DOCKET NO. CP17-___-000

RESOURCE REPORT NO. 11

RELIABILITY AND SAFETY

PUBLIC

DOCUMENT NUMBER: USAI-PE-SRREG-00-000011-000

RESOURCE REPORT NO. 11 SUMMARY OF FILING INFORMATION [1]	
Filing Requirement	**Found in Section**
Minimum Requirements to Avoid Rejection Describe how the project facilities will be designed, constructed, operated, and maintained to minimize potential hazard to the public from the failure of project components as a result of accidents or natural catastrophes. (§380.12(m))	Document-Wide

[1] Guidance Manual for Environmental Report Preparation, Volume I (FERC, 2017). Available online at: https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf.

Resource Report No. 11 Agency Comments and Requests for Information Concerning Reliability and Safety	
Comment	**Response/Resource Report Location**
The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made by FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable.	See below
a. Updated Table 11.1.2-1 with additional input solicited from meetings and correspondence as described in section 11.1.2.1. (section 11.1.2.1, page 11-4)	Resource Report No.11 has been updated to match the 2017 FERC Guidance. As such, Table 11.1.2-1 has been renamed Table 11.1.1.9 and has been updated to include additional consultations and input.
b. Summary of key outcomes of the TAPS Impact Study. (section 11.7.2.7.4, page 11-38)	Resource Report No.11 has been updated to include a summary of the TAPS Impact Study in section 11.7.2.7.4. Additional reports which have been created as a result of the TAPS study are included in the Appendices to RR11.
Include full citations for missing sources, referenced materials, and unreferenced statements, including web-based data. Review all citations and confirm that there are corresponding literature references. Confirm that where multiple references are listed in a year that there are alphabetical modifiers that accurately align between the citation and references, and confirm that literature references are listed alphabetically and then chronologically to facilitate location of the accurate reference. Full citations were found to be missing for the references identified below; however, the list is not considered all-inclusive.	See below
a. Provide a citation for all National Fire Protection Association (NFPA) 59A references within the text including the year/version of the NFPA 59a. Most references should cite the 2001 version.	Resource Report No.11 has been updated to ensure all references to NFPA 59A specify the intended revision
b. Update the NFPA 49A (2001) citation to 59A. (page 11-vi).	Resource Report No.11 has been updated to ensure all references to NFPA 59A specify the intended revision
c. Cite the NFPA 59A (2001) in the References section. (section 11.2.2, page 11-8)	Resource Report No.11 has been updated to ensure all references to NFPA 59A specify the intended revision
d. Cite the USDOT, 2015 information. (section 11.6.2.1, Table 11.6.2-1, page 11-28).	Reference is updated and cited in Section 11.12
e. Cite American Society of Mechanical Engineers (ASME) B31.8 (2014) in the references section. (section 11.7.2.8.2, page 11-41).	Reference is updated and cited in Section 11.12
Include a comprehensive discussion of design measures intended to address the geological hazards outlined in section 11.6.1.1 and detailed in Resource Reports 6 and 7 (section 11.6.1.1, page 11-25; section 6.4, page 6-43, section 7.5.2.1, page 7-51)	The Applicant will address this comment prior to the initiation of the EIS process.
State if an odorant would be utilized within the planned facilities and pipelines (i.e., Mainline, Prudhoe Bay Gas Transmission Line, and Point Thomson Gas Transmission Line). (section 11.6.1, page 11-25)	An odorant would not be utilized. Resource Report No.11, Section 11.7.2.11 has been updated to reflect no odorant would be utilized
Include clarification on whether stray direct currents are a potential hazard. Identify the facilities and location by milepost range where stray direct currents would be a hazard. Identify safety mitigation measures that would be employed to protect the pipeline. (section 11.6.1.2, page 11-26)	The Applicant will address this comment prior to the initiation of the EIS process.
State if the incident data presented in section 11.6.2 includes pipelines constructed under strain-based design. Include information on any	The Applicant will address this comment prior to the initiation of the EIS process.

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known incidents from pipelines constructed under strain-based design. (section 11.6.2, page 11-27 and 11-28)	
Include a description of the reliability of the pipeline and associated facilities and the design factors intended to minimize interruption of service. Discuss the results of the Reliability, Availability, and Maintainability analysis if such analysis was completed. (section 11.7, page 11-29)	The Applicant will address this comment prior to the initiation of the EIS process.
Include a comprehensive discussion on the safety mitigation measures that would be employed to protect the general public, construction workers, and wildlife during construction (i.e., traffic controls, public access, working above existing in-service pipelines, aboveground and underground utility crossovers). (section 11.7.2, page 11-29)	The Applicant will address this comment prior to the initiation of the EIS process.
Complete section 11.7.2.5. The text under table 11.7.2-6 is incomplete. (section 11.7.2.5, page 11-33)	Section 11.7.2.5 of Resource Report No.11 has been updated.
no comments, except should make sure that 49 CFR is used instead of "48" CFR.	All references to applicable codes in Resource Report No.11 are to 49 CFR Part 192 and 193.
Proposed Conditions need to be the current proposed conditions. They are not being used in this document.	The new conditions received from PHMSA have been included in Appendix B of Resource Report No.11
PHMSA has not agreed or disagreed on the proposed Mainline Block Valve spacing. 50-plus mile mainline valve spacing is too much and valves would need to be remote controlled or automatic closure valves. Proposed mainline valve spacing would probably have to be 35-miles or less. Developer/Owner/Operator would need to have further discussions with PHMSA. Both mainline valve spacing and the crack arrestor spacing changes would require a special permit in accordance with 49 CFR § 190.341	Section 11.7.2.8.3 clarifies that both Mainline Block Valve Spacing and Crack Arrestor spacing that does not meet the stated requirements of 49 CFR 192 would require a Special Permit, and gives additional information regarding both these subjects in the Appendices as noted in this section: "11.7.2.8.3 Mainline Block Valve and Crack Arrestor Spacing Special Permit Given the results of the aforementioned analyses, there are plans to apply for a MLBV and Crack Arrestor (CA) spacing SP from PHMSA in Class 1, remote locations…. Additional details can be found in Appendix C (Environmental Information for MLBV and CA Spacing SP) and Appendix E (Three Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit). Additional technical justification for the increase in MLBV spacing is included in Appendix G."
PHMSA has not agreed or disagreed that multi-layer coatings can be used, since they shield cathodic protection. A special permit would need to be submitted to PHMSA by the Developer/Owner/Operator and it would go through a public noticing process.	Section 11.7.2.9 clarifies that the proposed Multi-Layer Coating System would require a Special Permit (SP) and gives additional information about the Environmental Implications, as well as additional justification for use in the Appendix D, Appendix E and Appendix F as noted: "11.7.2.9 High Integrity Multi-Layer Coatings … Given the favorable industry experience with 3LPE coatings and their suitability for the Alaskan environment, a 3LPE SP would be requested from PHMSA. If PHMSA were to grant this SP, it would contain conditions that apply to the pipeline over its lifecycle. These conditions are summarized herein to demonstrate that there are negligible differences in environmental consequence between conventional

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	design and the proposed 3LPE SP. This SP would allow for the use of 3LPE coatings over the entire length of the onshore Mainline. . PHMSA SP approval is conditioned on achieving equal or greater level of safety than compliance with 49 C.F.R. 192. Additional details can be found in Three-Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit (Appendix E) and Environmental Information for Multi-Layer Coating Special Permit (Appendix D) for PHMSA. Additional technical justification for the use of 3LPE is included in Appendix F…”
PHMSA has not agreed or disagreed that multi-layer coatings can be used, since they shield cathodic protection. A special permit would need to be submitted to PHMSA by the Developer/Owner/Operator and it would go through a public noticing process.	Section 11.7.2.9 clarifies that the proposed Multi-Layer Coating System would require a Special Permit (SP) and gives additional information about the Environmental Implications, as well as additional justification for use in the Appendix D, Appendix E and Appendix F as noted: “11.7.2.9 High Integrity Multi-Layer Coatings … Given the favorable industry experience with 3LPE coatings and their suitability for the Alaskan environment, a 3LPE SP would be requested from PHMSA. If PHMSA were to grant this SP, it would contain conditions that apply to the pipeline over its lifecycle. These conditions are summarized herein to demonstrate that there are negligible differences in environmental consequence between conventional design and the proposed 3LPE SP. This SP would allow for the use of 3LPE coatings over the entire length of the onshore Mainline. . PHMSA SP approval is conditioned on achieving equal or greater level of safety than compliance with 49 C.F.R. 192. Additional details can be found in Three-Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit (Appendix E) and Environmental Information for Multi-Layer Coating Special Permit (Appendix D) for PHMSA. Additional technical justification for the use of 3LPE is included in Appendix F…”
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	allow for the use of 3LPE coatings over the entire length of the onshore Mainline. . PHMSA SP approval is conditioned on achieving equal or greater level of safety than compliance with 49 C.F.R. 192. Additional details can be found in Three-Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit (Appendix E) and Environmental Information for Multi-Layer Coating Special Permit (Appendix D) for PHMSA. Additional technical justification for the use of 3LPE is included in Appendix F…"
Table 1.3.2-4 - Suggest Developer/Owner/Operator to review strain-based design segments with PHMSA and show in RR how they were determined.	The Applicant will address this comment prior to the initiation of the EIS process.
Table – for mainline valve spacing – Does this table correctly show proposed location of mainline valves?	Yes

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ACRONYMS AND ABBREVIATIONS

ABBREVIATION	DEFINITION
3LPE	Three Layer Polyethylene
ºF	Degrees Fahrenheit
AC	alternating current
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADHSS	Alaska Department of Health and Social Services
ADNR	Alaska Department of Natural Resources
ADOT&PF	Alaska Department of Transportation and Public Facilities
AEGL	acute exposure guideline level
AMSC	Area Maritime Security Committee
ANSI	American National Standards Institute
APCI	Air Products and Chemicals, Inc.
API	American Petroleum Institute
Applicant	Alaska Gasline Development Corporation
APSC	Alyeska Pipeline Service Company
ATWS	additional temporary workspace
BACT	Best Available Control Technology
BLM	United States Department of the Interior, Bureau of Land Management
C.F.R.	Code of Federal Regulations
CA	Crack Arrestor
CGF	Central Gas Facility
CIRCAC	Cook Inlet Regional Citizens Advisory Council
CO_2	carbon dioxide
COC	Certificate of Compliance
COTP	Captain of the Port
CP	cathodic protection
CPS	corrosion protection system
C3MR™	Propane Pre-Cooled Mixed Refrigerant Process
DF	design factor
DHS	Department of Homeland Security
EIS	Environmental Impact Statement
EOC	Emergency Operations Center
EPA	U.S. Environmental Protection Agency
EPRP	Emergency Preparedness and Response Plan
ERP	Emergency Response Plan
ESD	Emergency Shutdown
exp	Exp Energy Services, Inc.
FBE	fusion bonded epoxy
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FGDS	Fire and Gas Detection System
FGL	Fuel Gas Line
FJC	field joint coating

ABBREVIATION	DEFINITION
FSP	facility security plan
GTP	Gas Treatment Plant
H_2S	hydrogen sulfide
HAZID	Hazard Identification and Analyses
HCA	High Consequence Area
HDMS	Hazard Detection and Mitigation System
HMI	human machine interface
HP	high pressure
IBC	International Building Code
ICSS	Integrated Control and Safety System
IFC	International Fire Code
ILI	in-line inspection
IMP	integrity management program
ISD	inherently safer design
ISO	International Organization for Standardization
KPB	Kenai Peninsula Borough
ksi	thousand pounds per square inch
Lcrit	critical length
LFL	lower flammability limit
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
LOI	Letter of Intent
LOR	Letter of Recommendation
LP	low pressure
MAOP	maximum allowable operating pressure
MGS	Major Gas Sales
MLBV	Mainline block valve
MMTPA	million metric tons per annum
MOF	material offloading facility
MOP	maximum operating pressure
MP	milepost
MR	mixed refrigerant
NACE	National Association of Corrosion Engineers
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NIMS	National Incident Management System
NIOSH	National Institute for Occupational Safety and Health
NMFS	National Oceanic and Atmospheric Administration, National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
North Slope	Alaska North Slope
NRG	Natural Resource Group
NSB	North Slope Borough
NVIC	Navigation and Vessel Inspection Circular
OSHA	Occupational Safety and Health Administration

ABBREVIATION	DEFINITION
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
PHMSA	United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration
PIR	potential impact radius
Project	Alaska LNG Project
PSD	Process Shutdown
psi	pounds per square inch
Psig	pounds per square inch gauge
PSV	pressure safety valve
PTTL	Point Thomson Gas Transmission Line
PTU	Point Thomson Unit
ROW	right-of-way
SBD	Strain-Based Design
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SIS	Safety Instrumented System
SMYS	specified minimum yield strength
SP	Special Permit
SPCS	Alaska Department of Natural Resources, State Pipeline Coordinator’s Section
SRA	Standard Risk Assessment
SSI	Sensitive Security Information
SWAPA	Southwest Alaska Pilots Association
TAPS	Trans-Alaska Pipeline System
TOTE	Totem Ocean Trailer Express
TSA	Transportation Security Administration
U.S.	United States
UCIDA	United Cook Inlet Drift Association
USCG	United States Coast Guard
USACE	United States Army Corps of Engineers
USDHS	United States Department of Homeland Security
USDOT	United States Department of Transportation
USFWS	United States Fish and Wildlife Service
WIO	Working Interest Owner
WSA	Waterway Suitability Assessment

11.0 RESOURCE REPORT NO. 11 – RELIABILITY AND SAFETY

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and Federal Energy Regulatory Commission (FERC) regulations, 18 Code of Federal Regulations (C.F.R.) § 153.2(d) (2014), define "LNG terminal" to include "all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is ... exported to a foreign country from the United States." With respect to this Project, the "LNG Terminal" includes the following: a liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL). All of these facilities are essential to export natural gas in foreign commerce and will have a nominal design life of 30 years.

These components are shown in Resource Report No. 1, Figure 1.1-1, as well as the maps found in Appendices A and B of Resource Report No. 1. Their proposed basis for design is described as follows.

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The Liquefaction Facility would include the structures, equipment, underlying access rights, and all other associated systems for final processing and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities and auxiliary marine vessels used to support Marine Terminal operations (excluding LNG carriers [LNGCs]). The Liquefaction Facility would include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Two 240,000-cubic-meter tanks would be constructed to store the LNG. The Liquefaction Facility would be capable of accommodating two LNGCs. The size of LNGCs that the Liquefaction Facility would accommodate would range between 125,000–216,000-cubic-meter vessels.

In addition to the Liquefaction Facility, the LNG Terminal would include the following interdependent facilities:

- Mainline: A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU, including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

Associated infrastructure facilities would include additional temporary workspace (ATWS), access roads, helipads, construction camps, pipe storage areas, material extraction sites, and material disposal sites.

Along the Mainline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 807 to serve the Kenai Peninsula. The size and location of the other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project. Potential third-party facilities are addressed in the Cumulative Impacts analysis found in Appendix L of Resource Report No. 1;

- GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads;

- PBU Gas Transmission Line: A new 60-inch natural gas transmission line would extend approximately 1 mile from the outlet flange of the PBU gas production facility to the inlet flange of the GTP. The PBU Gas Transmission Line would include one-meter station on the GTP pad; and

- PTU Gas Transmission Line: A new 32-inch natural gas transmission line would extend approximately 63 miles from the outlet flange of the PTU gas production facility to the inlet flange of the GTP. The PTU Gas Transmission Line would include one-meter station on the GTP pad, four MLBVs, and pig launcher and receiver facilities—one each at the PTU and GTP pads.

Existing State of Alaska transportation infrastructure would be used during the construction of these new facilities including ports, airports, roads, railroads, and airstrips (potentially including previously abandoned airstrips). A preliminary assessment of potential new infrastructure and modifications or additions to these existing in-state facilities is provided in Resource Report No. 1, Appendix L. The Liquefaction Facility, Mainline, and GTP would require the construction of modules that may or may not take place at existing or new manufacturing facilities in the United States.

Resource Report No. 1, Appendix A, contains maps of the Project footprint. Appendices B and E of Resource Report No. 1 depict the footprint, plot plans of the aboveground facilities, and typical layout of aboveground facilities.

Outside the scope of the Project, but in support of or related to the Project, additional facilities or expansion/modification of existing facilities would be needed to be constructed. These other projects may include:

- Modifications/new facilities at the PTU (PTU Expansion project);
- Modifications/new facilities at the PBU (PBU Major Gas Sales [MGS] project); and
- Relocation of the Kenai Spur Highway.

As required by 18 C.F.R. § 380.12, this Resource Report has been prepared in support of an application under Section 3 of the NGA to construct and operate the Project facilities. The purpose of this Resource Report is as follows:

- Describe how Project facilities would be designed, constructed, operated, and maintained to reduce potential hazards to the public and the environment from failure of Project components as a result of an accident or natural catastrophe;

- Evaluate the effect of an accident or natural catastrophe on the reliability and safety of the Project facilities; and

- Explain the procedures and design features proposed to reduce potential hazards.

This report should be used in conjunction with Resource Report No. 13, which provides specific technical details on engineering, design, and materials.

11.1 REGULATORY OVERSIGHT

11.1.1 Regulatory Oversight of Reliability and Safety

Multiple federal agencies share regulatory authority over the siting, design, construction and operation of the Liquefaction Facility.

The Federal Energy Regulatory Commission (FERC) issues an Order authorizing the siting and construction of LNG facilities under Section 3 of the Natural Gas Act. The FERC will be the lead federal agency for developing the Environmental Impact Statement for the Project. The FERC requires standard information to be submitted to perform safety and reliability engineering reviews for LNG facilities. The FERC's filing regulations are codified in 18 C.F.R. § 380.12(m) and (o) and require each applicant to identify how its proposed design complies with the U.S. Department of Transportation: Pipeline and Hazardous Materials Safety Administration ("DOT PHMSA") minimum federal safety standards for LNG facilities in 49 C.F.R. Part 193. The Pipeline Safety Act provides that a certification of 49 C.F.R. Part 193 compliance is binding on FERC unless an appropriate enforcement agency provides timely written notice that an applicant has violated one of PHMSA's safety standards. 49 U.S.C. § 60104(d)(2).

The FERC must ensure that all proposed LNG facilities will operate safely and securely. The design information that must be filed in the application to the Commission is specified by 18 C.F.R. § 380.12 (m) and (o). The level of detail necessary for this submittal requires the project to perform substantial front-end engineering of the complete facility. The design information is required to be site-specific and developed to the extent that further detailed design would not result in changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions or safety system designs. In addition, if the Liquefaction Facility is constructed and becomes operational, it will be subjected to FERC reviews during the operational phase.

11.1.1.1 U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration

PHMSA assists FERC staff in evaluating whether an applicant's proposed siting meets the 49 C.F.R. Part 193 requirements. If an LNG facility were to be constructed and become operational, the facility would be subject to PHMSA's inspection program. Final determination of whether a facility is in compliance with the requirements of 49 C.F.R. Part 193 would be made by PHMSA staff.

DOT PHMSA establishes federal safety regulations for siting, design, construction, operation and maintenance of LNG facilities as detailed in 49 C.F.R. Part 193. Many of the regulations in 49 C.F.R. Part 193 are based on the provisions in the National Fire Protection Association (NFPA) 59A (2001), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas," a consensus industry standard that is incorporated into PHMSA's regulations by reference. The 2006 edition of NFPA 59A is also incorporated by reference for purposes of certain provisions relating to the design and construction of LNG storage tanks. The regulations in 49 C.F.R. Part 193 prevail in the event a conflict arises with the incorporated provisions in NFPA 59A. In 1985, the FERC and DOT PHMSA entered into a Memorandum of Understanding regarding the execution of each agency's respective statutory responsibilities to ensure the safe siting and operation of LNG facilities. In addition to FERC's existing ability to impose requirements to ensure or enhance the operational reliability of LNG facilities, the Memorandum of Understanding specified that FERC may, with appropriate consultation with PHMSA, impose more stringent safety requirements than those in 49 C.F.R. Part 193.

DOT PHMSA also establishes federal safety standards for siting, design, construction, operation and maintenance of pipeline facilities as detailed in 49 C.F.R. Part 192.

The Project is currently consulting with DOT PHMSA on the following items:

- Special Permits for the Mainline
- Equivalency for pipe in pipe for the Liquefaction Facility
- Equivalency for concrete LNG storage tanks for the Liquefaction Facility
- Approval on a design spill duration for spills at the marine jetty
- Consultation on selection of design spills for hazard modeling

Final results of the above special permits, equivalencies, and approvals will be filed with FERC upon completion of consultations with DOT PHMSA.

11.1.1.2 United States Coast Guard

The USCG has authority over the safety of an LNG facility's marine transfer area and LNG marine traffic, as well as over security plans for the entire LNG facility and LNG marine traffic. The USCG regulations over LNG facilities are codified in 33 C.F.R. Parts 105 and 127. USCG is a cooperating agency in the permitting process for LNG terminal facilities with the FERC. As defined in 33 C.F.R. § 127.007 and 18

C.F.R. § 157.21, USCG requires LNG terminal applicants to submit a Letter of Intent (LOI), Preliminary Waterway Suitability Assessment (WSA) and a Follow-on WSA to the Captain of the Port (COTP). The WSA is USCG's review of the marine transportation component of an LNG terminal project and addresses the suitability of the waterway for additional LNGC marine traffic. The regulations require that full consideration be given to safety and security of the port, the waterway, the vessels transporting LNG, and the LNGC at berth.

In February 2004, the USCG, DOT, and FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals, including terminal facilities and tanker operations, and maximizing the exchange of information related to the safety and security aspects of the LNG facilities and related marine operations. Under the Interagency Agreement, the FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with Liquefaction Facility construction and operation. The DOT and Coast Guard participate as cooperating agencies, but remain responsible for enforcing their regulations covering LNG facility design, construction and operation.

11.1.1.3 U.S. Environmental Protection Agency

The Project is currently consulting with the US EPA on applicability of the RMP program. Outcomes of the consultation will be filed with FERC staff once completed.

11.1.1.4 U.S. Occupational Safety and Health Administration

The Project is currently consulting with the US EPA on applicability of the PSM program. Outcomes of the consultation will be filed with FERC staff once completed.

11.1.1.5 U.S. Department of Transportation Federal Aviation Administration

The closest airport to the Liquefaction Facility is the Johnson Airport located in Kenai, Alaska, which is approximately 3 miles south of the Liquefaction Facility. The Liquefaction Facility's design does not include any structure over approximately 160 feet, and AGDC does not anticipate any hazard to air travel from structures or ground flare operation during startup, shutdown or upset conditions. Therefore, no aeronautical operations will be impacted by the Liquefaction Facility construction or operation or by transportation to or from the Liquefaction Facility.

The closest airport to the GTP is the Deadhorse Airport located in Deadhorse, Alaska, which is approximately 12 miles south of the GTP. The GTP's design does not include any structure over approximately 160 feet, and AGDC does not anticipate any hazard to air travel from structures or ground flare operation during startup, shutdown or upset conditions. Therefore, no aeronautical operations will be impacted by the GTP construction or operation or by transportation to or from the GTP.

The following airports have been identified along with their type and distance to the proposed LNG ship route:

- Kenai Municipal Airport (Asphalt Runway) – 5.3 miles from proposed LNG ship route

- Homer Airport (Asphalt Runway) – 4.4 miles from proposed LNG ship route
- Kodiak Airport (Asphalt Runway) – 55 miles from proposed LNG ship route
- King Salmon Airport (Asphalt Runway) – 99 miles from proposed LNG ship route
- Egegik Airport (Gravel Runway) – 91 miles from proposed LNG ship route
- Port Heiden Airport (Gravel Runway) – 76 miles from proposed LNG ship route
- Sand Point Airport (Asphalt Runway) – 61 miles from proposed LNG ship route
- Unalaska Airport (Asphalt Runway) – 51 miles from proposed LNG ship route
- St. Paul Island Airport (Gravel Runway) – 154 miles from proposed LNG ship route

AGDC does not anticipate any hazard to air travel from LNG carriers traveling to and from the Liquefaction Facility.

11.1.1.6 U.S. Department of Defense

The closest military installation is the Joint Base Elmendorf Richardson, which is approximately 65 miles northeast of the proposed Liquefaction Facility. Therefore, no military installations will be impacted by the Liquefaction Facility construction or operation or by transportation to or from the Liquefaction Facility.

The closest military installation is the Eielson Air Force Base, which is approximately 394 miles South of the proposed GTP. Therefore, no military installations will be impacted by the GTP construction or operation or by transportation to or from the GTP.

11.1.1.7 U.S. Nuclear Regulatory Commission

There are no operating nuclear reactors in the state of Alaska[2]. Therefore, no nuclear plants will be impacted by the Liquefaction Facility or GTP construction or operation or by transportation to or from the Liquefaction Facility or GTP.

11.1.1.8 State Agencies

The Project is currently consulting with state and local agencies on various topics related to the Project. Results of those consultations will be provided to FERC, as applicable.

[2] https://www.nrc.gov/info-finder/region-state/alaska.html

11.1.1.9 Agency Consultation

Discussions were held with multiple federal agencies regarding various Project details, some of which are contained in this Resource Report. Table 11.1.1-1 includes meetings and correspondence where reliability and safety were raised.

A list of the required federal permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of public, agency, and stakeholder engagement is provided in Resource Report No. 1, Appendix D.

TABLE 11.1.1-1

Summary of Consultations with Federal and State Agencies

Date	Organizations	Topic(s)
15-Apr-14	U.S. Coast Guard (USCG)	Letter of Intent and Preliminary Waterway Suitability Assessment (WSA) Planning
17-Oct-14	USCG; North Slope Gas Commercialization Permitting Coordination Team	WSA Planning and Stakeholder List
6-Feb-15	USCG; North Slope Gas Commercialization Permitting Coordination Team	WSA Port Characterization Report Review
13-Feb-15	U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA)	Project Introduction and Overview
2-3 - Mar-15	PHMSA	Pipeline Overview
31-Mar-15	AcuTech; Alaska Department of Environmental Conservation (ADEC); Alaska Department of Fish and Game (ADF&G); Alaska Department of Military and Veteran's Affairs; ConocoPhillips; Cook Inlet Regional Citizens Advisory Council (CIRCAC); Crowley Maritime Corporation; Kenai Peninsula Borough (KPB); National Oceanic and Atmospheric Administration (NOAA); Nuka Research and Planning Group; Port of Homer; TOTE (Totem Ocean); United Cook Inlet Drift Fishermen''s Association (UCIDA); United States Army Corps of Engineers (USACE); USCG; U.S. Department of Homeland Security (USDHS); exp Energy Services (exp)	WSA Information Meeting – Technical Assessment Group
1-Apr-15	Alaska Department of Natural Resources (ADNR), Division of Mining, Land, and Water; AcuTech; Chickaloon Native Village; Matanuska-Susitna Borough; Nuka Research and Planning Group; Port Graham Tribal Council; Matanuska-Susitna Borough Port Mackenzie; Municipality of Anchorage Port of Anchorage; Southwest Alaska Pilots Association (SWAPA); USCG; exp	WSA Information Meeting – Stakeholder Representatives
23-24 -Apr-15	PHMSA	Offshore Pipeline Design; FERC Requirements; Materials, Testing and Full-Scale Testing; Special Permits (SPs)
24-Apr-15	UCIDA	Email from UCIDA for WSA – Considerations for LNGC Transit in Drift Net Fishing Areas
28-Apr-15	PHMSA	Correspondence with PHMSA regarding Crack Arrestor Spacing
29-Apr-15	FERC; PHMSA	Liquefaction Facility Overview

TABLE 11.1.1-1

Summary of Consultations with Federal and State Agencies

Date	Organizations	Topic(s)
30-Apr-15	AcuTech; Nuka Research and Planning Group; USCG; exp	Maritime Safety and Security Review
8-May-15	AcuTech; USCG	Preparation for WSA Workshop
12-May-15 to 14-May-15	AcuTech; ADEC; ADF&G; ADNR; Amergent Techs; City of Homer; ConocoPhillips; CIRCAC; Crowley Maritime Corporation; Hartley Marine; KPB; Port of Homer; SWAPA; ADNR, State Pipeline Coordinator's Section (SPCS); TOTE; UCIDA; USCG; USDHS; exp	WSA – Technical Risk Assessment
3-Jun-15	Federal Energy Regulatory Commission (FERC); State of Alaska DC Office	FERC Requirements and Hazard Analysis for Gas Treatment Plant (GTP)
5-Jun-15	Alaska State Fire Marshal's Office	Project Overview and Introductions
11-Jun-15	PHMSA	Strain-Based Design (SBD) Special Conditions; Updates on studies and work programs
24-Jun-15	ADEC; ADF&G; ADNR; ADOT&PF; North Slope Borough (NSB); ADNR, SPSC; USACE; U.S. Department of the Interior; U.S. Environmental Protection Agency (EPA); United States Fish and Wildlife Service (USFWS)	Multi-Agency Pipeline Construction Execution Workshop
9-Jul-15	FERC; PHMSA	LNG Vapor Dispersion Modeling Assumptions and LNG Storage Tank Design
10-Jul-15	PHMSA	Overview of SBD welding, to include scale test fabrication. Comments to SBD Special Permit Conditions.
29-Jul-15	Det Norske Veritas (U.S.A.), Inc; PHMSA	SBD Inspection Test Plan Review
30-Jul-15	PHMSA	PHMSA SP Filing Process and Schedule
12-Aug-15	ADNR, Division of Mining, Land, and Water; ADNR, Division of Mining, Land, and Water, Water Resources; ADNR, SPSC; ADEC; ADF&G; ADNR; Alaska Department of Health & Social Services (ADHSS); FERC; National Marine Fisheries Service (NMFS); Natural Resources Group (NRG); NSB; North Slope Gas Commercialization Permitting Coordination Team; ADNR, SPSC; USACE; USCG); United States Environmental Protection Agency (EPA); United States Fish and Wildlife Service (USFWS); exp Energy Services	GTP Footprint Workshop
19-Aug-15	ADNR, Commissioner's Office; ADEC; ADF&G; ADHSS; ADNR; FERC; IntecSea; KPB; Matanuska-Susitna Borough; NMFS; NRG; NewFields; North Slope Gas Commercialization Permitting Coordination Team; ADNR, SPSC; USFWS; USACE; EPA; exp	Cook Inlet Routing and Construction Review
20-Aug-15	PHMSA	Line Pipe Dimensional Test Results; SBD Line Pipe Requirements; High-Integrity Coating Systems; Shielding
2-Sep-15	ADNR, Commissioner's Office; ADNR, Division of Mining, Land, and Water, Water Resources; ADEC; ADF&G; ADHSS; ADNR; ADOT&PF; BP; FERC; KPB; NMFS; NRG; North Slope Gas Commercialization Permitting Coordination Team; ADNR, SPSC; PHMSA; USFWS; USACE; USCG; EPA; USFWS; exp	Liquefaction Facility (LNG Plant and Marine Terminal) Footprint Review

TABLE 11.1.1-1

Summary of Consultations with Federal and State Agencies

Date	Organizations	Topic(s)
16-Sep-15	ADNR; North Slope Gas Commercialization Permitting Coordination Team	GTP Exclusion Zone
21-Sep-15	PHMSA	SBD Line Pipe Requirements
22-Sep-15	Det Norske Veritas (U.S.A.), Inc; PHMSA	Small scale testing of test pipe
6-Oct-15	USCG	Introduction to pipe-in-pipe technology for the USCG
14-15 Oct-15	IntecSea; PHMSA	SBD SP; TAPS Lessons Learned; Offshore Pipeline Design; Multi-Layer Coatings
16-Oct-15	PHMSA	Correspondence regarding offshore pipeline cover
19-Oct-15	AcuTech; USCG	Review of Draft Follow-on WSA
30-Oct-15	PHMSA	Correspondence regarding Pipeline SP for SBD
5-6 Nov-15	Det Norske Veritas (U.S.A.), Inc; PHMSA	Introduction to SBD Pipeline Technology developed by ExxonMobil proposed for use in Strain Based Design SPs
5-Nov-15	PHMSA	Crack Arrestor Spacing SP and Thermal Radiation Analysis
24-Nov-15	Det Norske Veritas (U.S.A.), Inc; PHMSA	Correspondence regarding small scale test results
2-Dec-15	CRES; Rosen; PHMSA	Discuss pipeline coatings, in-line-inspection capabilities for strain monitoring, results of main line block valve spacing study, geotechnical program overview and SBD SP Language and Conditions
11-Dec-15	Det Norske Veritas (U.S.A.), Inc; PHMSA	Review Compressive Strain Capacity Finite Element Analysis modeling effort
16-Dec-15	PHMSA	LNG Year-end Review
16-Dec-15	PHMSA	Pipeline Year-end Review
25-26 Jan-16	Det Norske Veritas (U.S.A.), Inc; PHMSA	SBD Independent Third-Party Review report out and SP Filing Considerations
3-Feb-16	Det Norske Veritas (U.S.A.), Inc; PHMSA	Multi-Layer Coatings Independent Third-Party Review report out
22-Feb-16	USCG	Correspondence regarding alternative compliance per 33 C.F.R. 127
22-Feb-16	PHMSA	Review SBD SP Conditions and FERC/National Environmental Policy Act (NEPA) Filing Requirements for SPs

TABLE 11.1.1-1

Summary of Consultations with Federal and State Agencies

Date	Organizations	Topic(s)
15-Mar-16	PHMSA	Review Crack Arrestor and Main Line Block Valve SP analysis and discuss SBD Design Change Process
1-Apr-16	ADOT&PF; PHMSA	Review Mainline design and PHMSA Pipeline SP, with emphasis on Main Line Block Valve (MLBV) and Crack Arrestor Spacing and Proximity to Existing Bridge Infrastructure
19-Apr-16	ADNR; FERC; North Slope Gas Commercialization Permitting Coordination Team; PHMSA	PHMSA Pipeline SP and Environmental Overview
26 May-16	PHMSA	Review Multi-Layer Coatings SP and Environmental Information
13-Jun-16	Alyeska Pipeline Service Company; Bureau of Land Management (BLM), Alaska State Office; BLM; U.S. BLM Office of Pipeline Monitoring (JPO)	Overview of Alaska LNG and TAPS joint engineering study
23-Jun-16	USCG	USCG Sector Anchorage Issues Pipe-in-Pipe Authorization
28-Jun-16	AGDC; FERC, Division of Gas – Environment and Engineering Office of Energy Projects; FERC; PHMSA	Liquefaction Facility Update
28-Jun-16	USCG	Phone Call to Determine Status of USCG Review and Letter of Recommendation for Trestle Fire Hydrant
11-Jul-16	PHMSA	PHMSA Pipeline MLBV and Crack Arrestor Spacing SPs and TAPS Thermal Radiation Evaluation
21-Jul-16	PHMSA	PHMSA Pipe-in-Pipe Requirements
26-Aug-16	PHMSA	Acceptability of Concrete LNG Storage Tank Design
16-Dec-16	PHMSA	Project Year End Update
9-Feb-17	Department of Defense	DOD Siting Clearinghouse
21-Mar-17	PHMSA	Update on design spill package, special permits, and equivalencies.

11.2 LIQUEFACTION FACILITY HAZARD IDENTIFICATION

11.2.1 Hazardous Materials

11.2.1.1 LNG

Liquefied natural gas is natural gas in its liquid state that has been cooled at atmospheric pressure to 260 Degrees Fahrenheit ("ºF") below zero. Similar to natural gas in its vapor state, LNG is odorless, colorless, non-corrosive and nontoxic and as a cryogenic fluid, it is hazardous to unprotected skin. With a density of approximately 26.5 pounds per cubic foot ("lb/ft^3"), LNG is neither flammable nor explosive.

Liquefied natural gas vaporizes rapidly on contact with any surface that is at a temperature greater than the LNG itself. Under precise conditions, a Rapid Phase Transition (RPT) could occur. The LNG vapors are flammable in LNG vapor to air ratios of 5 to 15 percent. Unlike heavier hydrocarbons (such as propane), natural gas and LNG vapors do not have the potential for the explosion of unconfined vapor clouds. LNG vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure, potentially causing asphyxiation if a person were to enter a high concentration area. The primary component of LNG is methane. Table 11.2.1-1 summarizes the properties of methane.

TABLE 11.2.1-1

Properties of Methane

Property	Value			Notes
Melting temperature	-296.46 °F [a]			At normal pressure (14.7 psia)
Boiling temperature	-258.68 °F [a]			At normal pressure (14.7 psia)
Flash point	-306.7 °F [b]			Closed cup
Lower flammability limit	5.0 percent [a]			In air by percent volume
Upper flammability limit	15.0 percent [a]			In air by percent volume
Auto-ignition temperature	548.6 °F [b]			--
Heat of combustion	55.5 MJ/kg [a]			At 60 °F
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in process	-258 °F	Varies	482 °F	Includes LNG and natural gas
Operating temperatures in storage	TBD	-258 °F	TBD	Min/Max to be determined by vendor.
Operating pressures in process	0.7 psig	Varies	635 psig	LNG
	0.7 psig	Varies	1,035 psig	Natural gas
Operating pressures in storage	TBD	0.7 psig	TBD	Min/Max to be determined by vendor.
Operating densities in process	TBD	Varies	TBD	LNG. Min/Max to be determined by vendor.
	TBD	Varies	TBD	Natural gas. Min/Max to be determined by vendor.
Operating densities in storage	TBD	28.4 lb/ft^3	TBD	LNG. Min/Max to be determined by vendor.
Property	**Details**			
Aphyxiant and toxic properties	Simple asphyxiant, non-toxic [c]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen [c]			
Corrosion rate of skin	N/A			
Corrosion rate of metal surfaces	N/A			

[a] Gas Processors Association, 2012
[b] Airgas, 2015
[c] U.S. National Library of Medicine, 2015
lb/ft^3 pounds per cubic foot
MJ/kg megajoule per kilogram
N/A not applicable
ppm parts per million
psia pounds per square inch absolute
psig pounds per square inch gauge

11.2.1.2 Refrigerant

Liquid refrigerants (propane and mixed refrigerant) will be provided in sufficient volumes to perform chilling and liquefaction functions at the Liquefaction Facility. Tables 11.2.1-2, 11.2.1-3 and 11.2.1-4 summarize the properties of the refrigerants.

TABLE 11.2.1-2

Properties of Propane

Property	Value			Notes
Melting temperature	-305.7 °F [a]			At normal pressure (14.7 psia)
Boiling temperature	-258.7 °F [a]			At normal pressure (14.7 psia)
Flash point	-155.2 °F [b]			Closed cup
Lower flammability limit	1.8 percent [a]			In air by percent volume
Upper flammability limit	8.4 percent [a]			In air by percent volume
Auto-ignition temperature	548.6 °F [a]			--
Heat of combustion	50.4 MJ/kg			
Property	**Min**	**Normal**	**Max**	**Notes**
Capacity in Storage	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Operating temperatures in storage	-30 °F	37.4 °F	84 °F	
Operating pressures in process	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Operating pressures in storage	5.7 psig	60.5 psig	137.7 psig	
Operating densities in process	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Operating densities in storage	TBD	Varies	TBD	Min/Max to be determined by vendor.
Property	**Details**			
Asphyxiant and toxic properties	Simple asphyxiant, non-toxic [b]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen [b]			
Corrosion rate of skin	N/A			
Corrosion rate of metal surfaces	N/A			

[a] Airgas, 2015
[b] U.S. National Library of Medicine, 2016

TABLE 11.2.1-3

Properties of Ethane

Property	Value	Notes
Melting temperature	-305.7 °F [a]	At normal pressure (14.7 psia)
Boiling temperature	-258.7 °F [a]	At normal pressure (14.7 psia)
Flash point	-155.2 °F [a]	Closed cup
Lower flammability limit	2.9 percent [a]	In air by percent volume

Upper flammability limit	13 percent [a]			In air by percent volume
Auto-ignition temperature	548.6 °F [a]			--
Heat of combustion	51.9 MJ/kg [b]			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in process	N/A	N/A	N/A	Ethane does not exist on its own in the process.
Operating temperatures in storage	-16	Varies	-6	
Operating pressures in process	N/A	N/A	N/A	Ethane does not exist on its own in the process.
Operating pressures in storage	TBD	390.3	TBD	Min/Max to be determined by vendor.
Operating densities in process	N/A	N/A	N/A	Ethane does not exist on its own in the process.
Operating densities in storage	TBD	Varies	TBD	Min/Max to be determined by vendor.
Property	**Details**			
Asphyxiant and toxic properties	Simple asphyxiant, non-toxic [c]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen [c]			
Corrosion rate of skin	N/A			
Corrosion rate of metal surfaces	N/A			

[a] Airgas, 2016
[b] National Institute of Standards and Technology, 2016
[c] U.S. National Library of Medicine, 2016

TABLE 11.2.1-4

Properties of Butane

Property	**Value**			**Notes**
Melting temperature	-216.4 °F [a]			At normal pressure (14.7 psia)
Boiling temperature	31.1 °F [a]			At normal pressure (14.7 psia)
Flash point	-7.6 °F [a]			Closed cup
Lower flammability limit	1.8 percent [a]			In air by percent volume
Upper flammability limit	8.4 percent [a]			In air by percent volume
Auto-ignition temperature	689 °F [a]			--
Heat of combustion	49.5 MJ/kg [b]			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in process	N/A	N/A	N/A	Butane does not exist on its own in the process.
Operating temperatures in storage	N/A	N/A	N/A	Project does not include storage
Operating pressures in process	N/A	N/A	N/A	Butane does not exist on its own in the process.
Operating pressures in storage	N/A	N/A	N/A	Project does not include storage
Operating densities in process	N/A	N/A	N/A	Butane does not exist on its own in the process.
Operating densities in storage	N/A	N/A	N/A	Project does not include storage
Property	**Details**			

TABLE 11.2.1-4

Properties of Butane

Asphyxiant and toxic properties	Simple asphyxiant, non-toxic [c]
Maximum concentration of toxic component in process	N/A
Asphyxiation concentration	Below 6 percent oxygen [c]
Corrosion rate of skin	N/A
Corrosion rate of metal surfaces	N/A

[a] Airgas, 2015
[b] National Institute of Standards and Technology, 2016
[c] U.S. National Library of Medicine, 2016

TABLE 11.2.1-5

Properties of Mixed Refrigerant

Property	Min	Normal	Max	Notes
Operating Temperatures in Process	N/A	varies	N/A	Vendor confidential information, refer to heat & material balances
Operating Pressures in Process	N/A	varies	N/A	Vendor confidential information, refer to heat & material balances
Operating Densities in Process	N/A	varies	N/A	Vendor confidential information, refer to heat & material balances

11.2.1.3 Nitrogen

The Liquefaction Facility will use nitrogen for various purposes. Nitrogen is a non-toxic, odorless, colorless, non-corrosive and nonflammable material and as a cryogenic fluid, it is hazardous to unprotected skin. Liquid nitrogen vaporizes rapidly on contact with any surface that is at a temperature higher than the nitrogen itself. Nitrogen vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure, potentially causing asphyxiation if a person were to enter a high concentration area. Table 11.2.1-5 summarizes the properties of Nitrogen.

TABLE 11.2.1-6

Properties of Nitrogen

Property	Value			Notes
Melting temperature	-346.0 °F[a]			At normal pressure (14.7 psia)
Boiling temperature	-320.4 °F [a]			At normal pressure (14.7 psia)
Flash point	N/A			Closed cup
Lower flammability limit	N/A			In air by percent volume
Upper flammability limit	N/A			In air by percent volume
Auto-ignition temperature	N/A			
Heat of combustion	N/A			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in storage	TBD	TBD	TBD	To be determined by vendor

TABLE 11.2.1-6

Properties of Nitrogen

Property	Value			Notes
Operating pressures in storage	TBD	TBD	TBD	To be determined by vendor
Operating densities in storage	TBD	TBD	TBD	To be determined by vendor
Property	**Details**			
Asphyxiant and toxic properties	Simple asphyxiant, non-toxic[b]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen[b]			
Corrosion rate of skin	N/A			
Corrosion rate of metal surfaces	N/A			

[a] Gas Processors Association, 2012
[b] U.S. National Library of Medicine, 2016

11.2.1.4 Condensates

Heavy Hydrocarbons ("HHC") are present in the feed gas and will be removed during the liquefaction as product streams and condensates. HHC composition changes as the feed gas composition changes and as products are removed during fractionation; therefore, its exact density and flammability ranges are variable. The HHCs are flammable and may have the potential for overpressures if ignited in a confined area.

HHC will vaporize rapidly on contact with any surface that is at a temperature higher than the HHC itself. HHC vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure, potentially causing asphyxiation if a person were to enter a high concentration area.

Table 11.2.1-7 lists the properties of the condensate stream to storage.

TABLE 11.2.1-7

Properties of Condensate Stream

Property	Value			Notes
Melting Temperature	Varies			At normal pressure (14.7 psia)
Boiling Temperature	Varies			At normal pressure (14.7 psia)
Flash Point	Varies			Closed Cup
Lower Flammability Limit	Varies			In air by percent volume
Upper Flammability Limit	Varies			In air by percent volume
Auto-Ignition Temperature	Varies			--
Heat of Combustion	Varies			--
Property	**Min**	**Normal**	**Max**	**Notes**
Capacity in Storage	N/A	357,234 gal	N/A	

TABLE 11.2.1-7

Properties of Condensate Stream

Operating Temperatures in Condensate Storage	-30	Varies	84	
Operating Pressures in Condensate Storage	0.466 psig	Varies	8.86 psig	
Operating Densities in Condensate Storage	TBD	Varies	TBD	
Concentration in Process	N/A	Varies	N/A	Condensates include multiple components
Operating Temperatures in Process	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Operating Pressures in Process	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Operating Densities in Process	N/A	Varies	N/A	Vendor confidential information, refer to heat and material balances
Property	**Details**			
Asphyxiant Properties	Simple asphyxiant [a]			
Asphyxiation Concentration	Below 6% Oxygen [a]			
Toxic Properties	Certain components have toxic properties [b]			
Corrosion Rate of Skin	N/A			
Corrosion Rate of Metal Surfaces	N/A			

[a] U.S. National Library of Medicine, 2016
[b] U.S. Environmental Protection Agency ("USEPA"), 2017

11.2.1.5 Diesel

Diesel will be used to fuel the firewater pumps, air compressors, and plant vehicle use. Diesel is considered a combustible material. Table 11.2.1-8 summarizes the properties of diesel.

TABLE 11.2.1-8

Properties of Diesel

Property	Value	Notes
Boiling temperature	338 °F [a]	At normal pressure (14.7 psia)
Flash point	125°F [a]	Closed cup
Lower flammability limit	0.6 percent [a]	In air by percent volume
Upper flammability limit	7.5 percent [a]	In air by percent volume
Auto-ignition temperature	494°F [a]	
Heat of combustion	46 MJ/kg [b]	
Property	**Details**	
Asphyxiant and Toxic Properties	Harmful if swallowed [a]	
Asphyxiation Concentration	N/A	
Corrosion Rate of Skin	Irritant (Category 2) [a, b]	
Corrosion Rate of Metal Surfaces	Non-corrosive	

TABLE 11.2.1-8

Properties of Diesel

[a] Hess Corporation, 2012.
[b] Oak Ridge National Laboratory, 2011

11.2.1.6 Mercury

Mercury may be present in very small quantities in the feed gas. Mercury is reactive with aluminum which is used as the material of construction for the heat exchangers in the liquefaction system. Therefore, mercury will be removed via a mercury guard bed during the pretreatment process. Mercury is considered an environmentally hazardous material.

11.2.2 Process Hazards

11.2.2.1 Hazard Identification and Analyses

A Hazard Identification and Analyses ("HAZID") has been performed on the Liquefaction Facility engineering design by a group of qualified individuals. The objective of a HAZID is to perform a high-level, systematic analysis to identify potential hazards in the early stage of a project's design that can produce undesirable consequences through the occurrence of an incident by evaluating the materials, system, process and plant design.

The HAZID is based on the Liquefaction Facility's plot plan, process flow diagrams and heat and material balances, which are included in Appendix E of Resource Report No. 13. The results of the HAZID are included in Appendix G.1 of Resource Report No. 13. As a result of the HAZID, recommendations have been made to improve the engineering design to minimize the potential for a hazardous event. The recommendations from the HAZID and their implementation are also included in Appendix G.1 of Resource Report No. 13.

The following materials have been evaluated in the HAZID.

11.2.2.2 LNG

The principal hazards of LNG result from its cryogenic temperature (-260°F), flammability of vapors, potential for loss of containment and vapor dispersion characteristics. Natural gas is one of the most desirable sources of clean energy and has an excellent safety record; however, specific aspects of LNG safety must be taken into account. The inherent safety advantages of natural gas, such as buoyancy, a narrow range of flammability limits and high ignition temperature, are partially offset by the large storage volumes, potential for releases and low storage temperature of LNG.

Vapor resulting from the vaporization of LNG has a specific gravity of 1.5 and will initially behave as a liquid in that it will seek the lowest point near the LNG vaporization source (e.g., a release or spill). When warmed to approximately -160°F, LNG vapors become buoyant and will rise and rapidly disperse into the atmosphere. Initial vaporization following a release of LNG produces a large flow of vapor for a short period as the LNG temperature elevates to levels above -160°F. The distance that the vapor will travel depends on many variables, including the volume of the initial release or spill, its duration, the wind velocity and direction, terrain, atmospheric temperature and humidity. Flammable mixtures of LNG vapor will initially extend downwind for a short period. Therefore, the zone of flammability will be confined to the immediate vicinity of the release or spill. Although LNG vapor has no odor or color, its low temperature will cause condensation of water vapor in the air, forming a visible white cloud.

The LNG presents a low temperature hazard in the event of an LNG spill, which could result from failure of connected process lines, flanged joint leaks and pipe breaks on equipment containing LNG. All piping for the Liquefaction Facility will be designed for cryogenic service and LNG process and transfer systems will minimize the potential for leaks and failures. Equipment that may be in contact with pooled LNG will be designed to withstand the cold contact or protected by cryogenic insulation to prevent embrittlement. A spill containment system will be provided to route spills away from process equipment and to an impoundment sump. Any LNG in the spill containment system will warm over time and vaporize, producing a cold vapor cloud above or around the spill containment system. The insulated concrete design of the spill containment system decreases this vaporization rate. High expansion foam is provided at impoundment sumps, which also works to decrease the vaporization rate. Firewater monitors located at strategic places around the Liquefaction Facility can help control vapor cloud movement.

Exceedance of the spill containment area could result in the spread of LNG to areas not designed for cryogenic temperatures. In order to mitigate this hazard, LNG impoundment sumps are sized to contain the greatest flow capacity from a single pipe for ten minutes in the local area plus piping inventory and pump runout or the largest piece of equipment containing LNG. For the marine transfer line, a pipe is pipe system is used for spill containment and the conventional piping in the marine area is provided with an LNG impoundment sump sized for a 1 minute spill duration.

Vapor cloud migration may result in ingestion of the gas into the air intake of an enclosed building. At high concentrations (<6 percent Oxygen), this may present an asphyxiation hazard. While LNG vapors do not pose an overpressure hazard in an unconfined space, if the ingested vapor cloud—now in a confined space—reaches a concentration within the flammability limits and contacts an ignition source, an overpressure could occur. The overpressure event can create a pressure wave that can damage buildings, structures and process equipment. Most Project equipment is located outdoors to prevent the accumulation of gas, and air intakes for fired equipment and building ventilation are spaced away from sources of vapor. Process overpressures will be mitigated by having equipment designed in accordance with American Society of Mechanical Engineers ("ASME") codes and designing relief equipment to operate below design pressures. Additionally, gas detection at the air intakes will shut down affected equipment. These measures prevent the escalation of events associated with a spill of LNG.

When a pressurized leak occurs, the liquid jet will vaporize and, depending on the operating condition, a portion of the jet could rainout and pool on the ground. The vapor cloud formation associated with a spill of LNG presents a radiant heat hazard if the concentration falls within the flammability range and an ignition source is encountered. Radiant heat from a jet fire or pool fire could affect nearby equipment or personnel. A flash fire could also occur if there is a delayed ignition of the vapor cloud in an open area. This can result in a brief, high heat release that could ignite secondary fires or impact nearby equipment or personnel. The spill containment system channels spills away from process equipment, and the impoundment sumps are located away from equipment, structures and buildings. Dry chemical systems provided around the Liquefaction Facility can be used to extinguish LNG fires, and water spray systems can be used to cool adjacent equipment. Fireproofing on equipment and structures that are designed to withstand contact with radiant heat further reduces risk and prevents cascading failures.

Cascading events, including the failure of critical equipment or structures, may introduce a hazard to the Liquefaction Facility. However, the mitigation features presented above minimize the potential for the escalation of an event. As an additional measure of protection, an Emergency Response Plan ("ERP") will be developed for the Liquefaction Facility which ensures that any emergencies are handled quickly and efficiently.

11.2.2.3 Refrigerant

The principal hazards of the refrigerants result from their cryogenic temperature, flammability of vapors, potential loss of containment and vapor dispersion characteristics. Vapor resulting from the vaporization of a liquid Mixed Refrigerant ("MR") or refrigerant component spill has a specific gravity that is larger than air. It will initially behave as a liquid in that it will seek the lowest point near the refrigerant vaporization source (e.g., a release or spill). When warmed to approximately -160°F, refrigerant vapors become buoyant and will rise and rapidly disperse into the atmosphere. Initial vaporization following a release of liquid refrigerant produces a large flow of vapor for a short period as the refrigerant temperature elevates to levels above -160°F. The distance that the vapor will travel depends on many variables, including the volume of the initial release or spill, its duration, the wind velocity and direction, terrain, atmospheric temperature and humidity. Flammable mixtures of refrigerant vapor will initially extend downwind for a short period. Therefore, the zone of flammability will be confined to the immediate vicinity of the release or spill. Although refrigerant vapor has no odor or color, its low temperature will cause condensation of water vapor in the air, forming a visible white cloud.

Refrigerant presents a low temperature hazard in the event of a liquid refrigerant spill, which could result from failure of connected process lines, flanged joint leaks and pipe breaks on equipment containing liquid refrigerant. All liquid refrigerant piping for the Liquefaction Facility will be designed for cryogenic service and refrigerant process and transfer systems will minimize the potential for leaks and failures. Equipment that may be in contact with pooled refrigerant will be designed to withstand the cold contact or protected by cryogenic insulation to prevent embrittlement. A spill containment system will be provided to route spills away from process equipment and to an impoundment sump. Any liquid refrigerant in the spill containment system will warm over time and vaporize, producing a cold vapor cloud above or around the spill containment system. The insulated concrete design of the spill containment system decreases this vaporization rate. High expansion foam is provided at impoundment sumps, which also works to decrease the vaporization rate. Firewater monitors located at strategic places around the Liquefaction Facility can help control vapor cloud movement.

Exceedance of the spill containment area could result in the spread of liquid refrigerant to areas not designed for cryogenic temperatures. In order to mitigate this hazard, LNG impoundment sumps are sized to contain the greatest flow capacity from a single pipe for ten minutes in the local area plus piping inventory and pump runout or the largest piece of equipment containing LNG, which is larger than any potential spill of refrigerant.

Vapor cloud migration may result in ingestion of the gas into the air intake of an enclosed building. At high concentrations (<6 percent Oxygen), this may present an asphyxiation hazard. While vapors do not pose an overpressure hazard in an unconfined space, if the ingested vapor cloud—now in a confined space—reaches a concentration within the flammability limits and contacts an ignition source, an overpressure could occur. The overpressure event can create a pressure wave that can damage buildings, structures and process equipment. Most project equipment is located outdoors to prevent the accumulation of gas, and air intakes for fired equipment and building ventilation are spaced away from sources of vapor. Process overpressures will be mitigated by having equipment designed in accordance with ASME codes and designing relief equipment to operate below design pressures. Additionally, gas detection at the air intakes will shut down affected equipment. These measures prevent the escalation of events associated with a spill of refrigerant.

When a pressurized leak occurs, the liquid jet will vaporize and, depending on the operating condition, a portion of the jet could rainout and pool on the ground. The vapor cloud formation associated with a spill of liquid refrigerant presents a radiant heat hazard if the concentration falls within the flammability range and an ignition source is encountered. Radiant heat from a jet fire or pool fire could affect nearby equipment or personnel. A flash fire could also occur if there is a delayed ignition of the vapor cloud in an open area. This can result in a brief, high heat release that could ignite secondary fires or impact nearby equipment or personnel. The spill containment system channels spills away from process equipment, and the impoundment sumps are located away from equipment, structures and buildings. Dry chemical systems provided around the Liquefaction Facility can be used to extinguish refrigerant fires, and water spray systems can be used to cool adjacent equipment. Fireproofing on equipment and structures that are designed to withstand contact with radiant heat further reduces risk and prevents cascading failures.

Cascading events, including the failure of critical equipment or structures, may introduce a hazard to the Liquefaction Facility. However, the mitigation features presented above minimize the potential for the escalation of an event. As an additional measure of protection, an ERP will be developed for the Liquefaction Facility which ensures that any emergencies are handled quickly and efficiently.

11.2.2.4 Nitrogen

Nitrogen presents a low temperature hazard in the event of a leak of cryogenic nitrogen. However, nitrogen has a boiling point of -320°F, so even if the leak is of the liquid phase, it will vaporize rapidly and mix with the surrounding air.

While nitrogen is non-toxic, it is classified as a simple asphyxiate and can cause asphyxiation when concentrations are sufficient to reduce oxygen levels below 6 percent. Low oxygen detectors will be present near the nitrogen package to detect any leak and alert personnel.

Cascading events, including the failure of critical nitrogen equipment or structures, may introduce a hazard to the Liquefaction Facility. However, the mitigation features presented above minimize the potential for the escalation of an event. As an additional measure of protection, an ERP will be developed for the Liquefaction Facility which ensures that any emergencies are handled quickly and efficiently.

11.2.2.5 Heavy Hydrocarbons

Principal hazards associated with HHC result from its flammability, potential loss of containment, vapor dispersion characteristics and potential for overpressures if ignited.

The HHC presents a low temperature hazard in the event of an HHC spill in the Process Area, which could result from failure of connected process lines, flanged joint leaks and pipe breaks on equipment containing HHC. All HHC piping for the Liquefaction Facility will be designed for cryogenic service and HHC process and transfer systems will minimize the potential for leaks and failures. Equipment that may be in contact with pooled HHC will be designed to withstand the cold contact or protected by cryogenic insulation to prevent embrittlement. A spill containment system will be provided to route spills away from process equipment and to a local impoundment sump. Any HHC in the spill containment system will warm over time and vaporize, producing a cold vapor cloud above or around the spill containment system. The insulated concrete design of the spill containment system decreases this vaporization rate. High expansion foam is provided at impoundment sumps, which also works to decrease the vaporization rate. Firewater monitors located at the impoundment sumps can help control vapor cloud movement. Exceedance of the spill containment area could result in the spread of HHC to areas not designed for cryogenic temperatures. In order to mitigate this hazard, impoundment sumps are sized to contain the greatest flow capacity from a single pipe for ten minutes in the local area plus piping inventory and pump runout or the largest piece of equipment containing LNG, which exceeds the HHC flow rates.

Vapor cloud migration may result in ingestion of the gas into the air intake of an enclosed building. At high concentrations (<6 percent oxygen), this may present an asphyxiation hazard. HHC vapors may pose an overpressure hazard if it reaches a concentration within the flammability limits and contacts an ignition source. The overpressure event can create a pressure wave that can damage buildings, structures and process equipment. Most equipment is located outdoors to prevent the accumulation of gas, and air intakes for fired equipment and building ventilation are spaced away from sources of vapor. Process overpressures will be mitigated by having equipment designed in accordance with ASME codes and designing relief equipment to operate below design pressures. Additionally, gas detection at the air intakes will shut down affected equipment. These measures prevent the escalation of events associated with a spill of HHC.

When a pressurized leak occurs, the liquid jet will vaporize and, depending on the operating condition, a portion of the jet could rainout and pool on the ground. The vapor cloud formation associated with a spill of HHC presents a radiant heat hazard if the concentration falls within the flammability range and an ignition source is encountered. Radiant heat from a jet fire or pool fire could affect nearby equipment or personnel. A flash fire could also occur if there is a delayed ignition of the vapor cloud in an open area. This can result in a brief, high-heat release that could ignite secondary fires or affect nearby equipment or personnel. The spill containment system channels spills away from process equipment, and the impoundment sumps are located away from equipment, structures and buildings. Dry chemical systems provided around the Liquefaction Facility can be used to extinguish HHC fires, and water spray systems can be used to cool adjacent equipment. Fireproofing on equipment and structures that are designed to withstand contact with radiant heat further reduces risk and prevents cascading failures.

Cascading events, including the failure of critical equipment or structures, introduce a hazard to the Liquefaction Facility. However, the mitigation features presented above minimize the potential for the escalation of an event. As an additional measure of protection, an ERP will be developed for the Liquefaction Facility which ensures that any emergencies are handled quickly and efficiently.

11.2.2.6 Diesel

Diesel is used onsite for fueling the diesel firewater pump and the backup generator. Diesel storage associated with the backup diesel firewater pump will be contained in a double walled container and diesel storage associated with the backup generator will be contained in a double walled container within an enclosure. The diesel equipment is located away from the major process area to reduce the potential for cascading events. Any diesel leaks or spills in the Liquefaction Facility will be contained and disposed of properly. These measures ensure that there is no hazard posed to the public.

11.2.2.7 Mercury

Mercury is removed from the feed gas with a mercury guard bed, which chemically absorbs the mercury to form mercury sulfide. This stable compound remains in the guard bed. The guard bed is disposed of and replaced properly at the end of its life by qualified personnel. These steps ensure that the mercury on site does not have potential for a release and does not pose a hazard to the public.

11.2.3 Marine Transportation Hazards

The USCG has jurisdiction under 33 C.F.R. Part 127 for the "marine transfer area" of every waterfront LNG terminal facility. The "marine transfer area" is defined as the part of the facility handling LNG between the vessel, or where the vessel moors, and the last manifold or valve immediately before the receiving tanks. The regulations provide detailed requirements for safety and security design features, operations and emergency planning, operator training, and maintenance. More than 1,300 transits of LNG marine transports (including LNGCs) have occurred safely in Cook Inlet.

The Energy Policy Act of 2005[3] also requires an Emergency Response Plan (ERP) be prepared in consultation with USCG, as well as state and local agencies, and be approved by FERC prior to any approval to begin construction of the facilities. The ERP "shall include a cost-sharing plan and a description of any direct cost reimbursements that the applicant agrees to provide to any state and local agencies with responsibility for security and safety at the LNG terminal and in proximity to vessels that serve the facility."

A separate facility security assessment would be prepared for the proposed Marine Terminal, as required per 33 C.F.R. Part 105, and prior to facility startup. In accordance with 33 C.F.R. 105.410, the owner or operator of a liquefaction facility shall submit a facility security plan (FSP) for review and approval to the COTP 60 days prior to beginning operations. Once approved, the FSP is valid for five years. Details related to development of a FSP are defined in 33 C.F.R. Part 105, Subpart D.

USCG Letter of Intent and Waterway Suitability Assessment

An LOI and Preliminary WSA for this Project were submitted to the USCG Sector Commander COTP, on May 15, 2014, in accordance with 18 C.F.R. Part 157.21 and 33 C.F.R. Part 127.007.

3 Public Law 109–58—Aug. 8, 2005, Energy Policy Act of 2005

On March 18, 2016, a detailed Follow-on WSA was filed with the USCG COTP and is currently under review.

The Follow-on WSA process was conducted in accordance with Navigation and Vessel Inspection Circular (NVIC) 01-2011 "Guidance Related to Waterfront Liquefied Natural Gas (LNG) Facilities" (NVIC; USCG, 2011). This guidance sets forth a systematic and robust process for reviewing safety and security measures specific to the waterway and includes appropriate technical expertise and stakeholder involvement. NVIC 01-2011 calls for the involvement of a cross-section of public officials and industry responsible for the safe transit of LNG vessels inbound for or outbound from a U.S. port. The COTP may also involve existing ad-hoc committees, such as the Area Maritime Security Committee (AMSC), which is made up of law enforcement and other port stakeholders, to participate in the process.

The purpose of the Follow-on WSA specific to the Project was to:

- Provide a basis for an assessment of the suitability of Cook Inlet from a maritime safety and security standpoint;
- Identify credible navigational safety hazards and security threats associated with the additional LNG marine traffic, along with appropriate risk management strategies, mitigation measures, and resources necessary to mitigate those risks;
- Consider the transportation of LNG through Cook Inlet by LNGCs for both inbound (unladen, in-ballast) and outbound (laden) voyages to and from the proposed Marine Terminal, as per the requirements of 33 C.F.R. 127.007 and NVIC 01-2011[4];
- Provide the local COTP Western Alaska with the information necessary to advise the federal agencies involved in the permitting process that the Liquefaction Facility is appropriate for Cook Inlet; and
- Provide the basis for developing/updating safety and security plans for the transportation of LNG into and out of Cook Inlet and for determining resources required for LNGC transport and operations.

The WSA process considered potential infrastructure vulnerabilities and evaluated specific accidental and security threat scenarios, potential consequences of an LNG release, and existing safety systems and security countermeasures, as well as the need for additional risk management measures for the Marine Terminal. A primary objective of the WSA process was to identify the federal, state, local, and private-sector resources needed to carry out the mitigation measures developed during the assessment.

4 NVIC 01-2011, Comdtpub P16700.4

Follow-on WSA Stakeholder Representation

Two stakeholder groups were identified with the USCG to support the development of the Follow-on WSA. These groups included:

- Technical Assessment Group: Public officials and representatives of local industry who could contribute direct knowledge on some or all of the topics covered in the Follow-on WSA workshop; and
- Stakeholder Representatives: Individuals representing various waterway user interests who could participate in the WSA process through the public comment period, allowing USCG to consider and incorporate public comments.

An initial introduction to the Project and the Follow-on WSA process was provided in a meeting to each group in Anchorage, Alaska; the meeting with the Technical Assessment Group was held on March 31, 2015, and the meeting with the stakeholder representatives was held on April 1, 2015. Table 11.2.3-1 lists the stakeholders invited to the introductory Project meetings.

TABLE 11.2.3-1

Project WSA Stakeholders Invited to Introductory Meeting

Type	Company/Organization
Federal	USFWS, Alaska Maritime Refuge NOAA – Scientific Support Coordinator USACE U.S. Customs and Border Protection U.S. Department of Defense, Joint Base Elmendorf-Richardson U.S. Federal Bureau of Investigation USFWS
State	ADEC, Division of Spill Prevention and Response ADF&G ADNR, Division of Mining, Land and Water Alaska Department of Military & Veteran's Affairs (Division of Homeland Security and Emergency Services) Alaska Marine Highway System (ADOT&PF) Alaska State Troopers
Local Government	Anchorage – Port Director City of Seldovia Homer - Port Director KPB, Central Emergency Services/Nikiski Fire Department KPB – Office of Emergency Management Matanuska-Susitna Borough – Port Mackenzie
Tribal	Chickaloon Native Village Eklutna Native Village Kenaitze Indian Tribe Knik Tribe Nanwalek Indian Reorganization Act Council Native Village of Tyonek Ninilchik Traditional Village Council Port Graham Tribal Council Salamatof Tribal Council

TABLE 11.2.3-1

Project WSA Stakeholders Invited to Introductory Meeting

Type	Company/Organization
	Seldovia Village Tribe
Industry	Agrium ConocoPhillips Alaska Cook Inlet Energy Cook Inlet Tug & Barge Crowley Maritime Corporation Hartley Marin Hilcorp Alaska Horizon Lines Kirby Offshore Offshore Systems Kenai Tesoro TOTE
Organizations	SWAPA Cook Inlet Harbor Safety Committee UCIDA Homer Charter Association Cook Inlet Aquaculture Association CIRCAC

In addition to the introductory meeting, the Technical Assessment Group participated in the Follow-on WSA workshop, conducted May 12–14, 2015, in Anchorage, Alaska. The workshop was a participatory process whereby those responsible for engineering design, operational decisions, security, safety, and emergency response for various organizations in Cook Inlet had an opportunity to examine the risks in a collaborative manner and provide meaningful input to the process. The risk assessment process used by the team followed an industry standard risk assessment methodology (as further described in Section 11.4.2.2) and provided the participants with the information required for decision-making. The workshop included representatives from federal and state of Alaska departments and agencies, representatives of the Project team, the Port of Homer, local emergency responders, local industries, the Kenai Peninsula Borough (KPB), representatives of the local marine pilots association, and USCG. Table 11.2.3-2 lists the participants in the Follow-on WSA workshop.

TABLE 11.2.3-2

Project WSA Technical Assessment Group

Company/Agency
AcuTech
ADEC
ADNR/SPCS
ADF&G, Habitat Division
Alaska LNG Project
Amergent Techs
CIRCAC
ConocoPhillips
Crowley

TABLE 11.2.3-2

Project WSA Technical Assessment Group

Company/Agency
exp
Harley Marine Services
USDHS
KPB
Nikiski Fire Department
Nuka Research
Port of Homer
State of Alaska
State of Alaska – Homeland Security
SWAPA
TOTE
UCIDA
USCG Sector Anchorage

Follow-on WSA Risk Assessment Methodology

NVIC 01-2011 Enclosure 2, "Guidance on Conducting a WSA for LNG Marine Traffic," was followed to complete the Follow-on WSA. The American National Standards Institute (ANSI)/American Petroleum Institute (API) Standard 780 Standard Risk Assessment (SRA) Methodology was the basic approach used to assess the safety and security risks. The ANSI/API Standard 780 aligns with the requirements of NVIC 01-2011, and includes the following steps:

- Step 1 Characterization: Analysis of site/operation criticality and prioritization;
- Step 2 Scenario Development: Develop safety scenarios and security threats;
- Step 3 Risk Assessment: Define the severity of the scenarios and develop the safety mitigation measures and security countermeasures;
- Step 4 Risk Evaluation: Determination of the risk level and comparison to risk criteria; and
- Step 5 Risk Treatment: Development of recommendations to manage risk.

The Follow-on WSA Technical Assessment Group considered safety and security scenarios specified in NVIC 01-2011 along specific segments of the LNGC route, and evaluated the potential causes of accidental or intentional events, the contributing factors to the likelihood of occurrence given the adequacy of safety and security layers for each scenario, and the potential consequences of the events. Each scenario was risk ranked, and the WSA Technical Assessment Group considered the need for additional risk management measures to mitigate the risks. Recommendations were made to further reduce the likelihood or consequences as appropriate. At a minimum, each of the USCG recommended risk management measures from NVIC 01-2011 were considered.

Follow-on WSA Conclusions and Recommendations

The Follow-on WSA Technical Assessment Group concluded that additional LNGC operations in Cook Inlet associated with this Project were feasible with incorporation of certain recommendations prior to initiation of LNGC operations in the waterway. The required safety provisions of operations are well understood and the current Cook Inlet facilities, safety-related requirements, and procedures are adequate to manage the additional LNGC transits and new Marine Terminal facilities proposed by the Project. This is illustrated in Cook Inlet where LNG operations have existed for more than 40 years from the LNG facility in Kenai, which was built in 1969. The expected frequency of transits and size of LNGCs are within Southwest Alaska Pilots Association (SWAPA) capabilities to manage. Minor impacts to safety and security resources in Cook Inlet (based upon current staffing and equipment levels) would be further evaluated and addressed prior to initiation of facility operations.

The overall conclusion of the assessment was that the increase in LNGC traffic to Cook Inlet is manageable from a security and safety standpoint. The Follow-on WSA did not identify funding gaps in providing adequate safety and security protection in Cook Inlet. Continued coordination between Project representatives and the Harbor Safety Committee, AMSC, and other waterway users was recommended to ensure that waterway users continue to be informed as the Project is developed and waterway users work together to ensure safe and secure LNGC transits.

The Follow-on WSA report was submitted to USCG COTP on March 18, 2016, and included the following main sections:

- Port Characterization;
- Characterization of LNG Facility and LNGC Route;
- Risk Assessment for Marine Safety and Security;
- Risk Management Strategies; and
- Resources Needs for Marine Safety, Security and Response.

The USCG issued a letter of recommendation to FERC on August 17, 2016. In accordance with 33 C.F.R. 127.007, the WSA would be reviewed annually and a report would be submitted to the COTP until the facility begins operations in order to incorporate changes to facility design or waterway circumstances which might affect the WSA.

U.S. Coast Guard Transit Management Plan

It is anticipated that USCG would require development of a Transit Management Plan for the operation of LNGCs, which would address both safety and security measures. The LNGCs loading LNG at the Marine Terminal would comply with the provisions of the Transit Management Plan.

Certifications

LNGCs are required to have and maintain International Certifications as defined in 46 C.F.R. Part 154, as well as any certificates required by international standards. Prior to entering a U.S. port for the first time, foreign (non-U.S. flagged) LNGCs must obtain a USCG Certification of Compliance (COC). The COC must be renewed every two years with a mid-period annual inspection. Non-U.S. flagged LNGCs are subject to USCG Port State Control Inspections, encompassing all areas of security and safety. Based on these legal requirements, LNGCs must be fully vetted by a recognized agency prior to acceptance by the Project.

11.2.3.1 Results of the Ship Simulation Studies

Ship berthing/unberthing simulations demonstrate that LNGCs within the design range of 125,000 m^3 to 216,000 m^3 can safely be managed with three tugs, equipped with azimuth stern drives, of a minimum of 90 MT static bollard pull. Two azimuth stern drive tugs in the range of 120 MT static bollard pull for ice mitigation and towing work.

11.2.3.2 Depictions of the Marine Hazard Zones

LNG ships have been operating commercially since the first commercial LNG cargo was transported by ship in 1959. These ships have achieved an excellent safety record. LNG has been delivered across the oceans during this period without major accidents or safety problems, either in port or on the high seas. In that time, there have been more than 38,000 voyages by LNG ships, covering more than 60 million miles. Today, approximately 196 LNG ships safely transport more than 287 million m^3 of LNG annually to ports around the world.

LNG ships, like other ships, are subject to a number of hazards both in transit to and from a Liquefaction Facility and while moored at the berth. The risks associated with these hazards are mitigated in a number of ways, including: the specific manner of construction of the ships as required by the International Maritime Organization ("IMO") and validated by the flag states and classification societies; the training of the LNG ships' crews and the operation of the ships as required under the IMO International Safety "("ISM") Code and the International Ship and Port Facility Security ("ISPS") Code; the outfitting of the ships with state-of-the-art navigation aids such as automatic plotting radar and automatic identification of ships ("AIS"); the safe management of ship movements in port areas as required by USCG and administered by licensed pilots (supported by tugs); and the inspection of ships by USCG, as the port state inspectorate, to ensure that they comply with U.S. safety and security standards.

The hazards associated with the marine transportation of LNG differ from the land-based hazards. While in transit, ships are subject to collision, allision, and grounding. While moored at the berth, ships are subject to wave action or surge from passing ships that could affect mooring lines or connections to loading arms.

The United States Coast Guard (USCG) is a cooperating agency in the permitting process for LNG terminal facilities with FERC. As outlined in 33 C.F.R. 127.007 and 18 C.F.R. 157.21 the USCG requires LNG terminal applicants to submit a Letter of Intent (LOI), Preliminary Waterway Suitability Assessment (WSA) and, a Follow-on WSA to the Captain of the Port (COTP). On August 17, 2016, the Alaska LNG Project received the Letter of Recommendation (LOR) from the Captain of the Port (COTP), Western Alaska. The LOR is based on the USCG review of the Letter of Intent (LOI) and Waterway Suitability Assessment (WSA) submitted by the Project on May, 15 2014 and March 18, 2016, respectively. The LOR is a recommendation from the USCG COTP that the Cook Inlet is suitable for the additional LNG maritime traffic associated with the Project, with consideration to safety and security of the port, waterway, the vessels transporting LNG, and the LNGC at berth.

The Follow-on WSA analysis conducted for the Alaska LNG Project aligns with NVIC 01-2011 Navigational and Vessel Inspection Circular (NVIC) 01-2011, Guidance Related to Waterfront Liquefied Natural Gas (LNG) Facilities; January 11, 2011. The purpose of the WSA is to:

- Provide a basis for an assessment of the suitability of Cook Inlet for the proposed Project from a maritime safety and security standpoint.
- Identify credible navigational safety hazards and security threats associated with the additional LNG marine traffic related to the Project, along with appropriate risk management strategies, mitigation measures, and resources necessary to mitigate those risks.
- Consider the transportation of LNG through Cook Inlet by LNGCs for both inbound (unladen, in-ballast) and outbound (laden) voyages to and from the proposed Marine Terminal.
- Provide the local COTP Western Alaska with the information necessary to advise the federal agencies involved in the permitting process that the Liquefaction Facility is appropriate for Cook Inlet.
- Provide the basis for developing/updating safety and security plans for the transportation of LNG into and out of Cook Inlet and for determining resources required for LNGC transport and operations.

Safety scenarios included in the Follow-on WSA included:

- Collision
- Allison
- Grounding
- Averse Weather
- Visibility
- Environmental
- Fire on LNG Carrier
- Proximity of LNG Carrier Traffic to Fishing Activities

Security scenario include in the Follow-on WSA are consistent with Enclosure (7) to NVIC 01-2011. No additional details are provided as the Enclosure (7) is marked as Sensitive Security Information (SSI).

For each safety and security scenario evaluated in the Follow-on WSA for the Alaska LNG Project, the "Zones of Concern" listed in Enclosure (9) to NVIC 01-2011 were applied to the length of the LNG Carrier transit to determine the main areas of concern along the waterway. This includes graphics that depict the outer perimeter of the zones along the entire LNG vessel transit route, in order to assess what port and community features fall within them. This information is SSI, and included in the WSA Report details.

11.2.3.3 Areas Impacted by the Marine Hazard Zones

The Zones of Concern for each safety and security scenario for the LNG carrier are overlaid on nautical charts depicting the inbound/outbound route segments, and when the LNGC is at the Alaksa LNG marine terminal. This process was done to identify any specific impacts on and along the waterway to Cook Inlet infrastructure, marine traffic, workers, visitors, roadways, and the public. This information is SSI and is detailed in the WSA Report and Appendices:

- Appendix B – Critical Infrastructure along the Waterway
- Appendix C – Characterization of Alaska LNG Liquefaction Facility and LNGC Route Segments with Zones of Concern

11.2.3.4 Safeguards and Security Necessary to Mitigate Impacts

The Follow-on WSA followed a defined and structured risk analysis process to systematically evaluate the LNG Carrier inbound and outbound transits, as well as when the LNG Carrier is at the Alaska LNG Marine Terminal. The risk analysis worksheets are SSI and include current project safeguards and security countermeasures. The risk analysis worksheets are detailed in the WSA Report Appendices:

- Appendix C – Follow-On Workshop Worksheets: Safety Scenarios (Inbound – Unladen LNGC)
- Appendix E – Follow-On WSA Workshop Worksheets: Safety Scenarios (Outbound – Laden LNGC)
- Appendix F – Follow-On WSA Worksheets: Security Scenarios

As part of the risk analysis, additional strategies, mitigation measures, and resources were identified to further manage the safety and security risk of the additional LNG Carrier traffic. All safeguards and security necessary to mitigate any identified impacts of the additional LNG Carrier traffic in Cook Inlet is SSI, and detailed in the WSA report.

11.2.4 Other Transportation Hazards

The Liquefaction Facility has been designed to minimize impacts from hazards associated from road travel. The Liquefaction Facility is located away from the highway and the Project includes relocation of the Kenai Spur Highway.

Modules, equipment, and materials will be delivered to the Liquefaction Facility during construction via a temporary Marine Offloading Facility (MOF).

11.2.5 Crane and Lifting Hazards

During construction, construction workers may be exposed to crane and lifting hazards due to the potential for objects to be dropped at height. As construction would be within the facility property line, these hazards are note expected to impact offsite public.

During construction, the EPC Contractor will develop safety procedures to mitigate hazards associated with crane and object lifting. Typically, this includes (1) development of a lifting plan identifying when in the schedule critical lifts would occur, (2) development of safety procedures to be implemented during lifting operations, and (3) establishment of exclusion zones around lifting areas. Lifting operations will also be scheduled and located in the safest possible areas to minimize impacts to existing ground level equipment and personnel.

Lifting large equipment not only poses a hazard to construction workers, but also potential schedule delays of issues with lifting occur with critical long lead equipment items. Therefore, extreme precaution and planning goes into lifting operations to ensure that construction is performed safely and reliably.

11.2.6 Adjacent Hazards

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. There are no anticipated hazards from adjacent facilities which would impact the Liquefaction Facility.

The Liquefaction Facility berths have been positions to accommodate the steering radius of vessels departing from the Agrium berth.

11.2.7 Natural Hazards

The Liquefaction Facility is designed to mitigate against natural disasters to ensure the safety of the general public, facility staff, and ensure reliable energy supply for customers. Flooding/sea-level rise, hurricanes and storm surge, and seismic events may create situations which threaten the operational safety of the Facility, if the Facility is not adequately prepared for them. Appendix I and J in Resource Report 13 include the results of the Seismic and Geotechnical investigations.

11.2.8 Security Threats and Vulnerability Assessments

The security requirements for the onshore components of the Project are governed by 49 C.F.R. Part 193, Subpart J – Security which incorporates NFPA 59A (2001 Edition). This subpart includes requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources and warning signs.

Additional security requirements are contained in USCG regulations in 33 C.F.R. Part 127 and 33 C.F.R. Part 105, respectively. USCG is also responsible for the security of shipping in waters of the U.S.

The Department of Homeland Security's (DHS) Chemical Facility Anti-Terrorism Standards (CFATS) program identifies and regulates high-risk chemical facilities to ensure they have security measures in place to reduce the risks associated with the chemicals stored at each facility. These requirements are detailed in 6 CFR 127.

As required under 6 CFR 127, the Facility will submit a Top Screen within the required timeframes to DHS as the Facility will exceed a screening threshold for stored materials of interest. As required by 6 CFR 127, a Top Screen must be submitted within 60 calendar days for facilities that come into possession of any of the chemicals listed above the threshold quantity. It is expected that the submission to DHS would occur after detailed design when quantities are finalized. If the facility is covered under 6 CFR 127, a Security Vulnerability Assessment and Site Security Plan will be developed in accordance with DHS requirements and submitted to DHS for review.

11.3 LIQUEFACTION FACILITY HAZARD ANALYSIS

11.3.1 Hazardous Releases

In accordance with 49 C.F.R. § 193.2059, each LNG container and LNG transfer system must have a vapor dispersion exclusion zone in accordance with Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001 Edition).

The design spill selection for determining the exclusion zone is provided in Section 2.2.3.5 and Table 2.2.3.5 of NFPA 59A (2001 Edition).

NFPA 59A (2001 Edition) Table 2.2.3.5 requires containers with over-the-top fill, with no penetrations below the liquid level, to contain a design spill of the largest flow from any single line that could be pumped into the impounding area with the container withdrawal pumps(s) considered to be delivering the full rated capacity. This design spill is assumed to continue for 10 minutes based on the Liquefaction Facility's surveillance and shutdown equipment.

The NFPA 59A (2001 Edition) Table 2.2.3.5 requires impounding areas serving only vaporization, process or LNG transfer areas to contain a spill of LNG for 10 minutes from a single accidental leakage source. However, since a "single accidental leakage source" is not defined in either NFPA 59A (2001 edition) or 49 C.F.R. Part 193, DOT PHMSA has developed criteria detailed in their Frequently Asked Questions webpage to calculate design spill rates associated with such single accidental leakage sources . The resulting design spill rates are then used to calculate exclusion zones for impounding areas serving these areas.

Although not an exclusion zone by code, other hazards, such as hydrogen sulfide, HHC and refrigerant potential releases will also be considered and analyzed in a manner similar to the analysis applied to potential releases of LNG.

AKLNG has developed a Design Spill Package, including a Piping and Equipment Inventory Database, which will be submitted to DOT PHMSA for review. This Design Spill Package details the LNG Terminal's methodology and selection of design spills. The Piping and Equipment Inventory Database is included in the Hazard Analysis Report which is included in Resource Report No. 13, Appendix H.3.

A summary of the bounding design spills used for hazard analysis modeling is included in the table below:

TABLE 11.3.1-1

Design Spill Summary Table (Overall)

Scenario Number	**Fluid**	**Hole Size (in)**	**Pipe Diameter (in)**	**Location**	**Orientation**
LNG-2A	LNG	4	4	Liquefaction Area	Horizontal
LNG-3A	LNG	4	4	BOG Compression Area	Horizontal
LNG-3B	LNG	4	4	Berth Area	Horizontal
HC-1	Heavy Hydrocarbon	2	8	Liquefaction Area	Horizontal
HC-16	Heavy Hydrocarbon	2	8	Fractionation Area	Horizontal
HC-25	Heavy Hydrocarbon	4	4	Fractionation Area	Horizontal
HC-32	Heavy Hydrocarbon	2	6	Condensate Storage Area	Horizontal

TABLE 11.3.1-1

Design Spill Summary Table (Overall)

Scenario Number	Fluid	Hole Size (in)	Pipe Diameter (in)	Location	Orientation
HC-33	Heavy Hydrocarbon	3	3	Condensate Storage Area	Horizontal
MR-14A	MR	4	4	Liquefaction Area	Horizontal
MR-18A	MR	4	4	Liquefaction Area	Horizontal
PR-4	Propane	2	6	Utility and Storage Area	Horizontal
PR-6A	Propane	4	4	Liquefaction Area	Horizontal
PR-8A	Propane	4	4	Liquefaction Area	Horizontal
PR-31	Propane	4	4	Fractionation Area	Horizontal
ETH-1A	Ethane	3	3	Fractionation Area	Horizontal
ETH-4	Ethane	2	8	Fractionation Area	Horizontal
N-1	Nitrogen	4	4	Nitrogen Package Area	Horizontal

TABLE 11.3.1-2

Design Spill Summary Table (Release Parameters)

Scenario Number	Release Height (ft)	Release Temperature (ºF)	Release Pressure (psi)	Flow Rate (lb/hr)	Release Duration (s)	Liquid Rainout (%)
LNG-2A	10	-247	120	1,794,083	600	0.27
LNG-3A	10	-255	94.6	6,296,522	600	21
LNG-3B	5	-255	94.6	3,148,261	600	34
HC-1 (LFL)	10	143	854	142,795	600	0
HC-1 (toxic)	10	98	854	31,403	600	0
HC-16 (toxic)	10	191	33	25,629	600	0
HC-25 (LFL)	5	83	22	179,246	600	81
HC-32 (toxic)	10	59	2	41,161	600	95

TABLE 11.3.1-2

Design Spill Summary Table (Release Parameters)

Scenario Number	Release Height (ft)	Release Temperature (°F)	Release Pressure (psi)	Flow Rate (lb/hr)	Release Duration (s)	Liquid Rainout (%)
HC-33 (LFL)	5	84	46.7	45,494	600	95
MR-14A	12	45	851.3	1,803,778	600	0
MR-18A	58	-203	650	2,905,273	600	0
PR-4	5	37.4	68	39,463	600	0
PR-6A	10	74	152.5	4,129,187	600	0
PR-8A	10	-25	7.9	774,825	600	53
PR-31	10	81	131.6	19,606	18	0
ETH-1A	10	27	397.8	86,504	600	0
ETH-4	10	-14	390.3	74,160	26.5	0
N-1	5	-269.3	150	1,471,320	600	0

Additional details on the hazardous releases can be found in the Hazard Analysis in Appendix H of Resource Report No.13.

11.3.2 Hot and Cold Fluid Temperature Hazard Analysis

The materials used at the Liquefaction Facility could present hot and cold temperature hazards if unmitigated. These hazards could affect plant personnel and, to a significantly lesser extent, adjacent landowners.

The insulation specification provided in Appendix F of Resource Report No. 13 provides the requirements for insulation thickness on process piping. Insulation provides protection for heat leak from the environment into the piping and provides protection for plant personnel from cold touch hazards. Plant personnel will also have Personal Protective Equipment requirements to mitigate touch hazards further.

Areas where cryogenic spills could occur are provided with curbing, grating, and sloping to channel spills away from equipment and direct spills into impoundment sumps. Spill containment systems are designed for a range of temperatures and will ensure that cold hazards associated with a spill do not affect plant personnel or adjacent equipment. Spill containment drawings are included in Appendix S of Resource Report No.13.

Material selection for piping and equipment is based on industry experience and the use of recognized accepted materials for cryogenic and high heat service. Material selection is detailed in the piping specification provided in Appendix F of Resource Report No.13.

When hot or cold materials are released to the environment, they immediately begin to warm up or cool down based on the temperature differences between atmospheric conditions and the fluid condition. The passive physically installed spill containment systems keep spills localized and allow them to warm up or cool down away from plant personnel, equipment and property lines.

The Phast V6.7 model was used to evaluate temperatures around potential releases. The releases used in Table 11.3.1-1 were evaluated for temperature profiles to determine impacts to equipment, structures, buildings, and property lines. As shown in the Hazard Analysis in Appendix H of Resource Report No.13, all releases from LNG design spills remain well within the property line. At the interface of the ½ LFL limit, methane clouds are warming up and becoming buoyant and dispersing beyond the ½ LFL limit. As such, process spills will have no hot or cold temperature impact at the property lines.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

11.3.3 Asphyxiant and Toxic Vapor Dispersion Hazard Analysis

Section 2.1.1.d of NFPA 59A (2001 Edition) states that "other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility."

Therefore, toxic vapor dispersion analysis associated with jetting and flashing releases has been performed. As NFPA 59A (2001 Edition) and 49 C.F.R. Part 193 do not provide recommended thresholds for analyzing toxicity, FERC has required applicants to consider toxicity levels based on the Acute Exposure Guideline Levels ("AEGL") -1, -2, and -3 maintained by the U.S. Environmental Protection Agency. Specific AEGL levels for each component are detailed in the Hazard Analysis provided in Appendix H of Resource Report No.13.

Toxicity modeling will be performed on toxic components. Dispersion analysis will also be performed on the liquid nitrogen storage in order to determine the presence of an asphyxiation hazard. The Phast v6.7 model was used to perform the analysis. A safety factor of two was applied to the toxicity modeling. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 41.9°F, relative humidity of 50% and surface roughness factor of 0.03 meter ("m") for all wind directions.

The calculations and resulting toxic dispersion analysis results for the Liquefaction Facility is detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, no public receptors will be impacted by toxic or asphyxiation hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.3.3-1 and 11.3.3-2 summarizes the results of the asphyxiant and toxic vapor dispersion modeling.

TABLE 11.3.3-1

Asphyxiant Dispersion Results

Scenario:	**Distance (ft) to:**		
	19.5%	**16%**	**12.5%**
N-1	No Hazard	No Hazard	No Hazard

TABLE 11.3.3-2

Toxic Vapor Dispersion Results

Scenario:	**Distance (ft) to:**		
	½ AEGL-1	**½ AEGL-2**	**½ AEGL-3**
HC-1	1,541	662	246
HC-16	2,908	2,262	613
HC-32	1,049	676	440

11.3.4 Flammable Vapor Dispersion Hazard Analysis

In accordance with the requirements of Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001 Edition), 49 C.F.R. § 193.2059 and written interpretations issued by DOT PHMSA in July 2010, provisions have been made within the design of the Liquefaction Facility to minimize the possibility of flammable vapors reaching a property line that can be built upon and that would result in a distinct hazard. Specifically, in accordance with the requirements of 49 C.F.R. § 193.2059, dispersion distances have been calculated for one-half the lower flammability limit of natural gas and flammable hydrocarbon vapors. These distances have been calculated for jetting and flashing releases and also the conveyance and impoundment of a design spill of LNG, HHC and flammable refrigerants calculated in accordance with Section 2.2.3.5 of NFPA 59A (2001 Edition).

Atmospheric conditions used in the modeling comply with the requirements of 49 C.F.R. Part 193. The Phast v6.7 model was used to perform the analysis. A safety factor of two was applied to the dispersion modeling. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 41.9°F, relative humidity of 50% and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting vapor dispersion exclusion zones for the Liquefaction Facility is detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, all exclusion zones comply with the requirements of 49 CFR Part 193.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.3.4-1 summarizes the results of the flammable vapor dispersion modeling.

TABLE 11.3.4-1

Flammable Vapor Dispersion Results

Scenario:	**Distance (ft) to ½ LFL**
LNG-2A	2,477
LNG-3A	2,683
LNG-3 B	2,779
MR-14A	732
MR-18A	1,704
PR-4	608
PR-6A	1,157
PR-8A	1,700
PR-31	1,023
ETH-1A	179
ETH-4	237
HC-1	799
HC-25	1,174
HC-33	383

11.3.5 Vapor Cloud Overpressure Hazard Analysis

Section 2.1.1.d of NFPA 59A (2001 Edition) states that “other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility.”

Therefore, vapor cloud overpressure analysis associated with HHC and refrigerant releases is performed for the Liquefaction Facility. As NFPA 59A (2001 Edition) and 49 C.F.R. Part 193 do not provide recommended thresholds for analyzing overpressures, FERC has required applicants to consider an overpressure value of 1 psi to determine the potential impacts on the public. The Phast v6.7 model was used to perform the analysis. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 41.9°F, relative humidity of 50 percent and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting overpressure analysis for the Liquefaction Facility is detailed in the Hazard Analysis included in Resource Report No. 13 Appendix H.3. As detailed in the Report, no public receptors will be impacted by overpressure hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.3.5-1 summarizes the results of the overpressure modeling results.

TABLE 11.3.5-1

Overpressure Results

Scenario:	Distance (ft) to 1 psi:
MR-14A	820
MR-18A	1,913
PR-4	767
PR-6A	1,509
PR-8A	1,311
PR-31	1,424
ETH-1A	204
ETH-4	281
HC-1	963
HC-25	2,313
HC-33	842

11.3.6 Fire Hazard Analysis

11.3.6.1 Pool Fire

Exclusion zone and hazard distances for various flux levels for flammable hydrocarbon pool fires have been calculated in accordance with 49 C.F.R. § 193.2057 and Section 2.2.3.2 of NFPA 59A (2001 Edition), using the "LNGFIRE III" computer program model developed by the GRI. Atmospheric conditions used in the modeling comply with the requirements of 49 C.F.R. Part 193. Atmospheric conditions used were wind speed of up to 26 mph, temperature of -7 °F and relative humidity of 33 % for all wind directions.

The calculations and resulting LNG pool fire analysis for the Liquefaction Facility are detailed in the Hazard Analysis included in Appendix H.3 of Resource Report No. 13. The results of the modeling show that all thermal radiation hazards associated with pool fires remain within the Liquefaction Facility property boundaries and therefore meet the exclusion zone requirements detailed in 49 C.F.R. Part 193. Table 11.3.6-1 summarizes the thermal exclusion zones.

TABLE 11.3.6-1

Thermal Radiation Exclusion Zone

Sump:	Distance (ft) to:		
	10,000 Btu/ft^2-hr	3,000 Btu/ft^2-hr	1,600 Btu/ft^2-hr
Liquefaction Train Impoundment Sump	184	239	280
LNG Storage Area Impoundment Sump	238	312	368
LNG Storage Tanks	646	1,015	1,306

TABLE 11.3.6-1

Thermal Radiation Exclusion Zone

Sump:		Distance (ft) to:		
		10,000 Btu/ft^2-hr	**3,000 Btu/ft^2-hr**	**1,600 Btu/ft^2-hr**
BOG Compressor Area Impoundment Sump	Front View	63	79	91
	Side View	64	79	90
LNG Loading Berths Impoundment Sumps	Front View	59	79	118
	Side View	79	91	98

Although not exclusion zones, thermal radiation modeling was performed on other impoundments to determine the hazards associated with pool fires from those impoundments. The calculations and resulting pool fire analysis for the Liquefaction Facility are detailed in the Hazard Analysis included in Appendix H.3 of Resource Report No. 13. The results of the modeling show that all thermal radiation hazards associated with pool fires remain within the Liquefaction Facility property boundaries. Table 11.3.6-2 summarizes the thermal radiation distances.

TABLE 11.3.6-2

Thermal Radiation Distances

Sump:		Distance (ft) to:		
		10,000 Btu/ft^2-hr	**3,000 Btu/ft^2-hr**	**1,600 Btu/ft^2-hr**
Fractionation Area Impoundment Sump	Front View	63	79	91
	Side View	64	79	90
Condensate Truck Loading Area Impoundment Sump		91	115	132
Liquefaction Compressor Impoundment Sumps		61	76	86
Refrigerant Storage Area Impoundment Sump	Front View	129	166	193
	Side View	130	165	191
Condensate and Diesel Storage Area Dike	Front View	373	507	639
	Side View	375	486	568

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

11.3.6.2 LNG Jet Fire

Section 2.1.1.d of NFPA 59A (2001 Edition) states that "other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility."

Therefore, jet fires associated with LNG, HHC and refrigerant releases is performed for the Liquefaction Facility. As NFPA 59A (2001 Edition) and 49 C.F.R. Part 193 do not provide recommended thresholds for analyzing jet fires, FERC has required applicants to consider thermal flux endpoints of 10,000 BTU/ft^2-hr, 3,000 BTU/ft^2-hr 1,600 BTU/ft^2-hr to determine the potential impacts on the public. The Phast v6.7 model was used to perform the analysis. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 41.9°F, relative humidity of 50 percent and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting jet fire results for the Liquefaction Facility is detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, no public receptors will be impacted by jet fire hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.3.6-3 summarizes the results of the jet fire modeling results.

TABLE 11.3.6-3

Jet Fire Results

Scenario	**Distance (ft) to:**		
	10,000 Btu/ft^2-hr	**3,000 BTU/ft^2-hr**	**10,000 Btu/ft^2-hr**
LNG-2A	888	783	663
LNG-3A	866	774	643
LNG-3 B	865	775	643
MR-14A	556	464	326
MR-18A	1,088	955	767
PR-4	401	355	292
PR-6A	840	742	606
PR-8A	550	485	391
PR-31	806	712	582
ETH-1A	181	156	114
ETH-4	213	183	132
HC-1	526	458	364
HC-25	375	330	263
HC-33	104	92	75

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

11.3.7 Vessel Overpressure Hazard Analysis

Section 2.1.1.d of NFPA 59A (2001 Edition) states that "other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility."

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

In the event of a pool fire, hazard control systems can be used to put out the pool fire while firewater systems can be used to cool any vessels exposed to heat fluxes. The firewater system design and coverage area drawings are included in Appendix S of Resource Report No.13 demonstrate overlapping coverage for all areas.

In the event of a jet fire, hazard detection systems and instrumentation systems will be able to detect the release. Those devices would send a signal which would activate ESD valves in the area which would stop the flow of fuel to the jet fire and put out the jet fire. Firewater systems can be used to cool any vessels exposed to heat fluxes. The firewater system design and coverage area drawings are included in Appendix S of Resource Report No.13 demonstrate overlapping coverage for all areas.

Based on the layout of the firewater system, hazard detection system, and hazard control system, no vessel would be subjected to sufficient heat fluxes for an extended period which would result in a BLEVE.

11.3.8 Fog or Steam Hazard Analysis

Section 2.1.1.d of NFPA 59A (2001 Edition) states that "other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility."

Based on the current design, there are not any expected fog or steam hazards.

11.3.9 Other Hazard Analysis

Based on the current design, there are not any identified other hazard analysis required to demonstrate safety for plant personnel and the public.

11.3.10 Hazardous Material Disposal

Section 2.1.1.d of NFPA 59A (2001 Edition) states that "other factors applicable to the specific site that have a bearing on the safety of plant personnel and the surrounding public shall be considered. The review of such factors shall include an evaluation of potential incidents and safety measures incorporated in the design or operation of the facility."

Mercury is removed from feed gas prior to liquefaction in a mercury guard bed. The guard bed would absorb the mercury from the feed gas stream and is included in the design as a preventative measure to prevent mercury from impacting the exchangers in the MCHE. Based on the feed gas design parameters, no mercury is expected in the feed gas.

However, in the event that mercury is present and is collected in the closed guard bed, a specialized vendor would be contracted to safely remove the mercury, dispose of the mercury, and replenish the guard bed.

The guard bed is a closed bed which would prevent any accidental release which could impact plant personnel. Plant personnel would be trained to visually inspect the guard bed for abnormal signs in order to preventatively mitigate any release.

11.4 LIQUEFACTION FACILITY LAYERS OF PROTECTION

The design of the Liquefaction Facility includes multiple layers of protection to reduce the risk of a potentially hazardous scenario developing into an event, which could affect off-site infrastructure. The layers of protection are considered independent of one another, i.e., each layer would perform its designed function regardless of the function of other layers.

11.4.1 Structural Design of the Facilities and Components

The structural design of the Liquefaction Facility complies with the requirements detailed in 49 C.F.R. Part 193 and NFPA 59A (2001 Edition). The Liquefaction Facility is designed to meet the loading requirements for wind speed and the seismic hazards that could occur at the Liquefaction Facility. The Liquefaction Facility would be designed to withstand a sustained wind of 150 mph, which converts to 183 mph at a 3-second gust per 49 C.F.R. § 193.2067.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix I – Natural Hazard Design Investigations and Forces, Appendix J – Geotechnical Investigation, Appendix F – Specifications and Appendix B.2 – Design Philosophies.

11.4.2 Mechanical Design of the Facilities and Components

The mechanical design of the Liquefaction Facility complies with the requirements detailed in 49 C.F.R. Part 193 and NFPA 59A (2001 Edition). The design of the Liquefaction Facility includes the use of suitable materials of construction. LNG storage tanks are designed with appropriate materials and process piping is designed for cryogenic temperatures. Material selection for process components is compatible with the operational and design limits (pressure, temperature etc.) of the systems. Piping will be designed in accordance with ASME B31.3. LNG piping will consist of welded connections on the majority of the piping connections to minimize the possibility of flange leaks. Pressure vessels will be designed in accordance with ASME Section VIII. LNG storage tanks would be designed in accordance with American

Petroleum Institute ("API") Standard 620 and NFPA 59A (2001 and 2006 Editions) per the requirements of 49 C.F.R. Part 193.

In general, critical equipment required to support continuous operation of the Facility will be spared.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix F – Specifications, Appendix B.2 –Design Philosophies and Appendix L.3 - Preliminary LNG Tank and Foundation Structural Design.

11.4.3 Operations and Maintenance Plans

The design of the Liquefaction Facility will include Operations and Maintenance Plans as required by 49 C.F.R. Part 193. Measures such as operating control system tools, procedures and training address the potential for human error and incorrect operation. Procedures for operation and maintenance of the Liquefaction Facility will comply with NFPA standards as specified in the following sections of the NFPA 59A (2001 Edition):

- Chapter 11—Operating, Maintenance and Personnel Training.

  The procedure will include policies for operating procedures, monitoring of operations, emergency procedures, personnel safety, failure investigations, communication systems and operating records.

  The procedure will include policies for maintenance procedures, fire protection, isolating and purging, repairs, control systems, inspection of LNG storage tanks, corrosion control and maintenance records.

  Recruitment of the Operations and Maintenance Team will commence during the construction period, and personnel involved in the day-to-day operation and maintenance of the Terminal will receive required training.
- Appendix C—Security. This procedure will include policies for security procedures, protective enclosures, security communications, security monitoring, and warning signs.

A listing of the codes and standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix F – Specifications and Appendix B.2 –Design Philosophies.

11.4.4 Basic Plant Control Systems

The design of the Liquefaction Facility includes state-of-the-art control systems. These control systems include monitoring systems, process alarms and control and isolation valves that can be monitored in the control room. The Liquefaction Facility will also develop operating procedures in accordance with 49 C.F.R. Part 193, which will ensure the facility stays within the established operating and design limits. Alarms would have visual and audible notification in the control room, as well as in the field, to warn operators that process conditions may be approaching design limits. Operators would have the capability to take action from the control room to mitigate an upset. As required by 49 C.F.R. Part 193, all operators will undergo extensive training prior to operating the Liquefaction Facility.

Alarm and shutdown setpoints, where available, are shown on the P&IDs included in Appendix E.5 of Resource Report No. 13. Cause and effect matrices showing logic are provided in Appendix Q.1 of Resource Report No. 13. Finalized operating limits for flows, pressures and temperatures will be dependent on the final vendor selection for major process systems, which will be determined during final design.

A listing of the codes and standards to which the Liquefaction Facility will be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix P – Process Control & Instrumentation, Appendix E.5 – P&IDs and Appendix B.2 –Design Philosophies.

11.4.5 Safety Instrumented Systems

The design of the Liquefaction Facility includes safety-instrumented prevention systems that include safety control valves and emergency shutdown systems designed to prevent a release if design limits are exceeded during operation. The exclusive purpose of this system is to bring the Liquefaction Facility to a safe state. The system will be designed in accordance with International Society of Automation 84.01, Application of Safety Instrumented Systems ("SIS") for the Process Industry. Safety valves and instrumentation would be installed to monitor, alarm, shut down and isolate equipment and piping during process upsets or emergency conditions. The inherently fail-safe SIS will isolate process areas from incoming feed gas, sectionalize and isolate inventories to limit materials in release event, isolate potential ignition sources and depressurize equipment handling flammable materials. The control room will initiate emergency shutdowns or depressurizations. The system power is provided with a backup un-interruptible power supply system to maintain control operation. Through the features detailed above, the SIS provides protection for equipment, personnel and the surrounding environment.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix P – Process Control & Instrumentation, Appendix E.5 – P&IDs and Appendix B.2 –Design Philosophies.

11.4.6 Security Systems and Plans

The USCG has authority over the security plans for the entire Liquefaction Facility. A Facility Security Assessment ("FSA") would be prepared for the marine terminal as required by 33 C.F.R. Part 105 prior to Facility startup. In addition, a Facility Security Plan ("FSP") would be prepared as required by 33 C.F.R. Part 105 and submitted for review and approval to the COTP a minimum of 60 days prior to commencing operations. Once approved, the FSP is revalidated every five years. Additional security requirements for the Liquefaction Facility are provided by 49 C.F.R. Part 193, Subpart J - Security. This subpart includes requirements for conducting security inspections and patrols, liaison with local law enforcement officials and design and construction of protective enclosures, lighting, monitoring, alternative power sources and warning signs.

The design of the Liquefaction Facility includes state-of-the-art systems to help maintain and operate the Liquefaction Facility in a safe, secure and reliable environment. Advances in monitoring systems, alarm systems and communication systems have allowed LNG facilities to continue to have an impeccable security record. Security measures included in the design of the Project to control access include perimeter security including inspections and patrols, access points into/out of the Liquefaction Facility, restrictions and prohibitions applied at the access points, intrusion detection, security and safety Closed Circuit Television monitoring with digital video feed and recording capabilities, identification systems, screening procedures, response procedures to security breaches and liaison with local law enforcement officials. Lighting will be provided in locations to allow personnel to reach a place of safety in the event of a main power outage.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix B.2 –Design Philosophies, and Appendix E – Engineering Design Information.

11.4.7 Physical Protection Devices

The pressure relief and flare system will be designed to safely and reliably dispose of streams that are released during start-up, shutdown, cool down, plant upsets and emergency conditions. The design of the Liquefaction Facility includes relief valves for process piping that physically protects the piping systems from operating beyond their design limits. The relief valves are connected to a closed flare system by which any process upsets are sent to a ground flare for disposal. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per NFPA 59A (2001 Edition) and ASME Section VIII. The flare system will be designed such that the vent and drain systems are segregated from each other, the ground flare operates with minimal smoke generation and a highly reliable ignition system, and the thermal radiation will be in accordance with API RP 521.

The LNG storage tank includes both relief valves and vacuum relief valves to protect the LNG storage tank from both over- and under-pressure events.

Relief valves that discharge to atmosphere will be minimized.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix L.3 - Preliminary LNG Tank and Foundation Structural Design – LNG Storage Tank, Appendix E – Engineering Design Information and Appendix B.2 –Design Philosophies.

11.4.8 Ignition Controls

The design of the Liquefaction Facility includes ignition controls as specified in 49 C.F.R. Part 193 and NFPA 59A (2001 Edition). The Liquefaction Facility would include equipment that is electrically classified in accordance with NFPA 59A (2001 Edition), NFPA 497 and API RP 500 to mitigate potential ignition sources. The electrical design of the Liquefaction Facility includes grounding of equipment, as necessary. The Liquefaction Facility procedures will also include requirements for hot work permits to be obtained prior to work activities, smoking restrictions at the Liquefaction Facility and other measures to minimize potential ignition sources at the Liquefaction Facility. The Liquefaction Facility has been designed such that areas likely to contain flammable gas mixtures will be isolated from ignition sources in accordance with NFPA 70 and the National Electric Code ("NEC"). Electrical equipment used within these designated areas will be housed in enclosures approved for this service and application.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix N – Electrical Design Information and Appendix B.2 –Design Philosophies.

11.4.9 Spill Containment System

The Liquefaction Facility spill containment systems are designed to convey spills away from process equipment into impoundment systems located remotely. The design of all spill containment system meets the requirements of 49 C.F.R. Part 193 and NFPA 59A (2001 Edition). All spill containment systems will be equipped with detection devices that will activate an automated alarm alerting the operator in the unlikely event of a spill. All hazardous fluids will be contained within spill containment systems.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix S.3 – Spill Containment Drawings and Calculations, Appendix E – Engineering Design Information, Appendix I.6 – Rain, Ice and Snow, Appendix B.2 –Design Philosophies.

11.4.9.1 LNG Storage Tank

Section 193.2181 of 49 C.F.R. Part 193 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. The two LNG storage tanks designed for the Liquefaction Facility are full-containment tanks with a primary inner container and a secondary outer container. The tank has been designed and will be constructed so that the self-supporting primary container and the secondary container will be capable of independently containing the LNG. The primary, inner container has been designed and will be constructed in accordance with the requirements of API Standard 620 Appendix Q, and will contain the LNG under normal operating conditions. The secondary container will be capable of containing the maximum quantity of LNG to be stored at the Project site and controlling the vapor resulting from the unlikely occurrence of product leakage from the inner container. As part of its full containment design, the inner storage tank is surrounded by an outer concrete wall. In addition, a tertiary containment would be constructed around the LNG storage tanks which will be added in detailed design.

To increase the safety of the tanks, there are no penetrations through the inner container or outer container sidewall or bottom. Piping into and out of the inner and outer containers will enter from the top of the tank. The full containment design prevents water ingress into annular spaces and therefore there are no water removal requirements for this tank design. Further details are included in Resource Report No. 13, Appendix L.3 - Preliminary LNG Tank and Foundation Structural Design.

11.4.9.2 LNG Impoundment Sumps

The design of the Liquefaction Facility includes impoundment sumps described as follows:

- Fractionation Area Impoundment Sump;
- Condensate Truck Loading Area Impoundment Sump;
- Liquefaction Train Impoundment Sump;
- Liquefaction Compressor Impoundment Sumps;
- Refrigerant Storage Area Impoundment Sump;
- LNG Storage Area Impoundment Sump;
- BOG Compressor Area Impoundment Sump;
- Condensate and Diesel Storage Area Dike;
- LNG Loading Berths Impoundment Sumps; and
- LNG Storage Tank Outer Containment.

The locations of the impoundment sumps will be illustrated on plot plan included in Appendix E.5 of Resource Report No. 13. The flow of LNG spills into the impoundment sumps will be illustrated on the LNG Spill Containment Drawing included in Appendix S.3 of Resource Report No. 13.

In accordance with the requirements of Section 2.2.2.2 of NFPA 59A (2001 Edition), impounding areas that serve only vaporization, process or LNG transfer areas will have a minimum volumetric capacity equal to the greatest volume of LNG that can be discharged into the area during a 10-minute period from any single accidental leakage source or during a shorter time period based on demonstrable surveillance and shutdown provisions acceptable to the authority having jurisdiction. Each impoundment sump has been sized to contain the largest design LNG spill that could occur from a single accidental leakage source within its respective area for a period of 10 minutes, plus pump runout and pipe inventory.

LNG will flow into the impoundment sumps along insulated concrete troughs located alongside or beneath LNG pipelines and equipment as illustrated on the LNG Spill Containment Drawings that are included in Appendix S.3 of Resource Report No. 13. The troughs are sized to contain the largest design LNG spill that could occur from a single accidental leakage source within its respective area. The troughs will be constructed of insulated concrete and designed to minimize vapor cloud formation during LNG spills.

The LNG impoundment sumps will be of an insulated concrete design. The concrete insulates the LNG from the sump walls and floor, reducing the vaporization rate. Additionally, in accordance with the requirements of Section 2.2.2.8 of NFPA 59A (2001 Edition), the insulation system used for the impounding surfaces will be noncombustible and suitable for the intended service.

In accordance with the requirements of Section 2.2.2.7 of NFPA 59A (2001 Edition), each LNG impoundment sump will include a sump to collect rainwater from the containment area. A water removal system will be installed and will have the capacity to remove water at a minimum of 25 percent of the rate from a storm of a 10-year frequency and 1-hour duration. In accordance with the requirement of Section 2.2.2.7 of NFPA 59A (2001 Edition), automatically controlled sump pumps will be installed in the sump to remove water from the LNG impoundment sumps. The sump pumps will be fitted with an automatic cutoff device that prevents their operation when exposed to LNG temperatures.

11.4.10 Passive Protection for Cryogenic Fluids, Overpressures, Projectiles, and Fire

The design of the Liquefaction Facility includes additional passive protection measures that go beyond equipment layout and includes proper process design to minimize hydrocarbon inventory, isolate inventory segments and move flammable inventory out of the area of hazard to the flare in the shortest practical time, where applicable. Spacing of vessels and equipment, separation from ignition sources and setbacks from property lines were determined in accordance with 49 C.F.R. Part 193 and NFPA 59A (2001 Edition). The design of the Liquefaction Facility also complies with the exclusion zone requirements for thermal radiation and vapor dispersion detailed in 49 C.F.R. Part 193. All process areas will be designed to be as open as possible to minimize the potential for enclosed spaces leading to overpressures.

In addition to proper layout and process design, fire proofing and cryogenic protection is provided to structures, as needed. Fireproofing design will be in accordance with the recommendations of API 2218. Any fireproofing material used in areas where there is a risk of LNG splashing will be designed to handle the cold contact without losing its structural integrity or fireproofing ability.

Personnel heat protection via insulation or guarding will be provided for all equipment and piping with a potential external skin temperature above 140 °F. Cryogenic protection will be provided for cold equipment to prevent personnel injury. Protection against falling ice will be considered and implemented, as needed, during detailed design.

A listing of the codes and standards to which the Liquefaction Facility will be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix S.1 – Preliminary Fire Protection Evaluation and Appendix E – Engineering Design Information.

11.4.11 Hazard Detection and Mitigation Systems

The Liquefaction Facility is designed to minimize the occurrence of events that could result in the release of LNG and other flammable materials and to mitigate potential impacts to the public and Plant personnel. In the unlikely event that a release does occur, an Integrated Control and Safety System (ICSS) will be in place. Elements of these systems include the following:

- Flammable gas detectors;
- Low oxygen detectors (nitrogen, hydrogen sulfide);
- High and low temperature detectors;
- Smoke detectors;
- Flame detectors;
- Manual local ESD activation push buttons; and
- Automatic ESD activation features.

The ICSS will provide the means to monitor for and alert operators of hazardous conditions throughout the Liquefaction Facility resulting from fire, combustible gas leaks and low temperature LNG spills. The detection of these hazardous conditions by the ICSS will result in local audio and visual (e.g., strobe lights) signals with various alarms and colors depending on the detected hazard. The ICSS system will be independent of the process control system. When appropriate, the ICSS system will have the capability to initiate automatic shutdown of specific equipment and systems and may activate the wider ESD system response. Firewater and fire suppression/extinguishing systems will be provided to protect personnel, the public and Liquefaction Facility equipment in the event of a fire.

An NFPA 59A (2001 Edition) Fire Protection Evaluation has been performed to ensure that the design of the HDMS is sufficient and meets the requirements of Section 9.1.2 of NFPA 59A (2001 Edition). This evaluation is included in Appendix S.1 of Resource Report No. 13.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D or RR.13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix E – Engineering Design Information.

11.4.12 Hazard Control Equipment

The Liquefaction Facility is designed with hazard control equipment which, in the unlikely event that the ICSS detects an event, will operate to minimize the impact of the event. Elements of this system include the following:

- Dry chemical systems;
- Firewater systems;
- Clean agent systems; and
- CO2 and ABC extinguishers.

Portable, fixed and wheeled dry chemical extinguishers are strategically located around the Liquefaction Facility and provide a means to extinguish hydrocarbon fires. The Liquefaction Facility design incorporates a firewater system that includes monitors, hydrants and hoses, which can provide firewater to cool adjacent equipment and minimize impacts from an incident. High expansion foam systems will be provided at all impoundment sumps to reduce the vaporization rate of LNG being contained and provide additional protection by decreasing the rate of vaporization. Clean agent systems, which fill a room with a gaseous agent to suppress fires where water is not a desirable suppression agent, are provided for electrical equipment that is critical to Liquefaction Facility operation or to maintenance of control in an emergency. CO_2 extinguishers will be provided in the control room, instrument room, electrical room, electrical substations and other rooms/buildings where electrical hazards are present. ABC fire extinguishers will be provided in the open storage area, storage area, mechanical area, administration building, security building, control room and other buildings/rooms where non-process fire hazards could be present. The layout and design of the hazard control equipment meets the requirements of 49 C.F.R. Part 193 and NFPA 59A (2001 Edition).

A NFPA 59A (2001 Edition) Fire Protection Evaluation has been performed to ensure that the design of the HDMS is sufficient and meets the requirements of Section 9.1.2 of NFPA 59A (2001 Edition). This evaluation is included in Appendix S of Resource Report No. 13.

A listing of the Codes and Standards to which the Liquefaction Facility would be designed is included in Appendix D of Resource Report No. 13. Regulatory Compliance Matrix is available in Resource Report No. 13 Appendix C.3. Further details are included in Resource Report No. 13 Appendix B.2.21 – Hazard Detection Philosophies, Appendix S. – Explosion Protection and Appendix E – Engineering Design Information.

11.4.13 Emergency Response

An emergency response plan will be developed. The ERP establishes the procedures for responding to specific emergencies that may occur at the Liquefaction Facility as well as procedures for emergencies that could affect the public.

AKLNG will consult with local, state and Federal agencies to prepare a final version of the ERP for FERC's approval prior to the start of construction.

The ERP will include a cost-sharing plan describing any cost reimbursements that AKLNG agrees to provide to any state and local agencies with the responsibility for security and safety of the Liquefaction Facility. The ERP will be reviewed with community stakeholders and aforementioned authorities.

AKLNG will work with state and local emergency response organizations to develop and implement the ERP. Guidelines for response training required of appropriate personnel will be included in the ERP.

11.5 LIQUEFACTION FACILITY RELIABILITY

The design of the Liquefaction Facility includes numerous measures to ensure its overall reliability throughout its design life. The Liquefaction Facility will incorporate only proven design and technology and be built to the design codes and standards listed in the Design Codes and Standards document in Appendix D of Resource Report No. 13.

The design is further aimed at giving "state-of-the-art" levels of operability, reliability, availability and maintainability. Only cryogenic equipment from vendors who have a proven record of operation in LNG service will be used in this Liquefaction Facility. This equipment will include but not be limited to LNG storage tanks, refrigerant and boiloff gas ("BOG") compressors, pressure vessels, pumps, heat exchangers, valves, piping and instrumentation. The use of different manufacturers or types of vendor-supplied equipment for similar applications will be minimized in order to improve the operability and maintainability of the Liquefaction Facility and to consolidate and therefore minimize the holding of required spare parts.

The Liquefaction Facility will be designed to permit unconstrained operation over the absolute range of ambient conditions referred to in the Design Basis. It will be provided with suitable weather protection to enable all operation and maintenance procedures to be undertaken under all design weather conditions.

11.5.1 Equipment Redundancies

The Liquefaction Facility will be designed for continuous natural gas liquefaction except in the case of a total power outage. Necessary equipment redundancies will be included such that normal maintenance and inspection can be accomplished while sustaining the design liquefaction and loading rates.

11.5.2 Sparing Philosophy

The sparing philosophy for specific equipment and utilities is presented below.

Table 11.5-1 lists the equipment items that would be used in plant operation and the sparing consideration. Regarding the LNG Train, the equipment located in Train 1 are listed as a representative of Train 2 and

Train 3, which are identical to Train 1. Capital spares for compressor rotors and driver motors would be common to all three liquefaction units.

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	Equipment Description	Operating	Spare
MAJ623503A/B/C	Inlet Gas Filters	2	1
HBG623501	Inlet Gas Heater	1	0
JAT623505	Inlet Gas Heater Desuperheater	1	0
MBD623504	Inlet Gas Heater Condensate Pot	1	0
MBA669501/2/3	Mercury Adsorbers	3	0
MAJ669504A/B/C	Mercury Adsorber After-Filters	2	1
MBA661502/3/4/5/6/7	Molecular Sieve Dryers	6	0
MAJ661510A/B/C	Molecular Sieve Dryer After-Filters	2	1
NAP661513/4	Regeneration Gas Heaters	2	0
HFF661509	Regeneration Gas Cooler	1	0
MBD661512	Regeneration Gas KO Drum	1	0
NAP661113	Defrost Gas Heater	1	0
HBG695101	Feed Gas/MP Propane Cooler	1	0
HBG695102	Feed Gas/LP Propane Cooler	1	0
MAF695104	Scrub Column	1	0
NAP695105	Scrub Column Reboiler	1	0
HFF695110	Scrub Column Cooler	1	0
MBD695107	Scrub Column Reflux Drum	1	0
PBA695106A/B	Scrub Column Reflux Pumps	1	1
HBA695108	Main Cryogenic Heat Exchanger	1	0
TGT695109	LNG Hydraulic Turbine	1	0
MBD666101	HP MR Separator	1	0
TGT666102	MR Hydraulic Turbine	1	0
MBD666106/7	LP MR Compressor Suction Drums	2	0
MBD666124/64	MP MR Compressor Suction Drums	2	0
MBD666123/63	HP MR Compressor Suction Drums	2	0
CAE666113/53	LP MR Compressors	2	0
CAE666114/54	MP/HP MR Compressors	2	0
HFF666121/61	LP MR Compressor Intercoolers	2	0
HFF666122/62	MP MR Compressor Intercoolers	2	0
HFF666131/71	HP MR Compressor Desuperheaters	2	0
HFF666132/72	HP MR Compressor After-Coolers	2	0
MBD666141/81	LP Propane Suction Drums	2	0
MBD666142/82	MP Propane Suction Drums	2	0
MBD666143/83	HP Propane Suction Drums	2	0
CAE666112/52	Propane Refrigerant Compressors	2	0
HFF666144/84	Propane Desuperheaters	2	0
CGT666111/51	MR/PR Compressor Gas Turbine Drivers	2	0
HFF666191	Propane Condenser	1	0

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	**Equipment Description**	**Operating**	**Spare**
MBA666192	Propane Accumulator	1	0
MBA666196	Propane Reclaimer	1	0
HBG666197	Propane Reclaimer Condenser	1	0
HFF666193	Propane Subcooler	1	0
HBG666103	MR/LP Propane Cooler	1	0
HBG666104	MR/MP Propane Cooler	1	0
HBG666105	MR/HP Propane Cooler	1	0
MBA666194	Propane Transfer Drum	1	0
PBA666195	Propane Transfer Pump	1	0
MBD631522	Fractionation Feed Separator	1	0
MAF631501	Deethanizer Column	1	0
HBC631502	Deethanizer Reboiler	1	0
JAT631522	Deethanizer Reboiler Desuperheater	1	0
MBD631545	Deethanizer Reboiler Condensate Pot	1	0
HBG631503	Deethanizer Condenser	1	0
MBD631504	Deethanizer Reflux Drum	1	0
PBA631505A/B	Deethanizer Reflux Pumps	1	1
MAF631506	Depropanizer Column	1	0
HBC631507	Depropanizer Reboiler	1	0
JAT631523	Depropanizer Reboiler Desuperheater	1	0
MBD631546	Depropanizer Reboiler Condensate Pot	1	0
HFF631508	Depropanizer Condenser	1	0
MBD631509	Depropanizer Reflux Drum	1	0
PBA631510A/B	Depropanizer Reflux Pumps	1	1
PBA631511A/B	Propane Reinjection Pumps	1	1
MAF631512	Debutanizer Column	1	0
HBC631513	Debutanizer Reboiler	1	0
JAT631524	Debutanizer Reboiler Desuperheater	1	0
MBD631547	Debutanizer Reboiler Condensate Pot	1	0
HFF631514	Debutanizer Condenser	1	0
MBD631515	Debutanizer Reflux Drum	1	0
PBA631516A/B	Debutanizer Reflux Pumps	1	1
HFF631518	Debutanizer Condensate Product Cooler	1	0
PBA631517A/B	Butane Reinjection Pumps	1	1
HBG631519	LPG Reinjection Cooler	1	0
MBD631520	LPG Reinjection KO Drum	1	0
PBA631521A/B	LPG Reinjection Pumps	1	1
MBD612705	Wet Flare KO Drum	1	0
PBE612706A/B	Wet Flare KO Drum Pumps	1	1
NAP612709	Scrub Column Bottoms Vaporizer	1	0
MBD612701	Dry Flare KO Drum	1	0
MAB612708	Dry Flare Blowcase	1	0

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	**Equipment Description**	**Operating**	**Spare**
V612710	HP Flare Back Up Fuel Skid	1	0
V613802	LP Flare Back Up Fuel Skid	1	0
FLRH612703A/B/C	Wet & Dry Ground Flares	2	1
EZFG612703A/B/C	Wet and Dry Ground Flare Flame Front Generators	2	1
ABJ634701	Condensate Storage Tank	1	0
ABJ634704	Offspec Condensate Storage Tank	1	0
PBA634702A/B	Condensate Loading Pumps	1	1
PBA634705A/B	Offspec Condensate Pumps	1	1
EAL634706	Thermal Oxidizer	1	0
MBD634708	Vent KO Drum	1	0
BLW 634709A/B	Thermal Oxidizer Process Blowers	1	1
BLW634707A/B	Thermal Oxidizer Air Blowers	1	1
MBJ698701/2	Ethane Refrigerant Storage Bullets	2	0
NAP698711/2	Ethane Vaporizers	2	0
MBJ698721/2/3/4	Propane Refrigerant Storage Bullets	4	0
PBA698713	Propane Unloading Pump	1	0
PBA698718A	Propane Storage Pump	1	0
MBD613801	LP Flare KO Drum	1	0
FLRL613800	LP Flare	1	0
EZFG613800	LP Flare Flame Front Generator	1	0
ABJ691810	LNG Storage Tank	1	0
ABJ691820	LNG Storage Tank	1	0
PBA691811/12/13/14	LNG Loading and Circulating Pumps	4	0
PBA691821/22/23/24	LNG Loading and Circulating Pumps	4	1
MBD691815/25/35	BOG Compressor Suction Drums	2	1
MAB691840	BOG Compressor Suction Drum Blowcase	1	0
JAR691816/26/36	BOG Compressor Suction Drum Desuperheaters	2	1
CAE691841/51/61	LP BOG Compressors	3	0
CAE691842/52/62	HP BOG Compressors	3	0
HFF691843/53/63	BOG Compressor After-Cooler	3	0
FAY691871/2	LNG Loading Arms Berth 1	2	0
FAY691874	LNG Loading/Vapor Hybrid Arm Berth 1	1	0
FAY691873	Vapor Return Arm Berth 1	1	0
FAY691884	LNG Loading/Vapor Hybrid Arm Berth 2	1	0
FAY691881/2	LNG Loading Arms Berth 2	2	0
FAY691883	Vapor Return Arm Berth 2	1	0
MBD691876	Loading Arm Drain/Surge Drum Berth 1	1	0
MBD691877	Loading Arm Drain/Surge Drum Blowcase Berth 1	1	0
MBD691886	Loading Arm Drain/Surge Drum Berth 2	1	0
MBD691887	Loading Arm Drain/Surge Drum Blowcase Berth 2	1	0
BBH973001/2/3/4/5/6/7/8/9/10	Sanitary Lift Station	10	0
PBH973011/12/13/14/15/16/17/18/19/20A/B	Sanitary Lift Station Pump	10	10

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	**Equipment Description**	**Operating**	**Spare**
V973021	Sanitary Treatment Package	1	0
CAR966505	BOG Recycle Compressor	1	0
MAJ966501	Start Up Fuel Gas Filter	1	0
NAP966502	Start Up Fuel Gas Heater	1	0
NAP966516	Excess LPG Vaporizer	1	0
HFF966506	BOG Recycle Compressor After-Cooler	1	0
MFG966503	HP Fuel Gas Mixing Drum	1	0
MBD966510	HP Fuel Gas Heater Condensate Pot	1	0
JAT966514	HP Fuel Gas Heater Desuperheater	1	0
HBG966515	HP Fuel Gas Heater	1	0
PBE945613/23/33/43A/B/C	HP BFW Pumps 1/2/3/4	8 (Note 1)	4
MBD945611/21/31/41	Deaerator Drum 1/2/3/4	4 (Note 1)	0
TGT833611/21/31/41	Gas Turbine Generator 1/2/3/4	4 (Note 1)	0
EAC948611/21/31/41	Heat Recovery Steam Generator 1/2/3/4 (HRSG 1/2/3/4)	4 (Note 1)	0
JAT833612/22/32/42	Steam Turbine 1/2 HP Bypass Desuperheater	4 (Note 1)	0
JAT833615/25/35/45	Steam Turbine 1/2 LP Bypass Desuperheater	4 (Note 1)	0
TST833614//34	Steam Turbine Generator 1/2	2 (Note 1)	0
HFF987611/31	Steam Turbine 1/2 Surface Condenser	2 (Note 1)	0
MBD987612/32	Steam Turbine Condensate Drum 1/2	2 (Note 1)	0
PBE987613/33A/B	Condensate Forwarding Pumps 1/2	2 (Note 1)	2
V987614/34	Steam Turbine 1/2 Vacuum Package	2 (Note 1)	0
JAT987615/35	Motive Steam Desuperheater 1/2	2 (Note 1)	0
MFG965501	LP Fuel Gas Drum	1	0
HFF987660	LP Steam Dump Condenser	1	0
JAT987617/37	LP Steam Desuperheater1/2	2 (Note 1)	0
MBD948612/32	Continuous Blowdown Drum 1/2	2 (Note 1)	0
MBD948613/33	Intermittent Blowdown Drum 1/2	2 (Note 1)	0
HFF948614/34	Blowdown Condenser 1/2	2 (Note 1)	0
PBE948615/35A/B	Intermittent Blowdown Drum Pumps 1/2	2 (Note 1)	2
HFF948616/36	Blowdown Cooler 1/2	2 (Note 1)	0
V949651	Amine Injection Package	1	0
V949652	Oxygen Scavenger Injection Package	1	0
V949653	Scale Inhibitor Injection Package	1	0
PBE987669A/B	LP Condensate Pumps	1	1
MBD987667	LP Condensate Separator	1	0
HFF987668	LP Steam Condenser	1	0
HFF987661	Steam Condensate Cooler	1	0
HPL987662	Demin/Condensate Exchanger	1	0
ABJ987663	Steam Condensate Tank	1	0
PBE987664A/B/C	Steam Condensate Tank Pumps	2	1
MAJ987665A/B/C	Condensate Activated Carbon Filters	2	1
HBG987666	Contaminated Condensate Cooler	1	0

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	Equipment Description	Operating	Spare
ABJ955602	Air Compressor Diesel Day Tank	1	0
V955601	Air Compressor Package	1 (Note 2)	0
MAM956602	Compressed Air Receiver	1	0
V956603	Instrument Air Dryer Package	1	1
MIA956610	Instrument Air Receiver	1 (Note 3)	0
V961640	High Purity Liquid Nitrogen Storage & Vaporizer Package	1	0
V961602	High Purity Cryogenic Nitrogen Generation Package	1	0
V961601A/B	Purge Nitrogen Generation Packages	1	1
MBE961630	Nitrogen Receiver	1	0
PBA976601/02/41/42	Well Pumps	4	0
BBJ976605/6	Freshwater Tanks	2	0
BAP976603/4	Freshwater Tank Heating Coils	2	0
PBA976607A/B	Freshwater Tank Pumps	2	0
PBA976608/48	Firewater Make Up Pumps	2	0
HBG976609	Freshwater Pre-Heater	1	0
MBD976640	Freshwater Pre-Heater Condensate Pot	1	0
JAT976648	Freshwater Pre-Heater Desuperheater	1	0
PAU976611A/B	Oxidizer Injection Pumps	1	1
PAU976612A/B	Coagulant Injection Pumps	1	1
V976610	Clarification & Filter Press Package	1	0
ABM976613A/B	Clarifiers	1	1
BBJ976614	Clarified Water Clearwell Tank	1	0
PBH976616A/B	Reclaimed Water Sump Pumps	1	1
V976621	Water Purification UF Package	1	0
PAU976623A/B	Sodium Hypochloride Injection Pumps	1	1
PBM976617A/B	Clarified Water Forwarding Pumps	1	1
MAJ976622A/B	Ultrafiltration Filter Units	1	1
MAK976618	Filter Press	1	0
BBJ976626	Filtered Water Storage Tank	1	0
PBM976627A/B	Backwashwater Forwarding Pumps	1	1
PBA976628A/B	Filtered Water Forwarding Pumps	1	1
ABH976619	Reclaimed Water Sump	1	0
PBM976615A/B	Clarifier Sludge Forwarding Pumps	1	1
PAU976624A/B	Acid Injection Pumps	1	1
PAU976620A/B/C	Clarifier Polymer Feed Pumps	2	1
MAJ976629A/B	UF Cartridge Filters	1	1
MX976630	Clarifier Feed Mixer	1	0
BAP976636	Filtered Water Storage Tank Heating Coil	3	0
BAP976635	Clarified Water Clearwell Tank Heating Coil	3	0
MX976639	Backwashwater Mixer	1	0
ABD976625	Sludge Holding Tank	1	0

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	Equipment Description	Operating	Spare
V976631	Reverse Osmosis Package	1	0
V976638	CIP System	1	0
ABJ976644	CIP Cleaning Tank	1	0
PBE976645	CIP Cleaning pump	1	0
MAJ976646	CIP Cartridge Filter	1	0
PAU976632A/B	Sodium Bisulfite Metering Pumps	1	1
PAU976637A/B	Antiscalant Pumps	1	1
MX976643	1st Pass RO Feed Mixer	1	0
MAJ976633A/B	RO Cartridge Filter	1	1
PBA976647A/B	1st pass RO Booster Pumps	1	1
MAK976634	1st Pass RO Filter	1	0
BBJ977601	RO Permeate Tank	1	0
BAP977605	RO Permeate Tank Heating Coil	1	0
PBA977602A/B	RO Permeate Forwarding Pumps	1	1
V977611	Sodium Hypochlorite Generation Package	1	0
V977604	Potable Water Package	1	0
MAJ977632A/B	Activated Carbon Cartridge Filters	1	1
PAU977631A/B/C	Sodium Hypochlorite Feed Pumps	2	1
ABJ977613	Salt Dissolving Tank	1	0
PBE977614	Salt Dissolving Tank Pump	1	0
MAJ977615	Salt Water Filter	1	0
BBJ977621	Potable Water Storage Tank	1	0
BAP977622	Potable Water Storage Tank Heating Coil	1	0
ABJ977616	Brine Storage Tank	1	0
PBE977617	Brine Storage Tank Pump	1	0
ABE977618	Elecrolytic Cells	1	0
ABJ977619	Degas Tank	1	0
BLW977620	Degas Tank Blower	1	0
PBA977630A/B	Potable Water Forwarding Pumps	1	1
PBM977612A/B	Sodium Hypochlorite Distribution Pumps	1	1
V979601	Demineralization Package	1	0
BBJ979620	Demineralized Water Storage Tank	1	0
PBA979604A/B	2nd Pass RO Booster Pumps	1	1
MAK979603	Electro Deionization Filter	1	0
MAK979602	2nd Pass RO Filter	1	0
BAP979621	Demineralized Water Storage Tank Heating Coil	1	0
PBA979632A/B	Demineralized Water Forwarding Pumps	1	1
ABK979643A/B	Neutralization Tanks	1	1
PBH979634A/B	Chemical Sump Lift Pumps	1	1
ABH979638	Chemical Sump	1	0
PAH979644A/B/C	Waste Mixing Discharge Pumps	2	1
PAU979642A/B/C	Acid Pumps	2	1

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	**Equipment Description**	**Operating**	**Spare**
PAU979641A/B/C	Caustic Pumps	2	1
V979640	Neutralization Package	1	0
HFF987618	LP Steam Dump Condenser	1	0
MAJ911705	Diesel Truck Unloading Filter	1	0
BBJ911701	Diesel Storage Tank	1	0
PBA911702A/B	Diesel Transfer Pumps	1	1
MAJ911704	Diesel Fuel Filter	1	0
BAP911706	Diesel Storage Tank Heating Coil	3	0
ABH991101/601/602	Oil Sumps	3	0
PBH991111/611/612A/B	Oil Sump Pumps	3	3
MBJ964750	Slop Oil Tank	1	0
PBE964751	Slop Oil Transfer Pump	1	0
ABH997101/102/501/601/602/603/604	PCSW Collection Sump 1	7	0
PBH997111/121/112/122/511/521/611/621/612/622/613/623/614/624	PCSW Collection Sump 1 Pumps	14	0
ABH997503	PCSW Collection Sump 3	1	0
PBH997513/23	PCSW Collection Sump 3 Pumps	2	0
BAP997723	Equalization Tank Heating Coil	1	0
PBD997721	Equalization Tank Skimmer	1	0
BBJ997720	Equalization Tank	1	0
PBA997722A/B	Equalization Tank Pumps	1	1
V997731	CPI Separator Package	1	0
MBD997730	CPI Separator	1	0
PBA964736A/B	CPI Sludge Pumps	1	1
PBA964734A/B	CPI Slop Oil Pumps	1	1
ABJ997752	Coagulant and Flocculent Tank	1	0
ABJ997768	Oily Sludge Mixing Tank	1	0
PBM997753A/B	DGF Recycle Pumps	1	1
PAU997750A/B	Coagulant Metering Pumps	1	1
V997740	DGF Package	1	0
MBM997754	Saturation Vessel	1	0
ABJ997741	Flotation Tank	1	0
PBM997755A/B	DGF Sludge Pumps	1	1
PBA997769A/B	Flotation Unit Sludge Pumps	1	1
ABJ997760	Observation Basin	1	0
PBH997764A/B	Observation Basin Pumps	1	1
ABH998801	LNG Loading Berth 1 Impoundment Sump	1	0
PBH998811/21	LNG Loading Berth 1 Impoundment Sump Pumps	2	0
ABH998802	LNG Loading Berth 2 Impoundment Sump	1	0
PBH998812/22	LNG Loading Berth 2 Impoundment Sump Pumps	2	0
ABH998502	Fractionation Area Impoundment Sump	1	0
PBH998512/22	Fractionation Area Impoundment Sump Pumps	2	0

TABLE 11.5-1

Equipment Design and Sparing Consideration

Equipment Tag Number	Equipment Description	Operating	Spare
ABH998701	Condensate Truck Loading Area Impoundment Sump	1	0
PBH998711/21	Condensate Truck Loading Area Impoundment Sump Pumps	2	0
ABH998101	Liquefaction Train Impoundment Sump	1	0
PBH998111/21	Liquefaction Train Impoundment Sump Pumps	2	0
ABH998102/03	Liquefaction Compressor Impoundment Sumps	2	0
PBH998112/22/13/23	Liquefaction Compressor Impoundment Sump Pumps	4	0
ABH998702	Refrigerant Storage Area Impoundment Sump	1	0
PBH998112/22/13/23	Refrigerant Storage Area Impoundment Sump Pumps	4	0
ABH998803	LNG Storage Tank Area Impoundment Sump	1	0
PBH998813/23	LNG Storage Tank Area Impoundment Sump Pumps	2	0
ABH998804	BOG Compressor Area Impoundment Sump	1	0
PBH998814/24	BOG Compressor Area Impoundment Sump Pumps	2	0
ABJ411606	Diesel Day Tank (Firewater - Freshwater)	1	0
BBJ412601	Firewater Tank	1	0
BAP412602A/B	Firewater Tank Heater (Electric)	2	0
PFW411601	Firewater Pump (Electrical Driven)	1	0
PFW411602	Firewater Pump (Diesel Driven)	1	0
PFW411603A/B	Firewater Jockey Pump (Electrical Driven)	1	1
PFW411605A/B	Firewater Tank Circulation Pump (Electric)	1	1

Note 1: Equipment tags shown are for 2 Power Generation Units (four sets of GTG/HRSG and two sets of STG). In the event that one GTG or one STG is taken out of service, the power plant is able to supply the required electrical demand.

Note 2: Package consists of 3x50 percent air compressors with two in operation and one in spare.

Note 3: Instrument Air Receiver has 10 minutes of surge capacity between normal and minimum operating pressure at maximum continuous air flow rate. A 20 percent design margin would be applied on the air flow rate.

11.5.3 Warehouse Philosophy

Critical equipment and components to be stored in the warehouse will be determined in detailed design. The warehouse philosophy will ensure that the plant will have necessary equipment and components stored to ensure minimum availability requirements will be met.

11.5.4 Anticipated Plant Reliability and Availability

The liquefaction systems to be installed at the Facility will be designed to operate with a minimum reliability/availability of 95 percent. The detailed engineering contractor shall perform a Reliability, Availability and Maintainability ("RAM") Study to confirm that 95 percent availability is achievable with the design. In general, critical equipment required to support continuous operation of the Facility will be spared.

11.5.5 Contingency Plans

Contingency plans for failure of or impacts to major plant assets or operations due to accidental or natural disasters will be developed in detailed design.

11.5.6 Design Life

The design life of the Liquefaction Facility is 30-year service life. After the initial design life, further life expectancy can be accomplished through a system of operations and maintenance inspections. The facility will follow all operational and maintenance requirements detailed in 49 C.F.R. Part 193 to ensure a minimum design life of 30 plus years.

11.6 PIPELINE HAZARD IDENTIFICATION

11.6.1 Hazards

11.6.1.1 Leaks and Line Breaks

The primary potential hazard associated with natural gas pipeline operations is a pipeline failure including leaks and line breaks. Pipeline leaks or line breaks can occur as the consequence of operations, material defects, and corrosion. External forces can also cause leaks and line breaks. Construction activities (mechanical damage by others) can potentially lead to pipeline failures as well. Geological hazards are naturally occurring events or conditions that can potentially lead to pipeline failures. Geological hazards are addressed in Resource Report No. 6, which includes discussion of fault and seismic hazards, volcanic hazards, mass wasting, subsidence, acid rock drainage, erosion, and scour.

The worst outcome of a pipeline failure is a major rupture that could result in a fire or explosion and may lead to injury to life and property. Methane, the primary component of natural gas, has an ignition temperature of about 1,000 ºF and is flammable at concentrations between 5–15 percent in air. Unconfined mixtures of methane in air are not generally explosive, while confined releases can be explosive. Methane is buoyant at atmospheric temperatures and disperses rapidly when airborne.

Another potential hazard from a pipeline failure is the inhalation of natural gas. Methane is colorless, odorless, tasteless, and lighter than air. It is not toxic, but is classified as a simple asphyxiate, posing a slight inhalation hazard. If methane is breathed in concentrations above 50 percent, oxygen deficiency can occur, resulting in serious injury or death. If a pipeline were to develop a leak that migrated under an enclosed structure, there is a remote possibility that the atmosphere within the structure could exceed 50 percent and an asphyxiation risk would be present.

11.6.1.2 Stray Currents

Stray currents from high-voltage electric transmission lines is another hazard associated with pipelines. Alternating current and direct current electrical sources may cause stray currents to interfere with underground metallic structures such as underground steel pipelines. Additionally, fault currents may occur due to electrical shorts in some high-voltage electrical transmission power lines when a fault goes to an earth ground, affecting the pipeline and its cathodic protection system.

Since the pipeline route would parallel high voltage electrical transmission power lines from MP 510 to MP 670, there would be the possibility of interference by stray currents.

11.6.1.3 Alternating Current Interference Mitigation

Interference is defined as any detectable electrical disturbance on a structure caused by a stray current. Two kinds of alternating current (AC) interference that can affect the pipeline are described as follows.

11.6.1.3.1 Alternating Current Interference

Electrical energy from an overhead power line can be transferred to a pipeline by three possible mechanisms: conductive coupling (during fault conditions), electrostatic or capacitive coupling, and electromagnetic or inductive coupling.

The vast majority of interference problems are created by three-phase power transmission systems, because these involve both high currents and high voltages and are more likely to parallel pipelines for long distances than are low voltage distribution systems.

The most-effective method to mitigate most of the interference effects such as AC corrosion, step and touch voltage, and coating stress voltage is to install grounding. The planned cathodic protection system would provide adequate grounding to mitigate the AC interference effects. Therefore, in areas where interference is expected, such as abrupt changes in soil resistivity, locations of electrical isolations, crossings, or where the pipeline route parallels power lines, the pipeline would be evaluated for potential AC interference and a pipeline grounding system would be installed, (e.g., extension of the magnesium ribbon anodes).

11.6.1.3.2 Telluric Interference

Telluric currents are geomagnetically induced currents in the earth and in metallic structures on the earth, such as power lines and pipelines, as a result of the interaction of solar particles on the earth’s magnetic field. This induction process is similar to that caused by AC power lines, except the frequency and amplitude vary considerably due to many factors, such as the following:

- The solar cycle, a period of about 11 years between peaks of solar activity;
- The sun’s rotational frequency: 27 days;
- The earth’s daily rotation: 24 hours;
- Tidal fluctuations: about 12.5 hours; and
- Direction of the magnetic field in the solar particle plasma.

Mitigating telluric interference is similar to mitigating the AC interference produced by a power line since both are induced currents. Providing safe low-resistance leakage paths to ground is the principal objective of the mitigation systems. The magnesium ribbon anodes distributed along the pipeline route work as grounding to mitigate the telluric stray current corrosion effects.

In areas where the cathodic protection system does not include magnesium ribbon anodes, such as the Kenai portion of the pipeline, the installation of distributed sacrificial magnesium anodes would be required. Typically, the anodes can lower the pipe-to-earth resistance of a well-coated pipeline by more than an order of magnitude to mitigate the effects of the telluric currents.

11.6.2 Safety History of the Natural Gas Transportation Industry

Most of the natural gas consumed in the United States is delivered to consumers via underground pipelines. Over the past 50 years, more than 300,000 miles of pipelines (U.S. Energy Information Administration, 2014) have provided natural gas to more than 50 million consumers. Because of the critical role natural gas pipelines play in supplying the energy needs of a large segment of the country, it is imperative that they be safe and reliable. The transportation of natural gas by pipeline involves some risk to the public, workers, and contractors, in the event of an accident and subsequent release of natural gas. Overall, the natural gas pipeline industry has an excellent record of safety and reliability. System design, construction, operation, and maintenance practices would comply with regulation to minimize the potential for safety incidents.

11.6.2.1 U.S. Department of Transportation Historical Incident Data

The transportation of natural gas by pipeline is the safest mode for natural gas transportation (USDOT, 2010). Pipelines and related facilities are designed and maintained in strict accordance with USDOT standards to preserve public safety and pipeline reliability and minimize the potential for system failures.

PHMSA has been collecting and maintaining statistics on natural gas pipeline incidents since 1970. PHMSA reporting criteria have changed substantially over the years. PHMSA regulations at 49 C.F.R § 191.3 define a natural gas pipeline incident as:

- An event that involves a release of natural gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and could result in one or more of the following consequences: (i) a death or personal injury necessitating in-patient hospitalization, (ii) estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost or (iii) unintentional estimated gas loss of three million cubic feet or more;

- An event that could result in an emergency shutdown (ESD) of an LNG facility; activation of an ESD system for reasons other than an actual emergency does not constitute an incident; or

- An event that is significant in the judgment of the operator, even though it did not meet the criteria above.

All reported incidents have been maintained by PHMSA for the last 20 years. From 1995 through 2014, 1,946 total incidents were reported by natural gas transmission pipelines. Table 11.6.2-1 summarizes the incident statistics by year (USDOT, 2015).

TABLE 11.6.2-1

Natural Gas Service Incidents by Year

Year	Number	Fatalities	Injuries
1995	54	2	7
1996	76	1	5
1997	68	1	5
1998	88	1	11

TABLE 11.6.2-1

Natural Gas Service Incidents by Year

Year	Number	Fatalities	Injuries
1999	48	2	8
2000	76	15	16
2001	75	2	5
2002	73	1	4
2003	93	1	8
2004	103	0	2
2005	160	0	5
2006	130	3	3
2007	111	2	7
2008	122	0	5
2009	105	0	11
2010	107	10	61
2011	119	0	1
2012	103	0	7
2013	106	0	2
2014	132	1	1
Totals:	1,946	42	174

Source: USDOT, 2015

11.6.2.2 Relative Impact of Gas Transmission Pipelines on Public Safety

The nationwide totals for accidental fatalities from various manmade and natural hazards are listed in Table 11.6.2-2 to show the relative measure of the industry-wide safety of natural gas pipelines. The fatality rate related to natural gas pipelines is lower than the fatalities attributed to natural hazards such as lightning, tornados, floods, and earthquakes.

TABLE 11.6.2-2

Nationwide Accidental Deaths

Type of Accident	Average Fatalities per Year
Motor vehicles	36,676
Poisoning	15,206
Work Related	5,800
Large Trucks	5,150
Pedestrian	4,846

TABLE 11.6.2-2

Nationwide Accidental Deaths

Type of Accident	Average Fatalities per Year
Drowning	3,409
Fires	3,312
Flood	58
Tornado	57
Lightning	47
Gas Transmission Pipelines	2

Source: USDOT, 2004; USDOT, 2014

11.7 PIPELINE SAFETY AND RELIABILITY DESIGN

11.7.1 Introduction

The Mainline, PBTL, and PTTL and related aboveground facilities would be designed, constructed, operated, and maintained in accordance with applicable federal, state, and local laws and regulations. The pipelines would be operated in a manner that protects the safety of workers, customers, and the public.

PHMSA is responsible for regulating and enforcing pipeline safety in Alaska. The pipelines and related aboveground facilities would be designed, constructed, operated, and maintained in accordance with standards that comply with PHMSA's regulations defined in 49 C.F.R. Part 192 and any applicable special permits (SPs), which would follow 49 C.F.R. § 190.341.

11.7.2 Routing and Design Safety

Appendix A of Resource Report No. 1 provides an overview of the pipeline route and Section 1.3 of Resource Report No. 1 provides general descriptions of the pipeline and aboveground facility designs under evaluation. The pipeline route has been designed to account for public safety considerations and to comply with federal regulations. Pipeline design standards in 49 C.F.R Part 192 are based on "class location units," which classify locations based on population density in the vicinity of an existing or proposed pipeline system. The class location (1–4) increases with population density. The higher the class location, the more rigorous the design standards. For example, for any given pressure the required minimum pipeline wall thickness increases with class location.

A conservative estimate of class location has been performed based on preliminary reviews of aerial photography, from which buildings or structures were identified. This approach is commonly used to initially characterize class locations. Ground investigation would be performed during future Project phases to determine the nature of each structure. As such, the future class locations and associated MP ranges would most likely remain the same, or decrease as a result of this ground-truthing activity. At this stage, based on aerial photography, 99 percent of the Mainline route is in Class 1, which is defined as having 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of the pipeline.

The PTTL and PBTL lie entirely within Class 1 location. The design and construction of the Project pipelines would be performed in accordance with the corresponding pipeline facility class locations.

11.7.2.1 Mainline Route

The Mainline route (Revision C2) from Prudhoe Bay to Cook Inlet is primarily classified as Class 1 because dwellings are rare within 220 yards of the pipeline.

The onshore segment after the Cook Inlet crossing has shorter stretches of Class 2 and Class 3 as shown in Table 11.7.2-1.

TABLE 11.7.2-1

Class Locations for the Mainline

Milepost (MP)		**Class Location**
Start (MP)	**End (MP)**	
0.00	535.99	1
535.99	536.49	3
536.49	798.65	1
798.65	801.27	2
801.27	803.78	1
803.78	806.25	2
806.25	806.57	1

11.7.2.2 PTTL Route

For the centerline of the route defined by PTTL Route Revision B, the entire length from the Point Thomson plant to the Prudhoe Bay GTP, is Class 1 location.

TABLE 11.7.2-2

Class Location for PTTL

Milepost (MP)		**No. of Buildings**			**Proposed Class Location**
Start (Point Thomson MP)	**End (Point Thomson MP)**	**Occupied Dwelling**	**Commercial Building**	**Industrial**	
0	62.5	0	0	1	1

11.7.2.3 PBTL Route

For the centerline of the PBTL route the entire 0.6-mile length from the Central Gas Facility (CGF) to GTP is Class 1 location.

11.7.2.4 Selection of Pipe Material

The Mainline would have certain sections designed in accordance with strain-based design (SBD) requirements. These sections are preliminarily identified in Table 1.3.2-4 of Resource Report No. 1 (total of 34 miles). Table 11.7.2-3 summarizes the applicability of material selection for the pipelines.

TABLE 11.7.2-3

Design Parameters for the Pipe Selection

Pipeline	**Section**	**Material**	**Basic Design Factors**	**Code**
Mainline	Conventional (Stress-Based Design)	X80M PSL2	0.80/0.72/0.60/0.50	49 C.F.R. 192
Mainline	SBD	X70M PSL2	0.72/0.60	49 C.F.R. 192 and SBD Special Permit (SP)"
Mainline	Fault Crossings/Aerial/Horizontal Directional Drill	X70M PSL2	0.72/0.60/0.50	49 C.F.R. 192
Mainline	Offshore	X65M PSL2	0.72	49 C.F.R. 192
PTTL	All	X65M PSL2	0.72/0.60/0.50	49 C.F.R. 192
PBTL	All	API 5L-X65	0.72	49 C.F.R. 192

See Appendices A and B for SBD SP details"

Mainline line pipe can be designed using design factor of 0.50, 0.60, 0.72 and 0.80 per different class locations defined in 49 C.F.R. §§ 192.111 and 192.620. The design factor of 0.80 (Class 1 location) was selected from § 192.620, which allows the use of an alternative maximum allowable operating pressure (MAOP) based on an alternative design factor, if the requirements of §§ 192.112, 192.328 and 192.620 are met. Approximately 545 miles of the conventional Mainline would use alternative MAOP in Class 1 locations, while another 34 miles of SBD would also comply with the alternative MAOP requirements.

PTTL line pipe can be calculated using design factors of 0.72 and 0.60 for the different class locations defined in 49 C.F.R. § 192.111.

TABLE 11.7.2-4

Design Parameters for Wall Thickness Selection of the Line Pipe

Parameter	**Mainline X80M PSL2**	**Mainline X70M PSL2**	**PTTL X65M PSL2**	**PBTL** API 5L-X65
SMYS	80.5 ksi	70.3 ksi	65.3 ksi	65.0 ksi
Diameter	42 inches	42 inches	32 inches	60 inches
Design pressure	2,075 psig	2,075 psig	1,150 psig	790 psig

Notes:
psig = pounds per square inch gauge, ksi = thousands psi,
SMYS = specified minimum yield strength, referenced in API 5L specification

The minimum wall thickness is calculated in accordance with 49 C.F.R. § 192.105, which can be rearranged for wall thickness (t), and where P is the MAOP:

$$P = \frac{2St}{D} \cdot F \cdot E \cdot T \qquad (1)$$

Where:

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch.

t = Nominal wall thickness of the pipe in inches.

D = Nominal outside diameter of the pipe in inches.

F = Design factor.

E = Longitudinal joint factor (submerged arc welding [SAW] pipe = 1).

T = Temperature derating factor (for up to 250 °F = 1).

Rearranging Equation 1 to determine wall thickness:

$$t = \frac{P \cdot D}{2 \cdot S \cdot F \cdot E \cdot T} \qquad (2)$$

11.7.2.5 Selection of Wall Thickness

As specified in 49 C.F.R. § 192.105, minimum wall thicknesses are calculated using equation (2) of Section 11.7.2-5, including the alternative design factor for buried Class 1 location.

TABLE 11.7.2-5

Calculated Minimum Wall Thicknesses for Line Pipe

Design Factor	**Mainline X80M Wall Thickness (inches)**	**Mainline X70M Wall Thickness (inches)**	**PTTL X65M Wall Thickness (inches)**	**PBTL API 5L-X65 Wall Thickness (inches)**
0.80	0.677	N/A	N/A	N/A
0.72	0.752	0.862	0.392	0.632
0.60	0.903	1.034	0.470	N/A
0.50	1.083	1.240	N/A	N/A
*Minimum required wall thickness of 0.507 plus 0.125 corrosion allowance				

However, the PTTL wall thickness selection has additional requirements due to ballistics resistance and transportation considerations that result in a wall thickness of not less than 0.500 inches. For PTTL, no corrosion allowance is required based on PTU operating criteria, and no water condensation is anticipated to occur under normal operating conditions. This will be further evaluated in a later stage of the Project in collaboration with the PTU project team. A 0.125 corrosion allowance has been added to the minimum calculated wall thickness for the PBTL due to the appreciable levels of CO_2 and H_2S present in the gas stream, resulting in a minimum wall thickness of 0.632 inches. A standard wall thickness of 0.688 has been selected for the PBTL.

In summary, the following wall thickness values were selected for the PTTL and PBTL:

TABLE 11.7.2-6

Selected PTTL and PBTL Wall Thickness

Basic Design Factor	PTTL X65M Wall Thickness (inches)	PBTL API 5L-X65 Wall Thickness (inches)
0.72	0.500	.688
0.60	0.500	N/A

11.7.2.6 Design for Ground Movement (Strain-Based Design)

As explained in Resource Report No. 1 (Section 1.3.2.1.2), the Mainline design, both onshore and offshore, would comply with the requirements of 49 C.F.R. Part 192 Subpart C. Segments of the onshore Mainline, however, would cross areas that may exert higher structural demands on the pipe through displacement controlled external pipe movements such as frost heave or thaw settlement. Consistent with 49 C.F.R. § 192.103, Type 2 design (SBD), as opposed to the conventional Type 1 design (see Table 1.3.2-4), would be implemented to ensure that the pipeline can withstand these higher structural demands in these areas, in addition to pressure containment requirements. An SBD SP from PHMSA would be required to implement this Type 2 design.

If granted, this SP would allow continued operation of the pipeline after ground movements result in strains greater than 0.5 percent in Class 1 locations. The SBD SP would contain conditions that apply to the covered SBD Segments of the pipeline over its lifecycle. Discussions have been held with PHMSA to ensure that these conditions would fulfill the additional design and operational requirements that would be required in the SBD segments to ensure that these segments can safely withstand the higher strains that may occur in these areas. A level of pipeline safety that is greater than or equal to that provided by compliance with 49 C.F.R. Part 192 is provided by using SBD in compliance with these conditions. Thus, no differences are expected in environmental consequences between SBD and conventional design. These conditions are summarized herein to demonstrate that there are negligible differences in environmental consequence between SBD and conventional design. Additional details can be found in Appendix B (Proposed SBD SP Conditions) and Appendix A (SBD Environmental Information for PHMSA).

The SBD SP Conditions are organized into three groupings that follow the lifecycle of the pipeline: design and materials, construction, and operations and maintenance. The SBD SP Conditions specify that the Project must develop a SBD Plan, consisting of three Elements that correspond to these three stages of the pipeline life cycle. Project representatives will submit these SBD Plan Elements to PHMSA and an Independent Third-Party Reviewer for review and validation in accordance with the schedule in Condition 3 of the SBD SP (Appendix B).

SBD Plan Element I will include details on supplemental line pipe requirements, material testing requirements, and the process to determine longitudinal tensile and compressive strain capacity of pipe and girth welds. This testing will include a suite of small-scale and full-scale tests. The results of these tests and design procedures contained within SBD Plan Element I will determine the amount of axial strain that the pipeline can safely experience. The information developed for Element I will also help to define construction and operation requirements. SBD Plan Element I will provide the basis for the Project Material

Specifications used for procuring line pipe that is capable of withstanding the ground movements in the SBD regions.

SBD Plan Element II will consist of construction requirements, including procedures for the development of production girth weld quality requirements. Element II will describe supplemental requirements on girth weld properties and the requirements for testing of girth welds to demonstrate they will achieve the required strain capacity for the SBD segments. Element II will also describe requirements to demonstrate the qualifications of personnel performing welding and additional construction quality monitoring to ensure the engineering requirements necessary to safely operate the pipeline will be properly implemented. Enhanced girth weld traceability, supplemental cathodic protection system commissioning requirements, pipeline assessment using a deformation tool, and a right-of-way (ROW) construction monitoring program will also be described in Element II.

SBD Plan Element III will address operations and maintenance requirements. Ground movements that are addressed by SBD accumulate over a period of many years, allowing for an integrity management plan for strain to be applied to further enhance safety. Element III will describe the integrity management plan, including use of in-line inspection (ILI) tools to monitor deformation of the pipeline in the SBD segments and procedures to ensure that the strain remains within safe limits. The Operations and Maintenance Procedures will account for the effects of potential corrosion and/or mechanical damage on the strain capacity of the pipeline. However, the risk for corrosion damage is expected to be low given the cathodic protection and high integrity external coating systems that are proposed for use (see Section 11.6.2.8), both of which protect against external corrosion, and the LNG quality gas, which will have a very low potential for internal corrosion.

The SBD SP Conditions also require that the SBD segments must be designed, constructed, operated, and maintained in accordance with 49 C.F.R. Part 192 including, but not limited to, those additional requirements that are stated as pertaining to alternative MAOP (49 C.F.R. §§ 192.112, 192.328, and 192.620). These alternative MAOP sections set out the most robust requirements for pipeline safety in 49 C.F.R. Part 192, and like the SBD SP Conditions, encompass the full lifecycle of the pipeline as described as follows:

- 49 C.F.R. § 192.112 details design requirements that include enhanced steel pipe and line pipe manufacturing standards, a fracture control plan, as well as additional limits on the metallurgy of fittings, flanges, coating integrity and temperature limits in proximity to compressor stations;

- Additional construction requirements are detailed in 49 C.F.R. § 192.328. These include the need for a construction quality assurance plan, 100 percent non-destructive testing of all girth welds, minimum burial depth of 36 inches, initial strength test reporting requirements for any systemic material defects identified by hydrostatic testing, and the need to address the impacts of induced alternating currents on the cathodic protection system; and

- 49 C.F.R. § 192.620 describes additional operational and maintenance requirements. These include additional controls for both internal and external corrosion, assessment of coating condition through indirect assessment techniques (e.g., direct current voltage gradient or AC voltage gradient), patrolling the ROW 12 times per year with intervals not to exceed 45 days, requirements for both baseline and periodic assessment of pipeline integrity, notification of the public within close proximity of the pipeline, and implementation of a public education program, along with identifying and evaluation threats.

In addition to the alternative MAOP requirements, the SBD SP Conditions require the SBD segments to be treated as though they are covered segments in High Consequence Areas (HCAs) and to develop and implement an integrity management program (IMP) that meets the requirements of 49 C.F.R. Part 192, Subpart O, except for the reporting requirements contained in 49 C.F.R. § 192.945. Project representatives would perform a baseline assessment that includes ILI assessment along the entire length of the SBD segments no later than pipeline commissioning. ILI must be repeated at intervals not to exceed seven calendar years, and the variance between ILI tool measurements and actual field conditions must be monitored. Depending upon the severity of anomalies detected by ILI tools, an evaluation must be completed and, depending on the results of the evaluation, further remediation measures or monitoring must be implemented.

11.7.2.7 Design of Crossings

To validate wall thickness requirements for road and railroad crossings, the Recommended Practice API 1102 Steel Pipelines Crossing Railroads and Highways was used; adopted for application in a way to be compatible with ADOT&PF and ASME B31.8 Gas Transmission and Distribution Piping Systems requirements (temperature derating factors, design factors, etc.).

TABLE 11.7.2-7

General Crossing Parameters

Parameter	**Mainline X80M PSL2**	**Mainline X70M PSL2**	**PTTL X65M PSL2**
SMYS	80.5 ksi	70.3 ksi	65.3 ksi
Diameter	42 inches	42 inches	32 inches
Design pressure	2,075 psig	2,075 psig	1,150 psig
Longitudinal weld	SAWL	SAWL	SAWL
Installation temperature	-10 °F (winter)	-10 °F (winter)	-10 °F (winter)
Maximum operating temperature	80 °F	80 °F	70 °F
Soil unit weight	120 pounds/cubic feet	120 pounds/cubic feet	120 pounds/cubic feet
Soil type	Medium dense sands and gravels	Medium dense sands and gravels	Medium dense sands and gravels
Type of construction	Bored	Bored	Bored with conduit
Young's modulus	30,000 ksi (per API 5L Spec)	30,000 ksi (per API 5L Spec)	30,000 ksi (per API 5L Spec)

Notes:
psig = pounds per square inch gauge, ksi = thousands psi,
SMYS = specified minimum yield strength, referenced in API 5L specification
SAWL = submerged arc-welded pipe

11.7.2.7.1 Road Crossings

Table 11.7.2-8 lists the input parameters for calculating required wall thickness for crossings.

TABLE 11.7.2-8

Specific Design Parameters for Road and Highway Crossings

Parameter	**Mainline X80M PSL2**	**Mainline X70M PSL2**	**PTTL X65M PSL2**
Critical Axle Configuration	Tandem axle	Tandem axle	Tandem axle
Pavement type	Flexible pavement	Flexible pavement	Flexible pavement
Depth of cover – typical	4 feet	4 feet	4 feet

Notes:
Depth of cover – to travel surface (top of the road)

As defined in 49 C.F.R. Part 192, Table 11.7.2-9 shows the wall thickness used for differing nominal design factors.

TABLE 11.7.2-9

Summary of Wall Thickness at Road Crossings

Design Factor	**Mainline X80M Wall Thickness (inches)**	**Mainline X70M Wall Thickness (inches)**	**PTTL X65M Wall Thickness (inches)**
0.72	0.752	0.862	0.500
0.60	0.903	1.034	0.500
0.50	1.083	1.240	N/A

11.7.2.7.2 Railroad Crossings

Table 11.7.2-10 shows the input parameters for calculating required wall thickness for railroad crossings.

TABLE 11.7.2-10

Specific Design Parameters for Railroad Crossings

Parameter	Mainline X80M PSL2	Mainline X70M PSL2	PTTL X65M PSL2
Number of tracks	Dual	Dual	Dual
Depth of cover	10 feet	10 feet	10 feet

Notes:
Depth of cover – from base of the rail to the top of the pipe per the Alaska Railroad Corporation's Technical Standards for Roadway, Trail, and Utility Facilities

As defined in 49 C.F.R. Part 192, Table 11.7.2-11 shows the wall thickness calculated for different location classes.

TABLE 11.7.2-11 **Summary of Wall Thickness at Road Crossings**			
Design Factor	**Mainline X80M Wall Thickness (inches)**	**Mainline X70M Wall Thickness (inches)**	**PTTL X65M Wall Thickness (inches)**
0.60	0.903	1.034	0.500
0.50	1.083	1.24	N/A

11.7.2.7.3 Trans-Alaska Pipeline (TAPS) Crossings

Trans-Alaska Pipeline System (TAPS) is a major oil pipeline in Alaska. The Project Mainline alignment generally follows TAPS corridor for approximately 400 miles from the North Slope down to Livengood and currently crosses TAPS at 12 locations and the Fuel Gas Line (FGL) at 5 locations. The number of crossings and crossing locations may change based on future route adjustments.

For crossings where TAPS is below ground and depending on the depth of TAPS at the Mainline crossing location, a berm may be required to cover the Mainline and would be designed with a minimum of 3 feet from the top of the Mainline to the surface of the berm. For crossings where TAPS is above ground, a minimum 4 feet of cover would be maintained under TAPS and the TAPS access road. In both cases, the depth of cover for TAPS crossings exceeds the requirements set forth under 49 C.F.R. § 192.327 for pipeline Class Location 1 not operated at an alternative MAOP, and meets the requirements of 49 C.F.R. § 192.328(c) for pipelines eligible to be operated at an alternative MAOP, where applicable.

All TAPS crossing sites for the Mainline Route are within Class Location 1. The wall thickness to use for the pipe at TAPS crossings is subject to Crossing Agreement(s) with Alyeska Pipeline, current operator of TAPS, and will be confirmed at a later date.

Finally, the cathodic protection at all TAPS crossings would meet minimum design requirements, including, but not limited to, those set forth under 49 C.F.R. §§ 192.112(f), 192.473, 192.328(c) and 192.620(d)(6), where applicable. Cathodic protection at TAPS crossings would also be subject to agreement with Alyeska Pipeline Service Company (APSC).

11.7.2.7.4 Proximity to TAPS Studies

Alyeska Pipeline Service Company (APSC), agent for the Trans Alaska Pipeline System (TAPS) owners, participated in a Joint Engineering Study of AKLNG Gas Pipeline Impact on TAPS Operations and Integrity Maintenance (TAPS Impact Study) following initiation of the FERC Pre-Filing process in 2014. The Mainline, TAPS, and TAPS FGL would be located in proximity at various points from TAPS Pump Station 1 to approximately MP 400, at which point TAPS heads in a southeast direction to the Valdez Marine Terminal and the Project Mainline would head south to the Liquefaction Facility at Nikiski.

The joint study included consideration of the following topics:

- Construction Methods, including crossings, ROW use, separation distances for both TAPS buried and aboveground modes, and use of construction blasting for pipeline installation;

- Geotechnical considerations, including frozen debris lobes, slope stability, and aufeis potential;
- Hydraulics and hydrology considerations, including surface hydrology assessment of the Project's cleared ROW, construction of work pads, and granular material mining;
- Operational synergies for both pipelines, including communications, monitoring programs, and emergency response;
- Cathodic Protection design and interference mitigations in the vicinity of TAPS;
- Crater rupture analysis to understand crater width in the unlikely event of a rupture of the Mainline near TAPS; and
- Detailed crossing method analysis for the Yukon River crossing near the E.L. Patton bridge.
- Analysis to evaluate scenarios involving blasting when the Trans Alaska Pipeline System (TAPS) mainline, Fuel Gas Line (FGL), or other aboveground structures are in "proximity" to the Alaska Liquefied Natural Gas (LNG) pipeline.

The study referenced TAPS conditions and requirements, and involved developing a TAPS impact basis to further analyze the eight areas of concern. The resulting nine reports (the Basis and individual reports for each of the eight areas of concern) are included as Appendix I through Q to this Resource Report.

Coordination with APSC would be continued in future Project phases to advance the characterization and resolution of considerations related to the Project's Mainline in proximity to TAPS and FGL, including topics such as design, construction procedures, operations, and emergency response.

11.7.2.7.5 Cook Inlet Crossing

Operational risks associated with the segment of the Mainline crossing the Cook Inlet were considered in design and construction planning. Multi-year geophysical, geotechnical and metocean surveys were conducted to optimize the Mainline routing and the selection of landfalls. Numerical modeling were conducted to develop and test design criteria against likely environmental factors and potential extreme weather events. Physical impacts of the pipeline, route stability, and geohazard assessments were conducted and incorporated into the design to account for the potential risks of external forces such as moving boulders, anchors, vessels, ice keels, or seismic events. As a result of these studies and evaluations, the segment of the Mainline crossing Cook Inlet is designed with steel wall thickness of 1.25 inches, far exceeding governing code (49 C.F.R. Part 192) for pressure containment. In addition, the Cook Inlet crossing pipeline will also be coated with 3.5 inches of concrete coating for stability and added impact and abrasion protection, and in compliance with the cover requirement in C.F.R. § 192.327. The Mainline will be buried at the Cook Inlet shore crossings to avoid potential impacts of shallow water hazards such as ice, vessel keels, and beach erosion or soil scour that could create pipeline unsupported spans. The Mainline route across Cook Inlet was selected to avoid areas with significant changes in the seafloor, minimize the number of critical length pipeline spans to be rectified during operations and obviate vortex-induced vibrations. The Cook Inlet pipeline was also selected to eschew extreme current areas and avoid perpendicular alignment to the current direction to minimize pipeline vortex induced vibration (VIV) fatigue risks.

During operations, regular imaging surveys of the pipeline would assist in identifying potential unsupported spans or objects encroaching on the pipeline. Necessary equipment would be available and agreements would be in place to ensure timely mitigation and repair as required.

TABLE 11.7.2-12

Pipe Parameters

Outside Diameter		42-in
Design Pressure, psig		2075
Pipe Steel Grade		API 5L Gr X65
Design Factor		0.72 (not governing)
Allowable Fatigue Design Factor		10
Pipe Wall Thickness (in)		1.25
Anti-Corrosion Coating		16 mils FBE + CP as supplementary
Concrete Weight Coating	Thickness (in)	3.5
	Density (pcf)	190
Bracelet Anodes	No. of Anodes	769
	Anode Mass (lb)	933
	Anode Space	4-5

11.7.2.8 Fracture Control, Mainline Block Valve Spacing, and Crack Arrestor Spacing

11.7.2.8.1 Fracture Control

Because the entire onshore Mainline would be designed in accordance with the alternative MAOP requirements of 49 C.F.R. Part 192, it must comply with the fracture control conditions of 49 C.F.R. § 192.112., which require that "the toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures." Fracture initiation and propagation analyses have been performed in accordance with 49 C.F.R. § 192.112 for the range of pipe grades and wall thicknesses used for the Project. The results are provided in the Tables 11.7.2-13 and 11.7.2-14.

TABLE 11.7.2-13

Fracture Control: Fracture Initiation

Section	Grade	Class Location	Design Factor	Wall thickness (inches)	L_{crit} (in)	
					Pipe Body	Seam Weld/HAZ
Conventional (Type 1)	X80M	1 [a]	0.8	0.677	5.9	5.1
		1	0.72	0.752	7.5	6.5
		2	0.6	0.903	10.6	9.7
		3	0.5	1.083	13.4	10.2
Strain-Based (Type 2)	X70M	1	0.72	0.862	8.7	7.5
		2	0.6	1.034	11.4	9.0

Notes:[a] - utilizing Alternative MAOP

In Table 11.7.2.-13, the term "Lcrit" is the critical length, which is the length of through wall penetration in the axial direction that would be required to result in a pipeline rupture, being defined as a full bore bursting of the pipeline. Wall penetrations with length less than Lcrit would result in a leak, but not a rupture. As can be seen in Table 11.7.2.-13, even for the least conservative case, grade X80 pipe using 0.8 design factor (DF), the minimum Lcrit of 5.1 inches is quite large. The pipeline would not be put into service with any through wall defects. Additionally, given the dry gas composition it is highly unlikely that a through wall defect of any size would develop during service, let alone one that is > 5 inches. It is also very unlikely that third-party damage would result in this size through wall defect given the pipe strength (80 ksi minimum yield strength) and 0.68-inch minimum wall thickness. It is also worth noting that this is the least conservative condition in two ways. First, it is only for Class 1 Alternative MAOP X80 design. Second, it is only for the seam weld, which is a small fraction of the total pipe circumference. A penetration in the pipe body (the remainder of the circumference) would have to be at least 5.9 inches in length to result in a rupture. These results demonstrate the resistance of the Mainline to rupture.

In the unlikely event of a rupture, fracture control measures are required to ensure that the propagating fracture would arrest within a limited distance. Table 11.7.2.-14 illustrates the fracture control strategy that was selected for the different segments of the Mainline. In all but two design cases, a fracture that is propagating in the longitudinal direction of the pipe would self-arrest. This feature is known as intrinsic arrest, and meets the requirements of § 192.112(b)(2)(iii). Where intrinsic arrest is not feasible, mechanical crack arrestors would be used. This is needed in two design cases, grade X80 with 0.8 DF and 0.72 DF.

TABLE 11.7.2-14

Fracture Control: Fracture Arrest

Section	Grade	Class Location	Design Factor	Wall thickness (inches)	Fracture Arrest
Conventional (Type 1)	X80M	1*	0.8	0.677	Crack Arrestor
		1	0.72	0.752	Crack Arrestor
		2	0.6	0.903	Intrinsic
		3	0.5	1.083	Intrinsic
Strain-Based (Type 2)	X70M	1	0.72	0.862	Intrinsic
		2	0.6	1.034	Intrinsic

Note: * - utilizing Alternative MAOP

11.7.2.8.2 Mainline Block Valve and Crack Arrestor Spacing Studies

MLBVs serve the purpose of isolating pipeline sections 1) in the event of an emergency, and 2) for pipeline maintenance activities. Given their purpose of sectionalizing the pipeline, and importance both in emergency and for maintenance, ASME B31.8 (2014) requires an engineering analysis be performed[5] that incorporates the following considerations for number and placement of block valves:

5 ASME B31.8 (2014) Section 846.1.1 "Required Spacing of Valves: Transmission Lines"

- Locations that provide continuous accessibility to the valves;
- The amount of gas released due to repair and maintenance blowdowns, leaks, or ruptures;
- The time to blow down an isolated section;
- The impact in the area of gas release (e.g., nuisance and any hazard resulting from prolonged blowdowns);
- Continuity of service;
- Operating and maintenance flexibility of the system;
- Future development in the vicinity of the pipeline; and
- Significant conditions that may adversely affect the operation and security of the line.

If this engineering analysis is not performed, ASME B31.8 recommends the same MLBV spacing that is required in 49 C.F.R. § 192.179; 49 C.F.R. Part 192 does not provide the option to conduct the engineering analysis recommended by ASME B31.8.

An engineering study was performed that considered the above requirements from ASME B31.8.

Of primary importance was comparing the impact of MLBV spacing on pipeline safety, with the goal of determining whether increasing MLBV spacing in Class 1 locations beyond the 49 C.F.R. § 192.179 limits would result in an equivalent level of safety. With the primary safety concern being a pipeline rupture and ignition of gas within the pipeline, this comparison viewed the hazards in terms of the volume of natural gas released over time, the potential for damage to surrounding structures, and the life safety risk to personnel and the public. A summary of those results has been published[6] and concluded that "these results indicate that increased valve spacing could be implemented in remote, low population density areas without affecting safety."

This same study also evaluated the thermal radiation effects of increasing crack arrestor spacing from 320 feet to 3,200 feet. The 320-foot spacing corresponds to eight pipe lengths that are each 40 feet in length, and complies with 49 C.F.R. Part 192 requirements. It was found that there was no effect on the area exposed to accumulated heat exposure for people for crack arrestor spacings up to 1,600 feet, while an increase in exposed area of about 13 percent was found for the 3,200 feet fracture length scenario.

The results of this work analyzing MLBV spacing for the Project are consistent with previous studies that examined the results of National Transportation and Safety Board and PHMSA incident databases and

6 Rothwell, B., Dessein, T. and Collard, A. 2016. Effect of Block Valve and Crack Arrestor Spacing on Thermal Radiation Hazards Associated with Ignited Rupture Incidents for Natural Gas Pipelines. Proceedings of the International Pipeline Conference, ASME International, New York, NY. Paper IPC2016-64604. September.

concluded the risk to the public is independent of valve spacing.[7,8] This is attributed to the fact that “the injuries and fatalities on gas transmission pipelines generally occur during the first 30 seconds after gas has been released from a pipeline.” Valve spacing does not affect the thermal radiation field and accumulated heat exposure until well after the rupture has occurred. This is because valve spacing has no effect on outflow rate or thermal radiation until after approximately 17 minutes, which is much greater than 30 seconds.

Additionally, pipeline safety historical data demonstrates that the probability of incidents, injuries, and fatalities in Class 1 is significantly lower than in Class 2, 3, or 4 locations.[7] The Mainline route has been characterized for location of dwellings and structures in accordance with 49 C.F.R. § 192.5 and 99 percent of the Mainline route is in Class 1. This route characterization has also determined that there are more than 700 miles of pipeline route crossing areas with no inhabited dwellings. Given the geographic remoteness and robust size and grade of line pipe, there is an extremely low probability that the pipeline would be ruptured.

11.7.2.8.3 Mainline Block Valve and Crack Arrestor Spacing Special Permit

Given the results of the aforementioned analyses, there are plans to apply for a MLBV and Crack Arrestor (CA) spacing SP from PHMSA in Class 1, remote locations. If PHMSA grants this SP, it would contain conditions that would apply to the pipeline over its lifecycle. These conditions are summarized herein to demonstrate that there are negligible differences in environmental consequence between conventional design and the proposed MLBV and CA Spacing SP. This SP would allow for MLBV spacing in Class 1 locations to be increased to 50 miles north of Fairbanks and 30 miles south of Fairbanks. Similarly, in Class 1 locations, CA spacing would be increased to a nominal value of 1,600 feet, but in extremely remote, unpopulated areas the spacing may be up to 0.5 mile (2,640 feet). PHMSA SP approval is conditioned on achieving equal or greater level of safety than compliance with 49 C.F.R. Part 192. Additional details can be found in Appendix C (Environmental Information for MLBV and CA Spacing SP) and Appendix E (Three Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit). Additional technical justification for the increase in MLBV spacing is included in Appendix G.

The MLBV and CA spacing SP Conditions provide for enhanced MLBV monitoring, with equivalent or better valve actuation times than required by 49 C.F.R. Part 192 and common industry practice. The Conditions also require additional measures when in proximity to key infrastructure and Class 3 and 4 locations.

Real time monitoring and control of pipeline flows, pressure and temperature at 11 of the Main Line Block Valves (those located at compressor and heater stations and the start and end of the Mainline) would be managed from the Pipeline Control Center. Monitoring would enable diagnosis of pressure transients and if necessary, the remote closure of MLBVs and shut-down of compression equipment. These safety measures exceed the requirements of 49 C.F.R. Part 192 for sectionalizing valves. Additionally, stand-

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7 Eiber, R., McGehee, W., Hopkins, P., Smith, T., Diggory, I., Goodfellow, G., Baldwin, T. R. and McHugh, D. 2000. Valve Spacing Basis for Gas Transmission Pipelines. Pipeline Research Council International, PRCI Report PR 249 9728. January.

8 Eiber, R., and Kiefner, J. 2010. Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing. ASME Standards Technology, LLC. Columbus. July.

alone Automatic Shut Off Valves (ASV) would be located along the Mainline that would automatically close if the pressure falls below a predetermined set point (60% MOP).

After consultation with ADOT&PF and PHMSA regarding key infrastructure in Class 1 locations, the following five key bridges were identified within proximity to the Mainline: Dietrich River (13377)[9], Nenana River at Moody (1143), Nenana River at Windy (1243), Iceworm Gulch (1146), and Antler Creek (1141). Pipe capable of intrinsic arrest and with a larger Lcrit would be used, reducing the probability of rupture within proximity to these bridges. Similarly, all SBD pipeline segments would be capable of intrinsic arrest. The probability of rupture would thereby be further reduced in proximity to key bridges and in areas that are likely to experience ground movement.

The MLBV and CA Spacing SP Conditions also require that the Mainline must be designed, constructed, operated, and maintained in accordance with 49 C.F.R. Part 192 including, but not limited to, those requirements that are stated as pertaining to alternative MAOP (§§ 192.112, 192.328, and 192.620), but with exception to the crack arrestor spacing requirements of § 192.112(b)(2)(iii) and § 192.112(b)(3). These alternative MAOP sections set out the most robust requirements for pipeline safety in 49 C.F.R. Part 192, and like the SBD SP Conditions, encompass the full lifecycle of the pipeline.

11.7.2.9 High Integrity Multi-Layer Coatings

There are several challenges that a coating system must successfully face when being considered for use in Alaska. The coating system must be resistant to damage from multiple sources, including transport, UV degradation, and backfill. 49 C.F.R. § 192.461 "External corrosion control: Protective coating" provides additional details on what is required of pipeline external anti-corrosion coatings. Given these requirements in 49 C.F.R. Part 192, and the above unique demands of the Alaskan environment, a multi-layer coating system known as Three-Layer Polyethylene (3LPE) has been selected. 3LPE coatings contain a base layer of FBE, a copolymer adhesive layer, and outer layer of polyethylene. The presence of the outer polyethylene layer provides increased resistance to mechanical damage and UV degradation compared to single-layer FBE coatings. Because of their favorable properties and superior integrity, multi-layer coatings are the predominant coating system used in new construction worldwide[10], despite their increased cost compared to FBE, the commonly used coating system in the Lower 48 states.

The remote location of the onshore Mainline requires transporting the coated pipe significant distances by ship, rail, and truck. Substantial travel over unpaved roads and the unpaved ROW is required to deliver the pipe. This makes 3LPE coatings, with their increased resistance to transportation damage, particularly well-suited to the Alaska environment. 3LPE coatings would have less damage after installation and require fewer repairs. In addition, 3LPE coatings are more resistant to degradation over the service life of the pipeline. Because of reduced coating damage or degradation and increased electrical resistance, a 3LPE coated pipeline requires less cathodic protection current than a FBE coated pipeline. This has the added benefit of reducing potential for interference with adjacent cathodic protection systems, including that of TAPS. The reduced current density requirement would reduce the power requirements of the cathodic

9 Bridge numbers from "Alaska 2013 Bridge Inventory Report": http://www.dot.alaska.gov/stwddes/desbridge/assets/pdf/2013bridgeinventory.pdf

10 NACE Corrosion 2013 Paper No. 2080, 'A Critical Review of Industry Codes and Standards as They Related to Electrically Resistive Coatings and What That Means to Shielding', Robert Buchanan, Canusa-CPS.

protection system and may require fewer and smaller anode ground beds with a 3LPE coating than it would with an FBE coating.

An independent third-party review by DNV GL included the suitability of 3LPE for use for the entire length of the onshore Mainline. After review of the multi-layer coating plans, DNV GL concluded "multi-layer polyethylene coating is an effective option for long-term protection because of its ability to meet the performance demands of the Alaskan environment." This information was provided to PHMSA[11.]

The Mainline would be designed, constructed, operated, and maintained in accordance with 49 C.F.R. Part 192 including, but not limited to, those requirements that are stated as pertaining to alternative MAOP (§§ 192.112, 192.328, and 192.620). For pipelines operating using Alternative MAOP, 49 C.F.R. § 192.112 requires that "the pipe must be protected against external corrosion by a non-shielding coating." PHMSA's Alternative MAOP Frequently Asked Questions website[12] states "FBE coatings are considered modern pipe coatings for alternative MAOP pipelines. Other coating systems would require additional approvals from PHMSA for usage on alternative MAOP pipelines."

Given the favorable industry experience with 3LPE coatings and their suitability for the Alaskan environment, a 3LPE SP would be requested from PHMSA. If PHMSA were to grant this SP, it would contain conditions that apply to the pipeline over its lifecycle. These conditions are summarized herein to demonstrate that there are negligible differences in environmental consequence between conventional design and the proposed 3LPE SP. This SP would allow for the use of 3LPE coatings over the entire length of the onshore Mainline. PHMSA SP approval is conditioned on achieving equal or greater level of safety than compliance with 49 C.F.R. Part 192. Additional details can be found in Three-Layer Polyethylene Coating, Mainline Block Valve, and Crack Arrestor Spacing Special Permit (Appendix E) and Environmental Information for Multi-Layer Coating Special Permit (Appendix D) for PHMSA. Additional technical justification for the use of 3LPE is included in Appendix F.

The SP conditions would require that both the coating system and coating applicator complete qualification tests and meet the acceptance criteria in accordance with International Organization for Standardization 21809-1: 2011 Petroleum and natural gas industries -- External coatings for buried or submerged pipelines used in pipeline transportation systems -- Part 1: Polyolefin coatings (3-layer PE and 3-layer PP) (ISO 21809-10. A coating specification would be required that details the pipe surface preparation and inspection, dry film thickness of the coating system, and non-destructive inspection for holes in the coating system (holiday detection). During mill application the coating system must be inspected by a National Association of Corrosion Engineers (NACE)-certified Coatings Inspector, or equivalent.

During construction, the SP Conditions would require liquid applied epoxy, liquid applied urethane, or fusion bonded epoxy field joint coatings (FJCs). Heat shrink sleeves or tape wrap coatings, which have demonstrated problems associated with pipeline Stress Corrosion Cracking (SCC), a type of crack growth in corrosive environments, are not permitted. The conditions would also require a FJC coating application procedure that has been qualified using a variety of testing methods. During field joint coating, the coating system must be inspected by a NACE certified Coatings Inspector, or equivalent.

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11 Independent Third-Party Review of Strain-Based Pipeline Design, Final Report, DNV GL Report No.: PP139507-1.

12 http://primis.phmsa.dot.gov/maop/faqs.htm

PHMSA has inquired whether there is a concern that the use of 3LPE could potentially enhance the pipe susceptibility to SCC. After an extensive literature search, neither the Project representatives nor DNV GL were able to identify any instances of SCC associated with 3LPE[11], nor are there any known instances of SCC associated with the proposed FJCs. Given the greater than 20 years of field experience with these coating systems, their prevalence of use worldwide, and the aforementioned conditions, there would be a very low probability that SCC would develop. Nonetheless, during Operation, the SP conditions would require an assessment of the pipeline system for SCC by ILI with tools capable of detecting cracking.

11.7.2.10 Hydrostatic Testing Requirements

All pressure testing should comply with the requirements of 49 C.F.R. Part 192 to qualify the Mainline for an MAOP of 2,075 psig and the PTTL for an MAOP of 1,150 psig.

Preliminary pressure test calculations were completed for each of the proposed construction spreads. Table 11.7.2-15 summarizes the test sections within each construction spread, the number of test sections, and the quantity of both SBD heavy wall pipe based upon preliminary estimates and heavy wall pipe to facilitate pressure testing.

TABLE 11.7.2-15

Test Selections and Heavy Wall Pipe Summary for the Mainline

Construction Spread	Location		Length (miles)	Test Sections
	Start MP	End MP		
Spread 1	0.00	209.17	209.17	21
Spread 2	209.17	401.26	192.09	28
Spread 3	401.26	594.54	193.28	17
Spread 4	594.54	804.02	209.47	13
Total				79

It is proposed to use only summer hydrostatic testing procedures by testing pipeline segments constructed during the winter along with pipeline segments constructed during the following summer. The effect of permafrost on the hydrostatic test of the buried pipeline would be analyzed to determine what testing procedures are required for such test sections during a later stage of the Project. The procedure would account for the potential effect of ice on hydrostatic testing. The ice may inhibit drying the pipeline after the hydrostatic test. Winter testing procedures may include using heated fill water or glycol additive to prevent freezing.

PTTL requires three hydrostatic test sections, with all pressure testing completed during the summer following construction. Test section locations would be determined by summer access to the major water sources.

11.7.2.11 Hazard Detection and Mitigation System

A Hazard Detection and Mitigation System (HDMS) would be used at each compressor, heater, and meter station to detect and mitigate the occurrence of potential physical situations that could result in injury to personnel and/or damage to property and the environment. The HDMS would accomplish this by detecting and alerting the Facility Operators or Gas Control Center the presence of fire, smoke, or flammable gas hazards, so that the operators can respond appropriately to control these hazards.

The HDMS would consist of the following components: field-mounted flame, thermal/heat, combustible gas and smoke detection suitable for the hazards specific in the area/buildings (note that, unlike locations within gas distribution systems, no odorant is utilized in a high pressure, gas transmission system - the extensive monitoring within gas facilities is the alternative safety system.). Selection would be based on which type is suitable for the conditions at each detector location and would be finalized during Detailed Engineering. Sensors (fire detectors, heat detectors, gas monitors) would be selected according to Project specifications, regulatory requirements, fire hazard assessments, gas dispersion studies, and Project personnel experience.

Field-mounted visual and audio alarms (notification devices) that indicate local hazards, local fire alarm Human Machine Interfaces (HMIs) to activate notification devices (visual and audible alarms), and manual alarm activation switches throughout the facilities would be present.

11.7.3 Operations and Maintenance

To promote pipeline safety, regulations contained in Subparts L and M of 49 C.F.R. Part 192 require pipeline operators to establish public awareness and damage prevention programs, an ERP, and security practices; to maintain specific operating pressures; and to perform regular pipeline patrols, leak surveys, and other surveillance activities. PHMSA requires the operator to prepare an Operation and Maintenance Plan in accordance with the requirements in 49 C.F.R. § 192.605 *Procedural Manual for Operations, Maintenance, and Emergencies* before placing a natural gas pipeline into service. An Operation and Maintenance Plan would be prepared that would include the following activities and operating procedures:

- Worker qualification to operate and maintain the pipeline system in accordance with the 49 C.F.R. Part 192 Operator Qualification Rule;
- Periodic contact with property owners, utilities, local government agencies, contractors, and other interested parties to inform them of the pipeline location and procedures to be followed in reporting and responding to a pipeline system emergency;
- Public Education and Awareness Program, which includes education of contractors and the local public in damage prevention;
- Patrols of the ROW to check for signs of leakage, damage, erosion, pipeline marker, and unauthorized encroachments;
- Pipeline markers displaying telephone numbers for emergencies or general inquiries;
- Participation in Alaska's "One Call" system (811 Alaska Digline), including staking and marking service for third-party construction and landowner requests;
- Planned inspections of field locations to ensure conformance with existing operating and maintenance standards and safe work procedures;
- Periodic surveys and inspections to monitor and adjust performance of the cathodic protection system;

- ILIs;
- Training programs for operation and maintenance personnel to maintain competency in safety procedures and emergency preparedness;
- Standard procedures for protecting assets and ensuring public safety during planned maintenance and corrective maintenance activities; and
- Periodic testing and inspection of pressure-limiting devices and ESD systems at the compressor stations.

These procedures and programs would promote heightened safety behavior by pipeline system personnel, maintain the integrity of the pipeline, and minimize the potential for pipeline incidents.

The Mainline, PTTL and PBTL would be operated from a Gas Control Center with the capability to monitor and control the facilities (i.e., remotely start and stop compressor units; change control set points as required for pipeline operation; and monitor for alarm conditions). Aboveground facilities could also be operated locally as needed. The Gas Control Center would be staffed 24 hours a day, year-round. A fully functional Backup Control Center would be available in the event the primary Gas Control Center becomes unavailable for any reason. Both control centers would have redundant communication to monitor and control the pipeline; the location of the backup control center is to be determined in a later project phase after a comprehensive risk analysis.

The continuous monitoring and operation of the pipeline system would be accomplished principally through a Supervisory Control and Data Acquisition (SCADA) system, which is a computer system for gathering and analyzing data from real-time systems and operating remote facilities. The SCADA system would compile pipeline operating data (pressure, temperature, flow, compressor data, revolutions per minute, vibration, etc.) from facilities along the pipelines (meter stations, heater stations, compressor stations, etc.) and transmit the data to the Gas Control Center. The control room software would analyze the compiled information, evaluate against safe operating envelopes and prioritize and display the operating data (including alarm displays for operating set points that are outside pre-set operating criteria).

During the course of normal operations, planned maintenance activities at meter stations and compressor stations would include routine checks, calibration of equipment and instrumentation, inspection of critical components, and servicing and overhauls of equipment. Equipment health would be monitored for critical rotating equipment to enable troubleshooting, optimization, and predictive maintenance planning. Unplanned maintenance activities include investigation of problems identified by the Gas Control Center and station monitoring systems, and implementation of corrective actions. Operational procedures and programs to be developed would address job responsibilities, staffing, organization, and schedules. Planned maintenance shutdowns (turnarounds) would be scheduled and coordinated to meet the maintenance required for major equipment.

A corrosion protection system (CPS), which is required by 49 C.F.R. Part 192 Subpart I, would be installed along with external coating to mitigate external corrosion of the buried portions of the pipelines. The CPS would be designed to ground the pipeline from naturally occurring electrical currents (telluric currents) caused by variations in the earth's geomagnetic field in northern regions.

At a minimum, the CPS would be active within one year of operation start-up, but a passive CPS using sacrificial anodes would be used for the Mainline during the “dormant period,” the time between the finalization of the construction and the operation start-up. Periodic cathodic protection surveys would be conducted to monitor the status of the CPS and would adjust systems as required to maintain the integrity of the pipeline system. Operations staff would monitor the condition of the pipe, external coating, and the effectiveness of the CPS, as required by PHMSA. Workers would maintain and repair the pipe, the pipe coating, and the CPS as appropriate, and record such activities. Internal corrosion is not expected to be a factor because the natural gas stream is clean and dry. No CPS is required for an aboveground PTTL.

A regional operations and maintenance office in Alaska would maintain the pipelines and related aboveground facilities. Periodic ROW maintenance and brush control along the pipeline routes within the permanent ROW would be conducted as specified in the Alaska LNG Project *Upland Erosion Control, Revegetation, and Maintenance Plan* and the Alaska LNG Project *Wetland and Waterbody Construction and Mitigation Procedures.* Effective cathodic protection surveys, ILI runs, visual inspections (i.e., aerial or ground patrols), and facilities maintenance would also be enabled.

11.7.4 Integrity Management Plan (IMP)

Pipeline integrity regulations contained in Subpart O of 49 C.F.R. Part 192 require operators to develop and follow a written IMP containing prescribed program elements that address the risk for each covered segment of a natural gas transmission pipeline. A covered segment is defined in 49 C.F.R. Part 192 as a segment of a natural gas transmission pipeline located in an HCA. HCAs are identified based on class locations and/or the potential for a pipeline failure to impact buildings intended for human occupancy or a particular site.

The Project IMP would consider the following:

- Identification of all HCAs;
- Baseline Assessment Plan;
- Identification of threats to each covered segment, including by the use of data integration and risk assessment;
- Direct assessment plan, if applicable;
- Provisions for remediating conditions found during integrity assessments;
- Process for continual evaluation and assessment;
- Confirmatory direct assessment plan, if applicable;
- Process to identify and implement additional preventive and mitigation measures;
- Performance plan including the use of specific performance measures;
- Recordkeeping provisions;

- Management of change process;
- Quality assurance process;
- Communication plan;
- Procedures for providing to regulatory agencies copies of the risk analysis or IMP;
- Procedures to verify that integrity assessments are conducted to minimize environmental and safety risks; and
- Process to identify and assess newly identified HCAs.

On a preliminary basis, and for the route currently under consideration, these are the HCA identified for the Mainline at this time. HCAs were identified following the requirements of 49 C.F.R. § 192.903, with a PIR that was calculated to be 1,466 feet for the Mainline and 749 feet for PTTL.

TABLE 11.7.4-1

Potential HCA Takeoff Mainline Route Revision C2

From MP	To MP	Length (mi.)	Description
236.08	237.33	1.25	Marion Creek Campground
352.21	353.35	1.14	Hotspot Cafe
529.21	530.44	1.23	RV Park and Motel
535.54	537.74	2.20	Denali Riverside RV Park, McKinley Chalet Resort, Denali Rainbow Village and RV, Denali Princess Wilderness Lodge, Denali Crows Nest Cabins, Grand Denali Lodge, Denali Bluffs Hotel
551.34	552.27	0.93	Denali Perch Resort
565.77	567.23	1.46	ADOT&PF Cantwell Station
629.75	631.35	1.60	Byers Lake Campground (73 units)
633.75	634.50	0.75	Trappers Creek Pizza Pub
797.71	799.28	1.57	Nikiski Middle/High School, Kenai Heliport, Commercial Buildings, Industrial Sites
803.39	806.05	2.66	Conoco Phillips Property and Tesoro Kenai Refinery
Total		14.79	

For the PTTL:

TABLE 11.7.4-2

Potential HCA Takeoff PTTL Route Revision C2

From MP	To MP	Length (miles)	Description
0.00	0.14	0.14	PTU
62.38	62.52	0.14	GTP
Total		0.28	

In addition to the covered segments based on the classical definition of high consequence area, there are plans to incorporate the *SBD Segments*[13] in its written IMP and treat the *SBD Segments* as a "covered segment" in a HCA in accordance with 49 C.F.R. Part 192, Subpart O, except for the reporting requirements contained in 49 C.F.R. § 192.945.

The pipeline segments operating under an alternative MAOP are subject to the IMP requirements of 48 C.F.R. § 192.620. The IMP would specifically address the additional requirements for baseline assessments, threat identification, and integrity assessments.

In accordance with the IMP, operations staff would periodically assess the integrity of pipeline segments operating at the alternative MAOP using assessment methodologies acceptable to the industry and PHMSA. These segments would be periodically inspected using the appropriate ILI tools. ILI tools can be used for assessments of a number of potential hazards, including metal loss from corrosion. ILI tools can also be used to inspect for deformation caused by slope movements, fault displacements, frost heave, thaw settlement, or other mechanisms. Conditions that exceed applicable acceptance criteria would be assessed and remediated to maintain the integrity of the pipeline.

The written IMP and records that demonstrate compliance with 49 C.F.R. Part 192 Subpart O would be maintained and be available for review by PHMSA and/or state regulators during inspections, as required. The pre-front end engineering design (pre-FEED) for the buried pipeline, wall thickness, and grade on the Mainline meets the requirements in 49 C.F.R. § 192.111 and 192.620 using design factors of 0.50, 0.60, 0.72, and 0.80 as per different class locations and conditions.

The wall thickness of the PTTL meets the requirements in 49 C.F.R. § 192.111 using a design factor of 0.72. The PTTL has additional wall thickness selection requirements due to considerations of ballistic and transportation of field gas that results in a wall thickness of no less than 0.500 inch (see Table 11.7.2-5).

11.8 GAS TREATMENT PLANT HAZARD IDENTIFICATION

11.8.1 Hazardous Materials

A review of potential hazards and concerns associated with the GTP was conducted early in pre-FEED. This review considered flammable, combustible, and toxic materials. Potential issues that were identified included flammable hazards such as a leak in the feed gas, treated gas, fuel gas or propane refrigerant, which could result in a vapor cloud of any one of these fluids that could cause significant damage and destruction if ignited.

The primary potential hazard associated with GTP operations is equipment or piping system, including leaks and line breaks resulting in a loss of containment. Equipment leaks or line breaks can occur in several ways. Corrosion or material failures can be caused by abnormal process conditions (e.g., cold temperatures, high velocities, excess temperatures, or high concentrations of CO_2 or H_2S). Equipment leaks and line

[13] *SBD Segments* have not yet been determined for the Mainline at this phase of design. If pipeline route conditions require the use SBD to design for and manage the threat of earth movements a SP application for use of SBD would be submitted to PHMSA. The SP application for SBD would document the segments of the Mainline where SBD was identified as a design condition. These ***SBD Segments*** would constitute milepost descriptions of segments on the Mainline.

breaks can also be caused by material defects or external forces. Cold weather can cause freezing of water, which can result in equipment or piping rupture. A failure in process controls resulting in overpressure can cause leaks. Finally, human factors can result in overpressure or equipment/piping failure.

A leak or overpressure can cause a loss of containment of flammables or toxics. This can escalate because a loss of containment can cause an explosion or fire due to the presence of hydrocarbons. Loss of containment can also cause toxic exposure to H_2S as well as asphyxiation due to CO_2 and other inert gases. Any of these events could cause injury or loss of life.

11.8.1.1 Methane

Methane is the primary component in the natural gas stream. Methane vapors are flammable in air ratios of 5 to 15 percent. Unlike heavier hydrocarbons (such as propane), natural gas does not have the potential for the explosion of unconfined vapor clouds. Methane vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure, potentially causing asphyxiation if a person were to enter a high concentration area. Table 11.8.1-1 summarizes the properties of methane.

TABLE 11.8.1-1

Properties of Methane

Property	Value			Notes
Melting temperature	-296.46 °F [a]			At normal pressure (14.7 psia)
Boiling temperature	-258.68 °F [a]			At normal pressure (14.7 psia)
Flash point	-306.7 °F [b]			Closed cup
Lower flammability limit	5.0 percent [a]			In air by percent volume
Upper flammability limit	15.0 percent [a]			In air by percent volume
Auto-ignition temperature	548.6 °F [b]			--
Heat of combustion	55.5 MJ/kg [a]			At 60 °F
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in process	°F	Varies	°F	
Operating temperatures in storage	N/A	N/A	N/A	Project does not include storage
Operating pressures in process	psig	Varies	psig	
Operating pressures in storage	N/A	N/A	N/A	Project does not include storage
Operating densities in process	lb/ft^3	Varies	lb/ft^3	
Operating densities in storage	N/A	N/A	N/A	Project does not include storage
Property	**Details**			
Aphyxiant and toxic properties	Simple asphyxiant, non-toxic [c]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen [c]			
Corrosion rate of skin	N/A			

TABLE 11.8.1-1

Properties of Methane

Property	Value	Notes
Corrosion rate of metal surfaces	N/A	

a Gas Processors Association, 2012
b Airgas, 2015
c U.S. National Library of Medicine, 2016
lb/ft^3 pounds per cubic foot
MJ/kg megajoule per kilogram
N/A not applicable
ppm parts per million
psia pounds per square inch absolute
psig pounds per square inch gauge

11.8.1.2 Propane

Propane is used as a refrigerant for natural gas chilling. Table 11.8.1-2 summarizes the properties of propane.

TABLE 11.8.1-2

Properties of Propane

Property	Value			Notes
Melting temperature	-305.7 °F [a]			At normal pressure (14.7 psia)
Boiling temperature	-258.7 °F [a]			At normal pressure (14.7 psia)
Flash point	-155.2 °F [b]			Closed cup
Lower flammability limit	1.8 percent [a]			In air by percent volume
Upper flammability limit	8.4 percent [a]			In air by percent volume
Auto-ignition temperature	548.6 °F [a]			--
Heat of combustion	50.4 MJ/kg			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in process	18 °F	Varies	125 °F	
Operating temperatures in storage	N/A	N/A	N/A	Project does not include storage
Operating pressures in process	37.3 psig	Varies	173.3 psig	
Operating pressures in storage	N/A	N/A	N/A	Project does not include storage
Operating densities in process	TBD	Varies	TBD	Min/Max to be determined by vendor.
Operating densities in storage	N/A	N/A	N/A	Project does not include storage
Property	**Details**			
Asphyxiant and toxic properties	Simple asphyxiant, non-toxic [b]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen [b]			
Corrosion rate of skin	N/A			
Corrosion rate of metal surfaces	N/A			

[a] Airgas, 2015
[b] U.S. National Library of Medicine, 2016

11.8.1.3 Hydrogen Sulfide

Hydrogen Sulfide ("H_2S") is present in the feed gas and is removed using amine based absorber and regeneration columns. Acid gas from the regeneration column is sent to a thermal oxidizer for disposal. While it can only be anticipated in very small quantities within the process, H_2S is classified as a toxic material. Table 11.8.1-3 summarizes the properties of H_2S.

TABLE 11.8.1-3

Properties of Hydrogen Sulfide

Property	Details				
Asphyxiant Properties	Toxic[a]				
Maximum Concentration of H_2S in Process					
Asphyxiation Concentration	N/A[a]				
Corrosion Rate of Skin	N/A				
Corrosion Rate of Metal Surfaces	N/A				
AEGL	**10 min[b]**	**30 min[b]**	**60 min[b]**	**4 hr[b]**	**8 hr[b]**
AEGL-1	0.75 ppm	0.60 ppm	0.51 pm	0.36 ppm	0.33 ppm
AEGL-2	41 ppm	32 ppm	27 ppm	20 ppm	17 ppm
AEGL-3	76 ppm	59 ppm	50 ppm	37 ppm	31 ppm

[a] Airgas, 2017
[b] USEPA, 2016

11.8.1.4 Amine Solution

A set of absorber and regeneration columns using a propriety MDEA-containing solution technology removes H_2S and carbon dioxide ("CO_2") from the feed gas as a part of the pretreatment process. The amine solution is considered an environmental health hazard. Table 11.8.1-4 lists the properties of amine solution.

TABLE 11.8.1-4

Properties of Amine Solution

Property	Value	Notes
Melting Temperature	-6°F[a]	At normal pressure (14.7 psia)
Boiling Temperature	475-478 °F[a]	At normal pressure (14.7 psia)
Flash Point	261 °F[a]	Closed Cup

Auto-Ignition Temperature	509 °F[a]			
Property	**Min**	**Normal**	**Max**	**Notes**
Capacity in Storage	N/A	22,408 bbl	N/A	
Operating Temperatures in Storage	50 °F	Varies	95 °F	
Operating Pressures in Storage	TBD	0 psig	TBD	Min. and max. TBD by vendor
Operating Densities in Storage	TBD	Varies	TBD	Min. and max. TBD by vendor
Concentration in Process	TBD	TBD	TBD	TBD by vendor
Operating Pressures in Process	0 psig	Varies	750.3 psig	
Operating Densities in Process	TBD	Varies	TBD	Min. and max. TBD by vendor
Property	**Details**			
Asphyxiant and Toxic Properties	Skin and respiratory sensitizer [a]			
Asphyxiation Concentration	N/A			
Corrosion Rate of Skin	Non-corrosive			
Corrosion Rate of Metal Surfaces	Non-corrosive			
[a] Columbus Chemical Industries, 2013				

11.8.1.5 Nitrogen

The GTP will use nitrogen for utility purposes. Nitrogen is a non-toxic, odorless, colorless, non-corrosive and nonflammable material. Nitrogen vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure, potentially causing asphyxiation if a person were to enter a high concentration area. Table 11.8.1-5 summarizes the properties of Nitrogen.

TABLE 11.8.1-5

Properties of Nitrogen

Property	**Value**			**Notes**
Melting temperature	-346.0 °F[a]			At normal pressure (14.7 psia)
Boiling temperature	-320.4 °F [a]			At normal pressure (14.7 psia)
Flash point	N/A			Closed cup
Lower flammability limit	N/A			In air by percent volume
Upper flammability limit	N/A			In air by percent volume
Auto-ignition temperature	N/A			
Heat of combustion	N/A			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating temperatures in storage	N/A	N/A	N/A	Project does not include storage
Operating pressures in storage	N/A	N/A	N/A	Project does not include storage
Operating densities in storage	N/A	N/A	N/A	Project does not include storage
Property	**Details**			
Asphyxiant and toxic properties	Simple asphyxiant, non-toxic[b]			
Maximum concentration of toxic component in process	N/A			
Asphyxiation concentration	Below 6 percent oxygen[b]			

TABLE 11.8.1-5

Properties of Nitrogen

Property	Value	Notes
Corrosion rate of skin	N/A	
Corrosion rate of metal surfaces	N/A	

[a] Gas Processors Association, 2012
[b] U.S. National Library of Medicine, 2016

11.8.1.6 Triethylene Glycol

A Triethylene Glycol ("TEG") system will be used to remove water from the incoming natural gas, as well as act as a heating medium for the pretreatment process. The high operating temperature presents a hazard at the GTP Facility. The TEG system is considered an environmental health hazard. Table 11.8.1-6 summarizes the properties of Triethylene Glycol.

TABLE 11.8.1-6

Properties of Triethylene Glycol

Property	Value			Notes
Melting Temperature	23 °F [a]			At normal pressure (14.7 psia)
Boiling Temperature	545 °F [a]			At normal pressure (14.7 psia)
Flash Point	329.9 °F [a]			Closed Cup
Lower Flammability Limit	0.9 [a]			In air by percent volume
Upper Flammability Limit	9.2 [a]			In air by percent volume
Auto-Ignition Temperature	699.8 °F [a]			
Heat of Combustion	N/A			
Property	**Min**	**Normal**	**Max**	**Notes**
Operating Temperatures in Process	300 °F	varies	380 °F	
Operating Pressures in Process	240.3 psig	varies	252.3 psig	
Operating Densities in Process	TBD	varies	TBD	Min. and max. TBD by vendor
Property	**Details**			
Asphyxiant and Toxic Properties	Toxic[a]			
Asphyxiation Concentration	N/A[a]			
Corrosion Rate of Skin	Non-corrosive[a]			
Corrosion Rate of Metal Surfaces	Non-corrosive[a]			

[a] Science Lab, 2013

11.8.2 Hazard Identification and Analyses

A Hazard Identification and Analyses ("HAZID") has been performed on the GTP engineering design by a group of qualified individuals. The objective of a HAZID is to perform a high-level, systematic analysis to identify potential hazards in the early stage of a project's design that can produce undesirable consequences through the occurrence of an incident by evaluating the materials, system, process and plant design.

The HAZID is based on the GTP's plot plan, process flow diagrams and heat and material balances, which are included in Appendix E of Resource Report No. 13. The results of the HAZID are included in Appendix G.1 of Resource Report No. 13. As a result of the HAZID, recommendations have been made to improve the engineering design to minimize the potential for a hazardous event.

11.8.3 Safety History of Natural Gas Treatment Plants

Gas treatment plants have an overall excellent safety record, both in the United States and globally. Many LNG facilities have integrated gas treatment prior to liquefaction. Modern facilities use state of the art instrumentation, controls, hazard detection, and hazard control systems to minimize the potential for an incident while continually improving the overall excellent safety record.

11.9 GAS TREATMENT PLANT HAZARD ANALYSIS

11.9.1 Hazardous Releases

Although the GTP is not under the jurisdiction of 49 CFR Part 193, the same methodology used to perform the Liquefaction Facility hazard analysis was used to perform a Hazard Analysis for the GTP.

A summary of the bounding design spills used for hazard analysis modeling is included in Table 11.9.1-1.

TABLE 11.9.1-1

Design Spill Summary Table (Overall)

Scenario Number	Fluid	Hole Size (in)	Pipe Diameter	Location	Orientation
NG-1	Natural Gas	2	60"	Inlet PBU/PTU Header to AGRU	Horizontal
NG-7	Natural Gas	2	30"	AGRU Water Wash Tower to TGDU TEG Contactor	Horizontal
NG-13	Natural Gas	2	20"	Treated Gas Compressor Aftercooler to Treated Gas Header	Horizontal
NG-15	Natural Gas	2	42"	Treated Gas Chiller to Treated Gas Metering Station	Horizontal
NG-16	Natural Gas	2	32"	PTU Inlet to PTU KO Drum	Horizontal
NG-18	Natural Gas	2	60"	PBU Inlet to PBU/PTU Header	Horizontal

TABLE 11.9.1-1

Design Spill Summary Table (Overall)

Scenario Number	Fluid	Hole Size (in)	Pipe Diameter	Location	Orientation
R-5	Refrigerant	2	36”	Refrigerant Compressors to Refrigerant Condenser	Horizontal
R-6	Refrigerant	2	20”	Refrigerant Condenser to Refrigerant Accumulator	Horizontal
AG-3	Acid Gas	2	16”	Low Pressure Co2 Compressor to CO2 Compression 2nd Stage Outlet KO Drum	Horizontal
AG-4	Acid Gas	2	16”	CO2 Compression 2nd Stage Outlet KO Drum to CO2 Dehy TEG Contactor	Horizontal
AG-6	Acid Gas	2	12”	Outlet of High Pressure CO2 Compressor	Horizontal
AG-7	Acid Gas	2	24”	CO2 Transfer Meter to PBU Injection Point	Horizontal

TABLE 11.9.1-2

Design Spill Summary Table (Release Parameters)

Scenario Number	Release Height (ft)	Release Temperature (°F)	Release Pressure (psig)	Flow Rate (lb/hr)	Release Duration (s)	Liquid Rainout
NG-1	13	27.2	570.2	107,182	600	0%
NG-13	30	30	2,123.3	459,581	600	0%
NG-15	20	28.8	2,080.1	450,566	600	0%
NG-16	13	-2	650	129,118	600	0%
NG-18	13	38.4	569	105,220	600	0%
R-5	13	125	172.9	50,055	600	0%
R-6	13	97	169.9	51,698	600	0%
AG-3	25	79.7	520.3	171,670	600	0%
AG-4	33	57	517.1	170,613	600	0%
AG-6	15	328.7	1,582	383,386	600	0%
AG-7	15	147.7	2,123	951,472	600	0%

Additional details on the hazardous releases can be found in the Hazard Analysis in Appendix H.

11.9.2 Asphyxiant and Toxic Vapor Dispersion Hazard Analysis

Toxic vapor dispersion analysis associated with jetting and flashing releases has been performed. FERC has required applicants to consider toxicity levels based on the Acute Exposure Guideline Levels ("AEGL") -1, -2, and -3 maintained by the U.S. Environmental Protection Agency. Specific AEGL levels for each component are detailed in the Hazard Analysis provided in Appendix H of Resource Report 13.

Toxicity modeling has been performed on hydrogen sulfide in acid gas a CO_2 compression streams, and benzene, toluene, and hexane in process gas streams. The Phast v6.7 model was used to perform the analysis. A safety factor of two was applied to the toxicity modeling. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 49°F, relative humidity of 50% and surface roughness factor of 0.03 meter ("m") for all wind directions.

The calculations and resulting toxic dispersion analysis results for the GTP is detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, no public receptors will be impacted by toxic or asphyxiation hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.9.2-1 summarizes the results of the toxic vapor dispersion modeling.

TABLE 11.9.2-1

Toxic Vapor Dispersion Modeling

Scenario:	**Distance (ft) to:**		
	½ AEGL-1	**½ AEGL-2**	**½ AEGL-3**
AG-3	5,791	No Hazard	No Hazard
AG-4	5,806	No Hazard	No Hazard
AG-6	9,285	No Hazard	No Hazard
AG-7	11,191	No Hazard	No Hazard

11.9.3 Flammable Vapor Dispersion Hazard Analysis

Dispersion distances have been calculated for one-half the lower flammability limit of natural gas and flammable hydrocarbon vapors. These distances have been calculated for jetting and flashing releases.

The Phast v6.7 model was used to perform the analysis. A safety factor of two was applied to the dispersion modeling. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 49°F, relative humidity of 50% and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting vapor dispersion distances are detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, none of the vapor dispersion distances impact the public.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.9.3-1 summarizes the results of the flammable vapor dispersion modeling.

TABLE 11.9.3-1

Flammable Vapor Dispersion Modeling

Scenario:	**Distance (ft) to ½ LFL**
NG-1	218
NG-13	459
NG-15	491
NG-16	248
NG-18	214

11.9.4 Vapor Cloud Overpressure Hazard Analysis

Vapor cloud overpressure analysis associated with refrigerant releases is performed for the GTP. FERC has required applicants to consider an overpressure value of 1 psi to determine the potential impacts on the public. The Phast v6.7 model was used to perform the analysis. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 49°F, relative humidity of 50 percent and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting overpressure analysis for the GTP are detailed in the Hazard Analysis included in Resource Report No. 13 Appendix H.3. As detailed in the Report, no public receptors will be impacted by overpressure hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.9.4-1 summarizes the results of the flammable vapor dispersion modeling.

TABLE 11.9.4-1

Vapor Cloud Overpressure Modeling

Scenario:	**Distance (ft) to 1 psi:**
R-5	244
R-6	281

11.9.5 Fire Hazard Analysis

11.9.5.1 Pool Fire

Hazard distances for various flux levels for flammable hydrocarbon pool fires have been calculated using the "LNGFIRE III" computer program model developed by the GRI. Atmospheric conditions used were wind speed of up to 32 mph, temperature of -29 °F and relative humidity of 50 % for all wind directions.

The calculations and resulting pool fire analysis for the GTP are detailed in the Hazard Analysis included in Appendix H.3 of Resource Report No. 13. The results of the modeling show that all thermal radiation hazards associated with pool fires remain within the GTP property boundaries. Table 11.9.5-1 summarizes the thermal radiation distances.

TABLE 11.9.5-1

Pool Fire Modeling

Sump:	Distance (ft) to:		
	10,000 Btu/ft^2-hr	3,000 Btu/ft^2-hr	1,600 Btu/ft^2-hr
Diesel Fuel Tank Containment Dike (Front)	110.8	140	160.2
Diesel Fuel Tank Containment Dike (Side)	111	140	160
Hydrocarbon Holding Tank Containment Dike	187.9	241	279.9

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

11.9.5.2 Jet Fire

Jet fires associated with natural gas and refrigerant releases was performed for the GTP. FERC has required applicants to consider thermal flux endpoints of 10,000 BTU/ft^2-hr, 3,000 BTU/ft^2-hr 1,600 BTU/ft^2-hr to determine the potential impacts on the public. The Phast v6.7 model was used to perform the analysis. Atmospheric conditions used were stability F, wind speed of up to 2 m/s, temperature of 49°F, relative humidity of 50 percent and surface roughness factor of 0.03 m for all wind directions.

The calculations and resulting jet fire results for the Liquefaction Facility is detailed in the Hazard Analysis included in Resource Report No. 13, Appendix H.3. As detailed in the Report, no public receptors will be impacted by jet fire hazards as the hazards would remain within the plant boundaries.

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

Table 11.9.5-2 summarizes the results of the jet fire modeling.

TABLE 11.9.5-2

Jet Fire Modeling

Scenario:	**Distance (ft) to:**		
	10,000 Btu/ft^2-hr	**3,000 Btu/ft^2-hr**	**1,600 Btu/ft^2-hr**
NG-1	128	178	207
NG-2	128	177	207
NG-3	126	176	206
NG-4	Not Reached	149	188
NG-5	102	160	191
NG-6	103	161	193
NG-7	Not Reached	140	183
NG-8	Not Reached	157	190
NG-8A	Not Reached	156	189
NG-9	119	165	192
NG-10	155	216	252
NG-11	167	234	273
NG-12	222	311	367
NG-13	241	347	415
NG-14	240	346	413
NG-15	242	346	411
NG-16	139	194	227
NG-17	132	184	215
NG-18	127	176	205
R-1	68	87	99
R-2	68	87	99
R-3	68	87	99
R-4	84	118	138
R-5	84	118	138
R-6	86	121	141
R-7	86	121	141

Mitigation features to reduce cascading impacts include instrumentation and control, hazard detection devices, hazard control devices, firewater systems, impoundment systems, and emergency shutdown systems. The detail of these systems is included in Resource Report No.13.

11.10 GTP SAFETY AND RELIABILITY DESIGN

The GTP would be designed, constructed, operated, and maintained in accordance with applicable federal, state, and local laws and regulations. The GTP would be operated in a manner that protects the safety of workers, and others involved in its operations.

Safe worker exposure levels are established for a number of chemicals by the Occupational Safety and Health Administration (OSHA) and other government health agencies, including the National Institute for Occupational Safety and Health (NIOSH). Compliance with these safe worker exposure levels would be maintained at all times.

The GTP would have an ICSS with a number of automation systems that would monitor and manage the various aspects of the plant. One of these systems is the Safety Instrumented System (SIS), which is described in further detail in Section 11.9.2.

The purpose of the Fire Gas Detection System (FGDS) is to notify operations to take executive action and to initiate suppression, isolation, and blowdown. Fire suppression systems would be integrated into the FGDS for activation purposes.

An overpressure protection system at the GTP would maintain the integrity of the facilities for hydrocarbon and CO_2 containment. The purpose of the overpressure protection system is: 1) protection of personnel, 2) protection of the environment, 3) protection of equipment, and 4) continuity of production. The plant design would provide safe containment and disposal of hazardous materials, guarding against overpressure incidences using an appropriate combination from the following five main protection measures: 1) inherently safer design (ISD) – specification of design pressures higher than possible source pressure, 2) pressure control, 3) high pressure trips, 4) shut-in and depressurize, and 5) relief of excess pressure. Four flare systems would be incorporated into the GTP to handle the relief and blowdown requirements.

Strategic placement of valves and blinds would allow for the shutdown, drainage, and depressurization of particular sections of a plant, thus minimizing the need for a total shutdown and depressurization of the entire facility. Isolation valves would be used to segregate single or multiple components in a facility from the other parts in service. Two of the piperacks are designed to incorporate isolation valves. These battery limit extensions on the piperack modules provide a common location for all lines entering the Process Train to be shut off, leaving the Train unenergized. This is done to provide further flexibility and downtime reduction for operations, in addition to providing a safe work environment for emergency response and maintenance activities. In some cases, for longer maintenance activities, blinds can be inserted to provide positive isolation.

11.10.1 Equipment Redundancies

The GTP will be designed for continuous operations except in the case of a total power outage. Necessary equipment redundancies will be included such that normal maintenance and inspection can be accomplished while sustaining the design gas treatment rates.

11.10.2 Sparing Philosophy

The key principles of the redundancy and sparing philosophy are as follows:

- *Life and safety systems equipment use applicable codes, Owner/Operator guidelines, or an N+1 philosophy, whichever is more stringent;*
- *No planned maintenance activity that requires extended shutdown (greater than 12 hours or available line pack) of all trains. The assumed basis is to maintain domestic gas supply at all times; assumption shall be verified as commercial terms are defined during a later stage of the Project;*
- *Minimize single failures that result in the equivalent loss of more than one train of gas processing capacity;*
- *Redundancy and sparing decisions are justified by maximizing economic value; and*
- *Pumps in continuous service shall be spared, whether they are part of a train or not, to maximize train availability. Sparing of pumps in intermittent service shall be addressed on a case-by-case basis.*

A Reliability, Availability and Maintainability (RAM) analysis would be completed during detailed design to ensure that this philosophy provides the requirements outlined. Table 11.10-1 provides a list of the sparing provisions for the GTP.

TABLE 11.10-1

Equipment Sparing

Process Unit/Utility	**Sparing**	**Notes/Studies**
Acid Gas Recovery (AGRU)	• 1 AGRU Absorber/Regenerator per train (no sparing); • Minimum 3 x 33 percent critical service heat exchangers per train; • Spare plates for plate and frame heat exchangers, kept in warehouse; and • 3 x 50 percent Lean Solvent Pumps per train.	
Treated Gas Dehydration (TGDU) (including off gas compressors)	• 1 TEG contactor per train (no redundancy); and • 3 x 33 percent TEG regeneration.	Each TGDU regeneration system is capable of regenerating 100 percent of the TEG from the respective train's contactor.
Treated Gas Compression	6 x 20 percent (2 per train)	Common header upstream of compression to allow compressors to receive Treated Gas from any train.
Treated Gas Chilling and Refrigeration System	• 1 common chiller bank, 2 x 50 percent exchangers; • Refrigerant compressors = 2 x 50 percent; • Refrigerant accumulators = 1 x 100 percent; and • Multiple bay refrigerant condenser with isolation valves.	No chilling during winter (i.e., no refrigeration needed) equates to excess capacity available during winter months.
CO_2 Compression	6 x 20 percent (2 per train)	Common header upstream of first stage of compression to allow

TABLE 11.10-1

Equipment Sparing

Process Unit/Utility	Sparing	Notes/Studies
		compressors to receive acid gas from any train.
CO_2 Gas Dehydration Unit	• 2 TEG contactors per train, 1 per CO_2 compressor; and • 3 x 40 percent TEG regeneration.	Each CO_2 Gas Dehydration Unit regeneration system is capable of regenerating 100 percent of the TEG from the associated train's 2 contactors.
Process Heat Medium	• Supplemental firing in waste heat recovery unit (WHRU) for Individual Train loops	Each train would have its own process heat medium loop; no shared equipment or cross-ties.
Building Heat Medium	• Building Heat loop utility heaters = 3 x 50 percent; and • Building Heat medium pumps = 2 x 100 percent.	System is on essential power system to ensure high reliability to prevent freeze-related damage.
Cooling Medium	• Cooling Medium pumps = 2 x 100 percent.	Each train would have its own dedicated cooling medium circulation loop; no shared common equipment. The refrigeration unit would have its own cooling medium loop.
Fuel Gas	Supplemented with buy-back gas from Mainline	Black-start supply taken from 6-inch CGF inlet gas line or buy-back gas from pipeline.
Flares	• 2 x 100 percent sets of elevated flares; • KO Drums = 1 x 100 percent; and • KO Drum Pumps = 2 x 100 percent.	
Drains	• Common Process Closed Drain Drum = 1 x 100 percent; • Warehouse spares for open drain sump pumps; and • Disposal Injection well = 2 x 100 percent.	3 separate Closed Drain systems (Process, TEG, AGRU Solvent) and 1 Open Drain system per train. Process Closed Drain and Open Drain system also in common areas.
Water System	• Main Firewater Pump(s): 100 percent installed spare capacity. Firewater Jockey Pump does not require redundancy	100 percent of the facility maximum firewater flow demand shall be diesel engine driven; 100 percent of the facility maximum firewater flow demand shall be electric motor driven. A dedicated diesel fuel supply is required.
Chemical Injection	Essential chemical injection pumps = 1 x 100 percent	
Compressed Air (sum of service air, instrument air, breathing air, nitrogen generation)	• 3 x 50 percent electric motor driven compressors; • 1 x 100 percent dryer package with spare bed; and • 1 x 100 percent receiver. Secondary instrument air receivers in each train	Air receiver design margin to be studied/defined further. Would review air extraction from power generating turbines for redundancy in a later stage of the Project.
Nitrogen (N_2)	Spare membranes and/or membrane units provided to ensure full capacity operation	For large facility turnarounds, additional quantities of nitrogen would be trucked in to supply high volume or pressure requirements. Nitrogen bottles would be used for blanketing in some applications.

TABLE 11.10-1

Equipment Sparing

Process Unit/Utility	Sparing	Notes/Studies
		Other sources of continuous nitrogen to be further evaluated.
Diesel Fuel	• Diesel Fuel Pump = 1 x 100 percent	
Power Generation	• Main Power GT: 5 operating (shared spinning reserve), 1 spare; • Black Start Power Diesel Generator = 1 x 100 percent for initial and black start (common); and • Dormitory Emergency Diesel Generator = 1 x 100 percent	Main power Gas Turbine (GT) feed a common switchgear bus that distributes power throughout the facility.

11.10.3 Warehouse Philosophy

Critical equipment and components to be stored in the warehouse will be determined in detailed design. The warehouse philosophy will ensure that the plant will have necessary equipment and components stored to ensure minimum availability requirements will be met.

11.10.4 Anticipated Plant Reliability and Availability

The gas treatment systems to be installed at the GTP will be designed to operate with a minimum reliability/availability of 95%. The detailed engineering contractor shall perform a Reliability, Availability and Maintainability ("RAM") Study to confirm that 95% availability is achievable with the design. In general, critical equipment required to support continuous operation of the GTP will be spared.

11.10.5 Contingency Plans

Contingency plans for failure of or impacts to major plant assets or operations due to accidental or natural disasters will be developed in detailed design.

11.10.6 Design Life

The design life of the GTP is 30-year service life. After the initial design life, further life expectancy can be accomplished through a system of operations and maintenance inspections. The facility will follow all operational and maintenance requirements to ensure a minimum design life of 30 plus years.

11.10.7 Hazard Detection and Mitigation Systems

The GTP would be equipped with automatic emergency detection and shutdown systems. Audio and visual alarms (e.g., bells, horns, warning lights) would be provided throughout the modules so that personnel are made aware of emergencies. These safety and emergency systems would be tested routinely to ensure performance.

The SIS system would be implemented according to ANSI S84.01-2004. The SIS system would consist of three systems: PSD system, ESD system, and FGDS. There would be no direct operator interface to the SIS; operator interaction is generally limited to monitoring.

The Process Shutdown (PSD) system would be activated by process shutdowns (see preliminary Cause and Effect Diagrams in Resource Report No. 13, to be finalized in a later project phase). A minimum of two levels of overpressure protection would be provided on process equipment where it is possible to exceed the design pressure in circumstances other than fire. The primary protection would be a high-high pressure instrumented process shutdown to eliminate the source of overpressure. The ultimate protection would be a mechanical relief valve or rupture disc, adequately sized and installed on the protected equipment. A low-low liquid level instrumented process shutdown would be required on the low-low liquid level alarm for any vessel where there is a downstream pump or where there is a chance gas could blow through to a lower pressure rated system resulting in overpressure. A high-high level instrumented process shutdown would be required on any vessel that could be damaged by liquid carryover (such as a drum upstream of a compressor). High concentration levels of H_2S, CO_2, or H_2O that exceed treated gas specifications would initiate a shutdown of the corresponding train.

The ESD system would be designed to isolate, shut down, and/or de-pressure the appropriate GTP element upon mechanical malfunction or process upset. The ESD system would initiate an emergency shutdown due to an unplanned event such as loss of process control, process containment, or fire in the facility. The ESD system would be designed to protect personnel, the environment, and the facility in the event of upset emergency conditions such as fire (local or plant-wide), combustible or toxic fluid leak, mechanical failure of equipment, etc. There would be three ESD levels that would shut down/isolate the entire facility or a specific train or module within the GTP. These levels are Level 1 (GTP Plant), Level 2 (Train ESD), and Level 3 (System ESD). The ESD system would be separate and independent from process equipment shutdown/interlock systems, which are designed to protect the mechanical integrity of the equipment. ESD trip switches would have the capability for remote operation. Manual push buttons and emergency stop switches would be located throughout the facility.

The FGDS would determine if a possible fire or unsafe accumulation of combustible or toxic gas is present on the facility. There would be a fire detection and alarm system designed in accordance with NFPA 72. Multiple gas detectors would monitor for flammable and toxic gases, and fire detectors would cover all areas where either an accumulation of flammable or toxic gas may occur or a fire hazard may exist. All gas and fire detectors and alarms would be connected to a local fire and gas panel or to the facility SIS. Each panel would provide the system with visual alarms, circuit supervision, automatic control of ventilation systems, and automatic control for fire suppressant discharge into enclosed modules equipped with fire suppression. These systems would interface with the ESD system and the fire suppression system. The fire and gas detection system would be initiated automatically by fire and gas detectors.

Fire and gas detectors would be located in the process and utilities modules. Gas and fire detector locations are shown on the fire and gas devices module plans in Resource Report No. 13. Fire detectors would be located in the following modules: AGRU Regenerator, AGRU L/R Exchangers, Treated Gas & CO_2 Dehydration, CO_2 Compression, Treated Gas Compression, AGRU Absorber, refrigeration, and metering station. Fire suppression systems within the GTP are required by the International Building Code (IBC) and International Fire Code (IFC). GTP process and utility modules would comply with the prescriptive code requirement except where the nature of the facility and the process dictates flexibility, and then protection would be provided in conformation with good fire protection engineering practices that is acceptable to the authority having jurisdiction.

All pressure vessels would be protected against overpressure from external fire by means of suitably sized pressure safety valves, as required by code.

Emergency blowdown (depressurizing) would be used to reduce hazardous material inventories to minimize the risk of incident escalation (e.g., during a leak or gas release). It would also be employed to substantially de-pressure and de-inventory the system during a fire scenario, in which a vessel's integrity can be compromised due to the increased metal temperature. Segments or zones in the process flow path may be isolated and blown down manually in preparation for equipment maintenance. Maintenance blowdown flow rates would generally be smaller than emergency blowdown rates, as the amount of time to perform the blowdown is not a concern.

The design of the GTP facilities would not generate any continuous process/utility flow sources to flare or vent, except from limited pilot/purge streams, from the possible (but unexpected) leakage of valves connected to the flare, and from planned start-up or shutdown. In general, protection systems would be designed to minimize potential flaring/venting flow rate to reduce the impact on personnel, the environment and the facility.

Four flare systems would be included in the GTP design to handle the relief and blowdown requirements: 1) High Pressure (HP) hydrocarbon (HC) Flare System, 2) Low Pressure (LP) HC Flare System, 3) HP CO_2 Flare System, and 4) LP CO_2 Flare System. The HP and LP hydrocarbon services would be segregated to reduce the size of the flares and flare headers. HP and LP CO_2 services would be segregated to keep water out of the "cold, dry" high pressure CO_2 system. The CO_2 and HC flares would be segregated due to the design complications of low-British thermal unit flaring. The CO_2 flare system is required to ensure adequate destruction of the associated H_2S and dispersion of the CO_2 to comply with the personnel safety and Alaska Ambient Air Quality Standards for sulfur species.

The GTP would have systems in place to achieve safe isolation of plant systems and equipment for maintenance and inspection. Positive isolation (isolation with the level of integrity required to permit safe access inside the pressure boundary) would be required in the same areas that comparable facilities have positive isolation (for example facility, system, unit, and equipment boundaries). Positive isolation would be achieved through the appropriate selection and placement of blanks (i.e. blinds), valves, vents, and drains. Many factors would be taken into consideration when developing the isolation strategy such as fluid composition, pressure and temperature, applicant requirements, volume of fluid, potential back-flow, etc.

Drains for services containing >10 parts per million H_2S would be hard piped.

Standard fixed and portable fire protection, first aid, and safety equipment would be maintained at the GTP and facility personnel would be trained in proper equipment use and in first aid. Eye wash stations and safety showers would be located at a specific location within the facility.

Many pumps in the GTP are spare to increase reliability in the event that a pump needs to shut down and requires maintenance. The goals of the facility redundancy philosophy are that no single equipment failure or outage can shut down all trains and to minimize single equipment failures that can shut down more than one train.

11.10.8 Operations and Maintenance Plan

Procedures for the operation and maintenance of the GTP would be developed to comply with the applicable OSHA requirements, in particular:

- OSHA 29 C.F.R. 1910.119(f) – Operations. This would include policies for operating procedures, monitoring of operations, emergency procedures, personnel safety, investigation of failures, communication systems, and operating records.
- OSHA 29 C.F.R. 1910.119(g) –Training. The training would include emphasis on the specific safety and health hazards, emergency operations including shutdown, and safe work practices applicable to the employee's job tasks.
- OSHA Process Safety Management (PSM) requirements, including:
    - Process Safety Information;
    - Employee Involvement;
    - Process Hazard Analysis;
    - Operating Procedures;
    - Training;
    - Contractors;
    - Pre-Startup Safety Review;
    - Mechanical Integrity;
    - Hot Work;
    - Management of Change;
    - Incident Investigation;
    - Emergency Response; and
    - Compliance Audits.

11.10.9 Security Practices

The PBU is operated on behalf of the Working Interest Owners by BP. Figure 11.9.4-1 shows the location of the PBU on the North Slope of Alaska and the approximate location of the GTP in the PBU. The PBU is a collection of oil and gas leases from the State of Alaska.

Security measures at PBU are influenced by the geographic location of the PBU approximately 800 miles north of Anchorage on the coast of the Beaufort Sea and its geographic isolation from adjacent towns or cities. The nearest community of Nuiqsut is approximately 37 miles away and is not connected by a permanent road (only winter roads). Deadhorse, which is an unincorporated community within the PBU boundaries, primarily serves to house personnel working on the North Slope oil fields (including PBU) and TAPS. Therefore, personnel access to PBU facilities and operations is almost exclusively for purposes of business related to the oil and gas industry. Site access to PBU for the general public is generally not permitted. Existing security measures such as site access restrictions and checkpoints, security patrols, and coordinated management of logistics via the Dalton Highway and commercial and private air carrier operations would likely be continued and extended for applicability to the GTP based upon its location within the PBU.

Figure 11.9.4-1 GTP Facilities Overview

11.11 RISK MANAGEMENT AND PUBLIC ENGAGEMENT

11.11.1 Risk Management Framework

A management system would be developed and implemented to assess and manage the design, construction, and operation of the Project to maximize safety and health of the public, workers, and others involved in its operations. The management system would facilitate the identification and elimination or reduction of potential risks to worker and public health, safety, and the environment. The general framework for this approach to risk management is described as follows.

11.11.1.1 Project Risk Assessment and Risk Management Planning

Risk assessment and risk management plans would be developed and implemented. These plans aim to identify, assess, and control or eliminate risks by planning and creating mitigation strategies for handling the identified risks.

A risk management plan would be developed and implemented during the design phase of the Project to address the identified risks. The risk management plans would continue to be used throughout the construction and commissioning phases and would help establish the approach to risk management. The plans would include processes and procedures for the following:

- Risk management and loss prevention objectives;
- Risk management work processes;
- Implementation of risk assessments and loss prevention studies;
- Communication and approval levels associated with risk assessments;
- Roles and responsibilities; and
- List of risk assessments and loss prevention activities planned for the Project.

11.11.2 Liaison Procedures with Local Authorities

Meetings with the local emergency response and public officials in the communities where the Project facilities would be located would take place prior to first train start-up. During these meetings, the procedures and plans that would be put in place at each facility would be reviewed with emergency responders, as well as the frequency and plans for emergency preparedness training exercises. A discussion regarding how emergency responders would work during emergency situations would also take place.

11.11.2.1 Liquefaction Facility and GTP

Discussion regarding the Liquefaction Facility and GTP would take place with local port authorities, fire, police, and public officials. The comments and suggestions of these local agencies would be incorporated into the Project as appropriate. During implementation of the Project and throughout its operation, liaison and awareness programs would be maintained with these agencies to exchange information about the resources and responsibilities of each organization that may respond to accidents or natural catastrophes and to coordinate mutual assistance.

11.11.2.2 Pipelines

In accordance with PHMSA rules in 49 C.F.R. § 192.615, coordination with appropriate emergency responders and public officials would be established. The purpose of maintaining liaison would be to learn the resources and responsibilities of each organization that would respond to a pipeline emergency, and to coordinate mutual assistance in the event of an emergency. Liaison would occur through one-on-one meetings, One-Call Center participation, and a Pipeline Education and Awareness Program, discussed subsequently.

11.11.3 Public Education and Awareness Programs

Signage, educational materials, and periodic public awareness programs in the communities that surround the Project facility locations would be established. The intent would be to keep the communities, contractors, local governments and public aware of all stages and phases of construction and operations, including any scheduled emergency drills and tests that may be scheduled.

11.11.3.1 Liquefaction Facility and GTP

Public information, awareness, and education programs would be initiated to provide the public, neighboring industries, and government officials with knowledge of the Project, including its functions, benefits, and environmental and safety aspects. This effort would be focused primarily during the Project approval and implementation phases, but would continue at an appropriate level after operations have started.

11.11.3.2 Pipelines

On May 19, 2005, PHMSA issued a final rule on implementation of pipeline operator public awareness programs. The rule modifies Sections 192.616 (gas pipelines) and 192.440 (hazardous liquids pipelines) of PHMSA regulations to require that pipeline operators develop, implement, and maintain public awareness programs that are consistent with guidelines contained in API Recommended Practice 1162, Public Awareness Programs for Pipeline Operators. The final rule incorporates the requirements of Recommended Practice 1162 by reference.

The Pipeline Education and Awareness Program would be designed in accordance with applicable PHMSA and Alaska regulatory requirements. At a minimum, the program would be designed to raise public awareness of company facilities by providing information on hazard awareness and prevention, pipeline location information, leak recognition and response, and damage prevention. Efforts to communicate public awareness information about pipeline operations and safety would include regular interactions with the following stakeholders:

- State and local emergency response and planning officials (i.e., state and county emergency management agencies, local emergency planning committees, and first responder organizations);

- Local public officials and governing councils of affected municipalities and school districts;

- The public (including residents and places of congregation, such as businesses, schools, hospitals, prisons, and other places people gather) in the vicinity of the pipeline and its associated facilities; and

- Third parties such as excavators, loggers, drillers, miners.

Additionally, appropriate training to manage pipeline emergencies would be provided to local emergency service personnel.

11.11.4 Emergency Response Plans

Prior to operation of Project facilities, ERPs that meet all regulatory requirements and address the site-specific nature of the covered facilities would be prepared. A comprehensive ERP including the full scope of this Project would be developed. Ultimately, the Liquefaction Facility, pipelines, and gas treatment plant would be an integrated system and need to ensure proper and timely response to any emergency.

Each plan would require extensive participation with stakeholders to ensure that all responses to emergencies at the Project facilities are coordinated and understood by emergency responders, local community leaders, government, and the general public affected by the Project. Different agencies with jurisdiction over different parts of the Project each require an ERP.

The combined ERP would be developed using the nationally recognized Federal Emergency Management Agency (FEMA) guidelines and use the National Incident Management System (NIMS) as the methodology. The plan would address coordination with the fire prevention, law enforcement, and emergency response agencies in evaluating a particular incident and determining the most appropriate plan of action.

FERC requires an emergency plan along with a cost sharing plan prior to the start of construction in accordance with the Section 311 of the Energy Policy Act of 2005 in accordance with FERC's Draft Guidance for LNG Terminal Operator's ERP (FERC, 2006). The plan must be developed in coordination with the USCG, state, county, and local emergency planning groups, fire departments, state and local law enforcement, as well as appropriate federal agencies. It must include, as a minimum, designated contacts with state and local emergency response agencies, procedures for notification of local officials and emergency response agencies, procedures for notifying residents and recreational users within areas of potential hazard, and evacuation routes for residents and other public use areas that are within any transient hazard areas along the route of the LNG vessel transit. It must also contain the locations of permanent sirens and other warning devices and an "emergency coordinator" on each LNG vessel to activate sirens and other warning devices.

The Cost Sharing Plan is an agreement that is negotiated with the local community to provide resources and support as necessary to mitigate potential security and safety risks associated with operation of the facility and beyond current local capabilities to mitigate. It puts forth any cost reimbursements that the applicant agrees to provide to any state and local agencies with the responsibility for security and safety of the Liquefaction Facility and the vessels that serve the facility.

Guidelines for response training required of appropriate personnel as well as any community outreach programs would be included with the ERP.

11.11.4.1 Combined Emergency Response Plan

Manuals, procedures, and plans that address safety, reliability, and security would be developed in accordance with established regulations that would afford the public a high level of protection. A public awareness program would also be implemented to disseminate the information.

Fundamental to the preparation of the ERP, ongoing consultation with the local response and other community stakeholders would occur. During this time, the foundational documents, listed below, would be prepared. These documents are important inputs to the ERP.

- Command and Control Concept;
- Emergency Operations Concept for Land-Based Fire Resources;
- Emergency Operations Concept for Marine Fire Resources;
- Security Concept (Maritime and Land-Based);
- Resource List (part of cost sharing agreement); and
- Cost Share Agreements.

11.11.4.2 U.S. Coast Guard Emergency Response and Operations Manual

The USCG requires under 33 C.F.R. § 127.307 an Emergency Manual that must be submitted and approved by the local Captain of the Port prior to terminal operations. The manual must contain LNG release response procedures, including contacting local response organizations; ESD procedures; a description of the fire equipment and systems and their operating procedures; a description of the emergency lighting and emergency power systems and the telephone numbers of local USCG units, hospitals, fire departments, police departments, and other emergency response organizations. If the terminal handling LNG has personnel shelters, the location of and provisions in each shelter must also be provided, as well as first aid procedures and if there are first aid stations, the locations of each station. The emergency procedures for mooring and unmooring a vessel are also required.

The emergency plan and fire-prevention plan required by OSHA in 29 C.F.R. § 1910.38 may be used to comply with this section to the extent that they address the requirements specified in 33 C.F.R. § 127.307.

The USCG Emergency Manual and the Operations Manual may be combined to reduce the number of manuals and make emergency response a direct part of operating the facility.

11.11.4.3 Liquefaction Facility

The ERP would establish the procedures for responding to specific emergencies that may occur at the LNG Plant and the Marine Terminal. The ERP would also address procedures for emergency situations along the LNGC transit route. While the Project is not directly responsible for the arriving LNGCs, addressing the ship in firefighting planning is critical to ensure that an effective response could be managed properly. All arriving LNG carriers are required to comply with the USCG marine firefighting and salvage rules specified in 33 C.F.R. 155.5015. The Project emergency planning efforts pertaining to firefighting would be incorporated into the ERP and the ERP would be shared with those companies or shippers desiring to bring LNGCs to the Marine Terminal. While the responsibility for the ship would not be held by the Project, the intent is to ensure that clear command and control arrangements would be in place prior to the arrival of the first LNGC. The ERP would allow and facilitate the integration of the ship masters with the local firefighting assets. Tugs for assisting the ships would be provided. Each of these tugs would be fitted with a very high level of firefighting capacity (FIFI 1) to assist in any LNG ship board fire. These tug-based firefighting resources would be trained and prepared to respond in a timely manner.

An oil spill chapter, which would address the basic emergency response elements, would be included in the ERP for the Project. The ERP would be designed using FEMA guidance for emergency plans and covers all potential hazards. In addition to the ERP, the requirement for a separate Oil Spill Contingency Plan in accordance with Alaska Statute 46.04.900 is understood. The required plan would be submitted in sufficient time for the Alaska State Preparedness and Response Section to review and approve the plan before commencing operation of the Marine Terminal.

11.11.4.4 Pipelines and Related Aboveground Facilities

The regulations in 49 C.F.R. 192.615 require that pipeline operators prepare and follow a written ERP that includes procedures to identify the hazards and mitigate the risks associated with a natural gas pipeline emergency.

11.11.4.5 PHMSA Pipeline Emergency Plans

PHMSA requires that each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

- Receiving, identifying, and classifying notices of events which require immediate response by the operator;
- Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials;
- Prompt and effective response to a notice of each type of emergency, which include:
    - Gas detected inside or near a building;
    - Fire located near or directly involving a pipeline facility;
    - Explosion occurring near or directly involving a pipeline facility; and
    - Natural disaster.
- The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency;
- Actions directed toward protecting people first and then property;
- ESD and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property;

- Making safe any actual or potential hazard to life or property;
- Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency;
- Safely restoring any service outage;
- Beginning action under 49 C.F.R. 192.617, if applicable, as soon after the end of the emergency as possible; and
- Actions required to be taken by a controller during an emergency in accordance with 49 C.F.R. 192.631.

Local operating facilities would each have a site-specific Emergency Preparedness and Response Plan (EPRP). These plans would identify the types of emergencies that would require notification to appropriate agencies and detail the response organization and resources (e.g., diagrams, maps, plans, and procedures) necessary to adequately respond. Operations personnel would use the Incident Command System to coordinate with local emergency response agencies to ensure appropriate communications, understanding, and cooperation are in place. This would ensure that the EPRP are appropriately linked to plans maintained by other affected response agencies or third parties.

The local EPRP would be supported by various Emergency Operations Centers (EOCs). There would also be a backup EOC in the event that the primary EOC would not be operational. The purpose of the EOCs would be to provide coordinated support for field personnel and other emergency services following a system emergency, and to mobilize operations resources to work with local first responders to secure the incident site and control/contain the emergency event.

In the event of an emergency, operating personnel would take actions in accordance with the applicable EPRP to protect lives, reduce injuries and illnesses, protect property and the environment, and maintain customer service.

11.11.4.6 GTP

Emergency response resources consist of:

- An onsite organization. A site-level emergency response organization is defined and staffed with workers or contractors for both the construction and operating phases of the Project. These individuals are trained for their roles on the emergency response team. The on-site response team is supplemented by external resources as determined by the results of the disciplined approach to a given incident;
- Trained personnel;
- Appropriate staff trained in spill control and cleanup, as well as first aid and rescue techniques; and
- Facilities and equipment.

Appropriate emergency response facilities (relevant to fire protection) are provided at the GTP. These are anticipated to include:

- Fire extinguishers;
- Engineered fire suppression systems in selected areas; and
- Firewater sprinkler system in the normally manned, non-process buildings.

Detailed ERPs would be developed during detailed engineering. Fire response by Operations and Maintenance personnel would be incipient stage only, and medical response would be first responder type only. Shared emergency response agreements (fire medical, spill) would be negotiated in advance with nearby operators. Training of operations staff would include frequent drills dealing with a variety of emergency scenarios including spills, releases, and fires.

11.12 REFERENCES

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