Alaska LNG

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DRAFT RESOURCE REPORT NO. 11

RELIABILITY AND SAFETY

PUBLIC VERSION

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RESOURCE REPORT NO. 11 SUMMARY OF FILING INFORMATION	
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

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

ACRONYMS AND ABBREVIATIONS

ABBREVIATION	DEFINITION
Abbreviations for Units of Measurement	
°C	degrees Celsius
°F	degrees Fahrenheit
BSCF/D	billion standard cubic feet per day
cfs	cubic feet per second
cm	centimeters
dB	decibels
dBA	A-weighted decibels
ft	feet
g	grams
gpm	gallons per minute
ha	hectare
hp	horsepower
Hz	hertz
in	inches
kg	kilogram
kHz	kilohertz
kW	kilowatts
L_{dn}	day-night sound level
L_{eq}	equivalent sound level
L_{max}	maximum sound level
m^3	cubic meters
Ma	mega-annum (millions of years)
mg	milligrams
mg/L	milligrams per liter
mg/m^3	milligrams per cubic meter
MGD	million gallons per day
mm	millimeters
MMBtu/hr	million British thermal units per hour
MMSCF/D	million standard cubic feet per day
MPH	miles per hour
MMTA	million metric tons per annum
ng	nanograms
ppb	parts per billion
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
Psig	pounds per square inch gauge
rms	root mean square
SPL	sound pressure level
tpy	tons per year

ABBREVIATION	DEFINITION
µg	microgram
µg/kg	micrograms per kilogram
µPa	micropascals
Other Abbreviations	
§	section or paragraph
AAAQS	Alaska Ambient Air Quality Standards
AAC	Alaska Administrative Code
ACC	Alaska Conservation Corps
ACEC	Areas of Critical Environmental Concern
ACP	Arctic Coastal Plain
ACRC	Alaska Climate Research Center
ACS	U.S. Census, American Community Survey
AD	aggregate dock
ADCCED	Alaska Department of Commerce, Community, and Economic Development
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADGGS	Alaska Division of Geological and Geophysical Surveys
ADM	average daily membership
ADNR	Alaska Department of Natural Resources
ADOLWD	Alaska Department of Labor and Workforce Development
ADOT&PF	Alaska Department of Transportation and Public Facilities
AEIC	Alaska Earthquake Information Center
AES	Arctic Slope Regional Corporation Energy Service
AGDC	Alaska Gasline Development Corporation
AGPPT	Alaska Gas Producers Pipeline Team
AHPA	Alaska Historic Preservation Act
AHRS	Alaska Heritage Resources Survey
AIDEA	Alaska Industrial Development and Export Authority
AKNHP	Alaska Natural Heritage Program
AMP	approximate mile post
ANCSA	Alaska Native Claims Settlement Act
ANGPA	Alaska Natural Gas Pipeline Act
ANGTS	Alaska Natural Gas Transportation System
ANILCA	Alaska National Interest Lands Conservation Act
ANIMIDA	Arctic Nearshore Impact Monitoring in the Development Area
ANS Task Force	Aquatic Nuisance Species Task Force
ANVSA	Alaska Native Village Statistical Area
AOGCC	Alaska Oil and Gas Conservation Commission
AOI	Area of Interest
APCI	Air Products and Chemicals Inc.
APDES	Alaska Pollutant Discharge Elimination System
APE	Area of Potential Effect
API	American Petroleum Institute
APP	Alaska Pipeline Project

ABBREVIATION	DEFINITION
Applicants	ExxonMobil Alaska LNG LLC, ConocoPhillips Alaska LNG Company, BP Alaska LNG LLC, TransCanada Alaska Midstream LP, and Alaska Gasline Development Corporation
APSC	Alyeska Pipeline Service Company
AQRV	Air Quality Related Value
Arctic NWR	Arctic National Wildlife Refuge
ARD	acid rock drainage
ARDF	Alaska Resource Data File
ARPA	Archaeological Resources Protection Act of 1979
ARRC	Alaska Railroad Corporation
AS	Alaska Statute
ASAP	Alaska Stand Alone Pipeline
ASME	American Society of Mechanical Engineers
ASOS	Automated Surface Observation System
ASRC	Arctic Slope Regional Corporation
ATC	Allakaket Tribal Council
ATWS	additional temporary workspace
AWOS	Automated Weather Observing System
B.C.	British Columbia
BACT	Best Available Control Technology
BGEPA	Bald and Golden Eagle Protection Act
BIA	U.S. Department of the Interior, Bureau of Indian Affairs
BLM	U.S. Department of the Interior, Bureau of Land Management
BMP	best management practices
BOD_5	biochemical oxygen demand
BOEM	U.S. Department of the Interior, Bureau of Ocean Energy Management
BOG	boil-off gas
BP	Before Present
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
CAMA	Central Arctic Management Area
CCP	Comprehensive Conservation Plans
CDP	Census Designated Place
CEA	Chugach Electric Association
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CGF	Central Gas Facility
CGP	Construction General Permit
CH_4	methane
CHA	Critical Habitat Area
CIRCAC	Cook Inlet Regional Citizens Advisory Council
CIRI	Cook Inlet Region Inc.
CLG	Certified Local Government
CO	carbon monoxide

ABBREVIATION	DEFINITION
CO_2	carbon dioxide
CO_2e	total greenhouse gas emissions, in CO_2-equivalent global warming potential
COC	Certificate of Compliance
CONUS	Continental U.S.
COOP	National Weather Service, Cooperative Observer Program
CPCN	Certificate of Public Convenience and Necessity
CRA	Certificate of Reasonable Assurance
CSD	Contaminated Sites Database
CSP	Contaminated Sites Program
CSU	conservation system units
CV	coefficient of variation
CWA	Clean Water Act
DB	Denali Borough
DEM	Digital Elevation Model
DGGS	ADNR Division of Geological and Geophysical Surveys
DH	dock head
DHSS	Alaska Department of Health and Social Services
DMLW	Alaska Department of Natural Resources, Division of Mining, Land, and Water
DPS	Distinct Population Segment
DWPP	Drinking Water Protection Program
EDA	U.S. Department of Commerce, Economic Development Administration
EEZ	Exclusive Economic Zone
EFH	Essential Fish Habitat
EIS	Environmental Impact Statement
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPRP	Emergency Preparedness and Response Plan
ERL	Environmental, Regulatory and Lands
ERMA	Extended Recreation Management Areas
ESA	Endangered Species Act
ESD	Emergency Shut Down
ESU	Evolutionary Significant Unit
FAA	U.S. Department of Transportation, Federal Aviation Administration
FCC	Federal Communications Commission
FE	U.S. Department of Energy, Office of Fossil Energy
FEED	front-end engineering design
FEIS	Final Environmental Impact Statement
FEMA	U.S. Department of Homeland Security, Federal Emergency Management Agency
FERC	U.S. Department of Energy, Federal Energy Regulatory Commission
FERC Plan	FERC Erosion Control, Revegetation, and Maintenance Plan
FERC Procedures	FERC Wetland and Waterbody Construction and Mitigation Procedures
FLPMA	Federal Land Policy and Management Act (of 1976) BLM
FMP	Fisheries Management Plan

ABBREVIATION	DEFINITION
FNSB	Fairbanks North Star Borough
FR	Federal Regulation
GDP	Gross Domestic Product
GHG	greenhouse gases
GIS	geographic information system
GMU	Game Management Units
GP	General Permit
GRI	Gas Research Institute
GTP	gas treatment plant
GWP	Global Warming Potential
H_2S	hydrogen sulfide
HABS	Historic American Building Survey
HAER	Historic American Engineering Record
HAP	Hazardous Air Pollutant
HAPC	Habitat Areas of Particular Concern
HCA	High Consequence Area
HDD	horizontal directional drill
HDMS	Hazard Detection and Mitigation System
HGM	hydrogeomorphic
HLV	heavy lift vessel
HMR	Hazardous Materials Regulations
HRS	Hazard Ranking System
IBA	Important Bird Areas
ICS	Incident Command System
IHA	Incidental Harassment Authorization
IHLC	Inupiat History, Language, and Culture
ILI	In-line Inspection
IMP	Integrity Management Plan
IP	Individual Permit
ISO	International Organization for Standardization
JPO	State and Federal Joint Pipeline Office
kbpd	thousand barrels per day
KCC	Kuparuk Construction Camp
KOP	key observation points
KPB	Kenai Peninsula Borough
KTC	Kuparuk Transportation Company
LiDAR	light detection and ranging
Liquefaction Facility	natural gas liquefaction
LLC	Limited Liability Company
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
LOA	Letter of Authorization
LOD	Limits of Distribution

ABBREVIATION	DEFINITION
LP	Limited Partnership
LPG	liquefied petroleum gas
LUP	Land Use Permit
LUST	Leaking Underground Storage Tanks
MACT	maximum achievable control technology
Mainline	An approximately 800-mile-long, large-diameter gas pipeline
MAOP	maximum allowable operating pressure
MARPOL	Marine Pollution Protocol
MBTA	Migratory Bird Treaty Act
MCD	marine construction dock
MHHW	mean higher high water
MHW	mean high water
ML&P	Anchorage Municipal Light and Power
MLA	Mineral Leasing Act
MLBV	Mainline block valve
MLLW	mean lower low water
MLW	mean low water
MMPA	Marine Mammal Protection Act
MMS	Mainline Meter Station
MOE	margin of error
MOF	material offloading facility
MP	Mainline milepost
MPRSA	Marine Protection Research and Sanctuaries Act of 1972
MSB	Matanuska-Susitna Borough
MSCFD	Thousand standard cubic feet per day
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAS	nonindigenous aquatic species
NCC	national certification corporation
NCDC	National Climatic Data Center
NDE	non-destructive examination
NEP	non-essential experimental population
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NFIP	National Flood Insurance Program
NGA	Natural Gas Act
NHPA	National Historic Preservation Act of 1996, as amended
NID	Negligible Impact Determination
NLURA	Northern Land Use Research Alaska, LLC
NMFS	National Oceanic and Atmospheric Administration, National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NOAA	National Oceanographic and Atmospheric Administration

ABBREVIATION	DEFINITION
NOI	Notice of Intent
North Slope	Alaska North Slope
NPDES	National Pollutant Discharge Elimination Systems
NPL	National Priority List
NPP	National Park and Preserve
NPR-A	National Petroleum Reserve – Alaska
NPS	National Park Service
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NSA	Noise-Sensitive Areas
NSB	North Slope Borough
NSPS	New Source Performance Standards
NTC	national training center
NTP	Notice to Proceed
NVIC	Navigation and Vessel Inspection Circular
NWA	Northwest Alaska Pipeline
NWI	National Wetland Inventory
NWR	National Wildlife Refuge
O_3	Ozone
OC	open-cut
OCS	Outer Continental Shelf
OD	outside diameter
OEP	FERC, Office of Energy Projects
OHA	ADNR Division of Parks and Outdoor Recreation, Office of History and Archaeology
ONA	Outstanding Natural Area
OPMP	ADNR, Office of Project Management and Permitting
OU	Operating unit
PAC	potentially affected community
Pb	the element lead
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
PCB	polychlorinated biphenyl
PHMSA	Pipeline and Hazardous Materials Safety Administration
$PM_{2.5}$	particulate matter having an aerodynamic diameter of 2.5 microns or less
PM_{10}	particulate matter having an aerodynamic diameter of 10 microns or less
PMP	Point Thomson Gas Transmission Line milepost
POC	Plan of Cooperation
POD	Plan of Development
Project	Alaska LNG Project
PRPA	Paleontological Resources Preservation Act
PSD	Prevention of Significant Deterioration
PTTL	Point Thomson Gas Transmission Line
PTU	Point Thomson Unit

ABBREVIATION	DEFINITION
PWS	public water supply
Q&A	question and answer
RCA	Regulatory Commission of Alaska
RCRA	Resource Conservation and Recovery Act
RNA	Research Natural Area
ROD	Record of Decision
ROE	right-of-entry
ROW	right-of-way
RR	Resource Report
SCC	Deadhorse Airport
SDWA	Safe Drinking Water Act
SEIS	Supplemental Environmental Impact Statement
SGR	State Game Refuge
SHPO	State Historic Preservation Office(r)
SIP	State Implementation Plan
SMA	Special Management Areas
SRMA	Special Recreation Management Areas
SO_2	sulfur dioxide
SPCC	Spill Prevention, Control, and Countermeasure Plan
SPCO	State Pipeline Coordinator's Office
SPLASH	Structure of Populations, Levels of Abundance, and Status of Humpbacks
SPMT	self-propelled module transporters
SRA	State Recreation Area
SRR	State Recreation River
STATSGO	State Soil Geographic
STATSGO2	State Soil Geographic2 – General Soils Map of Alaska & Soils Data (2011)
SWAPA	Southwest Alaska Pilots Association
SWPPP	Stormwater Pollution Prevention Plan
TAHC	total aliphatic hydrocarbons
TAPS	Trans-Alaska Pipeline System
TBD	To be determined
TCC	Tanana Chiefs Conference
The Applicants' Plan	Applicants' Upland Erosion Control, Revegetation, and Maintenance Plan
The Applicants' Procedures	Applicants' Wetland and Waterbody Construction, and Mitigation Procedures
TPAH	total polycyclic aromatic hydrocarbons
TSA	Transportation Security Administration
TSCA	Toxic Substances Control Act
TSD	tug support dock
TSS	total suspended solids
UCIDA	United Cook Inlet Drift Association
UIC	Underground Injection Control
U.S.	United States
U.S.C.	U.S. Code

ABBREVIATION	DEFINITION
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard
USDA	U.S. Department of Agriculture
USDHHS	U.S. Department of Health and Human Services
USDOE	U.S. Department of Energy
USDOI	U.S. Department of the Interior
USDOT	U.S. Department of Transportation
USDW	underground sources of drinking water
USFS	U.S. Department of Agriculture, Forest Service
USFWS	U.S. Department of the Interior, Fish and Wildlife Service
USGS	U.S. Geological Survey
VOC	volatile organic compound
VPSO	Village Public Safety Officer
VRM	Visual Resource Management Methodology
VSM	Vertical Support Members
WELTS	Well Log Tracking System
WRCC	Western Regional Climate Center
WSA	Waterway Suitability Assessment
WSR	Wild and Scenic Rivers

Information in this draft Resource Report, including maps, is preliminary and may change during Project pre-filing. Updated information will be provided in the subsequent draft and final versions of the Resource Reports.

11.0 RESOURCE REPORT NO. 11 – RELIABILITY AND SAFETY

11.1 PROJECT DESCRIPTION

The Alaska Gasline Development Corporation, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LP (Applicants) plan to construct one integrated LNG Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular 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 opportunity for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and FERC regulations, 18 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 800-mile, large diameter gas pipeline (Mainline); a gas treatment plant (GTP) on the North Slope; a gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and a 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.

These components are shown in Resource Report No. 1, Figure 1.1-1, and their current basis for design is described below.

The new Liquefaction Facility will be constructed on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula. The Liquefaction Facility will include the structures, equipment, underlying access rights and all other associated systems for pre-processing (other than that performed by the GTP) and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities (dock) and auxiliary marine vessels used to support marine terminal operations (excluding LNG carriers). The Liquefaction Facility will include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Three 160,000 cubic meter (m^3) tanks will be constructed to store the LNG. The Liquefaction Facility will be capable of accommodating two LNG carriers. The size range of LNG carriers that the Liquefaction Facility will accommodate will be determined through further engineering study and consultation with the United States Coast Guard (USCG) as part of the Waterway Suitability Assessment (WSA) process.

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

- Mainline: A new large-diameter natural gas pipeline approximately 800 miles in length will extend from the Liquefaction Facility to the GTP on the North Slope, including the structures, equipment, and all other associated systems. The diameter of the pipeline has not been finalized but for the purpose of these resource reports a 42-inch diameter pipeline is assumed. The Mainline will include compressor stations, heater stations, meter stations, and various mainline block valves; pig launcher and receiver facilities; and associated ancillary and auxiliary facilities. Ancillary and auxiliary facilities will include additional temporary work spaces, access roads, helipads, construction camps, pipe storage areas, contractor yards, material extraction sites, and material disposal sites. Along the Mainline route, there will be at least five off-take interconnection points to allow for the opportunity for future in-state deliveries of natural gas. The size and location of such 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 off-take points will be part of the Project.

- GTP: A new GTP and associated facilities in the Prudhoe Bay area will receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP will treat/process the natural gas for delivery into the Mainline. The Project also includes a new pipeline that will deliver natural gas processing byproducts from the GTP to the PBU.

- PBU Gas Transmission Line: A new natural gas transmission line will extend approximately one mile from the inlet flange of the GTP to the outlet flange of the PBU gas production facility.

- PTU Gas Transmission Line: A new natural gas transmission line will extend approximately 60 miles from the inlet flange of the GTP to the outlet flange of the PTU gas production facility.

- Ancillary Facilities: Existing State of Alaska transportation infrastructure will be used during the construction of these new facilities including ports, airports, roads, and airstrips (potentially including previously abandoned airstrips). The potential need for new infrastructure and modifications or additions to these existing in-state facilities is under evaluation. The Liquefaction Facility, Mainline, and GTP will require the construction of material offloading facilities.

Draft Resource Report No. 1, Appendices A and B contain general maps of the Project footprint. Detailed plot plans will be developed during the pre-front-end engineering and design (Pre-FEED) process and will be provided to the Commission in a subsequent draft of Resource Report No. 1. An update to the current list of affected landowners is being filed under separate cover as privileged and confidential information.

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

- Modifications/new facilities at the PTU;

- Modifications/new facilities at the PBU;

- Relocation of the Kenai Spur Highway; and

- Third-party pipelines and associated infrastructure to transport natural gas from the off-take interconnection points to markets in Alaska.

11.1.1 Purpose of Resource Report

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

- Describe how Project facilities will 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.

11.1.2 Agency and Organization Consultations

This section describes consultations that will be conducted with agencies and other interested parties related to the Project. As Project details are refined in the Pre-FEED process currently underway, consultations will be conducted. A subsequent draft of this Resource Report will describe these consultations.

11.1.2.1 Federal Agencies

The Project Applicants' representatives have held discussions with several federal agencies regarding various Project details, some of which are contained in this Resource Report. A summary of these meetings with a synopsis of key issues discussed will be presented in a subsequent draft of this Resource Report. A summary of public, agency, and stakeholder engagement conducted by Alaska LNG Project Participants is provided in Resource Report No. 1, Appendix D and will be updated in subsequent report versions as additional input is solicited.

11.1.2.2 State Agencies

The Project Applicants' representatives have had discussions with several State of Alaska representatives regarding the Project details contained in this Resource Report. A summary of these meetings with a synopsis of key issues discussed will be presented in a subsequent draft of this Resource Report. A summary of public, agency, and stakeholder engagement is provided in Resource Report No. 1, Appendix D and will be updated in subsequent report versions as additional input is solicited.

11.2 LNG SAFETY BACKGROUND INFORMATION

11.2.1 LNG Properties

LNG is natural gas in its liquid state, which occurs when the gas has been cooled to 260 degrees Fahrenheit (ºF) below zero. Similar to natural gas in its vapor state, LNG is odorless, colorless, non-corrosive, and nontoxic. LNG has a density of approximately 26.5 pounds per cubic foot (lb/ft^3) and is neither flammable nor explosive. LNG vaporizes on contact with any surface that is at a temperature greater than the LNG itself. 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 (i.e., settle close to the ground) in the vicinity of the LNG vaporization source (i.e., a 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.

11.2.2 LNG Hazards

Natural gas is one of the most desirable sources of clean energy and the LNG industry has an excellent safety record. However, 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 and low storage temperature of the LNG. The principal hazards associated with LNG result from its cryogenic temperature (-260°F), the flammability of natural gas vapors, the dispersion characteristics of the natural gas vapors, and potential loss of containment. These hazards are discussed in more detail below.

Due to its cryogenic temperature, LNG spills, if touched by human skin, could result in frostbite injuries. In addition, brittle fracture and structural damage could occur if LNG spills were to touch materials incompatible with cryogenic temperatures. Unlike heavier hydrocarbons such as propane, natural gas and LNG do not have the potential for the explosion of unconfined vapor clouds. However, while the LNG in its liquid state is not flammable, LNG vapors resulting from a release or spill are flammable at concentrations of 5-15 percent. 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 of time as the LNG temperature elevates to levels above -160°F. Flammable mixtures of LNG vapor will initially extend downwind for only a short period of time, and as such, the zone of flammability will be confined to the immediate vicinity of the release or spill. The distance 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, and atmospheric temperature and humidity. Although LNG is nontoxic, LNG vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure. Thus, if a person were to enter a high concentration area most likely resulting from a LNG spill within a confined space, asphyxiation could result.

11.2.3 Safety History of the LNG Industry

The LNG industry has an overall excellent safety record, both in the United States and globally. LNG facilities in the United States are designed to stringent requirements detailed in the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration's (USDOT PHMSA) regulations in 49 C.F.R. Part 193, which incorporate *the National Fire Protection Association: Standards for the Protection, Storage, and Handling of Liquefied Natural Gas (LNG)*, 2001 edition (NFPA 59A). 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. While there have been some incidents over the years, those incidents have resulted in incorporation of additional safety measures into subsequent LNG facility designs. The most notable modern-day LNG incidents are described below:

- In 1979 at the Cove Point LNG facility in Lusby, Maryland, a pump seal failure resulted in gas vapors entering an electrical conduit and settling in a confined space. When a worker switched off a circuit breaker, the gas ignited, causing heavy damage to the building and a worker fatality. With the participation of the FERC, lessons learned from the 1979 Cove Point accident resulted in changing the national fire codes to better ensure that the situation would not occur again. Since the 1979 incident and incorporation of additional design measures to prevent recurrence, there has not been another similar incident at LNG facilities.

- In 2004, a blast occurred at the Skikda, Algeria, LNG liquefaction facility, which killed 27 people and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at a liquefaction train and was introduced to the high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent equipment and spread to the adjacent trains. To prevent recurrence, FERC has required applicants to evaluate all combustion and ventilation air intakes and install mitigation measures as necessary to prevent the introduction of flammables into the air intakes. Since the 2004 incident and the incorporation of additional evaluations and mitigation measures, there has not been another similar incident at LNG facilities.

- In 2014, an explosion and fire occurred at Northwest Pipeline Corporation's LNG peak-shaving facility in Plymouth, Washington. The facility was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No personnel or members of the public were injured. The accident investigation is still ongoing and once complete, necessary measures to prevent recurrence will be incorporated into LNG facilities.

In the roughly 40 years the LNG industry has been operating, there have been approximately 80,000 LNG Carrier (LNGC) voyages which have travelled more than 100 million miles, and there has been no loss of containment of an LNG Carrier cargo tank due to collision, allision or grounding, no cargo fires and no fatalities involved in cargo operations. Total LNG spilled due to small spills or pipeline failures equals about 45 m^3 in the entire history of LNG transportation by sea. This accomplishment is significant because LNGC frequently transit high-density marine traffic areas. For example, in the past 30 years, Japan has received numerous LNG cargos through Tokyo Bay and the U.S. has received numerous cargos through Boston Harbor. According to the U.S. Department of Energy (SNL, 2004), "Over the life of the industry, eight marine incidents worldwide have resulted in spillage of LNG, with some hulls damaged due to cold fracture, but no cargo fires have occurred. Seven incidents not involving spillage were recorded, two from groundings, but with no significant cargo loss; that is, repairs were quickly made and leaks were avoided. There have been no LNG shipboard fatalities."

11.3 MARINE LNG TRANSIT SAFETY AND RELIABILITY

11.3.1 LNG Shipping and Risk Reduction Measures

The USCG has jurisdiction under 33 C.F.R. Part 127 for the "marine transfer area" of every waterfront LNG 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. The USCG also has jurisdiction over the security of the entire LNG facility through 33 C.F.R. Part 105.

The FERC and the USCG require LNG terminal applicants to submit a Preliminary Waterway Suitability Assessment (WSA) and a Follow-on WSA to the Captain of the Port (COTP) as outlined in 33 C.F.R. 127.007 and 18 C.F.R. 157.21. The WSA is the USCG's review of the marine transportation component of an LNG terminal project and addresses the suitability of the waterway for the LNGC traffic. The regulations require that full consideration be given to safety and security of the port, the facility, and the vessels transporting LNG.

The WSA will be a major component of FERC's National Environmental Policy Act (NEPA) review of the Project. As part of that review, the USCG Sector Anchorage will issue a Letter of Recommendation (LOR) for the use of the Marine Terminal portion of the Liquefaction Facility. The LNGC shipping safety and security risk assessment, as well as need for any additional risk reduction measures for the Liquefaction Facility, will be addressed in the WSA.

11.3.2 USCG Letter of Intent

Representatives of the Applicants submitted a Letter of Intent (LOI) and Preliminary WSA to Captain Paul Mehler, III, USCG Sector Commander COTP, on May 15, 2014 (Appendix D and Appendix E), in accordance with 18 C.F.R. Part 157.21 and 33 C.F.R. Part 127.007.

11.3.3 Waterway Suitability Assessment

The Follow-on WSA must be submitted no later than the time an application is filed with FERC. The Follow-on WSA is a more detailed version of the Preliminary WSA and will identify credible security threats and safety hazards related to the transportation of LNG from the LNGC's entrance into U.S. territorial waters, LNGC transit to/from the Project's marine terminal, and operations at the vessel/ facility interface. The results of the WSA will provide the local COTP the information necessary to inform the permitting process that the proposed terminal facility is appropriate for the specific waterway. The results of the WSA study will also provide the basis for developing safety and security plans for LNGC transits and Marine Terminal operations within this waterway.

The WSA process is 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 issues 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 WSA process considers potential infrastructure vulnerabilities and evaluates 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 is to identify the federal, state, local, and private sector resources needed to carry out the mitigation measures developed during the assessment. The WSA identifies resources currently available and the mechanism by which funding will be provided for additional public resources needed for safe and secure LNGC transit.

The main steps for completion of the WSA include the following:

- WSA Work Plan and Schedule;
- Alignment of the WSA Approach with Sector Anchorage and local COTP requirements;
- Stakeholder Identification and Engagement;
- Characterization of the Port Environment and LNGC route(s);
- Conducting the WSA; and
- Development and Submission of the WSA Report to the COTP.

Additional updates will be provided in a subsequent draft of this Resource Report as the WSA process progresses.

11.3.4 U.S. Coast Guard Transit Management Plan

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

11.3.5 Certifications

LNGCs are required to have and maintain International Certifications as outlined in 46 C.F.R. Part 154, as well as any certificates required by international standards. USCG Certification of Compliance (COC) will need to be obtained by foreign (non-U.S. flagged) LNGCs prior to entering a U.S. port for the first time. 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. Finally, LNGCs must be fully vetted by a recognized agency prior to acceptance by the Project.

11.4 LIQUEFACTION FACILITY SAFETY AND RELIABILITY DESIGN

11.4.1 Introduction

The Liquefaction Facility will be designed, constructed, operated, and maintained in accordance with applicable federal, state, and local laws and regulations. The Liquefaction Facility will be operated in a manner that protects the safety of workers, customers, and the public.

As described in draft Resource Report No. 1, the proposed Liquefaction Facility will consist of the LNG Plant and the Marine Terminal. The LNG Plant will include storage and liquefaction processing facilities, and the Marine Terminal includes the trestles, piping, and berthing facilities associated with LNGC loading and berthing. The Liquefaction Facility is subject to the safety, security, and reliability requirements of the DOT PHMSA regulations in 49 C.F.R. Part 193, the USCG regulations in 33 C.F.R. Part 105 (facility-wide) and Part 127 (specific to the Marine Terminal), and the NFPA 59A standard.

Typical measures used to protect the public and facility personnel from potential hazards resulting from an unlikely release of LNG can be categorized as follows:

- Use of exclusion zones when siting facilities to separate the public from potential hazards (i.e., maximizing Liquefaction Facility equipment distances from Liquefaction Facility property lines and spacing of equipment);

- Thorough analysis of the potential hazard from component failures, including compliance with applicable codes for equipment selection and system design. Examples include use of well-proven equipment and materials, implementation of methods for minimizing flanges and potential leakage sources, and installation of appropriate control and safety systems;

- Minimizing the consequences of potential component failure by designing mitigation features into the facility. Examples include strategic placement of Emergency Shut Down valves and flammable gas detectors, provision of grading and drainage for spilled LNG in a safe location, and use of flame detectors and independent safety instrumented systems; and

- Structuring and managing facility operations to prevent failures and mitigate consequences through the use of appropriate procedures, inspections, maintenance, training, and supervision. Examples include an operations and maintenance manual, emergency response plan/manual, and frequent training sessions.

Although emergency response procedures will be in place, the design and siting of the Liquefaction Facility will inherently protect the public from potential consequences of a release, as further described below. Additional information about specific Project public safety and reliability measures will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.2 Preliminary Site Plan

Facility siting requirements are a key component of the NFPA 59A standard and 49 C.F.R. Part 193. The Liquefaction Facility will be designed to meet these regulatory requirements and related applicable guidance. As discussed below, key inputs into the Liquefaction Facility layout currently under

development will be the LNG spill containment design, thermal radiation and vapor dispersion exclusion zones, and other specified siting considerations. A preliminary site plan for the Liquefaction Facility will be provided in a subsequent draft of this Resource Report. More technical analysis of the facility siting plans will be provided in draft Resource Report No. 13.

11.4.2.1 LNG Spill Containment

All LNG and flammable refrigerant transfer piping will be provided with spill impoundment systems, which will be sloped to drain the LNG or refrigerant away from the piping and into spill containment basins. In accordance with the requirements of Section 2.2.2.2 of NFPA 59A, impounding areas that serve only vaporization, process, or LNG transfer areas will have a minimum volumetric capacity. The capacity is 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. The single accidental leakage source used as the design spill required in 49 C.F.R. Part 193 is based on the application of failure rates to LNG transfer piping and components. Based on instrumentation that will be installed to detect the occurrence of LNG leaks, however, an active automated alarm would alert the operator to shutdown the LNG transfer operations most likely in less time than the assumed 10-minute spill duration. This well-proven design is effective in reducing both the potential hazards that would result from the dispersion of an unignited vapor cloud and the hazards from thermal radiation caused by an LNG pool fire.

In the event of an LNG leak or spill, LNG will flow into the spill containment basins along troughs located alongside or beneath LNG pipelines. The troughs will be constructed of insulated concrete and will have been designed and sized to minimize vapor formation during LNG spills. The LNG spill containment basins will be constructed of a reinforced concrete construction lined with insulating polymer concrete. The insulating polymer 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, 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, each LNG spill containment basin will include a sump to collect rainwater from the containment area. Automatically controlled sump pumps will be installed in the sump to remove water from the LNG spill containment basin. This water removal system will have the capacity to remove water at a minimum rate of 25 percent of the rate from a storm of a 10-year frequency and 1-hour duration. The sump pumps will be fitted with an automatic shutoff device that prevents their operation when exposed to LNG temperatures.

11.4.2.2 Thermal Radiation Exclusion Zones

Exclusion distances for various flux levels will be calculated in accordance with 49 C.F.R. Part 193.2057 and Section 2.2.3.2 of NFPA 59A, using the "LNGFire III" computer program model developed by the GRI.

11.4.2.3 Flammable Vapor Exclusion Zones

The Liquefaction Facility will be designed to meet the flammable vapor exclusion zone requirements established by Sections 2.2.3.3 and 2.2.3.4 of NFPA 59A, 49 C.F.R. Part 193.2059, and written

interpretations issued by DOT PHMSA in July 2010. The design will minimize the possibility of flammable vapors creating a distinct hazard on any properties upon which structures can be built outside of the Liquefaction Facility. Specifically, in accordance with the requirements of 49 C.F.R. Part 193.2059, dispersion distances will be calculated for one half the lower flammability limit of natural gas and hydrocarbon refrigerant vapors (including mixed refrigerant). These distances will be calculated for jet releases and also the conveyance and impoundment of a design spill of LNG and flammable refrigerants calculated in accordance with Section 2.2.3.5 of NFPA 59A.

In accordance with NFPA 70, the Liquefaction Facility will also be designed such that areas likely to contain flammable gas mixtures will be isolated from ignition sources. Electrical equipment used within these designated areas will be housed in enclosures approved for this service and application. Upon completion of the final design, the hazards will again be reviewed in a formal hazards and operations review to confirm that appropriate emergency response equipment and procedures have been incorporated into the hazard detection and fire protection systems.

11.4.2.4 Other Hazardous Materials

There will be an analysis to quantify the consequence of other hazardous material releases (i.e., refrigerants), which will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.2.5 Overpressure Analysis

There will be an analysis to quantify the consequence of ignition of flammable refrigerant leaks consistent with a design spill used in performing flammable vapor dispersion exclusion analysis. This analysis will summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.3 LNG Liquefaction Trains

The LNG Plant will include three liquefaction trains, which will use Air Products and Chemicals Inc.'s (APCI) C3MR™ LNG technology to liquefy natural gas received from the Mainline. Spacing of the trains will comply with regulatory requirements and industry best practices. LNG spill containment troughs and basins will be provided to safely handle any LNG spills. A variety of hazard detection and mitigation systems as described in Section 11.4.6 will be included in this area of the LNG Plant.

Additional information associated with the LNG liquefaction trains will be provided during Pre-FEED.

11.4.4 LNG Storage Tanks

49 C.F.R. Part 193.2181 specifies that the impoundment system serving a single LNG storage tank must have a volumetric capacity of 110 percent of the LNG tank's maximum liquid capacity. Based on the current design, three full-containment LNG storage tanks, each with a net capacity of 160,000 m^3, will store the LNG product from the liquefaction trains. The LNG storage tanks will be designed for full containment with double-wall construction (i.e., primary and secondary containment), which is further described below. The LNG storage tanks will be designed to meet the requirements of NFPA 59A, 49 C.F.R. Part 193, and other applicable standards. A discussion concerning seismic design considerations is provided in Resource Report No. 13.

Each LNG storage tank will have the following features:

- Inner wall: 9 percent Ni stainless steel containment;
- Outer wall: Reinforced post-tensioned concrete with a steel liner;
- Reinforced concrete domed roof, supporting insulated deck, LNG pumps and tank top LNG and vapor pipework;
- Insulated aluminum deck over the inner containment suspended from the outer containment roof;
- Submerged motor pumps located in vertical pump caissons and supported by a structure attached to the roof and walls;
- Base heating system;
- Pressure, level, and temperature instrumentation, including monitoring of tank cool-down;
- Pressure and vacuum relief systems;
- Nozzles and internal pipework including two-phase inlet, top cool-down spray (all nozzle penetrations would be through the roof);
- Nitrogen purge and leak detection system for wall and floor insulation space;
- Roof platforms, walkways, and pipe supports; and
- External stairways, ladder, and pipe supports.

The full containment LNG storage tanks are designed and will be constructed so that the self-supporting primary containment and the secondary containment will be capable of independently containing the LNG. The primary, inner container has been designed and will be constructed in accordance with the requirements of American Petroleum Institute (API) Standard 620 Appendix Q, and will contain the LNG under normal operating conditions. The secondary container will be capable of containing the LNG (110 percent capacity of inner tank) and controlling the vapor resulting from the unlikely occurrence of product leakage from the inner container.

To increase the safety of the tanks, there will be 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 will prevent water ingress into annular spaces, and, therefore, there are no water removal requirements for this tank design.

11.4.5 Marine Terminal

The Marine Terminal will be constructed in the Cook Inlet and allow LNGC to dock and load LNG. The current design basis does not contemplate simultaneous bulk loading of two ships berthed at the

Liquefaction Facility. Based on the current design, marine facilities will include two loading berths and the following components:

- LNG trestle(s) to support two loading berths;
- Cryogenic pipelines from the LNG tanks to the loading berths;
- Aids to navigation;
- Material offloading facility (MOF);
- LNG loading arms with Emergency Release Couplings;
- Vapor return arm with Emergency Release Couplings;
- Control system;
- Drain connections; and
- Berthing and mooring dolphins.

Based on the current design, each berth will include three 16-inch LNG loading arms and one 16-inch vapor return arm. The design of the loading system is based on a loading rate of 12,500 m^3/hr (per berth). Each berth will be designed to accommodate LNGCs with a maximum capacity of 216,000 m^3. It is anticipated that the Marine Terminal will load 15–20 LNGCs per month with a capacity range of 125,000 to 216,000 m^3.

The size, location, and orientation of loading berths will be designed to optimize a number of safety criteria, including safe navigable approach and departure conditions, a safe mooring environment, proximity to the channel, and safe distance from the influence of passing vessels. Other influences on the ultimate design of the loading berths will include water depth and optimization of the cryogenic piping arrangement. LNG spill containment troughs and basins will be provided within areas of the Marine Terminal where LNG is present. A variety of hazard detection and mitigation systems as described in Section 11.4.6 will also be included within the Marine Terminal.

A discussion of dredging and dredge volumes is provided in draft Resource Report No. 2. Design specific information about the carrier capacity and the design carrier size fo the Marine Terminal will be provided during Pre-FEED. The actual number of port calls per week will be determined by contracts that are subsequently executed and the specific ships used.

11.4.6 Hazard Detection and Mitigation Systems

The Liquefaction Facility will be 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 facility personnel. In the unlikely event that a release does occur, a Hazard Detection and Mitigation System (HDMS) will be in place. Elements of this system include the following:

- Flammable gas detectors;

- High and low temperature detectors;
- Smoke detectors;
- Flame detectors;
- Manual local Emergency Shut Down (ESD) activation push buttons; and
- Automatic ESD activation features.

The HDMS 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 HDMS will result in local audio and visual (e.g., strobe lights) signals with various alarms and colors depending on the detected hazard. When appropriate, the HDMS 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 facility equipment in the event of a fire. Design specific information about the HDMS will be provided at a later date during Pre-FEED.

11.4.7 Flare Stacks

The pressure relief and flare system will be designed to safely and reliably dispose of streams which are released during start-up, shutdown, LNG loading, LNGC gas up and cool down, plant upsets, and emergency conditions. Additional information including the number of required flares will be provided by the Pre-FEED contractor as the design progresses.

11.4.8 Control, Administration, and Workshop Buildings

The following building facilities are planned for the Liquefaction Facility:

- Main Control Room;
- Emergency Response/Firefighting/Medical Facilities;
- Office/Administration Building including Permit Office;
- Assembly Room for Startup and Turnarounds (major gatherings);
- Marine Terminal Building/Loading Platform Control Room;
- Truck Loading Operations Control Room;
- Maintenance Facility/Workshop;
- Warehouse;
- Laboratory;

- Chemical Storage;
- Waste Storage/Hazardous Waste Storage;
- Security Office/Guard House;
- Weather Shelters;
- Equipment Enclosures;
- Construction Offices; and
- Other Temporary Construction Facilities (e.g., concrete batch plant).

Descriptions of the buildings will be provided in a subsequent draft of this Resource Report.

11.4.9 Power, Water, and Communications

11.4.9.1 Power Supply

Information about the Liquefaction Facility power supply will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.9.2 Water Supply

Information about the Liquefaction Facility water supply will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.9.3 Communications

Information about the Liquefaction Facility communications will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.10 Security

Information about the Liquefaction Facility security design features will be summarized in a subsequent draft of this Resource Report and described in technical detail in draft Resource Report No. 13.

11.4.11 Operations and Maintenance

Procedures for operating LNG facilities are a fundamental part of safe operating systems. As LNG technology has matured, the potential for mechanical equipment, system, and design failure has noticeably decreased. The strong safety record of the LNG industry is a result of several factors. First, the industry has technically and operationally evolved to ensure safe and secure operations. Technical and operational advances range from the engineering that underlies LNG facilities to operational procedures and technical competency of personnel. Second, the physical and chemical properties of LNG are such that risks and hazards are well understood and incorporated into technology and operations. Third, the standards, codes, and regulations that apply to the LNG industry further ensure safety. The

U.S. has its own regulatory requirements for LNG operators and has benefited from the evolving international standards and codes that regulate the industry.

Measures such as operating control system tools, procedures, and training address the potential for human error and incorrect operation. Regulatory requirements and appropriate procedures are established in 49 C.F.R. Part 193 and 33 C.F.R. Part 127. Procedures for operation and maintenance of the Project will comply with NFPA standards as specified in the following sections of the NFPA 59A:

- Chapter 11 — Operating, Maintenance and Personnel Training. This procedure will include policies for operating procedures, monitoring of operations, emergency procedures, personnel safety, investigation of failures, communication systems, and operating records;

- Chapter 11 — Operating, Maintenance and Personnel Training. This 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;

- Chapter 11 — Operating, Maintenance and Personnel Training. 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 Liquefaction Facility will receive required training; and

- Appendix C — Security. This procedure will include policies for security procedures, protective enclosures, security communications, security monitoring, and warning signs.

Planned maintenance shutdowns (turnarounds) will be scheduled and coordinated to meet the maintenance required for major equipment.

11.5 PIPELINE SAFETY BACKGROUND INFORMATION

11.5.1 Hazards

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. Geological hazards are naturally occurring events or conditions which 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. Construction activities (mechanical damage by others) can potentially lead to pipeline failures as well. Further information regarding the mitigation of these hazards will be provided in a subsequent draft of this Resource Report and Resource Report No. 6.

The worst outcome of a pipeline failure is a major rupture that results in a fire or explosion and may lead to injury to life and property. Methane has an ignition temperature of about 1,000ºF 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. Methane is buoyant at atmospheric temperatures and disperses rapidly when airborne.

A potential hazard from a pipeline failure, even if not a major rupture, is the inhalation of natural gas. Methane, the primary component of natural gas, 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 high concentration 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.

Stray current 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. Fault currents can occur due to electromagnetic fields around some high-voltage electrical transmission power lines when a fault goes to an earth ground affecting the cathodic protection system.

11.5.2 Safety History of the Natural Gas Transportation Industry

Most of the natural gas consumed in the U.S. is delivered to consumers via underground pipelines. Over the past 50 years, more than 300,000 miles of pipelines (EIA, 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, employees, 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. The Project will employ the system design, construction, operation, and maintenance practices to meet or exceed regulation to minimize the potential for safety incidents.

11.5.2.1 U.S. Department of Transportation Historical Incident Data

The transportation of natural gas by pipeline is the safest mode for natural gas transportation (DOT, 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.

USDOT PHMSA has been collecting and maintaining statistics on natural gas pipeline incidents since 1970. The USDOT PHMSA reporting criteria have changed substantially over the years. USDOT PHMSA regulations at 49 C.F.R Part 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 that results 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 results in an emergency shutdown of an LNG facility; activation of an emergency shutdown 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 are maintained by USDOT PHMSA for the last 20 years. From 1994 through 2013, 1,891 total incidents were reported by natural gas transmission pipelines. Table 11.5.2-1, summarizes the incident statistics by year (DOT, 2014).

TABLE 11.5.2-1

Natural Gas Service Incidents by Year

Year	Number	Fatalities	Injuries
1994	74	0	22
1995	54	2	7
1996	76	1	5
1997	68	1	5
1998	88	1	11
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
Totals:	1,891	41	195

Source: DOT, 2014

11.5.2.2 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 11.5.2-2 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 11.5.2-2

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
Drowning	3,409
Fires	3,312
Flood	58
Tornado	57
Lighting	47
Gas Transmission Pipelines	2

Source: DOT, 2004; DOT, 2014

11.6 PIPELINE SAFETY AND RELIABILITY DESIGN

11.6.1 Introduction

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

The DOT PHMSA is responsible for regulating and enforcing pipeline safety in Alaska. The pipelines and related aboveground facilities will be designed, constructed, operated, and maintained in accordance with standards that meet or exceed the DOT PHMSA's regulations defined in 49 C.F.R. Part 192. Any special permits will follow 49 C.F.R. Part 190.341.

11.6.2 Routing and Design Safety

Section 1.3 of draft Resource Report No. 1 provides an overview of the Project's preliminary pipeline corridors and general descriptions of the pipeline and aboveground facility designs under evaluation. The preliminary pipeline corridors have 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 higher the class location (1-4), the more rigorous the design standards are.

Based on preliminary reviews of aerial photography, it appears that the Mainline may be constructed within multiple class locations while the PTTL lies entirely within a Class 1 location. The preliminary classification of the the PBTL is still to be determined. The design and construction of the Project pipelines will be performed in accordance with the pipeline facility class locations.

In terms of aboveground facilities, compressor stations will be equipped with gas detection and fire protection equipment. An ESD system will be designed to shutdown and isolate each compressor station under predetermined conditions. Overpressure protection systems including relief valves, control valves, and/or isolation valves will protect each compressor stations; automatic shutdowns will occur if a mechanical failure poses risks to the equipment or otherwise constitutes a hazard. Mainline block valve (MLBVs) will be equipped with pressure-sensing devices that will automatically close a valve if the gas pressure in the pipeline drops below a pre-established value.

DOT PHMSA, at its discretion under 49 C.F.R. Part 190.341, may grant a special permit to allow an operator alternative compliance with one or more federal safety regulations in circumstances where the following conditions are met:

- It is not inconsistent with public safety;
- The applicant believes the applicability of that regulation or standard is unnecessary or inappropriate; and
- Sufficient alternative safeguards to public safety are implemented.

DOT PHMSA commonly applies additional safety conditions to its special permits to ensure safety, environmental protection, and that the action is in the public interest. A special permit may be pursued for the Project to utilize strain-based design (SBD) methodology for underground pipeline sections that may experience frost heave and thaw settlement. A SBD special permit would allow for a design that involves displacement-controlled loading and suitable monitoring and intervention limits for maintaining pipeline integrity. A separate special permit may also be pursued to use multi-layer coating systems if a 0.8 design factor and/or SBD is utilized.

Additional information regarding pipeline design, including updated classification information, will be provided in a subsequent draft of this Resource Report.

11.6.2.1 Hazard Detection and Management System

Information concerning the Hazard Detection & Management System for the pipelines will be provided in a subsequent draft of this Resource Report.

11.6.3 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 emergency response plan, and security practices; to maintain specific operating pressures; and to perform regular pipeline patrols, leak surveys, and other surveillance activities. The DOT PHMSA requires the operator to prepare an Operation and Maintenance Plan in accordance with the requirements in 49 C.F.R. 192.605 before placing a natural gas pipeline into service. An Operation and Maintenance Plan will be prepared that includes 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 right-of-way 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 (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;

- Inline Inspections;

- 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;

- Periodic testing and inspection of pressure-limiting devices and ESD systems at the compressor stations; and

These procedures and programs will 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 will be operated from a central 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 can also be operated locally as needed. The Gas Control Center will be staffed 24 hours a day, year-round. A second, fully functional Backup Control Center (in close proximity to the Gas Control Center) will be available in the event the primary Gas Control Center becomes unavailable for any reason. Both control centers would have redundant communication to monitor pipeline status.

The continuous monitoring and operation of the pipeline system will 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 will gather information from locations along the pipelines, such as meter stations and compressor stations;

transmit the information back to the Gas Control Center; compare collected data to pre-set safe operating data points; and organize and display the data including alarm displays for actual operating points that do not meet pre-set operating criteria.

During the course of normal operations, planned maintenance activities at meter stations and compressor stations will include routine checks, calibration of equipment and instrumentation, inspection of critical components, and servicing and overhauls of equipment. Equipment health will 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, will address job responsibilities, staffing, organization, and schedules. Planned maintenance shutdowns (turnarounds) will 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, will be installed along with external coating to mitigate external corrosion of the buried portions of the pipelines. The CPS will 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 will be active within one year of operation start-up, but CPS will also be addressed during the "dormant period." Periodic cathodic protection surveys will be conducted to monitor the status of the CPS and will adjust systems as required to maintain the integrity of the pipeline system. Operations staff will monitor the condition of the pipe, external coating, and the effectiveness of the CPS, as required by DOT PHMSA. Workers will 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.

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

11.6.4 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 Integrity Management Plan (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 a high consequence area (HCA). HCAs are identifed based on class locations and/or the potential for a pipeline failure to impact buildings intended for human occupancy or a particular site.

The development of an IMP begins with the creation of a framework for the document, including identification of covered segments, the required program elements, and the process for implementing each program element. This framework will evolve and develop into a more detailed and comprehensive IMP as information is gathered and incorporated into the program. The framework and subsequent IMP will include all of the following program elements:

- 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.

Regulations under 49 C.F.R. Part 192.903 require HCAs to be identified using one of two methods. Engineering staff will evaluate the Mainline, PTTL, and PBTL using an approved method during Pre-FEED, and these HCAs will be presented in a subsequent draft of this Resource Report.

The IMP for pipeline segments operating at an alternative maximum allowable operating pressure (MAOP) will include the integrity requirements of 49 C.F.R. 192.620, which lists additional integrity management activities required to operate at an alternative MAOP. These additional integrity management provisions apply to all pipeline segments operating in accordance with the alternative MAOP rule requirements. The IMP will specifically address the additional requirements for baseline assessments, threat identification, and integrity assessments.

In accordance with the IMP, operations staff will periodically assess the integrity of pipeline segments operating at the alternative MAOP using assessment methodologies acceptable to the industry and DOT

PHMSA. These segments will be periodically inspected using high-resolution in-line inspection tools**.** In-line inspection tools can be used for assessments of a number of potential hazards, including metal loss from corrosion. In-line inspection 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 will be maintained and be available for review by DOT PHMSA and/or state regulators during inspections, as required.

11.6.5 Security Practices

In December 2010, the Transportation Security Administration (TSA) revised its Pipeline Security Guidelines (TSA 2010). The guidelines provide explicit agency recommendations for pipeline industry security practices.

Security programs and practices will be developed as recommended by TSA and in accordance with an established management system for operations integrity. This will include development of a risk-based security program based on a security vulnerability assessment to address and document policies and procedures for managing security-related threats, incidents, and responses. The security program will include actions to reduce service interruptions and restore natural gas supply as soon as practical while maintaining public safety. Operations staff will develop plans for rapid recovery of natural gas service after an incident and will integrate these plans into its operating procedures.

The security program will be customized to the needs of the pipeline system and will include the following elements:

- System description;
- Security administration and management structure;
- Risk analysis and assessments;
- Physical security and access control measures (fences at appropriate aboveground facilities, lockable gates, chained and lockable equipment);
- Equipment maintenance and testing;
- Personnel screening;
- Communications;
- Personnel training;
- Drills and exercises;
- Security incident procedures;

- Escalating protective measures in face of elevated threats;
- Plan reviews;
- Recordkeeping;
- Cyber asset/SCADA system security measures; and
- Security testing and audits.

11.7 GAS TREATMENT SAFETY BACKGROUND INFORMATION

11.7.1 Hazards

The primary potential hazard associated with GTP operations is an equipment or piping failure including leaks and line breaks. Equipment leaks or line breaks can occur as the consequence of operations including material defects and corrosion. External forces can also cause leakes and line breaks.

11.7.2 Safety History of Natural Gas Treatment

GTPs have an overall excellent safety record, both in the United States and globally. Many LNG facilities in the United States 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.

11.8 GTP SAFETY AND RELIABILITY DESIGN

11.8.1 Introduction

The GTP will be designed, constructed, operated, and maintained in accordance with applicable federal, state, and local laws and regulations. The GTP will be operated in a manner that protects the safety of workers, others involved in its operations, customers, and the public. The current design basis is for the GTP to consist of three parallel treatment trains. The treated gas then will be compressed in stages and routed to a gas chilling unit. After refrigeration, the gas will be delivered to the Mainline.

11.8.2 Hazard Detection and Mitigation Systems

The GTP will be equipped with automatic emergency detection and shutdown systems. There will be a fire and gas detection and alarm system designed in accordance with NFPA 72. Multiple gas detectors will monitor for flammable and toxic gases, and fire detectors will cover areas with fired equipment and large rotating equipment. Audio and visual alarms (e.g., bells, horns, warning lights) will be provided throughout the modules so that personnel are made aware of emergencies. All gas and fire detectors and alarms will be connected to a local fire and gas panel or to the facility Safety Instrumented System. Each panel will 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 will interface with an ESD system. The ESD system will be designed to isolate, shut down, and/or de-pressure the appropriate GTP element upon mechanical malfunction or process upset. These safety and emergency systems will be tested routinely to ensure performance.

The GTP will be equipped with relief valves to protect the piping from over-pressurization. Standard fixed and portable fire protection, first aid, and safety equipment will be maintained at the GTP and facility personnel will be trained in proper equipment use and in first aid.

Additional information about specific Project safety and reliability measures will be summarized in a subsequent draft of this Resource Report.

11.8.3 Operation and Maintenance Plan

The GTP inspection, operation, and maintenance programs will be managed internally through a system for operations integrity management that will address safety, security, and health risks.

The GTP will be monitored and controlled from a Central Control Center. An Operation and Maintenance Plan will be prepared that includes the following activities and operating procedures:

- Worker qualification to operate and maintain the GTP systems;
- Measures to monitor conformance with existing operating and maintenance standards and safe work procedures;
- Training programs for operation and maintenance personnel to maintain skill levels, review safety procedures, and emergency preparedness;
- Standard procedures for protecting assets and preserving public safety during planned maintenance and corrective maintenance activities; and
- Periodic testing and inspection of pressure-limiting devices and ESD systems.

These procedures and programs will increase safety, maintain the integrity of the GTP, and reduce the potential for incidents.

Planned maintenance activities at the GTP will include routine checks, calibration of equipment and instrumentation, inspection of critical components, and servicing and overhauls of equipment. An equipment health monitoring system will be installed to collect and trend data, monitor critical rotating equipment, and manage data so that it can be accessed both locally and remotely to enable troubleshooting, optimization, and predictive maintenance planning. Unplanned maintenance activities include investigation of problems identified by the Central Control Center and monitoring system, and implementation of associated corrective actions. Operational procedures and programs, to be developed, will address job responsibilities, staffing, organization, and schedules. Planned maintenance shutdowns (turnarounds) will be scheduled and coordinated to meet the maintenance required for major equipment.

An integrity management program for the GTP will be developed which will include the following:

- Identification of all high risk equipment and process piping;
- Baseline assessment plan;

- Identification of threats to high risk equipment and piping, 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; and
- Procedures to verify that integrity assessments are conducted to minimize environmental and safety risks.

A combination of online condition monitoring, and offline inspections (during scheduled facility turnarounds) will be used for the baseline and continuous monitoring program. Specific methods will be determined as the design progresses and the specific equipment is selected, but will follow appropriate industry practice.

The GTP integrity management program and records demonstrating compliance will be maintained for the life of the facility and would be available for review during inspections.

11.9 RISK MANAGEMENT AND PUBLIC ENGAGEMENT

11.9.1 Risk Management Framework

A management system will be developed and implemented to assess and manage the design, construction, and operation of the Project to maximize safety and health of the public, employees, and others involved in its operations. The management system will 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 below.

11.9.1.1 Project Risk Assessment and Risk Management Planning

Risk assessment and risk management plans will 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.

Risk management plans will be developed and implemented during the design phase of the Project to address the identified risks. The risk management plans will continue to be used throughout the construction and commissioning phases and will set the tone for the approach to risk management.The plans will 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.

More details regarding these plans will be provided in a subsequent draft of this Resource Report.

11.9.2 Liaison Procedures with Local Authorities

The Project will meet with the local emergency response and public officials in the communities where the Project facilities will be located. During these meetings, the Project will inform emergency responders of the procedures and plans that will be put in place at each facility, the frequency and plans for emergency preparedness training exerises, as well as outline how emergency responders will work with the Project during emergency situations.

11.9.2.1 Liquefaction Facility and GTP

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

11.9.2.2 Pipelines

In accordance with the DOT PHMSA rules in 49 C.F.R. Part 192.615, coordination with appropriate emergency responders and public officials will be established. The purpose of maintaining liaison is two-fold: to learn the resources and responsibilities of each organization that will respond to a pipeline emergency, and to coordinate mutual assistance in the event of an emergency. Liaison will occur through

one-on-one meetings, One-Call Center participation, and a Pipeline Education and Awareness Program, discussed below.

11.9.3 Public Education and Awareness Programs

The Project will establish signage, educational materials and periodic public awareness programs in the communities that surround the Project facility locations. The intent is to keep the communities and general public aware of all stages and phases of construction and operations, including any scheduled emergency drills and tests that may be scheduled to keep equipment and personnel up to date with their training.

11.9.3.1 Liquefaction Facility and GTP

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

11.9.3.2 Pipelines

On May 19, 2005, the DOT 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 the DOT 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 will be designed in accordance with applicable DOT PHMSA and Alaska regulatory requirements. At a minimum, the program will 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 will 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 ancillary facilities; and
- Third parties such as excavators, loggers, drillers, miners.

Additionally, appropriate training to handle pipeline emergencies will be provided to local emergency service personnel.

11.9.4 Emergency Response Plans

Prior to operation of Project facilities, emergency response plans that meet all regulatory requirements and address the site-specific nature of the covered facilities will be prepared.

11.9.4.1 Liquefaction Facility

A draft Emergency Response Plan (ERP) will be included in a subsequent draft of this Resource Report. The ERP establishes the procedures for responding to specific emergencies that may occur at the Liquefaction Facility as well as procedures for emergency situations that could affect the public along the LNGC transit routes. The ERP will be developed in accordance with FERC's Draft Guidance for LNG Terminal Operator's Emergency Response Plan (FERC, 2006). FERC's Draft Guidance requires applicants to consult with local, state, and federal agencies, as well as other stakeholders, in preparing a final ERP for FERC's approval prior to the start of construction. The ERP includes a cost-sharing plan describing 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 will be included in the ERP.

11.9.4.2 Pipelines and Related Aboveground Facilities

Regulations at 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. Prior to startup of Project pipelines, an Emergency Management System (EMS) will be developed to provide an effective and comprehensive response to emergency events. The EMS will use the Incident Command System (ICS) structure to coordinate incident response that would meet all regulatory requirements and applicable laws. The EMS will describe and document plans to coordinate with federal, state, and local emergency agencies that may be affected by Project operations.

Local operating facilities will each have a site-specific Emergency Preparedness and Response Plan (EPRP). These plans will 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 will use the ICS to coordinate with local emergency response agencies to ensure appropriate communications, understanding, and cooperation are in place. This will ensure that the EPRP are appropriately linked to plans maintained by other affected response agencies or third parties.

The local EPRP will be supported by various Emergency Operations Centers (EOCs). There will also be a backup EOC in the event that the primary EOC is not operational**.** The purpose of the EOCs is 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 will take actions in accordance with the applicable EPRP to protect lives, reduce injuries and illnesses, protect property and the environment, and maintain customer service. Each individual EPRP will contain the following information:

- Location and contact numbers for the facility;
- Contacts in case of emergency, including company personnel, contracted response organizations, local emergency response authorities, and others as applicable;
- Listing of emergency equipment available at field locations and response equipment contracted through approved response organizations;
- Description of the ICS roles and responsibilities (i.e., roles of field supervisors, natural gas control operators, field crews, and support personnel during an emergency), including a Project Incident Management Team that will use the ICS Unified Command structure to contain and control the emergency onsite; and
- Mutual Aid Agreements and processes for securing additional assistance from non-company resources, if needed.

The EPRPs will include procedures for the following:

- Identifying and classifying emergency events, natural gas leakage, fires, explosions, and natural disasters;
- Documenting emergency events and reporting the emergency to company and regulatory authorities;
- Establishing and maintaining communications with local fire, police, public officials, and other contacts in order to coordinate emergency response within the framework established by the ICS;
- Making personnel, equipment, tools, and materials available at the scene of an emergency;
- Protecting people first and then environment and property, and making them safe from actual or potential hazards;
- Isolation, evacuation, and use of ESD systems; and
- Liaison with public authorities and local utilities.

There will also be EPRPs for construction activities and operation of construction camps.

11.9.4.3 GTP

Information about the GTP Emergency Response Plan will be provided in a subsequent draft of this Resource Report.

11.9.5 Military Installations

A discussion regarding safety coordination of Project construction and operation activities in the vicinity of military installations will be provided in a subsequent draft of this Resource Report if required.

11.10 REFERENCES

Federal Energy Regulatory Commission (FERC). 2006. *Draft Guidance for LNG Terminal Operator's Emergency Response Plan.*

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USDOT. June 16, 2010. PHMSA Interpretation #PI-10-0005

APPENDIX A LNG TERMINAL HAZARD ANALYSIS

TO BE PROVIDED IN A SUBSEQUENT DRAFT OF THIS RESOURCE REPORT

APPENDIX B TERMINAL OPERATIONS MANUAL FRAMEWORK

TO BE PROVIDED IN A SUBSEQUENT DRAFT OF THIS RESOURCE REPORT

APPENDIX C DRAFT EMERGENCY RESPONSE MANUAL

TO BE PROVIDED IN A SUBSEQUENT DRAFT OF THIS RESOURCE REPORT

APPENDIX D LETTER OF INTENT TO THE U.S. COAST GUARD

May 15, 2014

Captain Paul Mehler III
Captain of the Port, Western Alaska
Sector Anchorage
G-Wing Bldg 49000
Army Guard Road
JBER, Alaska 99505-0727

Re: **Letter of Intent**
Alaska LNG Project

Dear Captain Mehler III:

ExxonMobil Alaska LNG, LLC, ConocoPhillips Alaska LNG Company, and BP Alaska LNG LLC (the "Alaska Parties") are working together with other parties, including TransCanada Alaska Midstream LP and the Alaska Gasline Development Corporation, to develop the Alaska LNG Project ("Project"), which would consist of a liquefied natural gas ("LNG") terminal including natural gas liquefaction, storage and marine loading facilities ("LNG Plant"), a natural gas treatment plant, and natural gas transport pipelines. The Project is being developed for the purpose of liquefying supplies of natural gas from Alaska for export to foreign markets. The Alaska Parties are working to construct, own, and operate the LNG Plant, which would be an approximately 20 million metric tons per annum ("MTA") LNG facility near Nikiski, Alaska. The LNG Plant would be sited on 400 to 800 acres of land within the Kenai Peninsula Borough north of Nikiski and Kenai through the acquisition of property from private, commercial, and borough landowners. In accordance with U.S. Coast Guard ("USCG") regulations at 33 CFR § 127.007, the Alaska Parties are pleased to submit the following information about the Project.

1. Name, address and telephone number of the owner and operator.

The LNG Plant will be owned and operated by the Alaska Parties. The permanent address and telephone number for the owner and operator of the LNG Plant has not been established yet. In the interim, please contact the following representative of the Alaska Parties:

Charlie Kominas
Environmental, Regulatory and Land Manager
Alaska LNG Project
3201 C St., Suite 506
Anchorage, AK 99503
(832) 624-2816

Edward G. Stokes, Marine Project Manager for the Alaska LNG Project, will also be supporting the USCG engagement effort.

2. The name, address, and telephone number of the Federal, State, or local agency having Jurisdiction for siting, construction, and operation.

The lead federal agency with jurisdiction over the Project is the Federal Energy Regulatory Commission ("FERC" or "Commission"). FERC will have the responsibility of reviewing the environmental and safety aspects of the Project and preparing the environmental documents required by the National Environmental Policy Act of 1969 ("NEPA"). The mailing address and telephone number for general inquiries is:

Federal Energy Regulatory Commission
Lauren O'Donnell, Director
OEP, Division of Gas - Environment and Engineering (PJ-11)
888 First Street NE
Washington, DC 20426
Telephone: (202) 502-8325
lauren.odonnell@ferc.gov

In addition to the environmental reviews by the FERC for authorization of the Project under Section 3 of the Natural Gas Act (“NGA”), other federal, state, and local agencies participate in the overall regulatory process such as the U.S. Department of Energy (“DOE”) for authorization to export LNG to both Free Trade Agreement and Non-Free Trade Agreement countries, the U.S. Army Corps of Engineers ("USACE") for activities affecting wetlands and waterways, the Alaska Department of Environmental Conservation (“ADEC”) for air emissions and water discharge permits, the Kenai Peninsula Borough Planning Department, and other agencies as applicable.

3. Name, address, and telephone number of the facility

The permanent address and telephone number for the LNG Plant has not been established yet. In the interim, please contact the following representative of the Alaska Parties:

Charlie Kominas
Environmental, Regulatory and Land Manager
Alaska LNG Project
3201 C St., Suite 506
Anchorage, AK 99503
(832) 624-2816

4. The physical location of the facility

The LNG Plant site is located in a primarily industrial area in proximity to the existing ConocoPhillips LNG Plant near Nikiski, Alaska, on the eastern shore of Cook Inlet, approximately 100 nautical miles from the entrance to Cook Inlet from the Gulf of Alaska. Cook Inlet is approximately 180 nautical miles north to south. The LNG Plant site is located as shown in Attachment 1, Figure 1. The site is currently accessible by road and is located in proximity to the Kenai Spur Highway as shown in Attachment 1, Figure 3.

5. A description of the facility

The LNG Plant site will include the structures, equipment, underlying access rights and all other associated systems for pre-processing and liquefaction of natural gas, and storage and off-loading of LNG, including marine terminal facilities and auxiliary marine vessels used in support of marine terminal operations (but excluding LNG carriers). The LNG Plant will contain three (3) liquefaction trains that combined will process approximately 20 MTA of LNG. Three (3) 160,000 cubic meter (m^3) tanks will be used to store the LNG. The LNG Plant will be capable of accommodating two (2) LNG carriers.

The site location of the LNG Plant is shown in Attachment 1, Figures 1 – 3. Construction is projected to begin in the 2018/2019 timeframe with proposed facilities placed into service sometime in the 2024/2025 timeframe.

The LNG Plant will include the following features:

Inlet Receiving Station: Feed gas would be transported to the site boundary via a proposed 42-inch gas pipeline. The Inlet Receiving Station would include an incoming interconnect pipeline, a pig receiver, a filter/separator, custody transfer meter(s), a pressure regulator, an emergency shutdown valve, and a gas analyzer.

LNG Trains: Each individual LNG train would include the following essential facilities: Separators, Dehydration and Mercury Removal Beds, Compressors, Distillation Columns and Heat Exchangers.

LNG Storage: Three full containment LNG storage tanks each with a net working capacity of approximately 160,000 m^3 would store the LNG product. These LNG storage tanks would be designed to meet the requirements of the National Fire Protection Association (“NFPA”) Standard 59A, regulations of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") contained in 49 CFR Part 193, and other applicable standards.

LNG Vessel Loading: To accommodate LNG vessels and to minimize interference with existing ship channel traffic, the LNG loading terminal and berth pocket will be situated in Cook Inlet to enhance the safe and efficient loading of LNG vessels. Any required dredging would be done in accordance with the relevant guidelines and in coordination with the USACE. The berth size, location, and orientation would be designed to optimize a number of criteria, primarily to ensure safe navigable approach and departure conditions, a safe mooring environment, proximity to the channel, and safe distance from the influence of passing vessels. Other influences include water depth and optimization of the cryogenic piping arrangement. To achieve the currently proposed maximum 12,500 cubic meters per hour (m^3/hr.) loading rate for one LNG vessel, the main cryogenic LNG line from the LNG tank to the loading platform would be optimally sized. LNG loading arms would be used to transfer the LNG from the platform to the vessels. A vapor return arm for transfer of the boil-off gas from the vessels to the LNG facilities and a spare hybrid liquid / vapor arm would also be supplied.

Flare System: The pressure relief and flare system would include shore side flares and would be designed to safely and reliably dispose of streams that would need to be vented during startup, shutdown, LNG vessel gas-up operation, plant upsets, and emergency conditions.

Buildings: The LNG Plant would include separate buildings for administration, control room, and workshop functions.

Power Supply: The majority of the LNG Plant's power requirements for liquefaction would be generated by multiple gas turbines on site for each LNG train. Power from the turbines would also run motors for LNG loading pumps and boil-off gas compressors, lighting, and other items.

Water Supply: The LNG Plant would utilize air coolers as the base case. Water cooling using a closed loop system will be studied during the pre-front end engineering and design (pre-FEED) stage. Prior to filing the Follow-on Waterway Suitability Assessment (WSA) and FERC application, a decision on air versus water cooling will be completed. In either case, a source of water will be required for plant utility needs.

Communication System: The communication system at the LNG Plant site would be comprised of a telephone exchange, a radio system, a computer network, a plant telecommunication network, a telemetry system for data transfer to/from gas production sites, an electronic mail system for communication, and a closed-circuit television (CCTV) system.

Plant Safety: The LNG Plant will meet the requirements under NFPA 59A, PHMSA regulations at 49 CFR Part 193, USCG regulations at 33 CFR Part 127, and other applicable standards for safety and fire protection.

Plant Security: The LNG Plant would be subject to USCG facility security regulations under Maritime Transportation Security Act (MTSA) regulations at 33 CFR Part 105 and will have a facility security plan approved by the USCG. The LNG Plant will meet all necessary security measures required under those regulations including security fencing, lighting, access control, and CCTV.

6. The LNG vessels' characteristics and the frequency of the LNG export shipments from the Facility

The LNG Plant is being designed with new berthing and mooring configurations to accommodate LNG carriers. The berthing and mooring configurations will be able to accommodate LNG carriers with capacities between 125,000 and 216,000 m^3. It is currently projected that, on average, 20 LNG carriers per month would make port calls at the LNG Plant.

7. Charts showing waterway channels and identifying commercial, industrial, environmentally sensitive, and the residential areas in and adjacent to the waterway to be used by the LNG vessels in and out of the facility, within 25 kilometers (15.5 miles) of the Project.

A chart showing the waterway channel to be used by the LNG carriers to and from the facility is presented in the attached figure which also shows commercial, industrial, environmentally sensitive, and the residential areas in and adjacent to the waterway (See Attachment 1, Figure 2). In addition to the information above, the Alaska Parties are providing a Preliminary WSA ("PWSA") as Attachment 1. Our PWSA has been prepared in accordance with the guidance contained in USCG Navigation and Vessel Inspection Circular 01-2011. If the Coast Guard has any questions or requires any additional information or clarification, please feel free to contact Charlie Kominas at (832) 624-2816.

Sincerely,

Lydia Johnson ExxonMobil Alaska LNG, LLC	Darren Mezhirich ConocoPhillips Alaska LNG Company	David Van Tuyl BP Alaska LNG LLC

Attachments:

Preliminary Waterway Suitability Assessment
- Figure 1: Proposed LNG Carrier Transit Route
- Figure 2: LNG Plant Site
- Figure 3: LNG Plant Site Marine Facilities Conceptual Layout

cc: Joe Dubler, Alaska Gasline Development Corporation
Tony Palmer, TransCanada Midstream
Project File

APPENDIX E PRELIMINARY WATERWAY SUITABILITY ASSESSMENT

Alaska LNG Project
Preliminary Waterway Suitability Assessment

1. Introduction

The Alaska Parties have prepared this Preliminary Waterway Suitability Assessment ("WSA") in compliance with the requirements of the U.S Coast Guard ("USCG") and Federal Energy Regulatory Commission ("FERC") regulations (33 CFR § 127.007 and 18 CFR § 157.21, respectively) and as part of the process for approval, construction, and operation of a shore side Liquefied Natural Gas ("LNG") Plant. The Alaska Parties are proposing to develop an LNG Plant capable of producing a maximum of 20 million metric tons per annum (MTA) of LNG.

The Preliminary WSA for the Alaska LNG Project ("Project") has been developed according to the guidance contained in the USCG Navigation and Vessel Inspection Circular (NVIC) 01-2011 (and Enclosures (1) and (2)). As the Applicant, the Alaska Parties are submitting this Preliminary WSA with a Letter of Intent ("LOI") to the Coast Guard Captain of the Port ("COTP") Western Alaska (Anchorage). As required, the Preliminary WSA is being submitted in advance or concurrent with the start of the FERC Pre-Filing period. The Follow-on WSA will be submitted no later than the time the Alaska Parties file a formal application with FERC.

Representatives of the Project met with the COTP Anchorage and his staff on April 15, 2014. The USCG representatives concurred with the proposed LOI and Preliminary WSA content and format as presented in this document.

The Alaska Parties will facilitate the completion of the Follow-on WSA including consideration of public comments as part of this more detailed analysis. Representatives of the Alaska Parties will continue to engage the COTP and other stakeholders in the preparation, development, and completion of the Follow-on WSA. This will ensure the Follow-on WSA meets the expectations of the COTP and addresses all items and requirements listed in NVIC 01-2011.

2. Objective of the Preliminary and Follow-on WSA

This Preliminary WSA summarizes the study approach, organization, and schedule planned for the Follow-on WSA. It provides a brief discussion on the following topics that will be fully addressed, analyzed and developed in the Follow-on WSA:

(1) Port Characterization
(2) Characterization of LNG Plant and LNG Carrier Route
(3) Risk Assessments for Maritime Safety and Security
(4) Risk Management Strategies
(5) Resource Needs for Maritime Safety, Security and Response

The Preliminary WSA provides an outline to the COTP of the various risk factors and the risk analysis methodology that will be used in the Follow-on WSA for the Project. It gives the COTP the opportunity to identify and point out any issues or factors when considering the various potential safety and security impacts the additional LNG marine traffic may have on the port and associated waterway(s). It also

provides an opportunity for the Alaska Parties and the COTP to identify the stakeholders at the port that may be consulted in conducting and developing the Follow-on WSA.

The Follow-on WSA will provide a complete analysis of the topics outlined in the Preliminary WSA. It will identify credible navigational safety hazards and security threats associated with the additional LNG marine traffic associated with the Project, along with appropriate risk management strategies, mitigation measures, and resources.

If approved by FERC, the Alaska Parties will submit an Emergency Response Plan which will identify the resources that may be necessary to fill any gaps identified in the Follow-on WSA. The final risk management strategies, mitigation measures, and resources developed by the Alaska Parties and the COTP will ensure that necessary measures are taken to maintain the safety and security of the LNG vessels and the waterways.

3. Port Characterization

The proposed site for the LNG Plant is in a primarily industrial development near Nikiski, Alaska on the west coast of the Kenai Peninsula with access via Cook Inlet to the Gulf of Alaska (Figure 1).

According to the Cook Inlet Vessel Traffic Study (2011), the predominant vessel types transiting Cook Inlet include a mix of freight (container), tug and barge (refined petroleum products), and tank vessels (crude). There is also a mixture of other vessel types including ferries, passenger vessels, offshore supply vessels (OSV), and tugs. Most deep draft vessels transit along the east side of Cook Inlet while tank ships occasionally transit between Nikiski and the Drift River terminal on the western side of the middle Cook Inlet zone. Offshore supply vessels (OSV) servicing the oil and gas production account for most of the large vessel activity outside of the traditional north-south track lines.

Kachemak Bay in the lower Cook Inlet has the highest level of traffic activity in Cook Inlet with most deep draft vessels entering the mouth of the bay to board a marine pilot or awaiting Coast Guard inspection. Middle Cook Inlet vessel movements reflect tank ship activity in and around the Nikiski and Drift River terminals. Upper Cook Inlet vessel traffic reflects the influence of the Port of Anchorage.

The 2000 Cook Inlet Port Risk Assessment Workshop addressed fishing vessel related issues in Cook Inlet. Seasonally, there are up to 300 commercial fishing vessels operating in Cook Inlet, some of which utilize drift nets 1,000 feet long. Drift fishing generally occurs south and east of Kalgin Island and the highest density occurs in July. In addition, from Memorial Day to Labor Day there are higher traffic volumes of non-commercial fishing activity.

The LNG Plant is being designed with berthing and mooring configurations to accommodate LNG carriers. The Follow-on WSA will evaluate the impact that approximately 20 LNG vessel port calls per month to the LNG Plant will have on the waterways and the pilots' ability to safely move vessels as well as the overall safety and security within Cook Inlet.

4. Characterization of LNG Facility and LNG Carrier Route

The Project's design premise includes three (3) 160,000 m^3 onsite full containment LNG storage tanks. The Alaska Parties are proceeding with acquisition of the land (Figure 2). The site is accessible by road

and is located in proximity to the Kenai Spur Highway. Figure 3 includes a conceptual layout for the LNG Plant's marine facilities.

To accommodate LNG vessels and to minimize interference with existing channel traffic, the LNG loading terminal and berth pocket is planned to be close to the eastern shore of Cook Inlet. The berth size, location, and orientation will be designed to optimize a number of criteria, primarily to ensure: safe navigable approach and departure conditions, a safe mooring environment, proximity to the channel and safe distance from the influence of passing vessels. Other influences include water depth and optimization of the cryogenic piping arrangement.

Laden LNG carriers would depart the LNG Plant and proceed southbound to either Kennedy or Stevenson Entrances and enter the Gulf of Alaska.

5. Follow-on WSA Study Organization

The Follow-on WSA process will be prepared by the Alaska Parties and their contractor(s) with participation by key stakeholders. The Follow-on WSA will include:

- Scenario Development and Description
- Criticality Determination
- Threat Determination
- Threat Assessment
- Assess Risk
- Mitigation Measures – Existing (Port & Industry practice)
- Mitigation Measures – Additional (by MARSEC level)
- Resource Needs
- Review of Public Comment

The Follow-on WSA is required to be submitted to the COTP no later than the time the Applicant formally files with FERC, which is currently projected for end of 2016/early 2017. The Follow-on WSA will, therefore, be conducted in the timeframe of 2014 to 2017. The Follow-on WSA will include stakeholder workshops of various lengths in duration over the two year period.

The Alaska Parties:

- Are working to develop a subcontract with an experienced WSA firm to complete the Follow-on WSA
- Are working to develop a subcontract with a local consulting firm specializing in marine risk and stakeholder engagement
- Will share the final selection with the USCG when finalized

The Follow-on WSA study will be conducted in three phases per Table 1.

Table 1 - Follow-on WSA Study Phases

Phase I – Planning and Data Gathering
Site Visit
Port Characterization
Data Gathering
Stakeholder Selection
Stakeholder Introduction
Work plan Development

Phase II – Follow-on WSA Sessions
Follow-on WSA Session/Workshop
Resource Allocation Discussions
Follow-on WSA Draft Report
Comment Period on Draft

Phase III –Final Report
Final Draft Report
Comment Period Final Report
Final Report

Initial planning will be completed through a series of meetings and teleconferences between the WSA contractors, representatives of the Alaska Parties, the COTP (as required), and designated members of the Follow-on WSA Team. During this phase, the WSA contractors will:

- Plan for the Follow-on WSA Study;
- Confirm the scope of work, project goals and objectives for the key project phases;
- Define roles and responsibilities of the Follow-on WSA team;
- Participate in an on-site kick-off meeting, in conjunction with an on-scene survey;
- Conduct an onsite visit and collect the necessary data from the Alaska Parties, Area Maritime Security Committee (“AMSC”), USCG, Harbor Safety Committee (“HSC”), and the Port.

The planning of the Follow-on WSA Study involves the selection of a multi-disciplinary team to participate in the assessment. Team members will include key stakeholders knowledgeable of the Project, waterway design and operations, the port, maritime safety and security, risks of the waterway, mitigation measures and resources to ensure safe and secure LNG marine transit along the waterways. A tentative list of participants for the Follow-on WSA team is provided in Table 2. The Alaska Parties will review and vet this preliminary list with the Commanding Officer Sector Anchorage, USCG prior to initiating the Follow-on WSA.

Table 2 – Tentative List of Follow-on WSA Team (Alaska LNG Project)

Company	Point of Contact	Title	Phone number
ConocoPhillips Company	Edward G. Stokes	Marine Project Manager	(281) 930-3143
ConocoPhillips Company	Joseph Gibson	Senior Marine Project Advisor	(281) 293-4247
ExxonMobil Development Company	Jeff Raun	Downstream ERL Advisor	(907) 929-4105
Global CPT	Dennis Maguire	Marine Regulatory Advisor	(907) 929-4122
exp Energy Services, Inc.	Jon Schmidt	VP Environmental and Regulatory Services	(907) 868-1175
exp Energy Services, Inc.	Aurora Courtney	Environmental Project Manager	(907) 868-1175

6. Risk Assessments for Maritime Safety and Security

The Follow-on WSA for the Project will be conducted after review and approval of the Preliminary WSA by USCG and COTP. The Follow-on WSA is a risk-based assessment of the LNG vessel movements associated with the LNG Plant operations within Cook Inlet. The approach to conduct the Follow-on WSA will evaluate risk as the combination of the probability of an undesired event occurring and the consequences if the event does occur. Fundamentally, the approach will review and answer the following questions:

- What can go wrong?
- What is the likelihood that this will occur?
- How severe can the consequences be?

By answering these three questions, the Alaska Parties, in cooperation with local stakeholders, can effectively characterize and quantify the risk of the additional LNG marine transits to the waterways, and if merited, recommend strategies to reduce the identified risk.

To initiate the Follow-on WSA team sessions, the WSA contractors will provide an orientation of the Security Risk Assessment (SRA) methodology will facilitate the Follow-on WSA and will work with the team to assess the navigational hazards and security vulnerabilities, identify current mitigation measures, and recommendations to address gaps and any additional resource needs for the waterway. To enable efficient documentation of the Follow-on WSA team assessment sessions, appropriate risk assessment software will be used. Using this software, along with a laptop computer and projection device, allows for a more structured review, better team interaction, printable worksheet and recommendations in Microsoft-Word® format for efficient review.

The ANSI/API Standard 780, Security Risk Assessment Methodology will be employed for the LNG Plant. The standard describes the recommended approach for assessing security risks widely applicable to the types of facilities operated by the industry and the security issues the industry faces.

As per the NVIC 01-2011 guidance (Enclosure (2)), the Follow-on WSA will include:

1. **Safety Risk Assessment**. The safety assessment evaluates the risks of accidental releases of LNG. The set of incidents that may lead to an accidental release will be identified and the likelihood and consequences of those events should be evaluated.

2. **Security Risk Assessment.** The security assessment will evaluate the risks of security issues with the maritime operations. For each security related event, the estimated likelihood is evaluated in terms of threat and vulnerability, where "threat" is the likelihood of an attack and "vulnerability" is the likelihood that an attack will succeed.

a. **Threat Assessment.** A threat assessment will be an evaluation of ways in which particular assets may be attacked, the seriousness of such threats, and the potential means by which they may be carried out. The assessment will thoroughly address sabotage, projectiles, aerial, surface and underwater threats. It will also include a full consideration of potential attack methods throughout the waterway. The assessment will also identify areas in the port such as manmade structures, tributaries, and land masses along the transit waterway from which an attack could be launched.

b. **Vulnerability Assessment.** The vulnerability analysis is the portion of the Follow-on WSA that attempts to identify the exposures that might be exploited to ensure the success of an attempted terrorist attack. These may be considered as two types of vulnerabilities, asset and system. The asset vulnerabilities consider the physical properties of the target that may influence the likelihood of success of a terrorist attack. The system vulnerabilities consider the ability of the terrorist to successfully launch an attack.

c. **Consequence Analysis.** Using the zones of concern described in Enclosure (9) of NVIC 01-2011, the Follow-on WSA will graphically depict where the three zones of concern intersect with population areas, critical infrastructure and key assets, critical waterways, and commercial, industrial, or environmentally sensitive areas in and adjacent to the transit route. This will identify those areas where an intentional release of LNG would have the most significant consequences.

7. Risk Management Strategies

The Follow-on WSA risk assessment process provides for a robust review of safety and security issues specific to the proposed LNG marine transport for the Project. The Follow-on WSA will summarize, in general, the port safety and security implications of the LNG Plant operations and expanding LNG operations in the port. It will address the conclusions of the Follow-on WSA and suggested risk management strategies and resources.

Per NVIC 01-2011, risks can be mitigated using effective measures to reduce both the likelihood to and the consequences of a release of LNG from a vessel. Vessel, facility, and waterway safety and security assessments, and associated safety and security plans, are key components of the LNG risk management process. Since the risk factors for LNG marine traffic vary from port to port, it is not possible to mandate specific strategies or to create a "one size-fits-all" policy. Rather, a risk-based approach, which incorporates the knowledge and skills of experienced port stakeholders, will be used during the Follow-on WSA.

LNG carrier movements will be governed at a minimum by the following documents:

1. USCG: Navigation Rules, International – Inland (COMDTINST M16672.2D; March 25, 1999)
   http://www.uscg.mil/directives/cim/16000-16999/cim_16672_2d.pdf

2. Captain of the Port, Western Alaska: Navigation Advisory Subj: Operating Procedures for Ice Conditions in Cook Inlet (16710; November 21, 2013)
   http://www.uscg.mil/d17/sectoranchorage/prevention/icedocs/IceOperatingProcedures.pdf

3. State of Alaska: Statutes and Regulations Marine Pilots (AS 08.62; 12 AAC 56; January 2014)
   http://commerce.alaska.gov/dnn/portals/5/pub/MarineStatutes.pdf

LNG vessels traveling in Cook Inlet must engage a marine pilot to assist in the safe navigation of the vessel in accordance with the references listed above. Further, all currently practiced risk mitigation measures in the port will be reviewed at a minimum, and any additional recommended risk mitigation measures and resource needs will be evaluated as part of the Follow-on WSA.

The results of the Follow-on WSA will provide a gap analysis to identify what existing resources are present in the port, what additional resources may be needed and how these additional resources might be obtained. This is recognized to be a cooperative effort requiring federal, state, local (public) and private sector resources. The mix of resources will be dependent on a variety of factors, such as legal authorities, areas of expertise, availability, operational constraints, etc. However, the availability of USCG resources is subject to the COTP's daily mission prioritization and resource allocation that is based on many variables outside the Alaska Parties' control.

Finally, scalable risk management strategies will be developed to address LNG operations at elevated Maritime Security ("MARSEC") levels. The specifics of the threat or causal event leading to an elevated MARSEC level may dictate how the LNG safety and security should be enhanced. The Follow-on WSA may make recommendations about how to enhance safety and security for these non-specific threats.

Figure 1

Proposed LNG Carrier Transit Route

N

Yukon-Koyukuk Census Area

Bethel Census Area

Matanuska-Susitna Borough

Lake and Peninsula Borough

Kenai Peninsula Borough

Anchorage Municipality

Valdez-Cordova Census Area

Kodiak Island Borough

Talkeetna
Trapper Creek
Sunshine
Montana
Skwentna
Chickaloon
Eska
Jonesville
Sutton
Willow
Houston
Susitna
Big Lake
Cottonwood
Knik
Chugiak
Eagle River
Anchorage
Nunaka Valley
Spenard
Tyonek
Girdwood
Hope
Portage
Whittier
Silvertip
Port Nellie Juan
Nikiski
Proposed LNG Plant Site
Salamatof
Kenai
Ridgeway
Sterling
Soldotna
Kalifornsky
Cohoe
Kasilof
Clam Gulch
Cooper Landing
Moose Pass
Crown Point
Primrose
Seward
Ninilchik
Happy Valley
Fox River
Nikolaevsk
Anchor Point
Fritz Creek
Millers Landing
Homer
Kachemak City
Seldovia
Jakolof Bay

Cook Inlet

Gulf of Alaska

Portlock Bank

Shelikof Strait

Kamishak Bay

Kamishak Bay

Kachemak Bay

Kamishak Bay

Kamishak Bay

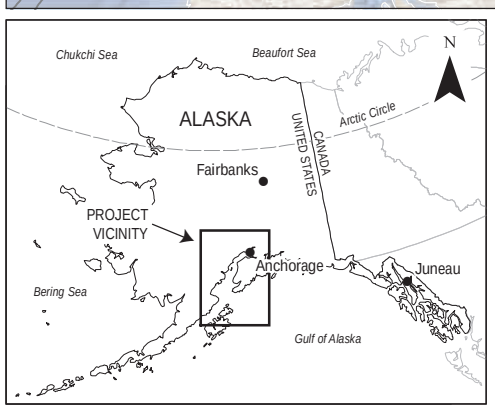
Katmai Bay

Marmot Bay

Perevalnoi Bay

Trading Bay

0 5 10 20 30 40 50 Miles



LEGEND

- LNG Plant Site
- Proposed Transit Route
- US Territorial Sea (12 nautical miles)
- City / Town
- Road
- Borough Boundary

DATA SOURCES

(1) Alaska LNG Project Data
(2) NOAA
(3)
(4)
(5)
(6)

PREPARED BY:	exp Energy Services Inc.
DATE:	2014-05-06
SCALE:	1 : 1,500,000
PROJECTION:	Alaska Albers Equal Area
LOCATION:	Cook Inlet (Kenai Peninsula Borough), Alaska

FIGURE 1

Proposed LNG Carrier Transit Route

AlaskaLNG

Figure 2

LNG Plant Site

N

REDOUBT BAY CRITICAL HABITAT AREA

Kenai National Wildlife Refuge

Lake Clark National Park & Preserve

Kenai Peninsula Borough

Lake Clark National Park & Preserve

Lake Clark National Park & Preserve

Kenai National Wildlife Refuge

KACHEMAK BAY OIL & GAS CLOSURE

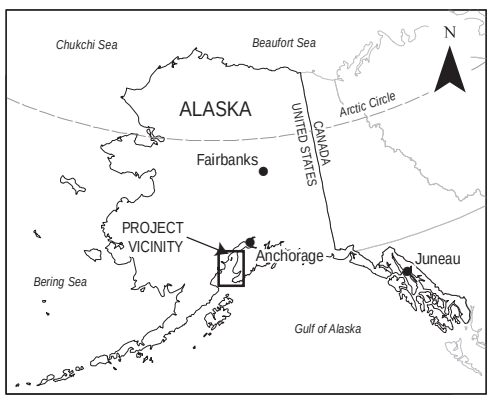
KACHEMAK BAY CRITICAL HABITAT AREA

KACHEMAK BAY STATE PARK

KACHEMAK BAY STATE WILDERNESS PARK

Kustatan
Nikiski
Salamatof
Kenai
Ridgeway
Sterling
Soldotna
Kalifornsky
Kasilof
Cohoe
Clam Gulch
Ninilchik
Happy Valley
Nikolaevsk
Anchor Point
Fritz Creek
Millers Landing
Kachemak City
Homer
Halibut Cove
Jakolof Bay
Seldovia
English Bay
Port Graham
Fox River

0 2.25 4.5 9 13.5 18 22.5 Miles



LEGEND

- City / Town
- Kenai Spur Highway
- Road
- LNG Plant Site Area
- State and Federal Management Areas
- Native Allotments
- Unknown
- Native Corporation Lands
- Village Lands

Land Use

- Unknown
- Vacant land
- Residential
- Commercial
- Agriculture
- Leased land
- Industrial
- Institutional
- Tidelands

DATA SOURCES

(1) Alaska LNG Project Data
(2) Alaska Department of Transportation
(3) Kenai Peninsula Borough
(4) NOAA
(5)
(6)

PREPARED BY:	exp Energy Services Inc.
DATE:	2014-05-06
SCALE:	1:550,000
PROJECTION:	Alaska Albers Equal Area
LOCATION:	Cook Inlet (Kenai Peninsula Borough), Alaska

FIGURE 2
LNG Plant Site

AlaskaLNG

Figure 3

LNG Plant Site Marine Facilities Conceptual Layout

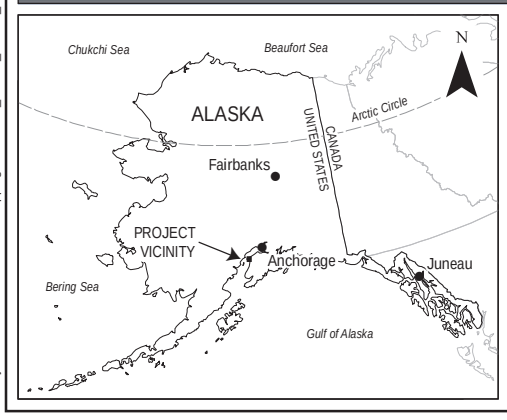
N

WIK ROAD
WIKISHA BEACH ROAD
KENAI SPUR HIGHWAY
MARHENKE STREET
ISLAND LAKE ROAD
WINDY ROAD
ALEXANDER ROAD
ROSS ROAD
SALAMATOF ROAD
BERNICE LAKE ROAD
MILLER LOOP ROAD
HOLT/LAMPLIGHT ROAD

Cook Inlet

0 0.125 0.25 0.5 0.75 1 Miles

PRELIMINARY



LEGEND

- Dock
- LNG Plant Site
- Road

DATA SOURCES

(1) Alaska LNG Project Data
(2) Alaska DOT
(3)
(4)
(5)
(6)

PREPARED BY:	exp Energy Services Inc.
DATE:	2014-05-06
SCALE:	1 : 50,000
PROJECTION:	Alaska Albers Equal Area
LOCATION:	Cook Inlet (Kenai Peninsula Borough), Alaska

FIGURE 3

LNG Plant Site Marine Facilities Conceptual Layout

AlaskaLNG

X:\Projects\ExxonMobil\SCLNG\Mapping\20140324_USCG_PWSA_LOI_Mapping\Figure 3 - LNG Plant and Marine Terminal Conceptual Layout - 2014-04-16.mxd

APPENDIX F GTP ENGINEERING INFORMATION

TO BE PROVIDED IN A SUBSEQUENT DRAFT OF THIS RESOURCE REPORT