ("H&MB") truckloading rich case, the maximum mass flow rate through the LNG truck loading line would be 75,394 pounds per hour (lb/hr). A 10 minute spill would therefore result in a volume of 3,430 gal (459 ft^3). However, LNG trucks will have a volumetric capacity of up to 12,000 gallons (1,604 ft^3). Therefore, the Truck Loading Area Impoundment Basin has been sized to contain the volume of an LNG trailer (1,604 ft^3).

Table 13.1-2 summarizes the dimensions of impoundment basins that will be installed at the Facility.

Table 13.1-2

Impoundment Basin Capacity

Spill Basin	Sizing Volume (ft^3)	Width (feet)	Length (feet)	Depth (feet)	Design Volume (ft^3)
Process (S-830)	6,550	35	35	11	13,475
Trucking (S-832)	1,604	15	15	13	2,925

The LNG impoundment basins will be insulated concrete design. In accordance with the requirements of Section 2.2.2.8 of NFPA 59A (2001), the insulation system used for the impounding surfaces will be, in the installed condition, noncombustible and suitable for the intended service, considering the anticipated thermal and mechanical stresses and loads.

Spills of LNG or HHCs will flow along insulated concrete troughs located beneath liquid pipelines. Conveyance of spills throughout the LNG Facility is illustrated in Spill Containment Drawing (15505-DG-600-102/3/4) that is included in Appendix Q.3 of this Resource Report.

13.1.18 Safety Features for Fire Protection

Hazard Detection and Mitigation System:

A Hazard Detection and Mitigation System ("HDMS") has been designed to continuously monitor and alert the operator to hazardous conditions throughout the LNG Facility from fire, combustible gas leaks and low temperature LNG spills. Monitoring capability will be provided via graphic display screens and/or mimic panel displays located in the Control Room. The LNG Facility will have a dedicated stand-alone system for fire, heat, combustible gas, smoke, toxic gas and low temperature LNG spill monitoring.

Hazard Detection Layout Plans:

Hazard detector layout plans have been prepared for the Access Northeast LNG Facility and are included in Appendix U.7 of this Resource Report.

Fire and gas detection and protection of offices and other buildings will be networked via fire panels located in individual buildings to a main fire alarm control panel located in the control room. They will provide common alarms and status information to the HDMS.

Safety Instrumented System and Emergency Shutdown System:

An independent Safety Instrumented System ("SIS") will be installed to allow the safe, sequential shutdown and isolation of rotating equipment, pretreatment facilities, liquefaction facilities (including nitrogen storage and handling) and LNG storage facilities when an emergency shutdown ("ESD") is initiated.

The ESD push buttons will be installed at various points throughout the LNG Facility. The ESD system is provided to initiate closure of valves and shutdown of process equipment during emergency situations.

Hazard Control System:

The LNG Facility design includes a firefighting system composed of fixed and portable firewater systems, fixed and portable dry chemical extinguishing systems. The preliminary Fire Protection Evaluation report for the Facility prepared in accordance with the requirements of Section 9.1.2 of NFPA 59A (2001 edition) is included in Appendix P.1 of this Resource Report and the philosophy for the HDMS is described in Appendix C.3.

The firewater system has been designed to deliver the maximum firewater demand to the most hydraulically remote part of the system. The maximum firewater demand is based on the maximum required flow to fixed fire protection systems at the required residual pressure plus a 1,000 gpm hose stream flow. Appendix P.2 includes the Firewater Equipment Sizing Calculation, which describes the design cases used in the design of the firewater system.

Dry chemical systems will be installed at the LNG Facility as they are effective against hydrocarbon pool and three-dimensional fires (e.g., jet fires), particularly those involving pressurized natural gas or LNG spills, provided re-ignition potential is low. The dry chemical agent specified is potassium bicarbonate as this has been found to be most effective of the dry chemical agents. The dry chemical systems consist of total flooding systems and portable and wheeled extinguishers. System selection depends on the type of hazard, the location of the hazard, the size of the hazard, existence of nearby ignition sources, ability to access the hazard and the potential consequences of the fire on the public, Facility personnel and equipment. The dry chemical systems will be located in strategic locations to facilitate effective fire extinguishment. These systems are designed in accordance with NFPA 17 for engineered systems and NFPA 10 for portable extinguishers and will be Underwriters Laboratories ("UL") listed or Factory Mutual ("FM") approved.

13.1.19 Emergency Response

The Project has developed a preliminary Emergency Response Plan ("ERP") in accordance with the requirements of the FERC Draft Guidance for Terminal Operator's Emergency Response Plan. The ERP contains details of the following:

- The structure of the emergency response team, including roles, responsibilities and contact details;
- Responses to emergency situations that occur within the LNG Facility;
- Emergency evacuation adjacent to the LNG Facility;
- Training and exercises;
- Documentation of consultations made with interested parties during the development of the ERP; and

- Details of cost sharing plans that have been negotiated to reimburse capital costs, annual costs and other expenses incurred by off-site emergency organizations in providing emergency response services to the LNG Facility.

In accordance with the above-mentioned FERC draft guidance document, the ERP will be prepared in consultation with state and local agencies, and the Project will request Commission approval prior to the commencement of construction.

13.1.20 Operating Modes

The LNG Facility has been designed to operate in the following operating modes:

Mode 1 - LNG sendout only, no liquefaction, no LNG truckloading.
Mode 2 - Liquefaction only, no LNG truckloading, no LNG sendout.
Mode 3 - LNG truckloading only, no liquefaction, no LNG sendout.
Mode 4 - Liquefaction, LNG truckloading, no sendout.
Mode 5 - No LNG sendout, no liquefaction, no LNG truckloading (Idle Facility).

13.1.21 Commissioning and Cooldown

Dryout:

Commissioning of the LNG Facility will commence once the construction contractor has achieved mechanical completion of equipment and systems. Mechanical completion will be achieved only when installation of equipment and systems has been completed and all have been cleaned out, quality control records have been completed and all operating and maintenance manuals have been provided. Algonquin will verify that mechanical completion has been achieved and will review commissioning procedures that will be prepared by the construction contractor.

Commissioning of equipment and systems will be in accordance with the commissioning procedures. With respect to cryogenic systems commissioning must include a controlled cooldown process.

The initial dryout of the cryogenic plant items for the natural gas and nitrogen refrigerant circuits and the LNG sendout system will be achieved in several steps. Nitrogen and/or instrument air will be used for bulk drying of plant during pre-commissioning. Once the nitrogen runs on the refrigerant compressors are completed, the natural gas and refrigeration circuits will be dried. Heated fuel gas supplied from the pretreatment dehydration unit will be used via the defrost gas network to dry the system to the required level suitable for cooldown.

Liquefaction Unit:

Cooldown and startup of each of the liquefaction units will be carried out in sequence. Cooldown of the coldbox will be carried out under vendor supervision. Nitrogen will be introduced to the refrigeration circuit to provide gradual cooling of the coldbox. Natural gas will then be introduced, with the LNG that is produced used for gradual cooldown of the LNG storage tanks with BOG recycled to coldbox and excess BOG sent to flare.

LNG Storage Tank:

The LNG storage tank will be dried and purged prior to commissioning. Drying will be performed by removing all standing water. The tank will be purged with gaseous nitrogen to a maximum oxygen content of 8.0 percent by volume. After the tank has been purged with nitrogen it will be purged to a combustible gas concentration of no less than 90 percent in preparation for tank cooldown.

The tank system has an independent cooldown fill line with spray nozzles designed specifically for cooldown of the LNG storage tank. During the initial introduction of liquid product, it is important to have uniform cooldown. The primary container temperature gradient between any two adjacent cooldown resistance temperature detectors ("RTDs") will not exceed 50°F and the gradient between any two RTDs will not exceed 100°F. The cooldown rate for the primary liquid container will be controlled to a maximum average of 9°F/hour and will not exceed 15°F/hour during any 1-hour period. The cooldown will be complete when 6 inches of product liquid is measured in the tank.

13.1.22 Operation and Maintenance

The LNG Facility will have a full time operations and maintenance staff to safely operate the plant and perform necessary maintenance. It will be operated and maintained in accordance with government safety standards and regulations including the DOT PHMSA's Federal Safety Standards for Liquefied Natural Gas Facilities (49 CFR Part 193), which incorporates the 2001 and 2006 editions of the NFPA 59A standard by reference. These standards are intended to ensure protection for the public and to prevent facility accidents and failures. All operations and maintenance personnel will be trained to properly and safely perform their assigned duties and responsibilities in accordance with the requirements of 49 CFR Part 193.

Operation and Maintenance Procedures:

Procedures for operation and maintenance ("O&M") of the LNG Facility will be developed to comply with the requirements of:

- 49 CFR Part 193 Subpart F – Operations, and NFPA 59A Chapter 14 – Operating, Maintenance and Personnel Training. This will include policies for operating procedures, monitoring of operations, emergency procedures, personnel safety, investigation of failures, communication systems and operating records;
- 49 CFR Part 193 Subpart G – Maintenance, and NFPA 59A Chapter 14 – Operating, Maintenance and Personnel Training. This will include policies for maintenance procedures, fire protection, isolating and purging, repairs, control systems, inspection of LNG storage tanks, corrosion control and maintenance records; and
- 49 CFR Part 193 Subpart J – Security, and NFPA 59A Annex C – Security. This will include policies for security procedures, protective enclosures, security communications, security monitoring, and warning signs.

Operation and Maintenance Personnel Training:

All permanent O&M personnel employed at the LNG Facility will be trained and sufficiently qualified to operate the LNG Facility in accordance with the requirements of 49 CFR Part 193 Subpart H – Personnel Qualifications and Training, and also NFPA 59A Chapter 14 – Operating, Maintenance and Personnel Training. All contractor personnel will be trained in accordance with the requirements of 49 CFR Part 193, as required.

Operations and maintenance personnel will receive the following training.

Basic LNG Training - A technical reference manual will be developed and will cover the following topics:

- Introductory information;
- Design basis, process and instrumentation diagrams and other technical references;
- Process systems;
- Utility and auxiliary systems;
- Hazard detection and mitigation systems; and
- Equipment O&M and troubleshooting procedures.

The basic training program will be based on the technical reference manual and will include:

- Basic orientation;
- Basic equipment study;
- Operations review;
- Basic utility and auxiliary systems;
- Hazard detection and mitigation;
- Communications;
- Sendout pipeline;
- Maintenance procedures; and
- Operations procedures.

Vendor Supplied Training - Training will be provided by the manufacturers of the major pieces of equipment that will be installed at the LNG Facility and will be based on the O&M manuals.

Health, Safety and Security Training - Training will be provided that will include:

- Safe systems of work;
- Personal protective equipment and clothing;
- Emergency response; and
- Training required by Occupational Safety and Health Administration and other training specific for the LNG Facility.

Environmental Training - Training will be provided in environmental management and mitigation to comply with the requirements of the various permits that will be issued for the LNG Facility at the federal, state and local levels.

Hands-On Training - Hands-on training will be provided at all stages of the construction of the LNG Facility, including:

- Factory acceptance testing - This will include the review of equipment design parameters, witness of factory tests, review of factory test results, final inspection of completed equipment packages and reports of any discrepancies or non-compliances;
- Construction - During this period, the O&M team will develop all of the software systems including policies and procedures and management information systems;

- Mechanical completion. During this period, the O&M team will assist the EPC contractor in the preparation for mechanical completion, which will include equipment and system clean-out, purge and cooldown;
- Start-up and commissioning - During this period, the O&M team will assist the EPC contractor in reviewing the start-up and commissioning procedures and checklists, completing valve-out of equipment and systems in accordance with commissioning procedures, preparing instrumentation in accordance with commissioning procedures and preparing electrical supplies and distribution systems; and
- Performance testing - During this period, the O&M team will assist the EPC contractor in demonstrating contractual performance guarantees for the LNG Facility.

Ongoing Training - During the commercial operation, the O&M team will receive on-going refresher training at a frequency of no less than every two years in the O&M of the LNG Facility, safety, security and fire protection. Individual training plans will be developed for each O&M team member, and training records will be maintained for audit during the annual FERC and DOT PHMSA inspections.

13.1.23 Staffing Structure

The LNG Facility will be operated on a permanent 24-hour basis and will be staffed accordingly. During operations, it is expected that the LNG Facility will employ approximately 22 full-time permanent personnel in administration, security and O&M areas. The proposed organization chart for the LNG Facility is included in Appendix A.1 of this Resource Report.

13.1.24 Drawings

An Area Plot Plan is included in Appendix A.2 of this Resource Report. An Overall Plot Plan is included in Appendix A.3 of this Resource Report 13. Unit Plot Plans are included in Appendix U.1 of this Resource Report.

13.2 Project Schedule

A Gantt chart of the proposed LNG Facility schedule is included in Appendix B.1 of this Resource Report. The Gantt chart provides details of the engineering, procurement, construction and startup of the LNG Facility.

13.3 Site Plans

13.3.1 Site Description

Location:

The proposed LNG Facility will be located on a 210-acre site owned by Eversource in Acushnet, Massachusetts, which is adjacent to an existing Eversource owned LNG facility. An area plot plan is included in Appendix A.2.

Construction:

Algonquin will require approximately 122.62 acres of construction workspace to construct the proposed LNG Facility. Construction workspace areas are currently planned to be located entirely within Eversource's 210-acre property in Acushnet, Bristol County, Massachusetts.

Soil and Site Preparation:

The first step of construction will involve marking by flags or fencing the boundaries of wetlands and other environmentally sensitive areas that must be avoided during construction. Immediately thereafter, the proposed locations of the LNG Facility components will also marked by flags and/or stakes.

Construction of the LNG Facility will start with initial site preparation including the following activities:

- Initial mobilization to site;
- Additional site surveys, as necessary;
- Installation of erosion control measures, as necessary;
- Clearing, grubbing, backfilling, grading and soil stabilization activities, as needed, to prepare the site for construction;
- Development of temporary workspaces, laydown areas and support areas;
- Development of construction related plant roads, security fences and access control gates; and
- Stormwater management.

For safety and to limit public access, fences will be placed along the boundaries of the LNG site and permanent and temporary gates will be installed, as required. Construction work areas will be cleared of shrubs and trees and other obstructions. In accordance with the FERC Upland Erosion Control, Revegetation, and Maintenance Plan, temporary erosion controls will be installed immediately after initial disturbance of the soil to minimize erosion and will be maintained throughout construction. The site will then be graded where necessary to create a reasonably level working surface to allow safe passage of construction equipment and materials. As needed, on-site material will be used as backfill; however, if additional backfill is required, local, clean fill will be imported from commercial sources.

Foundations:

Once the site is prepared for construction activity, construction will begin. The first construction activity will be to install foundations. A geotechnical investigation has been performed to determine sub surface soil conditions and provide recommendations for the foundation design of the facility. If additional geotechnical investigations are necessary, they will be performed during early construction. Foundation design will be based on guidance in the FERC's latest draft seismic guidelines and will meet the requirements of 49 CFR Part 193 and NFPA 59A. Once the foundations are completed, structural steel and equipment installation will occur.

Equipment:

Equipment and materials will be delivered to site by truck. The majority of the construction will be stick-built. However, larger equipment will be delivered in preassembled packages or skids, when practical. All equipment will be designed, fabricated and tested at their respective supplier facilities. Additional inspections of all equipment will be conducted upon arrival at the LNG Facility site. Pipe rack frames may arrive prefabricated and be assembled on site. Process piping will be installed after the pipe racks have been erected. After installation and testing, pipes will be painted, coated or insulated, as applicable. After the mechanical components are installed, cable trays and cables will be installed. Once construction is complete, road-paving and cleanup will take place and temporary construction facilities will be deconstructed.

The longest construction timeline will be associated with construction of the two 160,000-cubic meter full containment LNG storage tanks. Therefore, it is anticipated that the EPC Contractor construction schedule will be optimized to allow for construction activities of the LNG storage tanks to commence immediately, with the additional installation of pretreatment, liquefaction, sendout, vaporization and other facilities performed concurrently with the construction of the LNG storage tanks.

The final design sequence and timeline will be developed by the EPC Contractor. However, it is expected that the construction sequence of the LNG storage tanks will follow similar sequences used for other full containment tank installations as follows:

- Tank foundations;
- Tank base and outer concrete containment wall construction;
- Dome roof and suspended deck constructed inside the storage tank;
- Carbon steel vapor liner;
- Dome roof compression ring on top of the outer concrete containment wall;
- Dome roof raised into place and attached to the compression ring;
- Roof nozzles and penetrations along with concrete over the dome roof;
- 9 percent Ni steel inner container assembly;
- Internal connections including LNG pump columns, tank fill lines, spray ring and instrument connections;
- Roof platforms and structures including pipe supports and piping;
- Hydrostatic testing on inner tank;
- Pneumatic testing on outer tank;
- Insulation (perlite in annular space, suspended deck insulation, and external piping insulation);
- LNG pump installation into pump column;
- Nitrogen purge; and
- Cooldown.

It is anticipated that construction of the LNG storage tanks will be staggered with the second tank trailing the first tank by a few months such that hydrostatic testing water from the first tank may be reused for the hydrostatic test of the second tank.

Berms and Walls:

A low point northeast of the storage tanks inside the perimeter plant road will provide tertiary containment for the LNG storage tanks.

As further described in the LNG Storage Tank Tertiary Containment Calculation included in Appendix L.8 of this Resource Report, the tertiary containment will have a net volumetric capacity sufficient to contain the gross capacity of one LNG storage tank.

13.3.2 Drawings

An Area Plot Plan is included in Appendix A.2 of this Resource Report. An Overall Plot Plan is included in Appendix A.3 of this Resource Report 13. Unit Plot Plans are included in Appendix U.1 of this Resource Report 13.

13.4 Basis of Design

The LNG Facility is designed in accordance with the requirements of 49 CFR Part 193 and NFPA 59A (2001 edition and 2006 edition sections incorporated by reference therein). Appendix F.1 of this

Resource Report provides a summary of compliance with these requirements. Additional codes and standards that apply to the design of the Facility are included in Appendix D.1 of this Resource Report.

Although this section describes the basis for the design of the LNG Facility, the following reference documents are also appropriate to this design basis:

- Engineering Design Standard, 15505-TS-000-001 (Appendix C.1);
- Design Basis, 15505-TS-000-002 (Appendix C.2);
- Overall Plot Plan, 15505-DG-000-003 (Appendix A.3);
- Process Flow Diagrams (Appendix U.2);
- Heat and Mass Balance Diagrams (Appendix U.3); and
- Design Codes and Standards, 15505-TS-000-003 (Appendix D.1).

13.4.1 Guarantee Conditions

Total Net Storage Capacity	305,400 m^3 (1,920,966 bbl)
Total Gross Storage Capacity	320,034 m^3 (2,013,014 bbl)
Net Storage Capacity per Tank	152,700 m^3 (960,483 bbl)
Gross Storage Capacity per Tank	160,017 m^3 (1,006,507 bbl)
Liquefaction Capacity	54 MMscfd
Design LNG Sendout Rate	400 MMscfd

13.4.2 Site Conditions

Table 13.4-1 lists site elevations for major site areas based on the final site grading plan. All elevations are relative to North American Vertical Datum of 1988.

Table 13.4-1

Elevation for Major Site Areas

Area	Final Grade Elevation (ft)
Admin Building	+120
Tank	+120
Liquefaction Unit	+122

13.4.3 Emissions

Emissions from the operation of emission generating equipment are summarized in Resource Report 9, Air and Noise Quality.

13.4.4 Seismic

A site-specific seismic hazard evaluation has been performed for the LNG Facility and the results are described in the Seismic Hazard Evaluation Report (04.10150185) included in Appendix I.1 of this Resource Report. The site-specific seismic hazard evaluation was performed in accordance with the Draft FERC Seismic Design Guidelines and Data Submittal Requirements for LNG Facilities dated January 23, 2007. The Part II Section 3 of FERC Seismic Guidelines – Cross Reference Table (15505-LI-000-003) included in Appendix I.2 of this Resource Report demonstrates how the requirements of the Draft FERC Seismic Design Guidelines and Data Submittal Requirements have been considered in the design of the Access Northeast LNG Facility. Equipment, structures and buildings that comprise the Facility have been categorized as described in the Equipment, Structures and Buildings Seismic Categorization (15505-LI-000-0004) included in Appendix I.3 of this Resource Report.

13.4.5 Climatic Conditions

Minimum design temperature, °F	-9
Maximum design temperature, °F	102
Barometric pressure, inches Hg (mbar)	30 (1016)
Barometric pressure rate of change, inches Hg/h (mbar/h)	30
Wind direction, from	South
Design wind speed, mph	150[5]
Hurricane design force, mph or storm category	4
Storm surge height, ft	Not Applicable
Rain fall 100 year storm, in/hr	0.318
Snow load, ft	1.8

13.4.6 Shipping

Not applicable.

13.4.7 Mooring

Not applicable.

13.4.8 LNG Cargos

Not applicable.

13.4.9 Loading

Not applicable.

13.4.10 Feed Gas

Source	24″
Natural gas specifications, range of conditions	See Table 13.5.3.1-1
Composition, molecular weight, HHV, LHV	See Table 13.1.3.1-1
Maximum battery limit pressure, psig	819 psig
Minimum battery limit pressure, psig	500 psig

13.4.11 Pretreatment

Maximum flow rate to pretreatment, MMscfd	60
Minimum flow rate to pretreatment, MMscfd	27
Design pressure to pretreatment, psig	633
Design temperature to pretreatment, F	243
Treated gas specifications, range of conditions	See Stream 114 of H&MBs included in Appendix U.3
Composition, molecular weight, HHV, LHV	See Stream 114 of H&MBs included in Appendix U.3
Maximum pressure to liquefaction, psig	434 psig
Minimum pressure to liquefaction, psig	383 psig
Design temperature to liquefaction, F	95
Maximum flow rate to liquefaction, MMscfd	~ 59.7

[5] The wind speed of 150 miles per hour (mph) is a sustained wind speed and the 3-second gust design wind speed is 183 mph.

13.4.12 Regeneration Gas

Disposal of tail gas	Recycled or HP Fuel Gas
Regeneration gas specifications, range of conditions	See Streams 153-156 of H&MBs
Composition, molecular weight, HHV, LHV	See Streams 153-156 of H&MBs

13.4.13 Liquefaction

LNG to storage; specifications, range of conditions	See Stream 400 of H&MBs
Composition, molecular weight, HHV, LHV	Stream 400 of H&MBs included in Appendix U.3 of Resource Report 13
Air temperature, °F	75
Liquefaction outlet temperature, °F	-248
Liquefaction outlet pressure, psig	Between 380 and 431
Net LNG to storage, MMscfd	2 x 27

13.4.14 Fractionation Products

Fractionation products; specifications, range of conditions	See Streams 212 and 500 of H&MBs
Composition, molecular weight, HHV, LHV	See Streams 212 and 500 of H&MBs included in Appendix U.3 of Resource Report 13
Product flow rate, ft^3/hr (m^3/hr)	7,610 (215)
Product outlet temperature, °F	90
Product outlet pressure, psig	Between 380 and 413
Product storage pressure, psig	N/A

13.4.15 Storage

Type of tank	FCT
Foundation	Flat
Secondary containment	Concrete
Number of tanks	2
Gross capacity per tank, bbl (m^3)	1,006,507 (160,017)
Working capacity per tank, bbl (m^3)	960,483 (152,700)
Design pressure, psig	4.20
Design vacuum, inches H_2O	2
Working pressure, psig	0.5
Specific gravity	0.47
Boiloff rate, percent per day	0.05

13.4.16 In-tank LP LNG Pumps

Type of pump, in-tank, or pot-mounted	In-tank
Number of pumps, operating and spare	4 operating, 2 installed spares
Design flow rate, gpm	854
Head at rated flow, ft	317
Head at shutoff, ft	507
Maximum LNG, specific gravity	0.439
Shutoff pressure, psig (at design LNG specific gravity and suction pressure)	95.6
Rated and design, specific gravity	0.433

13.4.17 Pot-mounted HP LNG Pumps

Type of pump, in-tank, or pot-mounted	Pot-mounted
Number of pumps, operating and spare	4 operating, 1 installed spare
Design flow rate, gpm	854
Head at rated flow, ft	4,209
Head at shutoff, ft	4,454

Maximum LNG, specific gravity	0.439
Shutoff pressure, psig (at design LNG specific gravity and suction pressure)	896.1
Rated and design, specific gravity	0.433

13.4.18 Vaporizers

Vaporizer type	Shell and Tube
Vaporizers operating and spare	4 operating, 1 installed spare
Design flow rate each, MMscfd	102
Design heat rate each, MMBtu/h	63.6
Design pressure, psig	Tubes: 1440 Shell: 275
Design discharge pressure, psig	845
Design discharge temperature, °F	41

13.4.19 Gas Liquid Removal

Process	See Section 13.4.14
Throughput capacity, MMscfd	See Section 13.4.14
Column operating pressure, psig	See Section 13.4.14
Column design pressure, psig	See Section 13.4.14

13.4.20 Btu Adjustment

Not applicable.

13.4.21 Battery Limit

Design flow rate, MMscfd	400
Maximum pressure vaporizer outlet, psig	907.6
Pipeline maximum allowable operating pressure, psig	845
Maximum allowable pipeline temperature, °F	60
Minimum allowable pipeline temperature, °F	40

13.4.22 Vapor Handling

BOG compressor type	Reciprocating
Low pressure compressors, operating and spare	3 x 50 percent, 2 operating, 1 spare.
Low pressure compressors each, MMscfd	3.4
Low pressure compressor discharge pressure, psig	850
Vapor recondensation process	BOG from the LNG storage tanks is reliquefied in the coldbox and returned to the LNG storage tanks during liquefaction season
Maximum vapor flow rate, MMscfd	6.8
Design vapor recondensation flow rate, MMscfd	6.8

13.4.23 Vent Stacks

Not applicable.

13.4.24 Flares

Flare type	Ground; Thermal Oxidizer
Flare sources and rates	BOG Drum D-410; Thermal Oxidizer L-143
Maximum flow to flare	Preliminary estimates for the maximum flow to the flare are : Thermal Oxidizer = 1,000 lb/hr Ground Flare = 12,353 lb/hr

13.4.25 Fuel Gas

Source	HP: Heavy Hydrocarbon Gas, Molecular Sieve Regen Gas, BOG System Gas, Pipeline Gas; LP: BOG System Gas, Molecular Sieve Regen Gas, Amine Plant Flash Gas
Flow rate, MMscfd, MWt, °F.	Liquefaction: HP: 5.94, 17.7, 89.1 LP: 0.36, 16.3, 94.91 Sendout: HP: n/a LP: 8.0, 16.8, 41
Pressure levels, psig.	HP: 550; LP: 60
Minimum temperature at pressure levels, °F @ psig	57.0 @ 65.1
Odorized, yes/no	Yes, in HP system when using raw feed gas.

13.4.26 LNG Trucking

Number of trucks per year	TBD
Number of trucks per day unloading	TBD
LNG truck fill rate, gpm	343

13.4.27 Electrical

Main power utility supplier	NSTAR
Utility supply voltage, kV	230
Utility supply capacity, kVA	15 kVA
Main power generated onsite, yes/no	No
Emergency power supply, Utility/Generated	Generated
Emergency power generators, number, type, kV, kVA	3, natural gas, 4.16, 2500
	1, blackstart, .48, 150
Emergency power voltage, kV	0.48
Emergency power capacity, kVA	2300
UPS services, voltage, size and capacity, V, kVA, h	2 x 100 percent, 4 h minimum battery life

13.4.28 Control Instrumentation

DCS manufacturer	To be determined during final design
Control system software supplier	To be determined during final design
SIS type	Independent of DCS

13.4.29 Instrument Air & Plant Air

Compressors type	Centrifugal
Drying system type	Vertical Heatless
Flow rate, scfm	TBD
Pressure, psig	150

13.4.30 Plant Air

See section 13.4.29.

13.4.31 Inert Gas

Not applicable.

13.4.32 Nitrogen

Source	LIN Storage Package L-860
Liquid nitrogen storage capacity, gallons	TBD
Flow rate, scfm	TBD
Pressure, psig	250

13.4.33 Firewater

Source mains/storage/other	1 x 500,000 gal tank at grade
Pump and driver type	Centrifugal; Diesel and electric
Pump rated capacity, gpm	2,500
Pumps operating and standby	1 Electric Pump, 1 Diesel Pumps, 1 Electric Jockey Pump
Make up water source	Municipal Water Supply
Make up water available flow rate, gpm	The water supply is provided by a 16" connection to the main water line. Supply can vary up to 1,000 gpm
Make up water available pressure, psig	50
Firewater storage type and capacity, gallons	Suction tank at grade, 1 x 500,000
Firewater design flow rate, gpm	2,500
Firewater supply pressure, psig	125

13.4.34 Cooling Water

Not applicable.

13.4.35 Hydrostatic test water

Source	TBD during detailed design
Available flow rate, gpm	TBD during detailed design
Pressure, psig	TBD during detailed design

13.4.36 Utility Water

Source	Acushnet Municipal Water Supply

13.4.37 Fire Protection

Algonquin has developed a preliminary ERP for the LNG Facility and will continue development of a full ERP that will describe the coordination with external stakeholders, including fire protection service providers. See Section 13.15 and Resource Report 11 for additional information.

13.4.38 Site Security

The LNG Facility is designed and will be constructed and operated to provide the level of security and safety, consistent with the requirements of its design and location.

Security measures included within the design of the LNG Facility to control access include perimeter fencing, lighting, security personnel and cameras, monitored and controlled access points into the LNG Facility, restrictions and prohibitions applied at the access points, identification systems and screening procedures.

The LNG Facility site will be surrounded with a security fence with limited access openings. A closed circuit television ("CCTV") system will be installed at the LNG Facility and will monitor the perimeter fence line and active access points.

13.5 Major Process Systems

13.5.1 Marine Facilities

Not applicable.

13.5.2 Loading

Not applicable.

13.5.3 Feed Gas and Pretreatment

Approximately 60 MMscfd of natural gas will be contracted for transportation to the LNG Facility. Gas will be sourced from Algonquin's G System and will travel to the site via the proposed Acushnet 24-inch Connector. The Acushnet 24-inch Connector consists of approximately 2.70 miles of new 24-inch diameter pipeline in the towns of Freetown and Acushnet in Bristol County, Massachusetts. The Acushnet 24-inch Connector will begin (MP 0.00) in the Town of Freetown at the intersection of the Algonquin Line G-8 pipeline. From this starting point, the proposed Acushnet 24-inch Connector extends south over a greenfield route for approximately 1.26 miles, then continues in a west and then southerly direction along Dr. Braley and Keene Roads to MP 1.80. The pipeline continues along Nestles Lane, across the Freetown/Acushnet border at MP 2.17, to MP 2.58 where it heads southeast 0.12 miles within the Access Northeast LNG Facility off Peckham Road in Acushnet and terminating at MP 2.70.

The LNG Facility will be designed to handle the gas components limits specified by the Algonquin system pipeline.

The pretreatment system comprises gas sweetening and dehydration that remove components (principally CO_2, sulfur compounds, and water) in the pipeline gas which would otherwise freeze solid and block the liquefaction exchangers at cryogenic temperatures.

The purpose of the amine pretreatment system is to remove CO_2 from the gas stream as this would otherwise freeze in the liquefaction exchangers. The CO_2 content is typically 0.2-0.65 mol% however the amine plant is designed to remove up to 2 mol% of CO_2 down to 50 ppm to prevent CO_2 from solidifying and blocking the liquefaction exchangers.

A commercially available amine solvent will be utilized to remove CO_2 to acceptable levels. Though the amine solvent is non-corrosive, the primary contaminant captured, CO_2, is corrosive in aqueous solutions at high temperatures. Therefore, stainless steel material is used for those items in corrosive service and adequate corrosion allowance will be specified where required.

Water must be removed from the gas stream to < 1.0 ppm prior to liquefaction to avoid freezing in the liquefaction exchangers. This is achieved using three molecular sieve dehydrator vessels. Three vessels have been selected to accommodate the plant throughput required during capacity ramp-up so that the minimum required regeneration velocity through the sieve bed is met. Two beds will operate in adsorption mode with the third vessel in regeneration or standby mode. Each bed cycles consecutively through adsorption, heating, cooling and standby under control of a valve switching system. A side stream of dry gas is used for regeneration. This side stream is heated to approximately 500ºF before flowing upwards through the bed for regeneration. The expected bed life is approximately 4 years and replacement will coincide with other scheduled plant maintenance.

A non-regenerative mercury guard bed will be provided to remove mercury down to <1 ppb(v). This protects the aluminum heat exchangers used for liquefaction from corrosion.

The pretreatment system will be built by an EPC Contractor based on design information from the selected pretreatment system vendor. The pretreatment system vendor provides necessary guarantees for the performance of the system. The vendor will provide process simulations, equipment design data and process schematic under a Licensing Agreement.

13.5.4 Liquefaction

The liquefaction system comprises natural gas liquefaction and heavy hydrocarbon removal and produces LNG at a rate of 54 MMscfd measured in the LNG storage tank.

Natural gas will be liquefied using two Nitrogen Expander Cycles sized for 27 MMscfd production each. The Nitrogen Expander cycle is a relatively simple refrigerant cycle used primarily in small-scale liquefaction applications. There is also an inherent safety benefit in using only a non-flammable compound (nitrogen) as the refrigerant. The Nitrogen Expander process has been in use at LNG peak-shaveing facilities for over 30 years.

The nitrogen flows in a closed-loop cycle. Ambient, low pressure nitrogen vapor exits the coldbox and is then compressed by the Nitrogen Compressor boosting the pressure of the nitrogen. Each stage of compressor is cooled by forced draft air coolers. The nitrogen is further compressed by a warm and cold compressor and subsequently cooled by a forced draft air cooler.

The high pressure nitrogen stream then enters the Nitrogen Expander leaving at cryogenic temperatures and lower pressure. The heat from natural gas entering the Liquefier Exchanger is extracted by the cryogenic, low pressure nitrogen.

The removal of HHC will be accomplished by partially liquefying the incoming natural gas in the Liquefier Exchanger. The HHCs liquefy at a higher temperature than methane, the principal constituent of natural gas. The HHCs drop out of the feed gas stream and will be removed in the Demethanizer Column prior to the final liquid product entering the LNG storage tank. This HHC stream is then consumed as fuel gas.

13.5.5 Fractionation

Not applicable.

13.5.6 Vapor Handling

The Vapor Handling System includes the BOG Header, LNG storage tank vapor space, BOG Compressors, and overpressure relief line to flare.

The BOG is generated from the following sources:

- Heat leak into the LNG storage tank through the insulation systems;
- Displaced vapor due to the LNG volumes entering into the storage tanks from the liquefiers;
- LNG flash gas from LNG entering the storage tank;
- Heat generated by LNG in-tank (loading) pumps; and
- Heat leak into LNG piping, including transfer pipeline recirculation.

The composition of the BOG is predominantly a function of the mol% nitrogen in the LNG stream as it enters the LNG Storage Tank.

The LNG Facility will be designed to minimize fugitive emissions with no flaring during all normal operations using a Closed Vent/Drain System. All LNG and natural gas relief valves (excluding LNG storage tank, fuel gas drum and the LNG Vaporizer process relief valves) will be vented into a closed vent flare system that is common with the LNG storage tank vapor spaces.

All release in the liquefaction system during an operation upset or start-up will be sent to a closed flare system. The following is the basis of the flare design:

- Initial dryout and cooldown of liquefaction system; and
- Maximum emergency release during operation of the liquefaction system.

13.5.7 LNG Sendout System

In-Tank LP Pumps:

Each of the LNG storage tanks will have three LP Pumps. Each LP Pump will be mounted inside its own column and will be located inside the column near the bottom of the LNG storage tank. Each pump will be provided with an individual minimum flow recycle line and flow control to protect the pump from insufficient cooling and bearing lubrication at low flow rates. The pumps have remotely monitored pressure, flow, vibration and motor amperage signals. The pumps will include features to isolate and safely maintain a single pump without requiring other pumps to be removed from service. The LP Pumps will be removable for maintenance while maintaining an operating level in the LNG storage tank.

Sendout System:

The LP Pumps will supply LNG to the HP Pumps via the HP Pump Drum.

Each HP pump will be provided with an individual minimum flow recycle line and flow control to protect the pump from insufficient cooling and bearing lubrication at low flow rates. The recycle flow will be routed to the LNG storage tanks through the tank top fill lines. The pumps will have remotely monitored pressure, flow, vibration and motor amperage signals. The pumps will include features to isolate and safely maintain a single pump without requiring other pumps to be removed from service.

The HP Pumps will supply LNG vaporizers, which are shell and tube heat exchangers. Heat for vaporization will be via a solution of ethylene glycol and water that will be heated in fired heaters.

13.5.8 Gas Liquid Removal

Not applicable.

13.5.9 Btu Adjustment

Not applicable.

13.5.10 Pressure Relief and Flare Systems

The purpose of the flare system is to safely and reliably dispose of streams which are released during start-up, shutdown, plant upsets and emergency conditions. A single ground flare will be constructed and is explained further in this section. The LNG Facility will be designed to avoid continuous flaring. Flaring from the process will only occur during plant start-up or process upset conditions.

The source of the pressure relief flows to the flare systems are from the discharge of relief valves, depressuring valves and pressure control valves throughout the LNG Facility that open automatically during abnormal conditions. Some of the main causes of such overpressure are:

- Electric power failure, resulting in loss of cooling (air coolers);
- External fire;
- Instrument air failure;
- Entrapment of cold liquid that will expand upon warming (this is generally only for thermal relief valves);
- Failure of equipment;
- Incorrect operating procedures; and
- Exchanger tube ruptures.

The ground flare is designed to handle both wet/warm relief fluids and cold relief fluids. The ground flare will have heat shielding on all sides to provide personnel protection. The ground flare will only operate during abnormal operating conditions. A ground flare was chosen over an elevated flare to reduce visibility concerns from public receptors.

The cold relief fluids are fluids lower than ambient temperature such as BOG gas section and LNG storage tank venting system. The warm relief fluids are fluids from pretreatment and other fluids above ambient temperature.

The common header systems will be continuously purged with fuel gas or with nitrogen as backup, in order to maintain a positive pressure and prevent atmospheric air from being drawn into the system after a hot release.

The final design capacity of the ground flare will be determined during detailed design. The design will ensure a radiation level at the site boundary of less than the allowable level of 500 Btu/hr-ft^2 under unfavorable wind conditions and excluding solar radiation.

13.5.11 Sendout Metering

Natural gas product will be sent through a metering skid prior to entering Algonquin's natural gas pipeline system. The design of the metering skid will be provided by a vendor and finalized in final design.

13.5.12 LNG Product Loading Marine

Not applicable.

13.5.13 LNG Product Loading Trucking

The LNG Facility will include support facilities for trucking. The trucking facilities are designed to load LNG onto trucks in the event of a mutual aid request from other LNG facilities in the Northeast or to otherwise support emergency loading/unloading operations. The trucking facilities will also be capable of supporting LNG loading and delivery for distribution in the Northeast, should commercial arrangement for such deliveries be entered into at a future point. The trucking facilities are also designed to support operational, maintenance, and material delivery requirements (including liquid nitrogen for purging and refrigerant makeup).

The capacity of the LNG trucks will be up to 12,000 gallons with a loading flow rate of approximately 343 gallons per minute ("gpm"). LNG will be supplied to the truck loading station via the LNG storage tank's in-tank pumps. The truck loading station is a dual bay design and each truck will be loaded one at a time. The LNG truck loading facility will include the following components:

- Cryogenic pipework (loading and vapor return) from LNG storage tank(s) to the LNG truck loading facility;
- Flexible cryogenic hoses (loading and vapor return) for filling;
- Emergency Shut-off Control panel;
- Communication to Control Room;
- Truck weigh scales; and
- Driver Shelter.

13.5.14 Commissioning Plan

Commissioning will commence only when the construction contractor has achieved mechanical completion of equipment and systems.

Mechanical completion will be achieved only when installation of equipment and systems has been completed and cleaned out, quality control records have been completed and all operating and maintenance manuals have been provided. Algonquin will verify that mechanical completion has been achieved and will review commissioning procedures that will be prepared by the EPC Contractor.

Algonquin will provide the construction contractor with a signed certificate acknowledging that mechanical completion of the applicable equipment and systems has been achieved and that commissioning may commence.

Commissioning of equipment and systems will be conducted in accordance with commissioning procedures that will be prepared by the construction contractor in conjunction with equipment vendors. The commissioning procedures will be reviewed and approved by Algonquin.

Commissioning procedures will include pre-commissioning activities, which will include:

- Instrumentation and control system function and loop checks;
- Electrical system checks, including confirmation of electrical protection scheme settings;
- Confirmation of operation of all protective devices;
- Confirmation of alarm and trip set-points and operation;
- Confirmation of the operation of all protective devices including ESD valves;
- Confirmation of operation of all hazard detection and hazard control equipment; and
- Line out of the equipment and system valves including all relief devices to the vent system.

All pre-commissioning activities will be completed before the equipment and systems are commissioned.

Commissioning of equipment and systems will be in accordance with the commissioning procedures. With respect to cryogenic systems, commissioning must include a controlled cooldown process.
The initial dryout of the cryogenic plant items for the natural gas and mixed refrigerant circuits and the LNG loading system will be achieved in several steps. Nitrogen and/or instrument air will be used for bulk drying of plant during pre-commissioning. Once the nitrogen runs on the refrigerant compressors are completed the natural gas and refrigeration circuits will be dried. Heated fuel gas supplied from the dehydration unit will be used via the defrost gas network to dry the system to the required level suitable for cooldown.

Cooldown and startup of each of the liquefaction units will be carried out one after the other. Cooldown of the coldbox will be carried under vendor supervision. Nitrogen will be introduced to the refrigeration circuit to provide gradual cooling of the coldbox. Natural gas will be then introduced, with the LNG produced used for gradual cooldown of the LNG storage tanks, BOG recycled to coldbox, and excess BOG sent to flare.

The tank will be dried and purged prior to commissioning. Drying will be performed by removing all standing water. The tank will be purged with gaseous nitrogen to a maximum oxygen content of 8.0 percent by volume. After the tank has been purged with nitrogen it will be purged to a combustible gas concentration of no less than 90 percent in preparation for tank cooldown.

The tank system has an independent cooldown, with fill line with spray nozzles designed specifically for cooldown of the LNG storage tank. During the initial introduction of liquid product, it is important to have uniform cooldown. The primary container temperature gradient between any two adjacent cooldown RTDs will not exceed 50°F and the gradient between any two RTDs will not exceed 100°F. The cooldown rate for the primary liquid container will be controlled to a maximum average of 9°F/hr and will not exceed 15°F/hr during any one hour period. The cooldown will be complete when 6 inches of product liquid is measured in the tank.

13.6 LNG Storage Tanks

The following technical description of the proposed LNG storage tanks includes the essential features of the tank design and foundation system.

Appendix L.1 contains details of the LNG Storage Tank and Foundation specification 5101-0076_S-8001 that has been used in the preparation of the LNG storage tank design.

13.6.1 General

The LNG storage tanks will each be full containment, with a 9 percent Ni steel inner tank, post tensioned concrete outer tank, freestanding carbon steel liner and suspended insulation support deck. The inner tank will contain LNG, while the outer tank will contain product vapors. The concrete outer tank will provide secondary containment. The steel inner and concrete outer tanks will be supported on a common foundation. The tanks will be designed and constructed in accordance with the requirements of API Standard 620 (Eleventh Edition) including Appendix Q, American Concrete Institute ("ACI") 376, NFPA 59A and 49 CFR Part 193. Drawings series 3000, 4000, 5000 and 8000 in Appendix L.2 provide details of the tank design.

13.6.2 Tank Foundation

The concrete outer tank base slab will rest on grade, as indicated on Drawing 3011-01. The base slab will not be supported on piles due to appropriate soil characteristics ensuring proper foundation strength. The base slab will be nominally 2’-0 thick with a 6’-0 thick outer haunch starting at a radius 124’-0. This thickened outer radius is to allow for the vertical tendon connection and also to distribute the load from the inner tank and outer tank to the outer, thicker section of the slab.

The tank foundation has been designed per the requirements of the following codes:

- Reinforced concrete design is in accordance with ACI Standard 376-10 and ACI Standard 318, “Building Code Requirements for Reinforced Concrete”.
- Hydrostatic and pneumatic pressures are in accordance with API Standard 620, Appendix Q as applicable.
- Severe wind and seismic forces are in accordance with 49 CFR Part 193 and NFPA 59A.

Materials used in the concrete mix will conform to American Society for Testing and Materials (“ASTM”) standards and other recognized standards, as applicable. Reinforcing steel will be provided in accordance with ASTM A615 Grade 60. Design and quality requirements for concrete materials will be in accordance with ACI 318 and ACI 301. Concrete with a compressive strength (f'c) of 4,000 psi, based upon a characteristic cylinder strength, at 28 days as defined in ACI 318 will be used.

Foundation Heating System:

A foundation heating system will be provided to prevent frost heave of the soils underlying the tanks. The system consists of heating cables installed in conduits embedded within the foundation. Rigid galvanized steel conduits will be used and arranged in a parallel configuration and will exit the foundation at both ends. The conduits will be spaced at calculated intervals to provide an even heating layer and will be capable of providing 100 percent redundancy (available heat vs. expected heat). Constant wattage type heating cables will be employed. The foundation conduit heater layout is shown on Drawing 3012-01.

The RTD sensors will be installed in dedicated conduits at strategic locations within the foundation to accurately monitor the performance of the heating system. The sensors will constantly monitor the temperature at each location and input status to the tank foundation heater control system to maintain the foundation at the desired temperature within an acceptable deadband. Both the heating cables and temperature sensors can be readily accessed for replacement if necessary.

Power to the heating cables will be supplied by multiple circuits to the tank foundation heater control system. The power circuits will be alternated in relation to their designated breaker. If one circuit fails, the adjacent heaters will provide the heat necessary to maintain the proper temperature level in any area under the tank. This design feature will allow individual circuits to be repaired or replaced without affecting the overall performance of the heating system.

13.6.3 Outer Containment

The outer tank will have a concrete base, wall and roof. The concrete wall will be post-tensioned and will have a freestanding carbon steel liner and with embedments. The post-tensioning tendons run both vertically and horizontally. The vertical tendons are embedded into the thickened radial portion of the base slab.

The outer tank roof is a freestanding, reinforced concrete dome with a, carbon steel liner and a structural steel rafter system. The outer tank completely encloses the inner tank and insulation, providing a vapor barrier and insulation container. The outer tank is capable of both containing the liquid product and controlling the vapor release in the event of product leakage from the primary liquid container (inner tank); therefore the outer tank is considered the secondary liquid container of this full containment tank system as defined by API Standard 620, Appendix Q.

The carbon steel outer tank wall liner seams will be full penetration butt welds. Bottom plates will be welded with 2-pass (minimum) fillets welded from the topside. Roof plates will be butt-welded.
Outer tank liner, bottom and roof welds will be vacuum box or soap bubble inspected.

Full fusion butt welds will be used for the rim girder splice welds. Welds attaching the rim girder to the wall liner will be continuous fillet welds meeting API 620 and NFPA 59A requirements.

Appendix L.6 of this Resource Report includes calculations pertinent to the design of the outer containment, including containment capacity.

13.6.4 Inner Containment

The inner tank, which will contain the liquid product, is a cylindrical, flat bottom, open top tank, with a suspended insulation deck. The inner tank shell, bottom and stiffeners will be constructed of 9 percent Ni steel, per ASTM A553 Type 1 and will be provided with enhanced notch toughness. The average notch toughness value will be 100 foot-pounds. Weld metal notch toughness will have an average value of 20 foot-pounds.

The inner tank horizontal and vertical shell seams will be full penetration butt welds with 100 percent radiographic inspection. Shell welds above the hydrostatic test water level will be vacuum box inspected prior to the hydrostatic test.

Bottom annular plates will be full penetration butt welds in accordance with API Standard 620. Bottom plates will be lap welded with two-pass (minimum) fillets welded from the topside. The shell to annular plate weld will be a partial penetration weld with continuous cover fillets on each side. All bottom plate welds and the shell to bottom junction will be vacuum box inspected both before and after hydrostatic test. The shell to annular plate weld will be liquid penetrant inspected on each side prior to hydrostatic testing.

Shell stiffeners will be full penetration butt welded together and attached to the shell with continuous fillet welds top and bottom. Stiffener butt welds will be 25 percent radiographic inspected. Stiffener attachment welds to the shell will be liquid penetrant inspected top and bottom.

Appendix L.6 of this Resource Report includes calculations pertinent to the design of the inner containment.

13.6.5 Seismic Design

Seismic design of the inner and outer tank is in accordance with site specific design criteria in addition to NFPA 59A. Seismic design spectra used for calculation of earthquake load conditions are based on the seismic design response spectra contained in the site specific seismic hazard evaluation included in Appendix I.1 of this Resource Report.

Appendix L.6 of this Resource Report includes calculations pertinent to the seismic design of the LNG storage tank.

Inner Tank:

The inner tank has been designed using the methods in API 620 Appendix L, modified as appropriate to apply site specific operating base earthquake ("OBE") and safe shutdown earthquake ("SSE") criteria as described in the seismic design response spectra and as required by NFPA 59A. It has been assumed that the inner tank will be filled with LNG to maximum normal operating level (which is not an overfill or alarm level). When designing for the SSE condition, allowable stresses have been determined in accordance with NFPA 59A.

Outer Tank:

The outer tank has been designed using OBE and SSE criteria as described in the seismic design response spectra and as required by NFPA 59A. The overall response of the total LNG storage tank system has been determined by combining the significant modes using the square root sum of the squares ("SRSS") method.

The results have been combined with other load effects that are calculated using a finite element analysis method. For axial symmetric conditions, the concrete tank may be modeled using axially symmetric elements, including foundation elements.

Load Conditions and Combinations:

The horizontal and vertical response spectra for both the OBE and SSE have been input to the model as acceleration spectra. Vertical components (acceleration and the relationship between amplitude and frequency) are based on spectra contained in the site specific seismic design basis. The responses of the composite tank structure for each mode shape have been determined from the appropriate response spectrum, modal frequency and composite damping. Horizontal and vertical responses have been combined as follows.

- 100 percent horizontal +/- 40 percent vertical
- 40 percent horizontal +/- 100 percent vertical
- Load combinations that include vertical acceleration (hydrodynamic) components producing hoop (circumferential) tension in the inner tank shell plates have been evaluated using strength properties as permitted per Section 3.16 of the Specification for Full Containment LNG Storage S-8001 included in Appendix L.1 of this Resource Report. The hydrodynamic pressure components have been directly added to (combined with) static liquid pressure when using strength properties permitted per Section 3.16 of the Specification for Full Containment LNG Storage S-8001.

The response and displacement of each LNG storage tank component in two horizontal directions have been combined by using the SRSS method. Material structural damping factors will be as follows (unless higher system damping factors are justified by soil structure interaction analysis).

- OBE = 5 percent, SSE = 5 percent for the steel tank, and liquid sloshing = 0.5 percent for the inner tank contents
- OBE = 2 percent, SSE = 5 percent for the outer post tensioned concrete wall
- OBE = 2 percent, SSE = 5percent for the reinforced concrete roof and base slab [6]

Soil Structure Interaction and Reduction Factors:

Soil structure interaction ("SSI") and/or flexibility of a pile foundation system analysis has been performed per the requirements of NFPA 59A. A reduction factor for the SSE from over-strength, or ductility, and/or other phenomena may be used if justified by proper analysis.

The use of SSI damping ratios and reduction factors in addition to total system damping is subject to approval of the Owner/EPC Contractor and jurisdictional regulatory authorities.

In evaluating vertical earthquake loads using the response spectra approach, it has been confirmed that the loads used in the static analysis are at least 80 percent of the loads that would occur if soil-structure interaction is not accounted for.

Sloshing:

Seismic slosh wave shell freeboard allowances have been added to the normal maximum liquid level ("NMLL") to determine required inner tank shell height. Calculate shell freeboard allowance including slosh wave per the API 620 L.4.2.8 for OBE and L.4.3.2 for SSE.

For the SSE condition, the SSE calculated slosh wave height may be added to NMLL without any extra allowance.

Alternative sloshing height calculation methods may be used providing the calculated sloshing height is not less than 80 percent of the value required by these provisions, subject to approval by Owner/EPC Contractor and jurisdictional regulatory authorities.

The response acceleration for the sloshing mode has been computed using the horizontal seismic design spectra without consideration of the resultant of two horizontal ground motion acceleration components.

13.6.6 Wind Loads on Outer Tank

Outer containment is designed to withstand a wind velocity of 150 miles per hour ("mph") in accordance with 49 CFR Part 193.2067. This is a sustained wind speed which is equivalent to a 3-second gust of 183 mph.

13.6.7 Insulation System

The storage tank insulation system will be designed to accommodate the specified boiloff conditions.

The tank base insulation system will consist of four layers of 5-inch thick, cellular glass blocks. Asphalt impregnated sheet material will be placed between the cellular glass blocks to develop the compressive

[6] Reference; Earthquake Engineering Research Institute ("EERI") publication, "Earthquake Spectra and Design", by Newmark & Hall, page 54, Table 3.

capacity of the cellular glass blocks. A leveling course of concrete will be installed below the cellular glass blocks to provide a solid base. There will also be a leveling layer of lean concrete on top of the cellular glass blocks.

The inner tank shell will be supported on an insulation system consisting of a concrete bearing ring and two layers of 5-inch thick cellular glass blocks. The inner tank shell support will be capable of resisting seismic forces and concentrated shell loads.

The tank sidewall insulation will consist of expanded perlite ore. The perlite will be vibrated during installation to achieve proper density. A perlite make-up reservoir will be provided at the top of the annular space between the inner and outer tanks. A compaction control system consisting of resilient fiberglass blankets will be installed to limit the perlite compaction pressure against the inner tank.

A perlite insulation retaining curtain will be installed to prevent the perlite from spilling onto the suspended deck. This perlite retaining curtain will hold a reservoir of perlite over the annular space. A metal closure piece that joins to the suspended deck will be attached to the top of the inner tank. This metal closure, in conjunction with fiberglass blankets and cloth, will prevent perlite from entering the inner tank. Boots through the concrete roof will be used for piping penetrations through the outer tank shell and will be insulated with fiberglass. Fiberglass insulation will also be installed on the cold service piping that runs between the outer tank roof and the suspended deck.

13.6.8 Tank Instrumentation

The following is a summary of the instrumentation systems that will be installed on each LNG storage tank:

Cooldown Sensors:

To assist in cooldown and subsequent temperature measurement during commissioning and decommissioning of the tank, RTD elements will be installed. All cabling from these RTDs will be terminated at a junction box external to the tank roof.

Temperature Sensors:

The RTD elements will be placed on the inner shell, the inner container bottom, and the suspended deck of each tank. These temperature elements will be used to monitor the tank temperature during cooldown.

The RTDs will be located at two different heights in the tank bottom annular space for leak detection and they will be spaced equally around the circumference of each tank.

Liquid Level Instruments:

Each tank will include two liquid level gauges installed in stilling wells. The gauges will be servo-motor operated type and will include field indicators and a data transmitter to allow information to interface with the distributed control system (“DCS”) system.

An independent third instrument for level high alarm and level high-high alarm with trips will be provided. The trip switches from this third instrument, along with the other two automatic gauges, will be wired to the SIS.

Density Monitoring:

An independent Low Temperature Detector ("LTD") system monitor, with density difference alarm, will be installed in each tank. The system will monitor the level versus temperature versus density profile. This device will be used to monitor for liquid stratification and potential rollover situations.

13.6.9 Pressure and Vacuum Relief Systems

Three (3) 12-inch by16-inch, atmospheric pressure relief valves will be provided and installed including one spare valve on each tank. Isolation shutoff valves will be installed beneath each relief valve. The relief valves will be pilot operated and will utilize a common pressure sensor pipe that extends through the dome roof. Vertical discharge pipes with weather hoods will be on each relief valve. Design conditions, which were considered in the sizing of the pressure relief valves include:

- Heat gain occurring through the tank and the LNG fill flash, the barometer falling at a rate of 0.2 inches of mercury per hour, vapor being displaced from filling the tank and in-tank pump heat;
- A fire completely engulfs the LNG storage tank as defined in NFPA 59A combined with the barometer falling at a rate of 0.2 inches of mercury per hour; and
- 3 percent of the tank's contents are being vented in 24 hours as required by NFPA 59A.

Five (5) 12 inch vacuum relief vents will be provided. Isolation shutoff valves will be installed beneath each relief vent. Design conditions, which were considered in the sizing of the vacuum vents include:

- Vapor being withdrawn from the tank, liquid withdrawal from the tank and the barometer rising at a rate of 0.2 inches of mercury per hour. The four primary vacuum relief valves will be sized for a combined flowrate of 551,388.8 scfh, which exceeds the required capacity.

Appendix L.4 of this Resource Report includes calculations used to size the pressure and vacuum relief valves.

13.6.10 Fittings, Accessories and Tank Piping

Piping and instrumentation will be provided for the operation of the LNG storage tanks, in accordance with the requirements of 49 CFR Part 193. The specific piping, valves and instrumentation for the tanks are defined on drawings included in Appendix L.2 of this Resource Report.

Tank isolation valves for lines carrying LNG will be located at the base of the tanks.

Piping will be designed in accordance with American National Standards Institute B31.3. Cryogenic piping external to the tanks will be made of ASTM A312, Type 304 stainless steel. In general piping internal to the LNG storage tanks will be constructed from stainless steel material.

Pedestals will be provided for tank mounted piping and instrumentation. Supports attaching to the concrete roof and the roof platforms are shown are drawings 4002-01 and 4003-01 which are included in Appendix L.2 of this Resource Report. The LNG storage tank nozzles and penetrations are shown on drawing 8005-01, which is included in Appendix L.2 of this Resource Report.

13.6.11 Stairways and Platforms

A two-tiered level platform will be provided at the periphery of each tank roof near the stair tower and process piping penetration for servicing valves and instruments. The platforms will be of galvanized structural steel construction with galvanized grating and handrails. There will be a second platform near 180° from each stair tower for access to the pressure and vacuum relief valves.

A handrail will be installed at the periphery of the outer tank roof to give 360 degree access to the outside of the concrete tanks.

A stair tower will provide access from grade to the rooftop platform; an emergency ladder egress will be located 180 degrees from the stair tower access.

Handrails and lighting will be provided for all stairs and walkways. Lighting fixtures will be suitable for use in the electrical area classification that applies to the area in which they are installed.

13.6.12 Cryogenic Spill Protection

Any portion of the outer surface area of a warm product vapor container or external member that, if failure occurred, could result in loss in containment from accidental exposure to low temperatures resulting in the leakage of cryogenic liquid or vapor from flanges, valves, seals or other non-welded connections have been designed for such temperatures or otherwise protected from the effects of low-temperature exposure. The concrete roof is part of spill protection since the concrete has been designed for cryogenic temperatures.

13.6.13 Anchorage

The concrete outer tank wall and base connection is monolithic and does not require anchors.

13.6.14 Painting

The outer tank is concrete and does not have exterior carbon steel plates that need to be painted.
The underside of the bottom of the outer tank will not be painted. Stairs, platforms and pipe supports will be painted or galvanized. Stainless steel, aluminum and galvanized surfaces will not be painted. Galvanized stair treads and platform grating will be used on each LNG storage tank and stair tower.

13.6.15 Tank Lighting and Convenience Receptacles

General tank lighting systems will be provided. Lighting levels will be as defined in Illuminating Engineering Society of North America ("IESNA") recommendation.

Emergency escape lighting will be provided using self-contained battery fittings.

A dual aircraft warning light will be provided at the highest point on each tank in accordance with FAA directives. Outdoor convenience receptacles will be provided at each tank with a minimum of two at the top platform.

The electrical system will be designed in accordance with NFPA 70. To the greatest extent possible, all lighting will be directed inward to the Facility and will consist of low yellow lighting.

13.6.16 Electrical Grounding

Each LNG storage tank will be provided with electrical grounding. Nine grounding lugs will be provided on the exterior of each outer tank shell. Grounding cables will connect these lugs to a grounding loop buried at the base of the tank and connected to the LNG Facility grounding grid. Grounding will be done in accordance with the requirements of the most recent edition of NFPA-70. The grounding network will be Cadweld bonded.

Lightning protection will be provided and attached to the handrails and each tank to properly conduct the electricity from lightning away from the outer concrete shell.

13.6.17 Welding

LNG storage tank welding procedure qualifications and welder qualifications will be in accordance with American Society of Mechanical Engineers ("ASME") Section IX C13. The guidelines of API 620 Appendix Q will be followed for the quantity of tests. Test plates will be welded on a test stand.

Visual inspection will be performed in accordance with API 620.

The shell plate to annular plate joint will be smoothly finished to avoid undercuts and overlaps, provided that any undercut will be within the tolerances allowed by API 620.

13.6.18 Testing and Inspection

Testing and inspection of the welding, completed work and the completed structure will be performed under the direct supervision of a qualified welding supervisor inspector. Both visual inspection and radiographic inspection will be used. An inspection and quality assurance procedure applicable to LNG storage tanks will be used.

Alloy Verification:

All alloy material used in the construction of the inner and outer tanks will be subject to alloy verification. All alloy material external to the tank and in cryogenic service will be subject to alloy verification.

Alloy verification will be performed in accordance with specifications. Technical specification P-8001, included in Appendix L.5 of this Resource Report summarizes typical requirements.

Radiography:

The radiographic techniques and acceptance criteria will be in accordance with API 620. The extent of radiography will be in accordance with API 620 and NFPA 59A Section 4.2.1 (2001 edition). The radiographic test may be substituted with the ultrasonic test in accordance with API 620 Appendix U.

Liquid Penetrant Examination:

Liquid penetrant examination will be performed in accordance with API 620, with the exception that the water-washable method may be used.

Vacuum Box Testing:

Vacuum box testing will be carried out in accordance with API 620.

Hydrostatic Testing of Inner Tank:

Hydrostatic testing of the inner container of each tank will be in accordance with API 620 Appendix Q.6.

The LNG storage tank construction contractor will prepare hydrostatic test procedures that, in addition to the actual hydrostatic test procedure will also include the following:

- Requirements for water quality, including sampling, testing and treatment required to determine suitability prior to use;
- Rates at which water is to be pumped into the LNG storage tank. (Note: water will only be pumped into the tank at rates not exceeding the limitation set by API 620);
- Limits for the period of time that water used for hydrostatic testing will remain within the tank to prevent corrosion and biological fouling and will include any requirements for treatment;
- Requirements for re-using water for hydrostatic testing of additional LNG Storage Tanks; and
- Requirements for the disposal of water upon completion of the hydrostatic testing and any treatment prior to discharge.

Pressure and Vacuum Testing:

A pneumatic test of the outer container will be performed in accordance with API 620 Appendix Q.6. Pump columns will be tested in accordance with ASME B31.3, Chapter VI, 345.6 - Hydrostatic-Pneumatic Leak Test. The design pressure will be the pump discharge pressure at shutoff. Prior to the tank hydrostatic test, the pump wells will be emptied and sealed. Additional B31.3 piping will be tested as required.

Settlement Monitoring:

A settlement monitoring system will be provided to measure and record inner and outer container movements during construction and hydro test.

The LNG storage tank construction contractor will provide details of the survey/reference points and their location around the outer edge of each tank foundation. Measurements will be made from the inner container annular plate. Also, a reference point will be established on the outer container wall to measure differential settlement between inner and outer containers. Differential settlement and tilting of the foundation will be monitored and recorded.

During the hydro test, settlements, rotation and foundation tilting will be monitored at increments of water fill height. Measurements will also be recorded when the tanks are emptied. During construction, the settlement of the foundations and inner containers will be monitored on a weekly basis.

The LNG storage tank construction contractor will prepare a detailed civil monitoring specification.

Calibration:

Prior to mechanical completion of the LNG storage tanks, the construction contractor will arrange for calibration of the inner tanks by a specialist organization in accordance with the API Manual of Petroleum Management Standard, Chapter 2, Tank Calibration, or other internationally accepted code. The EPC Contractor will supply gauge tables or equivalent calibration curves and equations, which relate the actual tank volume under operating conditions and at various product levels to the warm, measured tank volume.

13.6.19 Procedures for Monitoring and Remediating Stratification

When tank rollover occurs, initially stratified layers of products equalize in density resulting in rapid circulation of lower volatile product that was previously suppressed in liquid form at the bottom of the tank to the top of the tank where it subsequently boils off at a more aggressive rate than normal steady state boiloff. The lower, denser layer of stratified product is able to match the density of the lighter, upper layer only after enough time and energy have been supplied to warm up the product and therefore decrease its density.

The potential for LNG product rollover can be reduced through careful product management and tank design. Four contributing factors that can lead to the rollover of products within an LNG storage tank include:

- Variation in stored product density;
- Nitrogen concentration within the stored product;
- The amount of time that the product stays within the tank; and
- The amount of heat energy supplied to the product.

Upon reviewing each of the factors listed, the LNG storage tanks for the LNG Facility are well positioned to avoid product rollover. Each case is discussed further below.

Product density variability should be well controlled since the liquefaction operation is coupled to the storage tank and not subject to external parties and supply chain fluctuations. Limiting density variability to less than 0.312 pound per feet cubed, or approximately 1 percent, has been shown to mitigate tank rollover.

Nitrogen concentration above 1 percent has been shown to lead to auto-stratification of LNG storage tank contents. It is not expected that feed gas concentrations will change drastically and if there is a change, it will likely be slow and over a long period of time.

The reduction in density of the lower stratified layer requires both time and energy so a well-insulated tank will also reduce the chance of LNG product rollover. The LNG Facility's tank are relatively large LNG storage tanks with a low surface area to volume ratio, which leads to lower heat input per unit of stored LNG. Additionally, the tank has a larger perlite space than typical LNG storage tanks, which should lead to even lower heat leak into the storage tank.

In addition to the above factors that reduce the potential for product rollover, regular monitoring of tank performance can help determine if a rollover event is more likely to occur. Boiloff rate can be monitored through the vapor recovery system. A stratified tank that is suppressing the boiloff of volatile material at the bottom of the tank will have lower rates of boiloff leading up to a rollover event. Furthermore, temperature and density measurement devices supplied with the tank can indicate if stratification has occurred within the tank. In either case, once the possibility of a rollover event has been identified, utilization of the tank pumps to introduce some circulation of the product can break up the stratified layers and reduce the chance of a rollover event.

Appendix L.7 of this Resource Report includes LNG Storage Tank Rollover Assessment (5101-0076_R-1010).

13.6.20 Tank Secondary Bottom and Corner Protection

A 9 percent Ni steel secondary bottom and 9 percent Ni steel insulated "Thermal Corner Protection" are required and will be linked together. The secondary bottom will be placed above the cellular glass bottom insulation.

13.6.21 Drawings

The LNG storage tanks' general arrangement and construction drawings are included in Appendix L.2 of this Resource Report.

13.7 Utilities

13.7.1 Instrument and Plant Air

Compressed air is required for plant and instrument air. Air filters, dryers and receiver are required to ensure dry air is supplied to all plant instruments and valve actuators. Two 100 percent compressors will be provided to ensure continuous supply of air.

Instrument Air and Plant Air Distribution Process Flow Diagram 15505-PF-800-001 included in Appendix U.2 of this Resource Report illustrate the general operation of the instrument and plant air system. Piping & Instrumentation Diagram (P&IDs) 15505-PI-800-001 included in Appendix U.4 of this Resource Report illustrate the instrument / plant air and associated distribution.

13.7.2 Nitrogen

Nitrogen is required in the LNG Facility for BOG compressor seals, purging and the refrigerant make-up for liquefaction. Nitrogen will be imported via trucks and stored in a vendor-supplied storage skid. When needed for make-up and utilities, the nitrogen will be vaporized using an ambient air vaporizer.

Nitrogen Distribution Process Flow Diagram 15505-PF-300-001 included in Appendix U.2 of this Resource Report illustrates the general operation of the nitrogen distribution system. Piping and instrument designs ("P&ID") 15505-PI-500-005 included in Appendix U.4 of this Resource Report illustrate the nitrogen storage, transfer and distribution system.

13.7.3 Utility Water

Potable water will be supplied locally from the existing water pipe available on Peckham Road. Potable water will be used for general ablutions, emergency showers, washdown and water supply to the firewater tanks.

Process Flow Diagram 15505-PF-800-002 included in Appendix U.2 of this Resource Report illustrates the general operation of the water distribution system. The P&ID 15505-PI-800-010 included in Appendix U.4 of this Resource Report also illustrates the water distribution system.

13.7.4 Stormwater and Sewerage

The stormwater removal system has been designed in accordance with the Rainfall Design Basis 15505-TS-000-008 included in Appendix C.4 of this Resource Report.

The sewage system will be developed to handle all waste water generated from ablutions.

Stormwater falling in the pretreatment area and trucking area will drain to local sumps and flow through an oily water treatment package before being discharged into a stormwater management pond for infiltration. Other stormwater falling within curbed areas, bermed areas and the LNG spill containment system will flow to local low points or sumps and drain to the stormwater management pond.

Process Flow Diagram 15505-PF-800-003 included in Appendix U.2 of this Resource Report illustrates the general operation of the waste water and storm water drainage system. The P&ID 15505-PI-800-040/041 included in Appendix U.4 of this Resource Report also illustrates the water distribution system.

13.8 Equipment Data

13.8.1 Equipment List with Design Conditions

An Equipment List (15505-LI-000-005) summarizing the major process, utility equipment and applicable design conditions that will be installed at the LNG Facility is included in Appendix M.1 of this Resource Report.

13.8.2 Equipment Data

Data sheets for the all process equipment are included in Appendix M.3 of this Resource Report.

13.9 Instrumentation

The following describes the basic instrumentation and control system philosophy for the Facility. The systems described are generic and final equipment designs and selection will be made during the detailed engineering and EPC phases.

13.9.1 Facility Control and Monitoring System Components

Distributed Control System ("DCS"):

The control and monitoring system that will be procured for the LNG Facility will be a state-of-art DCS with proven service in LNG applications.

Monitoring capability will be provided via human-machine interface ("HMI") units located in the control room. The HMI will be arranged similar to the LNG Facility piping and instrumentation diagrams/drawings (P&IDs). A logical hierarchy of the displays will be developed to allow easy navigation throughout the system.

The operator HMI will provide alarm configuration management and will allow the Operator to view all alarms with time stamping and trending screens, as well as historical trends. Access to the DCS will be configured to allow different levels of access control to maintain security, ensuring that only properly trained and authorized personnel can operate the various parts of the LNG Facility or access system tuning and alarm parameters.

The control system will include the capability to capture the sequence and times of significant events.

The DCS will contain the software and hardware required to perform the following functions:

- Control and monitoring;

- Automatic/manual remote start sequence and operation. Alarms and events will be available to the Operator to identify failures;
- Protection and interlocks;
- Data communication for integration with other Facility systems to provide more coordination between systems;
- Data acquisition for archiving; and
- Alarm and storage of all system faults.

The DCS will communicate with other systems and vendor packages installed in the LNG Facility via Modbus RTU protocol, using Ethernet or serial connections. Where only a few inputs/outputs ("I/O") are required to be monitored, hardwired connections will be used.

The DCS hierarchy consists of operator control level, LNG Facility control level, and field devices. The operator control level consists of workstations, hardware push button control stations and peripherals. The LNG Facility control level consists of DCS controllers, SIS, HDMS and package control systems.

The main components of the DCS consist of the Operator Workstations, the Engineer Workstation, I/O and Controllers and the Communication Devices. The configuration of the components for the DCS system will be determined during the detailed design phase, but, as a minimum, will include:

- Remote I/O cabinets;
- Interface with BOG Compressor, Nitrogen Compressors, and Booster Compressor;
- Interface with electrical substation and motor control center (MCC) controls;
- Interface with tank gauging and data acquisition system;
- Interface with LNG sendout and truck loading system;
- Interface with SIS and HDMS;
- Operator workstations and an engineering workstation;
- At least one workstation for the SIS and HDMS;
- Workstation for the tank monitoring system;
- A historian package that will be a configurable, real time and historical data collection package for trending, logging and reporting; and
- Interface with print servers.

SIS:

A completely independent, standalone, high integrity SIS will be provided to implement process safety related interlocks for the ESD. The SIS is described in Section 13.10 of this Resource Report.

HDMS:

A stand-alone independent HDMS will continuously monitor and alert the Operator of hazardous conditions throughout the LNG Facility due to fire or LNG/gas leaks.

Monitoring capability is provided in the SIS/HDMS workstation located in the Control Room.

In response to fire and gas leak alerts, operating personnel will have the ability to manually initiate appropriate firefighting and/or shutdown actions via hard-wired switches provided on the Control Room.

The HDMS will have interfaces with the following sub-systems:

- DCS – redundant Ethernet or serial links.
- SIS – hardwired; and
- Public Address/General Announcement ("PA/GA") system – hardwired.

The Hazard Detection System and equipment is further described in Section 13.14 of this Resource Report.

LNG Storage Tank Gauging System:

The LNG Storage Tank instrumentation is described in Section 13.6 of this Resource Report.

A microprocessor-based networked inventory management system will be used to consolidate all level, temperature and density measurements associated with the LNG storage tanks. The system will interface with the DCS via non-redundant Ethernet or serial link.

Vibration Monitoring System:

A vibration monitoring system will monitor shaft vibration, axial displacement and bearing temperatures of major rotating machines.

Automatic vibration shutdown devices will be installed on large, critical rotating machinery. The following guidelines will be used:

- All critical pumps and rotary or centrifugal gas or air compressors and all non-critical pumps will be equipped with bearing failure detection equipment (vibration detection);
- All critical pumps and rotary or centrifugal gas or air compressors will be equipped with two thrust proximity probes sensing the shaft end or shaft shoulder (not a collar), two radial proximity probes inboard and two radial proximity probes outboard;
- Equipment will be equipped with vibration trip functions on axial probes;
- Equipment will be equipped with vibration trip functions on axial and radial probes;
- Equipment will be equipped with trip function on radial probes;
- All critical pumps and centrifugal gas or air compressors and all non-critical pumps will be equipped with one RTD in the lube oil return; and
- All critical pumps and centrifugal gas or air compressors will be equipped with RTDs in the bearings.

Common alarms will be provided on the DCS. Trip signals will be hard-wired to the machine safeguarding system and alarmed on the DCS. Machinery suppliers will generally supply the vibration and temperature probes and related electronic cabinetry.

The vibration monitoring system supplier will provide the centralized monitors, servers and related software. This console will be located in the control room or remotely at the individual pieces of equipment.

Packaged Equipment Control Systems:

Packaged equipment, which uses hardwired local control panels or programmable logic controller ("PLC") based controls, will be provided by the equipment suppliers. These control systems will be mounted on or near the equipment skid where feasible. Common trouble alarms, common trip alarms and hand switches will be hardwired to the DCS. Additional important parameters may also be monitored on DCS via hard-wired, Ethernet or industry standard serial-linked interface such as Modbus RTU.

Vendor package PLCs and other systems will provide, at a minimum, a status and common alarm to the DCS. This information will be presented to the Operators in the operator displays. The graphic representation in the DCS will mimic the representation in the local panel.

13.9.2 Field Control Instruments

Electronic field transmitters will be of the "Smart" type capable of supporting full digital communications with the selected DCS system. Where full digital communication capabilities cannot be supported by a specific instrument system, "intelligent" transmitters with digital calibration signals superimposed on 2-wire, 4-20 mA signals will be used.

When "intelligent" transmitters are used, a feature that allows connection to the digital communication system will be available in the I/O rack marshalling panels.

All trips will require online testing capabilities through a switch or through the DCS. All field devices that are trip inputs to the control systems will have bypass capabilities for maintenance. This will be provided by either hardwired key-lock bypass switches or software configured screens that inhibit the input during testing. This feature will be password protected. When any device is in bypass, a status alarm will be displayed on the alarm panel.

Critical safety systems will have their own separate field-mounted input equipment. The physical detection of the measurement may be shared with another loop if necessary, but the electronic processing will be segregated. For example, one orifice plate may be shared by two transmitters, which also serves to minimize pipe penetrations and therefore reduce the potential for leaks.

For critical applications, voting systems will be used when dictated based on safety considerations, i.e., using two out of two or two out of three transmitters. The selection of voting systems will be based on the need for increased additional availability and the desire to minimize false readings. The voting logic will be defined during detailed design and will be based on a failure modes and effects analysis.

Control valves will have smart valve positioners as necessary.

Control valve actuators will be a pneumatic design. Hydraulic actuators will be used where fast stroking is required.

Potential-free contact type process switches will be used for fire detection tubing systems and enclosures in hazardous areas.

Rotary switches will be used for local trip switches. The trip switch enclosure color will be red. Push button switches will be used for local trip reset functions.

Thermocouples will be fabricated using International Society of Automation ("ISA") premium accuracy, calibrated, thermocouple lead wire of appropriate alloy. Thermocouple Type K will be used for general service and Type T for LNG service. RTDs will be considered in lieu of thermocouples for narrow spans or for higher accuracy. Four-wire, 100-ohm platinum RTDs will be used.

Level shutdowns will have separate level switches.

Vibration in stationary rotating mechanical equipment will be monitored and alarmed where equipment is critical to the uninterrupted operation of the LNG Facility.

13.9.3 Control Communication and Control Power

Control Communication:

The communications system will allow information to be transferred between the various components of the DCS. The system will consist of a fully redundant Ethernet communications network. Failure of the redundant communication paths will not result in the loss of the control functions of any device on the system. The Ethernet Network employs transmission control protocol/internet protocol ("TCP/IP") communications between all network resident devices. From the Operator Workstation, the Operator will be able to verify the conditions of devices connected on the redundant path and to switch to a redundant device if desired. When appropriate (e.g., when a problem occurs with device or communication path), the DCS will automatically switch "bumplessly" to a redundant device or communication path.

Continuous communications diagnostics will alarm a failure and switch to the redundant communications path automatically. Any communication errors will be logged at each console in the system. Communication system status/performance will be made available to any console in the system.

Nodes on the control network will be synchronized across the entire network to within plus or minus one millisecond via the DCS-based clock. All computers will be time synchronized.

Each sub-system will have the capability to communicate with the DCS system via Modbus RTU protocol, using Ethernet or serial connections. Where only a few I/O are required to be monitored, hardwired connections may be used.

Network interfaces to external networks such as the Facility computer network will be provided with adequate security such as a "firewall" to protect from misuse, viruses and intruders.

Control Power:

The instrument electrical power supply system will ensure an appropriate level of security for the functions served by the instrumentation.

In addition, redundant 24V DC systems will be provided for all equipment as required. This system will include dual battery chargers and 100 percent rated dual batteries, arranged so that a failure or removal from service of any one component will not interrupt service.

Power supply for instruments and related systems will be as follows:

- Field mounted: 24V DC (supplied by the Control System);
- Sub-systems: 120V AC, 60 Hertz;
- Solenoid valves: 24V DC; and
- Alarms/annunciators: 24V DC.

All system and I/O modules will be capable of operating at a minimum of +/-10 percent available voltage and +/ 5 percent available frequency.

Separate 24V DC redundant field interrogation voltage and final actuating element power supplies will also be provided.

As a minimum, power supplies will be dual, each capable of supplying complete system power.

Each power supply will be rated for expected duty including an additional 15 percent for installation of spare capacity. The system will accept power from two different power sources.

Power supplies will be replaceable on-line without disrupting the process and without impacting the main processor. The system will alarm if one of the power supplies in a redundant set fails.

13.9.4 Backup Power Supply

Critical instruments that require the most reliable power supplies will remain in service during power failures for a sufficient amount of time to shut down the LNG Facility. Typical supplies will be DC with dual battery backup, dual un-interruptible power supplies ("UPS") and dedicated switchboards. The backup generators will provide extended power capability and will also back up the critical supplies.

Critical instrument systems include:

- SIS and supporting system cabinets;
- DCS for process control and monitoring purposes including supporting system cabinets;
- Fire protection safeguarding and monitoring equipment, including supporting system cabinets;
- Other safety related instrument systems;
- Packaged equipment control cabinet electronic and PLCs including I/Os; and
- Primary and secondary communication systems.

13.9.5 Drawings

A control system block diagram is included in Appendix N.2 of this Resource Report.

13.10 Safety Instrumentation

The following provides a design philosophy and overview of the SIS for the LNG Facility. Final equipment selection and detail design requirements will be determined during the EPC phase.

The SIS will use redundant microprocessor hardware. Primary operator access to the SIS will be provided at the control room.

13.10.1 Description of the SIS

The SIS or ESD system will be used to automatically prevent the occurrence of any physical situation which could potentially cause loss, damage or undesirable effects on personnel, environment, plant equipment, production, raw material and property. It will:

- Initiate emergency shutdown actions to bring the plant to a safe condition; and
- Perform sequence of events recorder function.

The SIS will be totally separated and independent from DCS. The hardware and functionality of DCS and SIS will be fully segregated at the I/O and controller level but not at the server level.

SIS hardware and software will be designed using International Electrotechnical Commission ("IEC") 61511 - Functional Safety: Safety Instrumented Systems for the Process Industry. Instrumented Protected Function risk assessment and SIL classification will be performed.

Operator interface to the DCS and SIS will be integrated into a single HMI, with separate process graphics developed for each system type being made available to all HMIs. The operator will be provided with graphic diagrams to enable monitoring of the SIS. Should it become necessary to bypass or override inputs, this will be considered a maintenance operation requiring control under the prevailing permit regime. Failure of the HMI will not directly cause a failure of the SIS, but the SIS swill be configured to bring the process to a safe state in such an event.

The SIS will be based on fail-safe PLC in redundant, triple modular redundant ("TMR") or quadruple modular redundant ("QMR") or any suitable architecture.

The PLC will comply with the following requirements:

- Redundancy (TMR or QMR);
- Enhanced reliability design through the use of high reliability components and assembly;
- Maximum use of self-tests and watch-dog tests to detect malfunctions;
- Ability to fail to a predetermined state;
- Increased availability through the use of redundancy of critical components; and
- Inputs/Outputs are fail-safe design.

The fail-safe principles will apply for all SIS equipment as:

- The initiating contacts are closed in normal conditions and open to shut-down;
- The SIS logic system is self-checking and "fail-safe" when faults are detected; and
- The SIS valves move to their safe position in case of electrical or air failure.

The SIS will not be activated automatically from the HDMS but will be activated manually from operator intervention (ESD switches). Surge analysis of shut down valves during various ESD scenarios will be carried out during detailed design.

13.10.2 Position Indicators on ESD Valves

All ESD valves will have position indicators. Open/close valve position switches and/or valve position indication feedback are acceptable. Alarms will be provided to indicate an ESD valve position is out of position contrary to the ESD logic.

13.10.3 Use of Control Valves to Serve as ESD Valves

On a case-by-case basis, control valves can also be used as ESD valves where such use does not diminish the intent of the ESD activation. This may require higher degrees of shut off, fire-safe installation and provision of hand wheels to some valves.

13.10.4 Positioners on ESD Valves

On a case-by-case basis, positioners are permitted to be added to ESD valves to provide remotely controllable, throttle-able operation. All valves require independent valve position switches indicating when the valve is not fully closed.

13.10.5 ESD Logic

The ESD System is provided to initiate closure of valves and shutdown of process drivers during emergency situations. The ESD system is designed to cater for different shutdown levels with each representing increasing degrees of hazard.

13.10.6 Drawings and Tables

A cause and effect matrix is included in Appendix N.1 of this Resource Report.

13.11 Electrical

13.11.1 Description of Electrical System

Power from the local grid will be required to run motors for LNG and BOG compressors, lighting, and other items. At full liquefaction or sendout operations, the LNG Facility is expected to import a base load of less than 15 megawatt ("MW").

NSTAR Electric will supply power via 13.2 kilovolt ("kV") underground distribution feeders located on Peckham Road.

Single Line Drawing 15505-DG-700-001 included in Appendix O.2 of this Resource Report illustrates the distribution of power around the LNG Facility.

Standby Power:

Three standby power generators will be provided that will be capable of supplying enough power for 400 MMscfd of natural gas sendout, facility emergency lighting (including security lighting), security monitoring and warning systems, emergency communications systems, control systems, instrument air compression, and other necessary auxiliary systems. A blackstart diesel generator will be provided to provide the necessary power to start the first generator and bring it online.

The LNG Facility design provides for standby power capable of supplying enough power for the following cumulative loads:

- Firewater jockey pumps;
- Control Room;
- Guard Houses;
- Security Systems;
- Telecom systems;
- DCS;
- HDMS;
- Emergency Lighting Circuits;
- MCC;

- UPS charging system;
- Instrument Air Compressor;
- Nitrogen system;
- Flare Ignition system; and
- Tank heating systems

Control Power:

The UPS system will have a minimum total battery life of 4 hours. The UPS units are rated for 120 percent of the anticipated load and include all necessary indications with local alarm lamps and remote alarms in the control room. The UPS units, which are located in an air-conditioned room, are designed to ensure the operation and functioning of the process controls, ESD and Fire Safety systems. The UPS will be powered by either NiCad or Valve Regulated Lead Acid batteries.

Control Power:

The LNG Facility will be adequately lit to provide an average of 5 foot-candles at each active access point and an average of 1 foot-candle throughout the remainder of the LNG Facility. A minimum of ½ foot-candle of lighting will be provided throughout the LNG Facility. The lighting system will be connected to the emergency power bus to ensure lighting is available for operations and security during loss of offsite power events.

Although methods for reducing light impact are constrained by the fact that minimum light requirements for safety and security are set by industry standards, in all cases, the minimum amount of light necessary to complete construction and operation tasks will be used, and all lighting will be directed to work areas in order to minimize stray light. Light sources will also be located as close as possible to critical instruments, such as gauges, so that additional general lighting is unnecessary.

Measures to minimize the potential for lighting impacts on fish and wildlife include:

- the use of directional lighting facing equipment to the extent possible;
- the use of screens or lighting hoods;
- the use of motion-activated lighting;
- the use of full-cutoff light fixtures, which have no direct uplight, help eliminate glare and are more efficient by directing all lighting down to the intended area only; and
- the retention of vegetation along property lines and security fences to screen adjacent properties from operating lights.

Grounding and Cathodic Protection:

Grounding studies will be performed during detailed design to ensure conformance with IEEE 80 requirements. This will go hand-in-hand with any cathodic protection studies. All circuits will feature an equipment grounding conductor. All metallic parts of the electrical system will be bonded to the grounding system.

13.11.2 Hazardous Area Classification Basis

Electrical area classification drawings are included in Appendix O.3 of this Resource Report and are based on NFPA 59A (2001) and NFPA 497.

The LNG Facility is designed in compliance with NFPA 70. NFPA 70, Article 500.7 specifies acceptable protection techniques for electrical and electronic equipment in hazardous (classified) locations, including Class I, Group D, Divisions 1 and 2. The LNG Facility will employ these protection techniques to control ignition sources in the classified areas shown in the above referenced electrical area classification drawings in Appendix O.3. Specific practices may include one or more of the following:

- Using explosion-proof equipment;
- Purging and pressurizing enclosed spaces that could contain flammable gas;
- Installing intrinsically safe apparatus and wiring;
- Using nonincendive circuits, equipment and components in Division 2 areas;
- Immersing current-interrupting contacts in oil;
- Hermetically sealing equipment; and
- Providing a combustible gas detection system for detection of hazardous conditions.

With regard to safety procedures, the LNG Facility will be operated and maintained in accordance with 49 CFR Part 193 and NFPA 59A (2001 edition). Consistent with requirements in these regulations and standards, the LNG Facility will have the following provisions in safety procedures used for work in classified areas:

- Requirements for purging of components prior to maintenance;
- Requirements for system isolation using techniques including removal of spool pieces and installation of blank flanges in piping systems or provision of double block and bleed in piping systems; and
- Safety control measures (e.g., requirements for leak detection and repair, air sampling, equipment de-inventory, confined space entry permitting and hot work permitting).

Training will also be provided to workers as necessary to ensure personnel safety.

13.11.3 Electrical Tables and Lists

Appendix O.1 of this Resource Report provides the electrical load list (15505-LI-000-007) for the LNG Facility.

13.11.4 Electrical Drawings

Electrical single line drawings are included in Appendix O.2 and electrical area classification drawings are included in Appendix O.3 of this Resource Report.

13.11.5 Electrical Pass-through Seals for LNG Pumps and Instrumentation

Connections on the pressure boundary of each LNG pump for electrical leads and instrumentation cable conduits will be isolated to prevent the passage of LNG or natural gas through the associated seal into the conduit, as required by Section 7.6 of NPFA 59A (2001 edition). The connections will include a primary seal and at least one additional seal between the flammable fluid and the electrical system. The specific seal arrangement may vary depending on the vendor selected for the pumps. The arrangement will include provision for purge gas flow and for detection of flammable gas leakage through the primary seal. A preliminary "typical" seal arrangement with purge gas flow is shown in Appendix O.4 of this Resource Report 13. Final drawings illustrating these seals will be provided with vendor information packages to be obtained during final design. To allow for this usage, the nitrogen system has been sized to allow for consumption of some nitrogen purge gas for this demand.

Similarly, the pass-through seal design for other pressure boundary instrumentation will also meet NFPA 59A (2001 edition) Section 7.6 requirements. The specific sealing arrangement will be determined based on the vendor selected for each type of instrumentation. Drawings illustrating these seals will be provided with vendor information packages to be obtained during final design.

13.11.6 Emergency Lighting Plan

Emergency lighting drawings are included in Appendix U.10 of this Resource Report.

13.12 Fuel Gas

13.12.1 Description of Fuel Gas System

High pressure and low pressure fuel gas is required for the gas turbines and Water Ethylene Glycol boilers. No fuel gas compressors are required.

High pressure fuel will be supplied from heavy hydrocarbon from pipeline gas, BOG from the LNG storage tanks, and pipeline feed gas.

Low pressure fuel gas will mainly be supplied from the BOG system and pipeline feed gas.

Fuel gas metering will be provided to ensure the overall energy balance of the LNG Facility is monitored.

13.12.2 Drawings

Process Flow Diagram 15505-PF-500-001 for the fuel gas system is included in Appendix U.2 of this Resource Report. P&IDs 15505-PI-500-001 and -005 for the fuel gas system are included in Appendix U.4 of this Resource Report.

13.13 Spill Containment Systems

13.13.1 Description of Spill Containment System

The LNG Facility is subject to the siting requirements of 49 CFR 193 Subpart B and NFPA 59A 2001 edition.

49 CFR Part 193.2181 specifies that the impoundment system serving a single LNG storage tank must have a volumetric capacity of 110 percent of the LNG storage tank's maximum liquid capacity. Both LNG storage tanks are full containment design consisting of a primary inner containment and a secondary outer containment to meet this requirement.

In accordance with NFPA 59A Section 2.2.2.2 impounding areas will be installed at the LNG Facility to serve LNG and HHC process equipment and transfer areas.

For impoundment areas for containers with over-the-top fill connections with no penetrations below the liquid level, NFPA 59A (2001 edition) Section 2.2.3.5 requires that spill containment be designed to hold the largest flow from the failure of any single pipeline that could be pumped into the impounding area with the container withdrawal pump(s) considered to be delivering the full rated capacity for a duration of 10 minutes.

The process area impoundment basin has been sized to contain the greatest flow capacity from a single pipe for 10 minutes in the local area. This flow was determined to be a release from the LNG transfer pipeline during sendout. The design flow rate of the LNG transfer pipeline is 408 MMscfd via four (4) LNG pumps delivering LNG at a rate of 102 MMscfd per pump. Based on pump curves, the maximum continuous flow at the pump's rated impeller is 1,225 gpm. For four (4) LNG pumps, the maximum sendout flow rate would therefore be 4,900 gpm. A 10 minute spill would therefore result in a volume of 49,000 gal (6,550 ft^3).

The truck loading area impoundment basin has been sized to contain the greatest flow capacity from a single pipe for 10 minutes in the local area. This flow was determined to be a release from the LNG truck loading line. Based on the H&MB truck loading rich case, the maximum mass flow rate through the LNG truck loading line would be 75,394 lb/hr. A 10 minute spill would therefore result in a volume of 3,430 gal (459 ft^3). However, LNG trucks will have a volumetric capacity of up to 12,000 gallons (1,604 ft^3). Therefore, the truck loading area impoundment basin has been sized to contain the volume of an LNG trailer (1,604 ft^3).

The LNG impoundment basins will be insulated concrete design. In accordance with the requirements of Section 2.2.2.8 of NFPA 59A (2001), the insulation system used for the impounding surfaces will be, in the installed condition, noncombustible and suitable for the intended service, considering the anticipated thermal and mechanical stresses and loads.

Spills of LNG or HHCs will flow along insulated concrete troughs located alongside and beneath liquid pipelines. Conveyance of spills throughout the Facility is illustrated in Spill Containment Drawings 15505-DG-600-201/205 that are included in Appendix Q.3 of this Resource Report.

The Facility Hazard Analysis is included in Appendix Q.1 of this Resource Report.

13.14 Hazard Detection Systems

13.14.1 Description of Hazard Detection Systems

An HDMS will be installed to prevent the occurrence of physical situations that could result in injury to personnel and/or damage to property and the environment. The HDMS will accomplish this by detecting and alerting LNG Facility operators to the presence of spills and leaks of LNG and natural gas; leaks of other hazardous gases; and fires. Hazard Detection and Mitigation Philosophy document 15505-TS-000-007 is included in Appendix C.3 of this Resource Report: and the following is a summary of the details contained within that document.

The HDMS will be an independent, stand-alone, high integrity system and will continuously monitor and alert operating personnel to leaks of LNG, flammable liquids, flammable gases and fires. The HDMS will be based on a Proprietary Supervising Fire Alarm System in accordance with NFPA 72. This system will also be fault-tolerant and have self-diagnostics to alert operating personnel of fault conditions.

The main fire alarm control panel and operator interface will be located in the control room which will be attended 24-hours per day. Local control panels will be distributed around the LNG Facility to provide local detection, notification and system release functions. The local control panels and the main control panel will be networked together on a dedicated system. The HDMS will have a communication link to the DCS for the display of HDMS status and alarm signals at operator stations.

The HDMS will consist of the following components:

- Field-mounted addressable fire and flammable gas detectors and other sensors. All instruments will be accessible for operation and maintenance;
- Visual and audible alarms located in the field and the control room to notify personnel of hazardous conditions. Leak hazards and fire hazards will have distinct alarms;
- Local control panels for the initiating devices and notification devices. Automatic activation of fire suppression systems and control of other equipment (e.g., automatic shutoff of ventilation systems) are also accomplished from the local control panels. All circuits will be supervised to detect integrity problems;
- An HDMS main control panel that will be located in the control room. The main control panel will be networked with the local panels over a high integrity communications system. The network circuit will be supervised to detect integrity problems;
- Operator interface via video display screens and printers located in the control room;
- Mimic panels located in other buildings or rooms such as the admin office; and
- Hard-wired switches located in the control room (where applicable).

The HDMS will interface with the following systems:

- DCS;
- ESD System; and
- PA/GA system.

The HDMS will execute control logic for single detectors as well as for groups of detectors. For example, a voting scheme may be applied where three detectors are installed in a particular area and alarms from two out of the three detectors will initiate controlled actions. A deviation alarm will be generated for all signals used for voting purposes. This alarm will be generated whenever the magnitude of the difference between the minimum and maximum signal is greater than a preset value of 10 percent full span signal range. This alarm will not be generated if any of the signals are of bad quality.

Monitoring capability is provided via graphic display screens and mimic panel displays located in the control room. All HDMS alarms and shutdown conditions will be alarmed in the HDMS workstation. Fire alarms and overview graphics illustrating the location of the detectors will be repeated on the DCS via communications links.

Fire and flammable gas detection and protection of offices and other buildings will be via networked fire panels provided by the building supplier. These fire panels will be located in individual buildings and networked to the main fire alarm control panel in the control room. All hazard signals will alarm locally as well as in the control room. Local signals will be audible and visual (strobe lights) and will have distinctive alarms and colors for fire, flammable gas (leak) and toxic gas hazards. The light source color will be clear or nominal white for fire. Combustible gas leaks will be use an amber colored strobe or beacon. Toxic gas leaks will use blue colored strobe lights or beacons.

Operators will be able to initiate appropriate firefighting and/or shutdown actions via hard-wired switches provided at the control room in response to fire, toxic gas and/or combustible gas leaks.

Hazard trips that initiate automatic shutdown of equipment and systems and which will activate the ESD system are described in Section 13.10 of this Resource Report. The input and output relationship of all ESD initiators and actions will be illustrated in a cause and effect diagram.

The HDMS is designed such that no single failure point would affect system integrity. All circuits and devices will be supervised, and shorts to ground will not prevent alarm or communication capability. Failure of any single active component supplied within the system will not cause a multiple loss of field devices and during such a failure the system will remain on-line and will continue to monitor for fire and flammable gas. Additionally, the system will accommodate a means for alarming the fault.

On- and off-line diagnostics will be provided to assist in system maintenance and troubleshooting of every major system component and peripheral.

13.14.2 Description of Hazard Warning Systems Including Offsite, Plant Wide and Local Area

The HDS will include combustible gas, toxic gas, low temperature, heat, smoke, and flame detectors. A description of hazard detection equipment and associated warning equipment that will be installed at the LNG Facility is included in the NFPA 59A Preliminary Fire Protection Evaluation that is included in Appendix P.1 of this Resource Report.

13.14.3 Hazard Detector List

The Hazard Detection List (15505-LI-000-006), illustrating tag number, location, type, settings and method of activation of hazard control equipment for the above types of detectors, is included in Appendix M.2 of this Resource Report.

13.14.4 Drawings

Hazard detection layout plans are included in Appendix U.7 of this Resource Report.

13.15 Fire Suppression and Response Plan

The LNG Facility has developed a preliminary ERP in accordance with the requirements of the FERC Draft Guidance for Terminal Operator's ERP. The preliminary ERP contains details of:

- The structure of the emergency response team, including roles, responsibilities and contact details;
- Responses to emergency situations that occur within the Facility;
- Emergency evacuation adjacent to the Facility;
- Training and exercises;
- Documentation of consultations made with interested parties during the development of the ERP; and
- Details of cost sharing plans that have been negotiated to reimburse capital costs, annual costs and other expenses incurred by off-site emergency organizations in providing emergency response services to the Facility.

In accordance with the above-mentioned FERC draft guidance document, the final ERP will be prepared in consultation with state and local agencies, and the LNG Facility will request Commission approval prior to the commencement of construction.

13.15.1 Description of Response to Fire and Deployment of Resources

Emergencies are categorized based on two distinct criteria:

- Can the operations personnel prevent harm to personnel or property by taking reasonable and prudent actions? This criterion determines whether the emergency is a controllable emergency or uncontrollable emergency.
- If the emergency is an uncontrollable emergency, will it affect off-site personnel or property? This criterion determines whether the emergency is an LNG Facility site emergency or a general emergency.

Controllable Emergency:

A controllable emergency is an emergency in which operations personnel can prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment or initiating the ESD. Examples of controllable emergencies that may occur at the LNG Facility include:

- LNG or flammable liquid spills that are contained within the LNG spill containment system and do not result in fire;
- LNG or flammable liquid spills that are contained within the LNG spill containment system and result in a fire within the containment system;
- Overpressure of gas or liquid process piping;
- Collapse of buildings or systems and equipment that does not result in or does not have the potential to result in the loss of containment of LNG or flammable gases;
- Building fires that do not involve flammable gases;
- Electrical fires that do not involve flammable gases;
- Loss of electrical power;
- Vehicle accidents;
- Severe weather conditions; and
- Breaches of site security that do not result in or have the potential to result in substantial damage to the LNG Facility.

Uncontrollable Emergency:

An uncontrollable emergency is one in which the operations personnel cannot prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment or initiating the ESD. An uncontrollable emergency involves situations that have the potential to result in exposure of personnel or property to natural gas or refrigerant in a liquid, cold vapor, or gaseous state or may result in fire or explosion. Examples of uncontrollable emergencies that may occur include:

- LNG or flammable liquid spills that are not contained by the LNG spill containment system and do not result in fire;
- LNG or flammable liquid spills that are not contained by the LNG spill containment system and result in an unconfined fire;
- Flammable gas leaks from significant failure of a pipeline or equipment;
- Building or equipment fires that contain or have the potential to contain flammable gases;
- Structural failure of an LNG or refrigerant storage tank;
- Bomb threats; and

- Severe weather conditions that cause wide-scale damage to equipment and systems that result in or have the potential to result in a loss of containment of LNG or flammable gases.

In addition, a security breach that results in a high probability of substantial damage to the LNG Facility and may create an uncontrollable emergency will be considered an uncontrollable emergency, even if no damage has yet occurred. Examples of this situation include:

- Discovery of an explosive device in close proximity to an LNG storage tank or major LNG, natural gas or flammable liquid pipeline; and
- An act of sabotage that may result in structural failure of an LNG or flammable liquid storage tank or major LNG, natural gas or flammable liquid pipeline.

An uncontrollable emergency is then further classified as a facility site emergency or a general emergency.

Uncontrollable Emergency – Facility Site Emergency:

A facility site emergency is an uncontrollable emergency that threatens personnel or equipment with exposure to natural gas, or flammable fluids (liquid, cold vapor, or gaseous state) or involves a fire or explosion of a magnitude that involves a large portion of the LNG Facility.

A security breach that results in a high probability of substantial damage to the LNG Facility is considered a facility site emergency.

At the instruction of the Facility Emergency Director, emergency help will be requested by the public information contact from off-site emergency organizations during a facility site emergency.

Uncontrollable Emergency – General Emergency:

A general emergency is an uncontrollable emergency that threatens the public with exposure to natural gas or flammable fluids (liquid, cold vapor, or gaseous state) or involves a fire or explosion of a magnitude that affects persons or property off-site. At the instruction of the Facility Emergency Director, emergency help will be requested by the Public Information Contact from off-site emergency organizations during a General Emergency. Additionally, the Facility Emergency Director may recommend an evacuation of the local community.

Certain emergency actions will require emergency response from outside organizations. Effective emergency response planning and response is, therefore, dependent on close, ongoing coordination between the LNG Facility and those outside organizations.

To ensure effective coordination is maintained, there will be periodic meetings, drills, and familiarization tours conducted for these organizations at predetermined intervals. In addition, the outside organizations will be encouraged to send new members to the LNG Facility for familiarization tours.

The LNG Facility will coordinate the development of its ERP with the state and local agencies. A significant aspect of this plan will be the organization and staffing of local police, fire, and emergency response resources and personnel specific to the needs and action plans of the LNG Facility. The ERP will describe the roles and responsibilities of the off-site emergency services.

13.15.2 Organizational Chart for Emergency Response and Fire Fighting

The normal operating organization of the LNG Facility consists of the following:

- Operations personnel;
- Maintenance personnel;
- Security personnel;
- Management and support personnel (normal working hours only); and
- Contractor personnel (normal working hours only).

During normal working hours, LNG Facility management personnel will initiate the ERP. During off-normal working hours, operations personnel will initiate the ERP.

When the ERP is put into effect, LNG Facility personnel will assume designated positions, each with specific duties.

Facility Emergency Director:

The Facility Emergency Director is in command of the Facility Emergency Organization. If the emergency occurs outside of normal business hours, the Shift Supervisor will assume the Facility Emergency Director position until relieved by the LNG Facility Manager.

The role of the Facility Emergency Director involves interacting with both on-site groups (LNG Facility employees dealing with the emergency) as well as off-site groups (media and off-site emergency organizations). If the emergency continues for an extended period, then the Facility Emergency Director position may be filled in rotation by more than one person. The Facility Emergency Director is normally based in the Emergency Control Center, which will be located in the Administration Building.

The specific duties of the Facility Emergency Director position will include the following tasks:

- Assessing each emergency and determining the appropriate emergency classification using information provided by the Emergency Response Team Leader;
- Designating and directing the LNG Facility Public Information Contact or acting as the Public Information Contact until another individual is designated for that position;
- Coordinating activities with off-site emergency organizations and, if acting as the LNG Facility Public Information Contact, requesting off-site assistance for emergency response;
- Determining which resources are required to respond to an emergency and directing the call-in of additional LNG Facility employees;
- Directing on-site evacuation and providing recommendations for off-site evacuation as needed;
- Overseeing the Security Shift Supervisor;
- Overseeing the Assembly Leaders;
- Developing re-entry plans for any areas previously evacuated; and
- Maintaining the LNG Facility Emergency Control Center Status Board.

Public Information Contact:

In the event of an emergency at the LNG Facility, it is critical that information released to public agencies, the media and ultimately the general public is accurate. During an emergency situation, LNG Facility employees may be contacted by the media or by members of the general public regarding the emergency. In order to ensure that accurate information is disseminated, only the Public Information

Contact will be authorized to provide information to the media, local agencies or the public. Employees will refer all persons with questions regarding the emergency to the Public Information Contact. Also, if employees are questioned about statements or speculations that arise, they will also refer the person to the Public Information Contact.

The Public Information Contact will be designated as the information point of contact by the Facility Emergency Director and acts as the spokesperson for disseminating information to all media outlets and state and local emergency organizations. The Public Information Contact reports to the Facility Emergency Director.

The specific duties of the Public Information Contact include the following tasks:

- Contacting off-site emergency organizations to request emergency support during an emergency condition as directed by the Facility Emergency Director;
- Providing off-site emergency organizations with the status of the emergency;
- Appointing and overseeing a liaison to communicate with local emergency organizations during general emergencies; and
- Designating a media area, preparing news releases and disseminating information to the media in accordance with established protocols.

Emergency Response Team Leader:

The Emergency Response Team Leader will be the on-duty shift supervisor or lead operator. The Emergency Response Team Leader will command the on-site Emergency Response Team and will report to the Facility Emergency Director. Generally, the Emergency Response Team Leader will direct the operations team and off-site emergency organizations while they are performing emergency actions at the LNG Facility.

The specific duties of the Emergency Response Team Leader include the following tasks:

- Assessing each emergency situation and assuming the role of Facility Emergency Director until relieved by the LNG Facility Manager;
- Identifying the actual and potential hazards affecting the LNG Facility, its personnel and/or areas adjacent to the LNG Facility;
- Directing Emergency Response Team members;
- Identifying specific off-site resources that may be needed in an emergency; and
- Providing the Facility Emergency Director with the current information about the emergency situation.

Emergency Response Team:

The Emergency Response Team will report directly to the Emergency Response Team Leader. The Emergency Response Team's responsibilities include the direct actions to bring the LNG Facility to a safe status.

The Emergency Response Team consists of:

- Operations personnel;
- Maintenance personnel;
- Selected contractor personnel as requested by the Emergency Response Team Leader; and

- Selected off-site emergency personnel as requested by Emergency Response Team Leader.

The specific duties of the Emergency Response Team include the following tasks:

- LNG and flammable gas release control. This role will primarily utilize operations and maintenance personnel, who will implement immediate actions required to terminate any release and mitigate the consequences of the emergency incident.
- Emergency recovery and restoration. This role will primarily utilize operations and maintenance personnel, who will implement immediate actions required to bring the Facility to a safe condition and mitigate the consequences of the emergency incident.
- Firefighting. This role will primarily utilize off-site firefighting personnel. LNG Facility employees will also be trained to fight fires.
- Re-entry into areas that were previously evacuated. Re-entry will be approved only by the Facility Emergency Director. Re-entry will primarily utilize operations and maintenance personnel, who will search for unaccounted personnel, rescue trapped or injured personnel; perform maintenance or operations activities to terminate or mitigate the emergency; determine safe areas and personnel exclusion areas; and determine the nature and magnitude of the emergency.
- Medical Aid. This role will utilize employees, including the Safety and Health Coordinator and off-site rescue squads as needed. The employees will perform this function until off-site rescue squad personnel arrive. As off-site rescue squad personnel arrive, medical aid activities will be taken over by rescue squad personnel to free the employees for recovery activities. Medical aid activities include transporting injured persons to a safe location, administering first aid, determining if transport off-site is needed, notifying hospital(s) of incoming injured, transporting injured personnel to appropriate medical facilities and maintaining accurate records of all first aid treatment.
- Escort. Escort off-site emergency personnel as required.

Security Shift Supervisor:

The Security Shift Supervisor supervises the Security Force and reports directly to the Facility Emergency Director. The Security Shift Supervisor is responsible for ensuring the Security Force carries out its assigned duties.

Security Force:

The specific duties of Security Force Personnel include the following tasks:

- Securing and maintaining the LNG Facility perimeter;
- Controlling access to the LNG Facility;
- Ensuring that LNG Facility access roads are clear for use by emergency vehicles and essential personnel;
- Coordinating and directing off-site emergency response teams to staging areas as directed by the Emergency Response Team Leader;
- Assisting with on-site evacuations as directed by the Facility Emergency Director;
- Assisting with accountability activities;
- Overseeing direct coordination with local law enforcement agencies; and
- Identifying needs for additional security requirements (i.e., local law enforcement) and communicating those needs to the Facility Emergency Director.

Assembly Leaders:

Assembly Leaders will perform an accountability function and direct personnel safely to assembly areas. Assembly Leaders will assume their designated roles when an evacuation is ordered by the Facility Emergency Director.

Although the Assembly Leaders report to the Facility Emergency Director, they will also communicate directly with the Emergency Response Team Leader.

13.16 Hazard Control Systems

Hazard control systems are described in detail within the Hazard Detection and Mitigation Philosophy (15505-TS-000-007) included in Appendix C.3 of this Resource Report 13.

13.16.1 Description of Hazard Control Equipment and Systems

Dry chemical systems are effective against hydrocarbon pool and three-dimensional fires (e.g., jet fires), particularly those involving pressurized natural gas or LNG spills, provided re-ignition potential is low. The dry chemical agent that will be used at the LNG Facility is potassium bicarbonate, as this has been found to be most effective of the dry chemical agents. In addition, dry chemical systems may be used in conjunction with high expansion (“Hi-Ex”) foam systems in select areas. Therefore, the dry chemical agent must be compatible with the Hi-Ex foam agent.

Dry chemical systems installed at the LNG Facility will consist of total flooding systems and wheeled and portable extinguishers. System selection, as discussed in Section 13.16.2 below, depends on the type, location, and size of the hazard; existence of nearby ignition sources; ability to access the hazard; and the potential consequences of the fire on the public, personnel and equipment. As described in Section 13.16.4, these systems will be located at strategic locations to facilitate effective fire extinguishment. These systems are designed in accordance with NFPA 17 for engineered systems and NFPA 10 for portable extinguishers and will be UL listed or FM approved.

13.16.2 Dry Chemical Basis of Design

Dry chemical system selection is based on the configuration of the area containing the hydrocarbon hazard. Specifically:

- The HP Pump House, containing high pressure LNG, will be protected with a total flooding system due to the risk of a three-dimensional fire. These systems will be automatically or manually activated by the HDMS using heat and/or flame detectors;
- Areas where LNG spills may collect will be provided with portable and/or wheeled extinguishers, depending on the results of a hazards evaluation that considers the size of the hazard, ignition sources available, time required for response and other factors; and.
- Open areas where plausible leaks, sprays or ruptures involving natural gas or LNG may occur will be provided with portable and/or wheeled extinguishers. As these potential fires are likely to be small and less likely to significantly affect the public or personnel or equipment, extinguishers will be applied.

Systems will meet the requirements of NFPA 17 and be UL Listed or FM Approved. Manual systems consisting of either portable or wheeled extinguishers will be employed, provided:

- The area to be protected does not typically have ignition sources;
- The area to be protected is easily accessible;
- The fire size is such that personnel can approach the fire to effectively apply the dry chemical agent; and
- The consequences of the fire to the public and the LNG Facility are found to be low, allowing time for a manual response.

If an automatic system is determined to be appropriate for a local application, the dry chemical will be applied by nozzles. Sufficient detection equipment, such as heat and/or flame detectors, will be provided for system activation.

Portable and wheeled dry chemical extinguishers will be provided throughout the process area for fast response to small fires. The placement and sizing of these portable extinguishers will be based on NFPA 10.

Dry chemical system sizing is described in the Hazard Detection and Mitigation Philosophy (15505-TS-000-007) included in Appendix C.3 of this Resource Report.

13.16.3 Matrix of Hazard Control Equipment

The Hazard Detection Equipment List (15505-LI-000-006) included in Appendix M.2 of the Resource Report summarizes the location, tag number, area covered, type, size, discharge conditions and activation method for all dry chemical equipment that will be installed at the LNG Facility.

13.16.4 Dry Chemical System Drawings

Hazard detection and control drawings, including dry chemical system drawings, are included in Appendix U.7 of this Resource Report.

13.17 Firewater

13.17.1 Description of Firewater System

The firewater system that will be installed at the LNG Facility will be a private, freshwater distributed fire main loop that is fed via electric firewater pumps from a firewater storage tank. The distributed loop will provide firewater to various sprinkler systems, automatic water spray systems, hydrants, monitors, Hi-Ex foam systems and other systems as needed. The total water storage tank capacity will be sufficient to provide water to the largest system demand for two hours. The largest system demand is the design basis firewater demand plus a 1,000 gpm hose stream allowance per NFPA 59A.

Sizing Calculation:

Firewater System Sizing Calculation (15505-CA-600-001) included in Appendix P.2 of this Resource Report demonstrates that the design of firewater supply and distribution systems are based on the volume and pressure of water required to combat and protect against the maximum credible fire event, thereby establishing the "design basis firewater demand" for the LNG Facility.

Firewater Tanks:

Firewater Tanks will receive supply water under the action of an on/off level controller in the tank, which is required to keep the tanks full and available for use. The required size of the firewater tanks is 325,000 gallons. However, the working capacity of the firewater tank will be 500,000 gallons to handle the maximum credible fire event for two hours.

Firewater Pumps:

One Electric Firewater Pump (P-601) and one Diesel Firewater Pump (P-602) will be provided for the freshwater supply system. Each pump is designed to supply the largest expected freshwater demand (100 percent redundancy) at the required outlet pressure.

A firewater jockey pump (P-603) will be provided for the freshwater supply system. A firewater jockey pump will be used where it is desirable to maintain a uniform pressure on the fire protection system. Per Reference 7, Section A.5.24 Firewater Jockey Pumps will be sized to make up the allowable leakage rate within 10 minutes or 1 gpm, whichever is larger. The firewater jockey pump will be sized to maintain system pressure during bleeds of up to 50 gpm. This allows the intermittent use of up to 50 gpm of water from the freshwater supply system without requiring the larger firewater pump(s) to start. For design purposes, the system leak rate is expected to be 10 gpm or less. The specified capacity of the firewater jockey pump is substantially greater than the anticipated design leakage rate, which ensures that the firewater jockey pump will be able to make up any leakage losses throughout the freshwater supply system during normal operation.

Fire pump installation, including the fire pumps, drivers, controllers, piping, valves, fuel tanks, interconnecting wiring etc., will be in accordance with NFPA 20. Data Sheet DS-600-000-601/2/3 for the firewater pumps are included in Appendix M.3 of this Resource Report 13.

Firewater Piping:

A looped, underground firewater distribution network will be provided around all areas of the LNG Facility in accordance with NFPA 24. The layout of the system will provide a supply to each area from a minimum of two directions. Post indicating valves (“PIV”) will be provided to isolate sections of piping in the event of failures and still maintain the ability to supply firewater to each designated area. The distribution system will be sized to deliver the design firewater demand to the most hydraulically remote location in the network at the demand's minimum residual (flowing) pressure.

All piping will be listed or approved for fire service. Above ground piping will be welded carbon steel, with fused epoxy internal coating and seawater corrosion-resistant outer coating if piping is exposed to seawater. PIVs will be resilient type gate valves that are locked open so as not to require electrical supervision. Butterfly valves will not be used.

Hydrants:

Fire hydrants will be provided throughout the LNG Facility (process areas, LNG storage tank areas, and truck loading areas) in accordance with NFPA 24. Hydrants will be spaced at not more than 150 feet in process areas and not more the 300 feet along the roads and will be red or some other conspicuous color.

Three types of fire hydrants will be provided:

- 2-way fire hydrants with 2½ inch hose connections;

- 3-way fire hydrants (with one 3½ inch pumper connection and two 2½ inch hose connections); and
- 3-way monitor mounted fire hydrants with two 2½ inch hose connections.

Hydrants located along the roadways will be 2-way type. Hydrants located in the LNG truck loading area, LNG storage tank area, and process areas will be 2-way or 3-way types or 3-way monitor mounted types.

Monitors:

Monitors will be located as needed to provide cooling to equipment. Monitor remote controls will be located at least 50 feet from the probable fire location.

Process areas will be provided with monitors as needed to cool equipment and structures. All monitors will be remotely controlled to minimize local manual actions in areas with hazardous conditions. Monitor mounted hydrants will be provided with brass monitor outlet attachments. Monitors will be complete with a combination fog/straight stream brass nozzle.

The capacity of monitors will be based on required flows and reach for the cooling flow. In general, monitor selection is based on a 100 psig pressure and a narrow fog flow. Based on this, 500 gpm monitors are considered to have a reach of about 100 feet (with a capability to reach 170 feet with solid stream flow).

Monitors will be red or some other conspicuous color.

Hose Reels and Hose Boxes:

Outside hose boxes with fire hose carts, nozzles, hydrant wrenches, spanners and other necessary equipment will be provided strategically around the LNG Facility, storage and loading platform area in accordance with NFPA 24. Hose boxes at hydrants will have hoses pre-connected to the hydrant.

Hose reels and hose boxes will be red or some other conspicuous color.

Automatic Sprinklers:

Automatic (either wet pipe or dry pipe) sprinkler systems will be provided in non-process areas in accordance with NFPA 13 and local building codes. Sprinkler systems may also be provided in structures in process areas where water fire suppression is effective. Systems will be hydraulically designed for the occupancy classification of the application.

Fixed Water Spray Systems:

Local water spray systems may be used for cooling storage and process vessels and equipment exposed to fires. Systems will be designed per NFPA 15 and/or API 2510A. Systems may be automatically or manually activated in response to hazard detection.

Water Supply for High Expansion Foam:

The fire main system will supply water to the Hi-Ex foam skids. The fire main will be verified to meet the flow and pressure demands for firewater used in the Hi-Ex foam systems, but the peak flow demand for the foam systems will not be used to determine the fire main system maximum demand since the foam system operates intermittently based on need to maintain the foam blanket.

13.17.2 Matrix of All Firewater Delivery Equipment

Firewater System Equipment List 15505-LI-000-007, included in Appendix M.2 of this Resource Report, summarizes the location, tag number, area covered, type, discharge conditions, activation method for all firewater equipment including water spray systems, sprinklers, monitors, hydrants and hose boxes that will be installed at the LNG Facility.

13.17.3 Firewater Drawings

The Firewater Flow Diagram (1550-PF-800-008) is included in Appendix U.2 of this Resource Report.

Firewater Layout and P&IDs (15505-PI-600-002 and 15505-PI-600-003) are included in Appendix U.4 of this Resource Report.

Fire Protection Drawings (15505-PI-600-004 to -009), including coverage plans, are included in Appendix U.8 of this Resource Report.

13.18 High Expansion Foam System

13.18.1 Description of Foam System and Equipment

Hi-Ex foam systems will be provided for the impoundment basins and will be used to reduce the vaporization rate of spilled LNG; provide additional vapor dispersion control (since vapors traveling through the foam warm sufficiently to better disperse in the atmosphere); and reduce the heat release rate of a basin fire, if ignited, by reducing the vaporization rate from the basin under fire conditions.

Each system will consist of a foam concentrate storage tank, a proportioning device to mix the concentrate with fire main water and a foam generator powered by a water-driven reaction motor to distribute the foam over the liquid surface of any spilled LNG in the basins. The foam concentrate has an expansion ratio of at least 500:1. The systems will be activated manually by operators as required. The foam generators are designed to withstand high temperatures and will be of a design proven for LNG service. Foam fences will also be used to minimize the loss of foam as a result of wind.

The foam systems will provide at least 1 foot deep coverage over the basin areas within 30 seconds of system actuation and 5 feet deep coverage over the basin areas within one minute of activation. System capacity will be sufficient to maintain this foam blanket for a 24 hour period by periodically adding more foam.

13.18.2 Foam System Basis of Design

The Hi-Ex foam systems will be designed in accordance with NFPA 11 and be UL listed or FM approved. The design will further be proven for LNG service. System capacity will be based on an initial foam discharge rate of 6 cfm/ft^2 and on maintaining a depth of 5 feet. The discharge rate and foam depth are based on LNG spill testing where the 6 cfm/ft^2 rate resulted in total foam coverage within 30 seconds of system actuation. The 5 feet depth was selected to provide margin over testing that showed 3 feet was sufficient to significantly reduce downwind gas concentrations. These values were based on the assumption that the system response time is less than 30 seconds. The 5 feet depth provides additional conservatism for the LNG Facility since the basins are insulated, resulting in lower LNG boiloff rates, which in turn has been shown to provide additional protection time per foot of foam. (See "Considerations Relating to Fire Protection Requirements for LNG Plants (75-T-47)" by H. R. Wesson, Operating Section Proceedings, American Gas Association, Los Angeles, CA May 5-7, 1975, pp. T-121 - T-136.)

System capacity to maintain a 5 feet depth of foam for 24 hours for the impoundment basins will be conservatively selected to provide sufficient time to disperse the LNG vapors in a controlled and safe manner. This capacity also provides margin to account for wind-driven or rain-driven foam depth loss. The Hi-Ex foam system will be used for local application, where the foam is discharged directly onto the fire or LNG spill. The system will consist of fixed foam generating apparatus complete with a piped supply of foam concentrate and water that is arranged to discharge foam directly onto a fire or spill hazard.

Potassium bicarbonate dry chemical agents may be used in addition to the foam system to control impoundment basin fires. As a result, the dry chemical and foam agents used for the Access Northeast LNG Facility will be compatible. Hi-Ex foam system sizing is described in the Hazard Detection and Mitigation Philosophy document (15505-TS-000-007) included in Appendix C.3 to this Resource Report.

13.18.3 Matrix with Tag Number, Location, Type/Model of Foam Equipment.

Hi-Ex foam equipment is listed in the Extinguisher System Equipment List (15505-LI-000-008) which is included in Appendix M.2 of this Resource Report. The list summarizes the location, type and discharge condition of the Hi-Ex foam system equipment that will be installed.

13.18.4 Drawings

The location of the Hi-Ex foam system for the impoundment basins and their areas of coverage are illustrated in drawings 15505-PI-600-101 to 15505-PI-600-103, which are included in Appendix U.8 of this Resource Report.

The Hi-Ex foam system connections to the firewater system for the impoundment basins are illustrated in drawings 15505-PI-600-002 and 15505-PI-600-003, which are included in Appendix U.4 of this Resource Report.

13.19 Security

The LNG Facility is designed and will be constructed and operated to provide the level of security and safety, consistent with the requirements of its design and location. A security specification is included in Appendix T.8 of this Resource Report. A separate Facility Security Plan, describing site security provisions and features, will be prepared. Key elements of the Facility Security Plan are summarized below.

13.19.1 Security Description

The LNG Facility will employ a Facility Security Plan developed to provide procedures that will enhance the safety and security of the LNG Facility against unlawful acts. Security measures included in the Facility Security Plan include:

- Perimeter security;
- Access points into the LNG Facility;
- Restrictions and prohibitions applied at the access points;

- Identification systems; and
- Screening procedures.

A CCTV system will be installed to monitor the fence line, active access points to the LNG Facility and the interior of the LNG Facility.

Intrusion detection systems will be installed at the perimeter security fence and also in all buildings.

Key features of the Facility Security Plan include:

- Security Procedures
  - Description of the LNG Facility security administration and organization;
  - Security monitoring procedures;
  - Security incident procedures (such as evacuation, reporting incidents, briefing personnel, securing non-critical operations);
  - Security measures for access control, including perimeter security, access points into the LNG Facility, restriction and prohibitions applied at the access points, identification system, acceptable forms of personnel identification, visitors' log and passes, screening procedures for personnel and vehicles, access control and screening procedures;
  - Restricted areas and procedures; and
  - Audits and security plan amendments.

- Security Systems and Equipment Maintenance
  - Security fencing system;
  - Buildings, equipment and other structures that will be enclosed;
  - Location of the means of access and egress through the protective enclosure;
  - Methods of maintaining security of gates that are used for access and egress and procedures that will be used during emergency situations;
  - Security lighting systems; and
  - Security systems and equipment maintenance requirements.

- Communications
  - The Facility Security Plan includes communication systems and procedures to provide effective and continuous communications between all personnel, federal, state and local authorities with security responsibilities.

- Security Training
  - The Facility Security Plan includes details of training that must be provided to all personnel who will be involved in providing security at the LNG Facility. Training will be provided to comply with the requirements of 49 CFR Part 193 Subpart H, NFPA 59A (2001 edition).

    - Required personnel training and qualifications;
    - Training documentation and review requirements; and
    - Required drills and exercises.

13.19.2 Site Access Control

Security measures will be implemented to control entry to and egress from the LNG Facility. Entry will be controlled by an automated key card badge system for employees and security at the main entrance for any visitors. The purpose of such measures will be to:

- Deter the unauthorized introduction of dangerous substances and devices including any device intended to damage or destroy persons or facilities;
- Secure dangerous substances and devices that are not authorized by the owner or operator to be on the Facility site; and
- Control access to the Facility.

13.19.3 Cameras

A CCTV system will be installed to provide remote surveillance capability. The CCTV system will monitor the fence line, all access and egress points and the interior of the LNG Facility.

The system will include pan/tilt/zoom cameras to provide the coverage based on the lighting requirements, the application, the required field of view and the camera location. The cameras will be low-light or ultra-low-light depending on the lighting in each area. Monitors will be located in the control room and the Admin/Control Room Building. The layout of the security cameras is illustrated in drawing 15505-DG-000-250, which is included in Appendix U.10 of this Resource Report.

13.19.4 Intrusion Detection

Intrusion detection systems will be installed at the perimeter security fence and also in all buildings. The fence line system will detect, alarm and accurately identify the locations of any attempts of intrusion through the security fence. The fence line perimeter will be partitioned into zones, and each zone will be alarmed and logged at the security system console. The fence line perimeter is shown in drawing 15505-DG-000-250, which is included in Appendix U.10 to this Resource Report.

The intrusion detection system will also include sensors for early warning of approaching vehicles and will be capable of controlling vehicle access gates. To minimize false alarms, surrounding weather conditions will be appropriately considered when installing the system.

13.20 Piping

13.20.1 Piping Systems

Process-related piping systems are designed in accordance with the design fluid velocities described in the Engineering Design Standard (15505-TS-000-001) included in Appendix C.1 of this Resource Report.

The use of flanges in cryogenic piping will be minimized. Vessels and equipment will use welded connections, except where entry or disassembly for inspections or maintenance after start-up is anticipated or required, such as for heat exchangers or relief valves. In these cases, there will be a case-by-case evaluation to confirm that flanges are required.

Small diameter weld penetrations increase pipe thermal stresses during cooldown. Consequently, all piping penetrations for vents, drains and instruments sensing lines will be evaluated during detailed engineering. If the thermal stresses for a given penetration cannot be diminished by pipe hangers or pipe supports, the penetration will be a minimum of 2 inches. All efforts will be made to minimize the number and size of penetrations. Wherever possible, penetrations for sensing lines for level, pressure and differential pressure will be combined for both local and remote instrumentation.

13.20.2 Piping Specification

The Piping Specification (15505-TS-000-004) included in Appendix T.1 of this Resource Report defines the acceptable piping components and minimum requirements for piping materials for all piping classes.

13.20.3 Piping Insulation

The Insulation Specification (15505-TS-000-005) included in Appendix T.2 of this Resource Report defines the requirements for exterior insulation for piping and equipment that will be used at the LNG Facility.

13.20.4 Pipe Racks

The locations of major pipe racks at the LNG Facility are illustrated on plot plan (15505-DG-000-003) included in Appendix A.3 of this Resource Report and further in detail on unit plot plans (15505-DG-000-004/5/6) included in Appendix U.1 of this Resource Report.

Pipe rack sections drawings are included in Appendix U.5 of this Resource Report. The section drawings include dimensions and elevations of pipe racks, locations and dimensions of LNG spill containment troughs and configuration of typical piping support systems.

13.20.5 Piping Specification Tabular Summary

Piping Specification (15505-TS-000-004) included in Appendix T.1 of this Resource Report includes a table of the service, material, class and pressure/temperature rating of piping systems used at the LNG Facility.

13.20.6 Piping Insulation Tabular Summary

Insulation Specification (15505-TS-000-005) included in Appendix T.2 of this Resource Report includes tables of insulation classes, type and thickness requirements for nominal pipe sizes that will be used in process piping at the LNG Facility.

13.20.7 Piping Arrangement Drawings

Drawings illustrating the plan and elevations of major process equipment piping systems that will be installed at the LNG Facility are included in Appendix U.5 of this Resource Report.

13.21 Foundations and Supports

13.21.1 Description of Foundations and Supports

Building Foundations:

Appendix J.1 of this Resource Report contains the Geotechnical Investigation Report, which discusses the site conditions, geotechnical analyses and preliminary foundation design and construction recommendations.

LNG Storage Tanks:

Foundation requirements for the LNG storage tanks are described in Section 13.6.2 of this Resource Report.

LNG Spill Containment Basins:

The LNG spill containment basins are described in Section 13.13 of this Resource Report.

The layout of the containment basins is illustrated on the plot plan (15505-DG-000-003) included in Appendix A.3 of this Resource Report and further in detail on unit plot plans (15505-DG-000-004/5/6) included in Appendix U.1 of this Resource Report. Spill containment drawings (15505-DG-600-102/3/4) are included in Appendix Q.3 of this Resource Report.

The sidewalls of the basins will consist of reinforced concrete in order to provide separation between the LNG and the adjacent ground and groundwater. Final thickness of the sidewalls will be determined during detailed engineering design. The joint between each wall and the mat will be sealed using a water stop component. To protect the structural concrete in the event of an LNG spill, all interior surfaces will be coated with a lightweight concrete that contains Perlite® aggregates. This type of mixture is preferred for sumps used in cryogenic applications as it provides resistance to heat transfer, thereby slowing the rate of generation of vapor during LNG spills.

13.22 Buildings and Structures

13.22.1 List of Buildings and Structures with Dimensions

Table 13.22-1 lists buildings that are or will be installed at the LNG Facility.

Table 13.22-1

Facility Building Dimensions

Building Number	Building Description	Dimensions (ft - in)		
		Length	Width	Wall Height
A-901	Administration Building and Control Room	100′	40′	TBD
A-902	Warehouse and Maintenance Building	100′	60′	TBD
A-904	Truck Loading Building	10′	6′	TBD
A-910	Compressor Shelter	140′	105′	TBD
A-915	Booster Compressor Shelter	20′	15′	TBD
A-920	HP Pump House	100′	30′	TBD
A-925	BOG Compressor Shelter	75′	40′	TBD
A-930	WEG Shelter	187′	60′	TBD
A-960	Firewater Pump House	50′	25′	TBD
A-990	Electric Switchgear Building	60′	65′	TBD

These building sizes are preliminary and will be reviewed and adjusted as required during detailed design.

13.22.2 Drawings

Preliminary plan and elevation drawings for buildings to be installed at the LNG Facility are provided in Appendix U.9 of this Resource Report.

13.23 Process Drawings

13.23.1 PFDs

Process flow diagrams are included in Appendix U.2 of this Resource Report.

13.23.2 H&MBs

H&MBs are included in Appendix U.3 of this Resource Report.

13.24 Piping and Instrument Diagrams

P&IDs are included in Appendix U.4 of this Resource Report.