Federal Energy Regulatory Commission

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Federal Energy Regulatory Commission
Office of Energy Projects
888 First Street NE, Washington, DC 20426

FERC Docket No. CP17-178-000

Alaska LNG Project
Final Environmental Impact Statement
Volume 1 of 3

Cooperating Agencies:

Bureau of Land Management | National Marine Fisheries Service | National Park Service | U.S. Army Corps of Engineers | U.S. Coast Guard | U.S. Department of Energy | U.S. Department of Transportation | U.S. Environmental Protection Agency | U.S. Fish and Wildlife Service

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas Branch 3
Alaska LNG Project
Alaska Gasline Development Corporation
Docket No. CP17-178-000
FERC/EIS-0296F

TO THE INTERESTED PARTIES:

The staff of the Federal Energy Regulatory Commission (FERC or Commission), with the participation of the cooperating agencies listed below, has prepared a final environmental impact statement (EIS) for the Alaska LNG Project (Project) proposed by the Alaska Gasline Development Corporation (AGDC). AGDC requests authorization to construct and operate new gas treatment facilities, an 806.9-mile-long natural gas pipeline and associated aboveground facilities, and a 20 million-metric-ton per annum liquefaction facility to commercialize the natural gas resources of Alaska's North Slope. The Project would have an annual average inlet design capacity of up to 3.7 billion standard cubic feet per day and a 3.9 billion standard cubic feet per day peak capacity.

The EIS assesses the potential environmental effects of Project construction and operation in accordance with the requirements of the National Environmental Policy Act (NEPA). As described in the EIS, the FERC staff concludes that approval of the Project would result in a number of significant environmental impacts; however, the majority of impacts would be less than significant based on the impact avoidance, minimization, and mitigation measures proposed by AGDC; AGDC's commitments to additional measures; and measures recommended by staff in the final EIS. However, some of the adverse impacts would be significant even after the implementation of mitigation measures.

The United States (U.S.) Department of Transportation Pipeline and Hazardous Materials Safety Administration, U.S. Environmental Protection Agency, U.S. Army Corps of Engineers, U.S. Coast Guard, Bureau of Land Management (BLM), U.S. Fish and Wildlife Service, National Park Service (NPS), U.S. Department of Energy, and National Marine Fisheries Service participated as cooperating agencies in the preparation of this final EIS. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposal and participate in the NEPA analysis. Although the cooperating agencies provided input to the conclusions and recommendations presented in the EIS, the agencies will present their own conclusions and recommendations in their respective Records of Decision for the Project.

The BLM and NPS will adopt and use the EIS to consider issuing a right-of-way grant for the portions of the Project on BLM- and NPS-managed lands, respectively. Other cooperating agencies will use this EIS in their regulatory process, and to satisfy compliance with NEPA and other related federal environmental laws (e.g., the National Historic Preservation Act).

Section 810(a) of the Alaska National Interest Lands Conservation Act, 16 United States Code 3120(a), requires the BLM to evaluate the effects of the alternatives presented in the EIS on subsistence activities, and to hold public hearings if it finds that any alternative may significantly restrict subsistence uses. The evaluation of subsistence impacts indicated that the cumulative case analyzed in the EIS could significantly restrict subsistence uses for the communities of Nuiqsut, Kaktovik, Utqiagvik, and Anaktuvuk Pass. Therefore, the BLM held public hearings and solicited public testimony for these potentially affected communities.

The Commission mailed a copy of the final EIS to federal, state, and local government representatives and agencies; elected officials; Alaska Native tribal governments and Alaska Native Claims Settlement Act Corporations; and local libraries and newspapers in the area of the Project. The final EIS was also mailed to property owners that could be affected by Project facilities, individuals requesting intervenor status in FERC's proceedings, and other interested parties (i.e., individuals and environmental and public interest groups who provided scoping comments or asked to remain on the mailing list). Paper copy and CD versions of this final EIS were mailed to subsistence communities, libraries, and those specifically requesting them; all others received a CD version.

The final EIS is also available in electronic format. It may be viewed and downloaded from FERC's website (www.ferc.gov) on the Environmental Documents page (http://www.ferc.gov/industries/gas/enviro/eis.asp). In addition, the final EIS may be accessed by using the eLibrary link on FERC's website. Click on the eLibrary link (https://www.ferc.gov/docs-filing/elibrary.asp), then click on General Search and enter the docket number in the "Docket Number" field, excluding the last three digits (i.e., CP17-178). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659.

<u>Questions?</u>

Additional information about the Project is available from the Commission's Office of External Affairs, at **(866) 208-FERC,** or on the FERC website (www.ferc.gov) using the eLibrary link. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to www.ferc.gov/docs-filing/esubscription.asp.

Kimberly D. Bose
Secretary

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LIST OF APPENDICES

ACRONYMS AND ABBREVIATIONS

Acronym	Definition
°C	degrees Celsius
°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
AAAQS	Alaska Ambient Air Quality Standards
AAC	Alaska Administrative Code
AADT	annual average daily traffic
AAQS	ambient air quality standards
ACCS	Alaska Center for Conservation Science
ACEC	Areas of Critical Environmental Concern
ACHP	Advisory Council on Historic Preservation
ACI	American Concrete Institute
ACS	American Community Survey (U.S. Census Bureau)
ADCCED	Alaska Department of Commerce, Community and Economic Development
ADCP	Acoustic Doppler Current Profiler Station
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADHSS	Alaska Department of Health and Social Services
ADL	Alaska Division of Lands number
ADNR	Alaska Department of Natural Resources
ADOLWD	Alaska Department of Labor and Workforce Development
ADOT&PF	Alaska Department of Transportation and Public Facilities
AEC	Alaska Earthquake Center
AEGL	Acute Exposure Guideline Level
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
AEWC	Alaskan Eskimo Whaling Commission
AFS	Air Force Station
AGDC	Alaska Gasline Development Corporation
AGRU	Acid Gas Removal Unit
AHRS	Alaska Heritage Resources Survey
AIChE	American Institute of Chemical Engineers
AK-IBIS	Alaska Indicator-Based Information System
AKNHP	Alaska Natural Heritage Program
Alaska DEED	Alaska Department of Education and Early Development
AMBCC	Alaska Migratory Bird Co-management Council
amsl	above mean sea level
ANCSA	Alaska Native Claims Settlement Act

Acronym	Definition
ANILCA	Alaska National Interest Lands Conservation Act
ANS	aquatic nuisance species
ANVSA	Alaska Native Village Statistical Area
ANWR	Arctic National Wildlife Refuge
AOGCC	Alaska Oil and Gas Conservation Commission
AOI	area of interest
APDES	Alaska Pollutant Discharge Elimination System
APE	area of potential effects
API	American Petroleum Institute
API RP	American Petroleum Institute Recommended Practice
AQCR	Air Quality Control Region
ARD	acid rock drainage
ARD/ML	acid rock drainage and metal leaching
ARDF	Alaska Resource Data File 11
ARRC	Alaska Railroad Corporation
AS	Alaska Statute
ASAP	Alaska Stand Alone Pipeline
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASRC	Arctic Slope Regional Corporation Energy Services, LLC
ASTM	American Society for Testing and Materials
ASV	automatic shut-off valves
ATC	Applied Technology Council
ATV	all-terrain vehicles
ATWS	additional temporary workspaces
AVO	Alaska Volcano Observatory
AWC	Anadromous Waters Catalog
AWQS	Alaska Water Quality Standards
BA	Biological Assessment
BACT	Best Available Control Technology
BCC	Birds of Conservation Concern
Bcf	billion cubic feet
BCR	Bird Conservation Region
Beaufort Sea ITR	USFWWS Biological Opinion for Issuance of 2016-2021 Beaufort Sea ITR
BGEPA	Bald and Golden Eagle Protection Act
BIA	Biologically Important Area
Blasting Standard	Alaska Blasting Standard for the Proper Protection of Fish
BLEVE	boiling liquid expanding vapor explosion
BLM	Bureau of Land Management
BLM Manual H-8410-1	BLM Manual H-8410-1 - Visual Resource Inventory

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
BLM Manual H-8431	BLM Manual H-8431 - Visual Resources Contrast Rating
BMP	best management practice
BOEM	Bureau of Ocean Energy Management
BOG	boil-off-gas
BPVC	Boiler and Pressure Vessel Code
BSC	biological soil crusts
BTU	British thermal units
BWM	Ballast Water Management
C^3T	composite concrete cryogenic tank
CAA	Clean Air Act
CADD	computer aided design and drafting
CCPS	Center for Chemical Process Safety
CDP	census-designated place
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFATS	Chemical Facility Anti-Terrorism Standards
CFD	computational fluid dynamics
CFR	Code of Federal Regulations
CGF	Central Gas Facility [see also PBU CGF]
CH_4	methane
CHA	critical habitat areas
CI ICE	compression ignition internal combustion engines
CIRA	Cook Inlet Risk Assessment
CIRCAC	Cook Inlet Regional Citizens Advisory Council
CIRI	Cook Inlet Region, Inc.
cm	centimeter
CM	compliance monitors
CM Program	Third-Party Compliance Monitoring Program
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalent
Coast Guard	U.S. Coast Guard
COE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission (also see FERC)
Conv	conversion
COTP	Captain of the Port
Cp	Plume contrast
CPR	continuous plankton recorder
CSB	U.S. Chemical Safety and Hazard Investigation Board
CSRP	Contaminated Sites Remediation Program

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
CSU	Conservation System Units
CUI/PRIV	Controlled Unclassified Information/Privileged
CWA	Clean Water Act
DA	Department of the Army
dB	decibel
dB re 1 µPa	decibels relative to 1 microPascal
dB re 1 µPa^2-s	decibels relative to 1 microPascal squared seconds
dBA	A-weighted decibel
DCH	Designated Critical Habitat
DEGADIS	Dense Gas Dispersion Model
DEM	Digital Elevation Model
DGGS	Alaska Division of Geological and Geophysical Surveys
DHS	Department of Homeland Security
DMLW	Division of Mining, Land, and Water
DMMP	Dredged Material Management Program
DMT	directional micro-tunneling
DNPP	Denali National Park and Preserve
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
DP	disposal location
DPS	Distinct Population Segment
Dredged Material User Manual	Dredged Material Evaluation and Disposal Procedures User Manual
DWP	Drinking Water Program
DWPA	Drinking Water Protection Area
DWTT	limits for when brittle fracture would not propagate under dynamic load
East Alternative	Cook Inlet East Alternative
EEZ	Exclusive Economic Zone
EFH	Essential Fish Habitat
EI	environmental inspector
EIS	environmental impact statement
ENSTAR	ENSTAR Natural Gas Company
EO	Executive Order
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Emergency Response Plan
ESA	Endangered Species Act of 1973
ESD	Emergency Shutdown

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
ESU	Evolutionarily Significant Unit
FAA	Federal Aviation Administration
FBE	fusion bonded epoxy
FE	Office of Fossil Energy (of DOE)
FEA	finite element analysis
FEED	front end-engineering design
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission (also see Commission)
FEU	foot equivalent unit
FHWA	Federal Highway Administration
FIRM	Flood Insurance Rate Maps
FLM	Federal Land Manager
FLPMA	Federal Land Policy and Management Act
FMP	Fishery Management Plan
FR	Federal Register
FSA	Facility Security Assessment
FSC	Fish Stocks of Concern
FSP	Facility Security Plan
ft^2	square feet
FTA	Free Trade Agreement
FY	fiscal year
GAP	Gap Analysis Project
Geotechnical Data Report	*LNG Facilities Onshore Geotechnical Data Report*
GHG	greenhouse gas
GIS	geographic information system
GMD	geomagnetic disturbances
GMU	Game Management Unit
GOA	Gulf of Alaska
gpd	gallons per day
gpm	gallons per minute
GPS	global positioning system
gpy	gallons per year
GT	Gas Treatment Facilities
GTP	Gas Treatment Plant
GWP	Global Warming Potential
H2S	hydrogen sulfide
HAP	hazardous air pollutant
HAZID	hazard identification
HAZOP	hazard and operability review

Acronym	Definition
HCA	High Consequence Areas
HCA	high consequence area
HDD	horizontal directional drill
HDD Plan	HDD Inadvertent Release Contingency Plan
HEC	health effects category
HEM	helicopter electromagnetic
HFO	heavy fuel oil
HGM	Hydrogeomorphic
HIA	Health Impact Assessment
HIFLD	Homeland Infrastructure Foundation Level Data
HLV	heavy lift vessel
hp	horsepower
hr	hour
HUC	Hydrologic Unit Code
HVAC	heating, ventilation, and air conditioning
Hwy	Highway
IBA	Important Bird Area
IBC	International Building Code
ICC	International Code Council
IDLH	immediately dangerous to life or health
IEEE	Institute of Electrical and Electronics Engineers
IFC	International Fire Code
IFO	intermediate fuel oil
IHA	Incidental Harassment Authorization
INHT	Iditarod National Historic Trail
Integrated Report	*Integrated Water Quality Monitoring and Assessment Report*
Invasives Plan	Noxious/Invasive Plant and Animal Control Plan
ISA	International Society for Automation
ISO	International Organization for Standardization
ISPMP	Invasive Species Prevention and Management Plan
ITA	Incidental Take Authorization
ITR	Incidental Take Regulations
kg	kilogram
kg/ha/yr	kilogram per hectare per year
km	kilometer
km^2	square kilometers
km^3	cubic kilometers
KOP	key observation points
KSH	Kenai Spur Highway
Kw	soil erosion factor

Acronym	Definition
kW	kilowatt
kW/m^2	kilowatts per meter squared
L	liter
L_{50}	Equivalent sound level exceeded 50 percent of the time
L_d	daytime sound level
L_{dn}	day-night average sound level
LEDPA	least environmentally damaging practicable alternative
L_{eq}	equivalent sound level
LER	Local Electrical Room
LF	Liquefaction Facilities
LFL	lower flammability limit
LiDAR	Light Detection and Ranging
L_{max}	maximum A-weighted sound level
L_n	nighttime sound level
LNG	liquefied natural gas
LO/LO	Lift-on/Lift-off
LOA	Letter of Authorization
LOD	Letter of Determination
LOI	Letter of Intent
LOR	Letter of Recommendation
LP	Low-pressure
L_{peak}	peak sound level
LPG	liquefied petroleum gas
LUST	Leaking Underground Storage Tank
LWCF	Land and Water Conservation Fund
m^3	cubic meters
MAOP	Maximum Allowable Operating Pressure
MBTA	Migratory Bird Treaty Act
MCA	moderate consequence area
MDMT	minimum design metal temperature
MDT-BF	lowest temperature in which pipe stress exceeds threshold stress
MF	Mainline Facilities
mg	milligrams
MGO	marine gasoil
MGS	Major Gas Sales [also see PBU MGS]
MHHW	mean higher high water
MHW	mean high water
mi^2	square miles
MLA	Mineral Leasing Act
MLLW	mean lower low water

Acronym	Definition
MLRA	Major Land Resource Area
MLV	Mainline valve
MMBtu	million British thermal units [this should be MMBtu] never seen it all caps!
MMI	Modified Mercalli Intensity
MMPA	Marine Mammal Protection Act
MMS	U.S. Minerals Management Service
MMTPA	million metric tons per annum
Mode	Construction mode
MOF	material offloading facility
MOU	Memorandum of Understanding
MOVES2014	Motor Vehicle Emissions Simulator 2014
MP	milepost
mph	miles per hour
MPRSA	Marine Protection, Research, and Sanctuaries Act
MSA	Magnuson-Stevens Fishery Conservation and Management Act of 1976
MSB	Matanuska-Susitna Borough
MTSA	Maritime Transportation Security Act
n.d.	no date
N/A	Not applicable
NA	Not available
NAAQS	National Ambient Air Quality Standards
NACE	National Association of Corrosion Engineers
NAS	nonindigenous aquatic species
Natural Gas Memorandum	Memorandum of Understanding on Natural Gas Transportation Facilities
Navy	U.S. Navy
NCP	National Oil and Hazardous Substances Pollution Contingency Plan
NEPA	National Environmental Policy Act
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NHPA	National Historic Preservation Act
NHTSA	National Highway Traffic Safety Administration
NLCD	National Land Cover Database
NMFS	National Marine Fisheries Service
NMFS Technical Guidance	Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing—Underwater Acoustic Thresholds for Onset of Permanent and Temporary Threshold Shifts
NNIS	non-native invasive plant species
NO_2	nitrogen dioxide

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
NOA	naturally occurring asbestos
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
North Slope	Alaska's North Slope
NOx	nitrogen oxides
NP	Not provided
NPDES	National Pollutant Discharge Elimination System
NPFMC	North Pacific Fisheries Management Council
NPP	National Park and Preserve
NPS	National Park Service
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NRI	Nationwide Rivers Inventory
NSA	Noise Sensitive Area
NSPS	New Source Performance Standards
NSR	New Source Review
NTSA	National Trails Systems Act of 1968
NTU	nephelometric turbidity units
NVIC	Naviation and Vessel Inspection Circular
NWI	National Wetland Inventory
NWR	National Wildlife Refuge
O_3	ozone
OBE	operating basis earthquake
ODPCP	Oil Discharge Prevention and Contingency Plan
OEP	Office of Energy Projects
OLGA simulations	oil and gas simulations
ONA	Outstanding Natural Area
ORPC	Ocean Renewable Power Company
ORV	outstandingly remarkable values
OSHA	Occupational Safety and Health Administration
PA	Programmatic Agreement
P&ID	piping and instrument diagrams
PAC	potentially affected community
PAH	polycyclic aromatic hydrocarbons
Parks Highway	George Parks Highway
PBOSA	Prudhoe Bay Operations Staging Area
PBTL	Prudhoe Bay Unit Gas Transmission Line
PBU	Prudhoe Bay Unit
PEM	palustrine emergent
PFO	palustrine forested

Acronym	Definition
PFYC	Potential Fossil Yield Classification
PGA	peak ground acceleration
pH	potential hydrogen
PHA	process hazard analysis
PHMSA	Pipeline and Hazardous Material Safety Administration
Pipeline Operation and Maintenance Plan	Pipeline Right-of-Way Operational Monitoring and Maintenance Plan
Plan	Upland Erosion Control, Revegetation, and Maintenance Plan
PLF	product loading facility
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
PND Engineers	PND Engineers, Inc.
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
ppt	parts per thousand
PRIV	Priviledged
PRMP	Paleontological Resources Management Plan
Procedures	Wetland and Waterbody Construction and Mitigation Procedures
Project	Alaska LNG Project
PRUDP	Paleontological Resources Unanticipated Discoveries Plan
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
PSO	protected species observers
PSS	palustrine scrub-shrub
PTE	potential to emit
PTMP	Point Thomson milepost
PTTL	Point Thomson Unit Gas Transmission Line
PTU	Point Thomson Unit
PUT-23 Mine	Putuligayuk Mine site
PVC	polyvinyl chloride
PWS	Public Water System
RAGAGEP	recognized and generally accepted good engineering practices
RCP	Representative Concentration Pathway
RCRA	Resource Conservation and Recovery Act
RCV	remote controlled valves
re	relative to

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
REL	reference exposure levels
Revegetation White Paper	Comparative Belowground Designs and Revegetation Efforts in Northern and Interior Alaska
RFD	Reasonably Foreseeable Development
RHA	Rivers and Harbors Act of 1899
RICE	reciprocating internal combustion engines
~~RMA~~	Resource Management Area
RMES	Representative Monitoring Evaluation Sites
RMP	Resource Management Plan
RNA	Research Natural Area
RO/RO	roll-on/roll-off
ROD	Record of Decision
RP	Recommended Practice
RS	Revised Statute
RST	Revised Statute 2477 Trail
RV	recreational vehicle
SAV	submerged aquatic vegetation
SCADA	Supervisory Control and Data Acquisition
SDA	Special Design Area
SDWA	Safe Drinking Water Act
Secretary	Secretary of the Commission
SEL	sound exposure level
SGCN	species of greatest conservation need
SGR	state game refuge
SHPO	State Historic Preservation Office
SIGRID	sea-ice gridded
SIL	Safety Integrity Level
SIP	State Implementation Plan
SIS	Safety Instrumented System
SIV	scenic inventory value
SLOSH	Sea, Lake and Overland Surges from Hurricanes
SO_2	sulfur dioxide
SOPEP	Shipboard Oil Pollution Emergency Plan
SPCC Plan	Spill Prevention, Control, and Countermeasure Plan
SPL	sound pressure level
SQuiRT	Screening Quick Reference Tables
SRR	State Recreation River
SRS	San Rafael Swell
SSA	sole source aquifer
SSE	safe shutdown earthquake

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
SSURGO	Soil Survey Geographic Database
STATSGO2	Digital General Soil Map of the United States
SUA	special use area
SVRA	sensitive visual resource area
SWP	Alaska Solid Waste Program
SWPPP	Stormwater Pollution Prevention Plan
SWTP	alaska Solid Waste Program
TAPS	Trans Alaska Pipeline System (no hyphen)
TEG	triethylene glycol
TEL	threshold effects level
TGDU	Treated Gas Dehydration Unit
the Services	U.S. Fish and Wildlife Service and National Marine Fisheries Service
TLVC	total live vascular cover
TNC	The Nature Conservancy
TOTE	Totem Ocean Trailer Express, Inc.
tpy	tons per year
TSD	treatment, storage, and disposal
TSS	total suspended solids
TWIC	Transportation Worker Identification Credential
U.S.	United States
UIC	underground injection control
UL	Underwriters Laboratories
USARC	U.S. Arctic Research Commission
USC	United States Code
USDA	U.S. Department of Agriculture
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGCRP	U.S. Global Change Research Program
USGS	U.S. Geological Survey
VGP	Vessel General Permit for Discharges Incidental to the Normal Operation of Vessels
VISCREEN	Visual Impact Screening and Analysis Model
VOC	volatile organic compounds
VPSO	Village Public Safety Officer
VRI	Visual Resource Inventory
VRM	Visual Resource Management
VSM	vertical support member
WEG	wind erodibility group
WELTS	Well Log Tracking System
West Alternative	Cook Inlet West Alternative

ACRONYMS AND ABBREVIATIONS (CONTINUED)

Acronym	Definition
WSA	Waterway Suitability Assessment
WSR	National Wild and Scenic Rivers
WSRA	National Wild and Scenic Rivers Act
yd^3	cubic yards
ΔE	total color contrast
μPa	microPascal

EXECUTIVE SUMMARY

INTRODUCTION AND BACKGROUND

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared this final environmental impact statement (EIS) to assess the impacts of constructing and operating the Alaska LNG Project (Project) proposed by the Alaska Gasline Development Corporation (AGDC). The purpose and need of the Project is to commercialize the natural gas resources of Alaska's North Slope (North Slope) by converting the existing natural gas supply to liquefied natural gas (LNG) for export and use within the State of Alaska.

The purpose of this EIS is to inform the FERC decision-makers, public, and permitting agencies about the potential adverse and beneficial environmental impacts of the proposed Project and recommend mitigation measures that would reduce adverse impacts to the extent practicable. We[1] prepared this EIS based on: information provided by AGDC; our independent review of this information; consultation with federal cooperating agencies (see below); consideration of comments provided by federal, state, and local agencies; and input from Alaska Native communities and members of the public. This EIS was prepared in accordance with the requirements of the National Environmental Policy Act of 1969 and the Commission's implementing regulations under Title 18 of the Code of Federal Regulations (CFR), Part 380.

FERC is the federal agency responsible for authorizing onshore LNG facilities used for exportation of natural gas. FERC is the lead federal agency responsible for the preparation of the EIS. The U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), U.S. Environmental Protection Agency, U.S. Army Corps of Engineers, U.S. Coast Guard (Coast Guard), Bureau of Land Management (BLM), U.S. Fish and Wildlife Service, National Park Service, U.S. Department of Energy, and National Marine Fisheries Service are cooperating agencies because they have jurisdiction by law or special expertise with respect to environmental resources and impacts associated with the Project. The cooperating agencies provided input to the conclusions and recommendations presented in the EIS. Following issuance of this final EIS, the cooperating agencies will issue subsequent decisions, determinations, permits, or authorizations for the Project in accordance with each individual agency's regulatory requirements.

PROPOSED ACTION

On April 17, 2017, AGDC filed an application with FERC in Docket No. CP17-178-000, pursuant to Section 3 of the Natural Gas Act and Part 153 of the Commission's regulations, seeking authorization to construct and operate the following facilities in Alaska: a new Gas Treatment Plant (GTP); a 1.0-mile-long, 60-inch-diameter Prudhoe Bay Unit Gas Transmission Line (PBTL); a 62.5-mile-long, 32-inch-diameter Point Thomson Unit Gas Transmission Line (PTTL); an 806.9-mile-long, 42-inch-diameter natural gas pipeline (Mainline Pipeline) and associated aboveground facilities, including eight compressor stations and a heater station; and a 20 million metric-ton per annum liquefaction facility, including an LNG Plant and Marine Terminal (Liquefaction Facilities).

The Gas Treatment Facilities (GTP, PBTL, and PTTL) would be on state land designated for oil and natural gas development within the North Slope Borough. The Mainline Pipeline would start at the GTP and generally follow the existing Trans Alaska Pipeline System crude oil pipeline and adjacent highways south to Livengood, Alaska. From Livengood, the Mainline Pipeline would head south–southwest to Trapper Creek. It would then follow the George Parks Highway (passing through a portion

[1] "We," "us," and "our" refer to the environmental and engineering staff of FERC's Office of Energy Projects.

of the Denali National Park and Preserve [DNPP]) and Beluga Highway, and then turn south–southeast around Viapan Lake. It would then cross Cook Inlet entering near Beluga Landing and exiting at a landing near Suneva Lake on the northern part of the Kenai Peninsula. The Mainline Pipeline would terminate at the Liquefaction Facilities, which would be sited on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula.

The Project would have an annual average inlet design capacity of up to 3.7 billion standard cubic feet per day and a peak capacity of 3.9 billion standard cubic feet per day. During operation, AGDC expects that between 204 and 360 LNG carriers would call at the Marine Terminal each year.

FERC considers all factors bearing on the public interest as part of its decision to authorize natural gas export facilities. Occasionally, projects reviewed by FERC have associated facilities that do not fall under the jurisdiction of the Commission. For the Project, non-jurisdictional activities would include modifications/new facilities at the Point Thomson Unit, modifications/new facilities at the Prudhoe Bay Unit, relocation of the Kenai Spur Highway, upgrades to the City of Kenai water system, in-state gas interconnections, and LNG carrier transits to and from the Liquefaction Facilities during Project operation. We discuss these facilities and activities in our cumulative impacts analysis in section 4.19.

PUBLIC INVOLVEMENT

AGDC[2] began participating in the Commission's pre-filing process in September 2014 (Docket No. PF14-21-000). FERC's pre-filing process encourages the early involvement of interested stakeholders and regulatory agencies to identify and resolve environmental issues before an application is filed with FERC. During the pre-filing process, AGDC held 14 open houses in Nikiski, Tyonek, Anchorage, Healy, Nenana, Minto, Barrow, Fairbanks, Trapper Creek, Wasilla, Houston, Nuiqsut, Kaktovik, and Anaktuvuk Pass, Alaska, from October 2014 through January 2015. The purpose of the open houses was to provide the public with information about the Project and to solicit comments.

In March 2015, FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Alaska LNG Project and Request for Comments on Environmental Issues* (NOI). The NOI was sent to over 1,850 interested parties, including federal, state, and local officials; agency representatives; conservation organizations; Native Alaskan communities; local libraries; newspapers; and property owners along the pipeline route and within 0.5 mile of the planned compressor stations and LNG Plant. The NOI established a 9-month public scoping period for the submission of comments, concerns, and issues related to environmental aspects of the Project. The extended 9-month scoping period was in recognition of subsistence harvesting windows observed by communities potentially affected by the Project. During the scoping period, FERC held 12 public scoping meetings to receive comments about the Project. The meetings were attended by about 310 people, including stakeholders, representatives from FERC, cooperating agencies, and AGDC. During scoping, FERC staff gathered feedback from local communities, including residents, elected officials, tribal leaders, community leaders, and other interested stakeholders.

On July 27, 2016, FERC issued a *Supplemental Notice Requesting Comments on the Denali National Park and Preserve Alternative for the Planned Alaska LNG Project.* The supplemental notice was issued to solicit feedback from the public and agencies regarding the Denali Alternative, an alternative route that would pass directly through the DNPP entrance area and be closely aligned with the George Parks Highway. On August 23, 2016, FERC held a public forum within the DNPP to discuss the Denali

[2] AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LLP filed a *Request to Commence Pre-Filing Process* on September 5, 2014. On January 4, 2017, AGDC informed the Commission that it had taken over sole ownership of the Project. Because AGDC assumed full control of the Project and was part of the previous applicant team, AGDC is referred to as the Project applicant throughout the document regardless of the timeframe of the activity.

Alternative. About 16 people attended, including DNPP staff. The comment period for the supplemental notice closed on September 25, 2016.

On June 28, 2019, we issued a *Notice of Availability of the Draft Environmental Impact Statement for the Proposed Alaska LNG Project*, which opened a public comment period on the draft EIS. The draft EIS was mailed to 1,341 federal, state, and local government agencies; elected officials; Native Alaskan communities; local libraries and newspapers; property owners that could be affected by Project facilities; individuals requesting intervenor status in FERC's proceedings; and other interested parties. The draft EIS was filed with the U.S. Environmental Protection Agency, which issued a formal notice of availability in the Federal Register on July 8, 2019, indicating that the draft EIS was available online. We held eight public comment meetings for the draft EIS at various locations in the Project area in September 2019. The comment period for the draft EIS closed on October 3, 2019.

Before publication of the draft EIS, including during pre-filing and the application process, we received 248 written comments and form letters on the Project. We received 116 letters commenting on the draft EIS. Thirty-five individuals made oral comments on the draft EIS at public comment meetings; some of these oral comments were also submitted as written comments.

We received comments during scoping and during the draft EIS comment period regarding the proximity of the Project facilities to, and potential impacts on, residential properties in the Nikiski area. Landowners and stakeholders from the Nikiski area also commented on AGDC's plans to move the Kenai Spur Highway and the associated impact on the community. We received comments on several route and facility alternatives including the Denali Alternative, Cook Inlet West Alternative, Port McKenzie Alternative, Port Valdez Alternative, and Fairbanks Alternative. We received comments from the Kenai community regarding increased traffic and population increases due to the influx of construction workers.

We received numerous comments on the Project's potential impact on wildlife—more specifically the caribou (*Rangifer tarandus*) population and its migration routes, the endangered Cook Inlet beluga whale (*Delphinapterus leucas*) population, and Cook Inlet fish habitat—and on how the Project could affect local subsistence on the North Slope. Other comments addressed potential impacts on the local fishing industry, beach access, wetland ecosystems, nature reserves or parks, and safety. We also received comments regarding the purpose and need for the Project, interconnections for in-state delivery of natural gas, pipeline leak detection, invasive plant species, the offshore pipeline design, impacts on water quality, water use and discharge, spill prevention and response, cumulative impacts, air quality impacts, and climate change. Commenters from Fairbanks noted the air quality benefits of natural gas relative to other fossil fuels.

All comments received before issuance of this EIS were considered and addressed as appropriate in our analysis.

PROJECT IMPACTS

Project construction and operation would affect geological resources, soils and sediments, water resources, wetlands, vegetation, wildlife, aquatic resources, threatened and endangered species, other species of concern, land use, recreation, special use areas, visual resources, socioeconomics, transportation, cultural resources, subsistence resources, air quality, noise, health, and public safety. Our analysis also evaluated the potential for cumulative impacts on these resources.

Project construction would require the use of about 35,474 acres of land, of which AGDC would maintain about 8,507 acres for Project operation. Permanent impacts would total about 16,069 acres, including those both in and outside the operational area. Construction impacts are those that would occur during Project construction. Operational impacts are those that are associated with the operation of the Project facilities (e.g., the operational right-of-way for a pipeline facility or an aboveground facility). Permanent impacts outside the operational area would include surface alterations that could extend beyond the life of the Project, including material sites and areas where granular fill would be placed during construction but not removed. The Project would result in significant long-term to permanent impacts on thaw sensitive permafrost (about 6,218 acres), thaw stable permafrost (about 3,499 acres), forest (about 12,440 acres); and wetlands (about 8,225 acres).

The Mainline Pipeline would require 553 waterbody crossings, and the PTTL would require 106 waterbody crossings. Access roads for the Mainline Facilities and GTP would require 102 and 2 waterbody crossings, respectively. Five rivers (the Middle Fork Koyukuk, Yukon, Tanana, Chulitna, and Deshka Rivers) would be crossed using the directional micro-tunneling method, which would avoid direct disturbance of these waterbodies. Surface flow patterns in the Project area would be affected by clearing and ground disturbing activities and the permanent placement of granular fill material in construction areas. AGDC would restore surface flow and contour granular fill material to maintain drainage and hydrologic connectivity.

Impacts on wildlife, including terrestrial wildlife, avian resources, marine mammals, fisheries, and federally listed threatened and endangered species, would result from the loss, alteration, or isolation of habitat; introduction or spread of invasive species; changes in migration patterns; direct injury or mortality; impediment to movement; noise; artificial lighting; and turbidity and sedimentation. With the implementation of various best management practices, AGDC's commitments, and our recommendations, most impacts on wildlife would be less than significant, but significant adverse impacts on the caribou Central Arctic Herd could occur, along with adverse effects on federally designated critical habitat and a number of federally listed threatened and endangered species.

The Project would cross or pass near several recreation areas, including the Arctic National Wildlife Refuge, DNPP, George Parks Highway National Scenic Byway, Iditarod National Historic Trail, Dalton Highway Scenic Byway, and Denali State Park. Most impacts on recreation areas during construction would be temporary and minor. AGDC would provide alternate access to affected sites, schedule activities outside peak tourist seasons to the extent practicable, and comply with applicable crossing permits to minimize impacts. One impact of Project operation on recreation areas would be long-term to permanent changes in the landscape due to maintenance of the pipeline right-of-way or installation of aboveground facilities. These impacts similarly would result in visual impacts, particularly in rugged terrain, due to elevated views. Project effects on visual resources during operation in the DNPP would have low to moderate visual impacts at key observation points in and near the DNPP. Any additional impacts on these same areas from other development projects would contribute to cumulative visual effects, although these would not likely be significant. Operation of aboveground facilities could result in impacts on air quality in recreation areas (see discussion on air quality below).

Construction and maintenance of offshore facilities in Cook Inlet and Prudhoe Bay would temporarily increase turbidity and sedimentation, while Project operation would result in the permanent loss of some open marine habitat. Increases in marine vessel traffic would occur in Cook Inlet and Prudhoe Bay during construction and in Cook Inlet during operation.

Emissions from vehicles and equipment, marine and air traffic, waste incinerators, open burning, and fugitive dust would affect air quality during Project construction. Emissions from operation of the GTP, Mainline compressor stations and heater station, and Liquefaction Facilities would not cause or contribute to exceedances of National or Alaska Ambient Air Quality Standards under normal operating conditions. Operational emissions from the aboveground facilities could exceed thresholds for nitrogen and sulfur deposition and visibility at nearby Class I and II protected areas (e.g., the Arctic National Wildlife

Refuge) as designated under the Clean Air Act. Mitigation measures could be implemented by the State of Alaska during the air permitting phase that would reduce these impacts.

Noise impacts on noise sensitive areas during construction would mostly be temporary and minor, but could be moderate to significant at some locations. Noise associated with the Liquefaction Facilities at the two nearest noise sensitive areas would likely double due to facility operation, but would be below our requirement for operational noise.

Project construction would increase population due to worker influx, but impacts would be minor due to the use of closed construction camps. Population growth in urban areas would result from indirect and induced economic impacts, which would increase the demand for housing and public services in these areas. Project construction and operation would result in economic benefits from worker spending, purchases of materials and services, and taxes, although certain areas, such as McKinley Village near the DNPP, could experience lost revenue during construction.

Project construction and operation have the potential to affect the subsistence practices of Native Alaska communities due to reductions in resource abundance and availability, reduced access to harvest areas, and increased competition from non-local harvesters. Impacts would result from the loss or alteration of habitat and loss or displacement of wildlife. The extent of impacts would vary by community, but overall, the impacts would be less than significant. The BLM prepared an analysis under Section 810 of the Alaska National Interest Lands Conservation Act because a portion of Project construction and operation would occur on BLM lands. The EIS incorporates traditional knowledge regarding various characteristics of Alaskan natural resources and management practices as passed down from generation to generation in Alaska Native communities. Traditional knowledge was collected through community workshops, questionnaires, and review of ethnographic research. Traditional knowledge was used to supplement our descriptions of the affected environment and inform our resource impact analyses and conclusions.

AGDC prepared a Health Impact Assessment (HIA) that evaluated the potential impacts and benefits of Project construction and operation on eight health effects categories (HEC). The HIA rated impacts from Project construction as “high adverse” on one HEC (infectious disease); “medium adverse” on three HECs (social determinants of health; accidents and injuries; and food, nutrition, and subsistence activity); and “low adverse” on four HECs. Positive impacts from Project construction could include increased employment opportunities and household income. The HIA rated impacts from Project operation as “medium adverse” on three HECs (social determinants of health, accidents and injuries, and infectious disease) and “low adverse” on four HECs. Positive impacts from Project operation include increased employment and household income and improved air quality in the Fairbanks area based on the conversion from other fuels to natural gas.

We conducted a preliminary engineering and technical review of AGDC’s proposed design for its Gas Treatment and Liquefaction Facilities. With one exception, we found that the designs provide acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could affect the off-site public. We concluded that high-pressure piping at the GTP could pose a significant safety impact on off-site persons. Therefore, we recommend that emergency response plans for the GTP be coordinated with adjacent operators and that AGDC provide validation or verification for the modeling assumptions and methods.

PHMSA assists FERC by determining whether AGDC’s proposed design would meet the DOT’s 49 CFR 193 Subpart B siting requirements. PHMSA provided a Letter of Determination on the Project’s compliance with 49 CFR 193 Subpart B on February 4, 2020. The Letter of Determination will serve as one of the considerations for the Commission to deliberate in its decision to authorize or deny the Project.

The Coast Guard also assisted us by reviewing the proposed Liquefaction Facilities and the associated LNG marine vessel traffic. On August 17, 2016, the Coast Guard issued a Letter of Recommendation indicating Cook Inlet would be considered suitable for accommodating the type and frequency of LNG marine traffic associated with the Project.

The Mainline Pipeline and associated aboveground facilities would be designed, constructed, operated, and maintained to meet the PHMSA's *Minimum Federal Safety Standards* in 49 CFR 192 and other applicable federal and state regulations. AGDC applied for four Special Permits from PHMSA for strain-based design, multi-layer coating, mainline valve spacing, and crack arrestor coating for the Mainline Facilities. After a public notice and comment period, PHMSA determined that the Special Permit applications comply with the requirements of 49 CFR 190.341 and that waivers of the relevant regulations or standards are not inconsistent with pipeline safety. PHMSA granted these permits in September 2019. AGDC has since submitted a fifth Special Permit application for the use of a pipe-in-pipe design at the Liquefaction Facilities.

ALTERNATIVES CONSIDERED

As required by the National Environmental Policy Act of 1969, and in consultation with the cooperating agencies, we identified and considered reasonable alternatives to the Project to determine if the implementation of an alternative would be preferable to the proposed action. An alternative is considered reasonable if it meets the stated purpose of the Project and is technically and economically feasible and practical. A preferable alternative would offer a significant environmental advantage over the proposed action. In our alternatives analysis, we considered the no action alternative, system alternatives, site alternatives, alternative delivery systems and docking stations, and alternative pipeline routes and design. The EIS evaluates alternatives developed by FERC staff, developed by AGDC, or suggested by stakeholders.

Under the no action alternative, the impacts described in this EIS would not occur, but the purpose of the Project would not be met. In response, AGDC or other applicants would likely develop a new project to transport gas from the North Slope for export and in-state delivery. Given the infrastructure needed to transport the same gas volumes, environmental impacts would likely be comparable to those of the Project. Therefore, we concluded that the no action alternative provides no significant environmental advantage over the Project.

We assessed the potential use of existing, proposed, or modified natural gas infrastructure to meet the same objectives as the Project. We evaluated expansion of the existing Kenai LNG terminal, proposed Alaska Stand Alone Pipeline Project, and existing and proposed LNG export terminals in the United States and Canada. These alternatives would require design changes or new infrastructure that would result in similar or greater impacts than the Project. We concluded that none of the system alternatives would be preferable to the Project.

We examined four alternative sites for the GTP, but found that none would reduce impacts or provide significant environmental advantages relative to the Project. We also considered if the GTP work pad footprint could be modified to reduce impacts, but no technically feasible alternative configurations were identified.

We evaluated five alternative docking stations for module delivery to the proposed GTP. Each would increase the length of access roads, require more dredging, or be farther from the GTP than the Project. We also analyzed alternative sites at the West Dock Causeway associated with the Gas Treatment Facilities that require less marine habitat disturbance, but each would require dredging or infrastructure upgrades. We concluded that none of the alternative docking stations or sites would provide a significant environmental advantage over the Project.

We evaluated several alternative routes for the Mainline Pipeline, including routes in and around Cook Inlet and near Fairbanks. We found that none of these alternatives would provide a significant environmental advantage over the Project. In the draft EIS, we evaluated an alternative route through the DNPP—the Denali Alternative—and found that both the proposed route and this alternative would be acceptable, with neither having a significant advantage over the other. AGDC adopted the Denali Alternative as part of the proposed route in August 2019; this route is included as part of the proposed action evaluated in the final EIS. We evaluated an alternative aboveground design for the Mainline Pipeline, but found that the small reduction in permafrost impacts from an aboveground pipeline would not provide a significant environmental advantage over the Project.

Finally, we evaluated alternative sites, with their associated pipeline routes, for the Liquefaction Facilities in the Port of Valdez, Resurrection Bay, and Cook Inlet. We also considered alternative sites for dredged material disposal and the Mainline Pipeline material offloading facility in Cook Inlet. We found that none of the alternatives would provide a significant environmental advantage over the Project.

CONCLUSIONS

We conclude that Project construction and operation would result in temporary, long-term, and permanent impacts on the environment. Most impacts would not be significant or would be reduced to less than significant levels with the implementation of proposed or recommended avoidance, minimization, and mitigation measures, but some impacts would be adverse and significant.

We conclude that constructing the Project would have significant impacts on permafrost due to granular fill placement, particularly for the Mainline Facilities. The Project would have significant adverse impacts on wetlands from granular fill placement resulting in substantial conversions of wetlands to uplands and from the long recovery time for forested wetlands. Significant adverse impacts on forest would result from permanent losses or conversions from installation of aboveground facilities, granular fill placement, vegetative maintenance in the Mainline Pipeline right-of-way, and the long recovery time for forests. For caribou, the impacts on the Central Arctic Herd would likely be significant due to the timing of impacts during sensitive periods, permanent impacts on sensitive habitats, and the Project location at the center of the herd's range.

Emissions from the GTP and Liquefaction Facilities could have a significant impact on regional haze and acid deposition in some Class I and Class II nationally designated areas. As noted above, mitigation measures could be implemented by the State of Alaska during the air permitting phase that would reduce these impacts. Certain short-term activities, such as flaring at the GTP and Liquefaction Facilities, have the potential to result in short-term significant effects.

The Project would result in positive impacts on the state and local economies, but adverse impacts on housing, population, public services, and local businesses could occur in some areas during construction. The Project could disproportionately affect some environmental justice populations due to impacts on subsistence practices and public health effects based on the HIA prepared by AGDC, but these impacts are not expected to be high and adverse.

Project construction and operation is *likely to adversely affect* six federally listed species (spectacled eider [*Somateria fischeri*], polar bear [*Ursus maritimus*], bearded seal [*Erignathus barbatus*], Cook Inlet beluga whale, humpback whale [*Megaptera novaeangliae*], and ringed seal [*Phoca hispida*]), and designated critical habitat for two species (polar bear and Cook Inlet beluga whale). With the issuance of the draft EIS, we requested initiation of formal consultation with the U.S. Fish and Wildlife Service and National Marine Fisheries Service regarding Project effects on federally listed species. Consultation with these agencies is ongoing.

High-pressure piping at the GTP could pose a significant safety impact on off-site persons. To address this, we recommend that emergency response plans for the GTP be coordinated with adjacent operators and that AGDC provide validation or verification for the modeling assumptions and methods.

The Project would result in significant impacts on permafrost, wetlands, forest, and caribou (the Central Arctic Herd). Because the other current or reasonably foreseeable projects in the study area would similarly affect these resources, we found that cumulative impacts on these resources would be significant.

Our conclusions in the EIS are based wholly or in part on the factors provided below.

- The Project would be constructed in compliance with all applicable federal laws, regulations, permits, and authorizations.
- AGDC would implement all best management practices and the measures described in the Project Upland Erosion Control, Revegetation, and Maintenance Plan and Project Wetland and Waterbody Construction and Mitigation Procedures.
- AGDC has committed to following impact minimization measures contained in plans it has prepared for resources, such as a Blasting Plan; Fugitive Dust Control Plan; Gravel Sourcing Plan and Reclamation Measures; Migratory Bird Conservation Plan; Noxious/Invasive Plant and Animal Control Plan; Paleontological Resources Management Plan; Polar Bear and Pacific Walrus Avoidance and Interaction Plan; Plan for Unanticipated Discovery of Cultural Resources and Human Remains; Revegetation Plan; Spill Prevention, Control, and Countermeasures Plan; and Winter and Permafrost Construction Plan, among others.
- AGDC would be required to satisfy the U.S. Army Corps of Engineers' regulatory requirements to mitigate unavoidable impacts on waters of the United States, including wetlands.
- Compliance with the Endangered Species Act and the National Historic Preservation Act would be complete prior to construction.
- The Project would include protections and safeguards that ensure facility integrity and public safety.
- The Coast Guard determined that Cook Inlet is suitable for accommodating LNG carrier activity associated with the Project.
- PHMSA determined that the Liquefaction Facilities are in compliance with 49 CFR 193 Subpart B.
- FERC's environmental and LNG engineering construction inspection programs would ensure compliance with AGDC's commitments and the conditions of any FERC Authorization.

In addition, we recommend that the Project-specific impact avoidance, minimization, and mitigation measures we have developed (included in this final EIS as recommendations) be attached as conditions to any Authorization issued by the Commission for the Project.

1.0 INTRODUCTION

The Federal Energy Regulatory Commission (FERC or Commission) is an independent federal agency. Under Section 3 of the Natural Gas Act of 1938 (NGA), the Commission has the approval authority for the siting, construction, expansion, or operation of liquefied natural gas (LNG) terminals. The National Environmental Policy Act of 1969 (NEPA) requires the Commission to consider the impacts on the natural and human environment resulting from the construction and operation of a proposed project. Commission staff have prepared this environmental impact statement (EIS) to satisfy the requirements of NEPA and to inform the public and the Commission decision makers of the anticipated environmental impacts associated with approval of an application, as described further below.[1]

> The vertical line in the margin identifies text that is new or modified in the final EIS and differs materially from corresponding text in the draft EIS. Changes were made to address comments on the draft EIS from cooperating agencies and other stakeholders; incorporate modifications to the Project proposed by the Alaska Gasline Development Corporation (AGDC) after publication of the draft EIS; update information included in the draft EIS; and incorporate information filed by AGDC in response to our recommendations in the draft EIS.

On September 5, 2014, AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LLP filed a *Request to Commence Pre-Filing Process* for the proposed Alaska LNG Project (Project). The Commission approved the request on September 12, 2014, and FERC assigned the Project Docket No. PF14-21-000. Commission staff worked with the Project proponents, agencies, tribes, and stakeholders to implement the pre-filing process over the next 27 months. On January 4, 2017, AGDC informed the Commission that it had taken over sole ownership of the Project.[2]

On April 17, 2017, AGDC filed an application with FERC in Docket No. CP17-178-000 for approval of the Project pursuant to Section 3 of the NGA and Part 153 of the Commission's regulations. AGDC is seeking authorization to construct and operate a new Gas Treatment Plant (GTP); a 1.0-mile-long, 60-inch-diameter Prudhoe Bay Unit Gas Transmission Line (PBTL); a 62.5-mile-long, 32-inch-diameter Point Thomson Unit Gas Transmission Line (PTTL); an 806.9-mile-long, 42-inch-diameter natural gas pipeline (Mainline Pipeline) and associated aboveground facilities (Mainline Facilities); and a 20 million-metric-ton per annum (MMTPA) liquefaction facility (Liquefaction Facilities) in Alaska. If the Project receives all necessary approvals, AGDC proposes to start construction as expeditiously as possible. Construction would last a total of about 8 years. The Project would have an annual average inlet design capacity of up to 3.7 billion standard cubic feet per day and a 3.9 billion standard cubic feet per day peak capacity. AGDC states that the Project would have a nominal design life of 30 years.

Figure 1-1 provides an overview map of the Project. A detailed Project description is presented in section 2.0, and detailed maps are included as appendix B.

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1 The distribution list for the Notice of Availability for the EIS is provided in appendix A.

2 Because AGDC has assumed full control of the Project and was part of the previous applicant team, AGDC is referred to as the Project applicant throughout the document regardless of the timeframe of the activity.

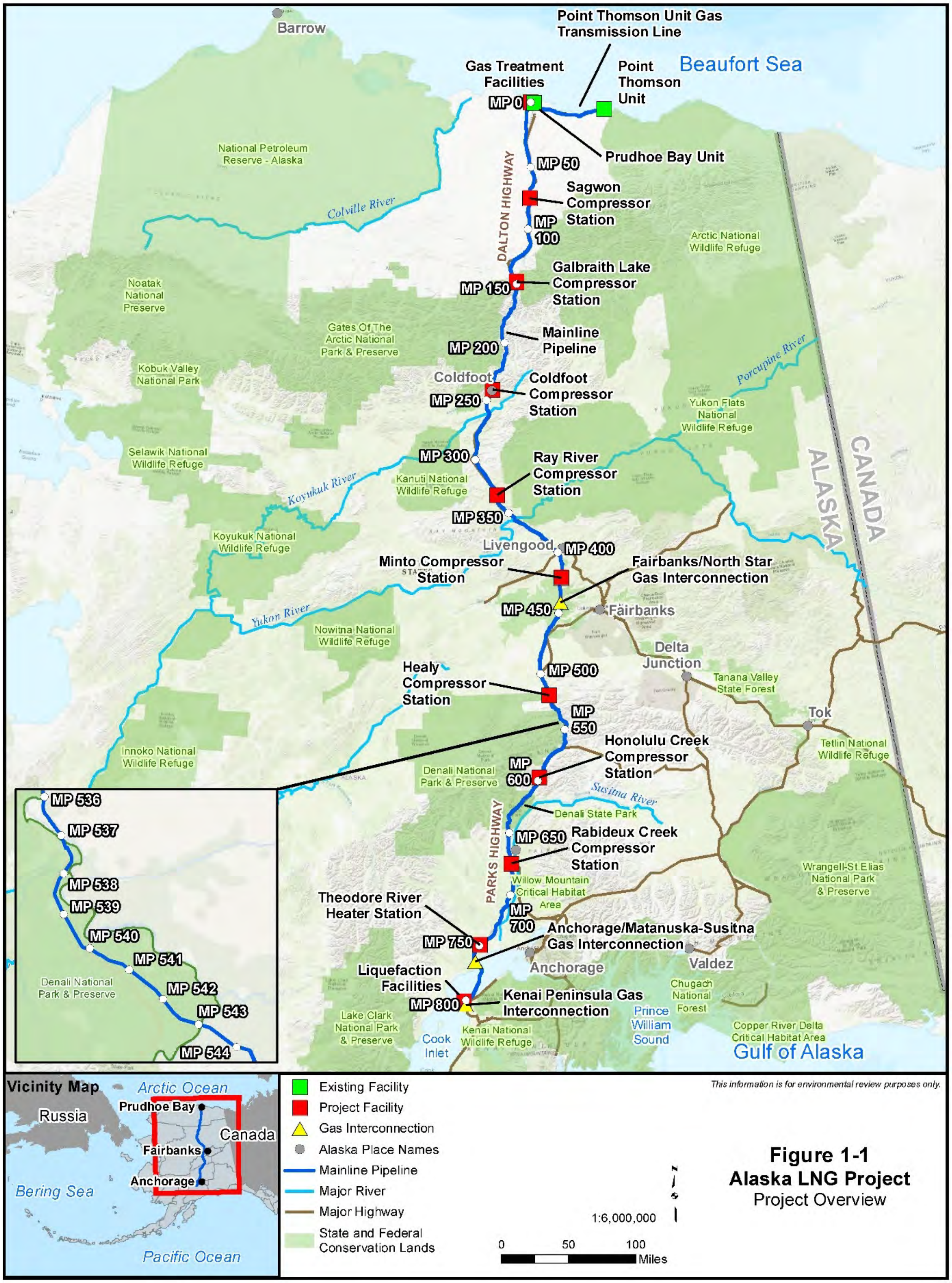

Figure 1-1
Alaska LNG Project
Project Overview

1.1 PROJECT PURPOSE AND NEED

The Commission's purpose for reviewing the Project is based on its obligations under Section 3 of the NGA, which requires the Commission to consider as part of its decision to authorize natural gas facilities, all factors bearing on the public interest. Specifically, regarding whether to authorize natural gas facilities used for exportation, the Commission would authorize the proposal unless it finds that the proposed facilities would not be consistent with the public interest.

FERC does not plan, design, build, or operate natural gas infrastructure. As an independent regulatory commission, FERC reviews proposals developed by other entities. Accordingly, the Project proponent is the source for identifying the purpose for developing and constructing the Project. AGDC's purpose and objectives in proposing the Project were defined in its application to FERC. According to AGDC, the Project purpose is to commercialize the natural gas resources of Alaska's North Slope (North Slope), primarily by converting the existing natural gas supply to LNG for export and providing gas to users within Alaska. Specifically, AGDC's stated objectives for the Project are to:

- commercialize natural gas resources on the North Slope during the economic life of the Prudhoe Bay Unit (PBU) and the Point Thomson Unit (PTU) fields and achieve efficiencies through the use of existing common oil and gas infrastructure and economies of scale;

- bring cost-competitive LNG from Alaska to foreign markets in a timely manner; and

- provide interconnections along the pipeline to allow for in-state gas deliveries, benefiting Alaska gas users and supporting long-term economic development.[3]

1.2 PURPOSE AND SCOPE OF THIS EIS

The Commission's environmental staff has prepared this EIS in compliance with NEPA to assess the anticipated environmental impacts from construction and operation of the Project. The United States (U.S.) Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), U.S. Environmental Protection Agency (EPA), U.S. Army Corps of Engineers (COE), U.S. Coast Guard (Coast Guard), Bureau of Land Management (BLM), U.S. Fish and Wildlife Service (USFWS), National Park Service (NPS), U.S. Department of Energy (DOE), and National Marine Fisheries Service (NMFS) are cooperating agencies assisting in the preparation of the EIS because they have jurisdiction by law or special expertise with respect to environmental resources and environmental impacts associated with the Project. Several of the cooperating agencies also have NEPA obligations in order to issue their respective decisions on the Project. The federal cooperating agencies may adopt this EIS according to Title 40 of the Code of Federal Regulations (CFR), Part 1506.3 (40 CFR 1506.3) if, after independent review, they conclude that their permitting requirements and/or regulatory responsibilities are satisfied.

This EIS is intended to provide a basis for coordinated federal decision making in a single document, avoiding duplication among federal agencies in the environmental review process. In addition to the lead and cooperating agencies, other federal, state, and local agencies may use this EIS in approving or issuing permits for all or part of the Project. The following subsections explain FERC's and other agencies' authorities and roles. Federal, state, and local permits, approvals, and consultations for the Project are discussed in section 1.6.

[3] AGDC identified three specific in-state gas interconnections in its application to FERC. These interconnections are shown on figure 1-1 and described in more detail in section 4.19.

1.2.1 Federal Energy Regulatory Commission

The Commission has authority over the siting, construction, and operation of onshore LNG terminals under Section 3 of the NGA. In the case of the Project, FERC also has jurisdiction over the Mainline Pipeline, GTP, PBTL, and PTTL. As the lead federal agency, FERC has prepared this document in compliance with the requirements of NEPA; the Council on Environmental Quality's (CEQ) regulations implementing procedural provisions of NEPA in 40 CFR 1500−1508; and FERC's regulations implementing NEPA in 18 CFR 380.

The Commission will consider the findings in this EIS during its review of AGDC's application. The identification of environmental impacts related to Project construction and operation and the mitigation of those impacts, as disclosed in this EIS, will be components of the Commission's decision-making process. The Commission would issue its decision in an Order. If the Project is approved, the Order would specify that the LNG terminal and related facilities can be constructed and operated under the authority of Section 3 of the NGA. The Commission may accept the application in whole or in part, and can attach engineering and environmental conditions to the Order that would be enforceable actions to assure that the proper mitigation measures are implemented.

1.2.2 U.S. Department of Transportation—Pipeline and Hazardous Materials Safety Administration

PHMSA has authority to enforce safety regulations and design standards for LNG terminals as well as safety regulations and standards related to the design, construction, and operation of natural gas pipelines under the Natural Gas Pipeline Safety Act of 1968 (Title 49 of the United States Code [USC], Section 1671 et seq.).

PHMSA has prescribed the minimum federal safety standards for LNG facilities in compliance with 49 USC 60101. Those standards are codified in 49 CFR 193 and apply to the siting, design, construction, operation, maintenance, and security of LNG facilities. National Fire Protection Association (NFPA) Standard 59A, (2001 edition) *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*, is incorporated into these requirements by reference with regulatory preemption in the event of conflict.[4] In accordance with the 1985 Memorandum of Understanding (MOU) on LNG facilities and the 2004 Interagency Agreement on the safety and security review of waterfront import/export LNG facilities, PHMSA participates as a cooperating agency and assists in assessing any mitigation measures that may become conditions of approval for any project. In addition, the August 31, 2018 MOU between FERC and PHMSA provides guidance and policy on each agency's respective statutory responsibility to ensure that each agency works in a coordinated and comprehensive manner.[5] In the 2018 MOU, PHMSA agreed to issue a Letter of Determination (LOD) stating whether LNG facilities would be capable of complying with location criteria and design standards contained in Subpart B of Part 193. PHMSA provided its LOD to FERC on February 4, 2020, indicating that the proposed siting of the Project complies with the standards set forth in Subpart B of Part 193. Additional details on this analysis are provided in section 4.18.

The pipeline facilities would be designed, constructed, operated, and maintained in accordance with PHMSA regulations in *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards* (49 CFR 192). Among other design standards, these regulations specify pipeline material selection; minimum design requirements; protection from internal, external, and atmospheric corrosion; and qualification procedures for welders and operations personnel. Any modifications to the provisions of

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[4] 49 CFR 193.2013, 193.2051

[5] The MOU can be viewed online at https://www.ferc.gov/legal/mou/2018/FERC-PHMSA-MOU.pdf.

the 49 CFR 192 regulations would be addressed through PHMSA special permits in accordance with 49 CFR 190.341, Pipeline Safety Enforcement and Regulatory Procedures.

In accordance with 49 CFR 190.341, a Special Permit is an order by which PHMSA waives compliance with one or more of the federal pipeline safety regulations under the standards set forth in 49 USC 60118(c) and subject to conditions set forth in the order. A Special Permit is issued to a pipeline operator (or prospective operator) for specified facilities that are, or—absent a waiver—would be subject to the regulation. AGDC filed five Special Permit applications with PHMSA to waive compliance with certain standards set forth in various regulations to construct, operate, and maintain the Mainline Pipeline and Liquefaction Facilities. The waivers are discussed in section 4.18. PHMSA provided notice to the public of its intent to consider the applications and invite comment. This notification is separate from FERC's NEPA public process associated with this EIS.

In light of the analysis contained in this EIS and public comments received during PHMSA's public comment process, the DOT Associate Administrator determines whether AGDC's applications for Special Permits comply with the requirements of 49 CFR 190.341 and whether waivers of the relevant regulation or standard are consistent with pipeline safety. On September 9, 2019, PHMSA granted four Special Permits for the Mainline Pipeline associated with the Project. Each permit includes special permit terms and conditions that are intended to ensure safety or environmental protection, or that are otherwise in the public interest. The granted special permits are posted at www.regulations.gov and on PHMSA's website at http://www.phmsa.dot.gov under docket numbers PHMSA-2017-0044, 0045, 0046, and 0047.

1.2.3 U.S. Environmental Protection Agency

The EPA is the federal agency responsible for protecting human health and safeguarding the natural environment. It establishes and enforces national standards under a variety of environmental laws and regulations in consultation with state, tribal, and local governments. The EPA has responsibilities under NEPA as well as the Clean Water Act of 1972 (CWA) (33 USC 1251 et seq.); Clean Air Act of 1963 (CAA) (42 USC 7401 et seq.); Marine Protection, Research, and Sanctuaries Act of 1972 (MPRSA) (16 USC 1431 et seq.); and the Safe Drinking Water Act of 1974 (SDWA) (42 USC 300), as well as other federal environmental laws.

Under CWA Section 402, the EPA regulates point source discharges of pollutants to waters of the United States through the National Pollutant Discharge Elimination System (NPDES) program. On October 31, 2008, the EPA authorized the State of Alaska to implement the NPDES program through a phased transfer of the NPDES program components. The State of Alaska Department of Environmental Conservation (ADEC) assumed authority to administer the Alaska Pollutant Discharge Elimination System (APDES) permitting program for discharges to state waters on November 1, 2012. The EPA maintains oversight of the state's APDES program and retains CWA Section 402 authority for facilities within the Denali National Park and Preserve (DNPP), facilities operating in federal waters outside state waters, facilities that have been issued CWA Section 301(h) waivers, and facilities in Indian Country (Metlakatla Indian Community, Annette Island Reserve). The EPA authorizes discharges of ballast water under the Vessel General Permit for Discharges Incidental to the Normal Operation of Vessels (VGP). Under CWA Section 401, the EPA retains the authority to issue water quality certifications within the DNPP (ADEC issues Section 401 certifications for other areas of the Project outside the DNPP). The EPA also has the authority to review, elevate, and/or object to permits issued by the COE under Section 404 of the CWA.

In addition to its authority under the CWA, the EPA has authority under the CAA (42 USC 85) to control air pollution by developing and enforcing rules and regulations for all entities that emit pollutants into the air. Under this authority, the EPA has developed regulations for major sources of air pollution. State and local agencies (e.g., ADEC, Division of Air Quality) are given the authority to implement these regulations through EPA delegation or through EPA-approval of state air operating permit programs and State Implementation Plans (SIP). State and local agencies also can develop and implement their own regulations for non-major sources of air pollutants through an EPA-approved SIP. The EPA maintains oversight authority of the state's programs. The EPA also establishes general conformity applicability thresholds that a federal agency can use to determine whether a specific action requires a general conformity assessment to ensure actions taken by federal agencies do not interfere with a state plan to maintain national air quality standards. In addition to its permitting responsibilities, the EPA is required under Section 309 of the CAA to review and publicly comment in writing on the environmental impacts of major federal actions under the provisions of NEPA.

The EPA also co-administers the MPRSA with the COE. Section 103 of the MPRSA authorizes the COE to issue permits for the transportation of dredged material for ocean disposal, in accordance with regulatory requirements and subject to the EPA's concurrence. If disposal is proposed at an EPA-designated site under Section 102 of the MPRSA, that disposal must be consistent with that site's *Site Management and Monitoring Plan*.

The Underground Injection Control (UIC) program in Alaska for Class I, III, IV, V, and VI wells is administered by the EPA pursuant to the SDWA.[6] The EPA has direct implementation responsibility in Alaska for the regulation of Class I injection wells through the UIC Program, which is authorized by Part C of the SDWA.

1.2.4 U.S. Army Corps of Engineers

The COE, Alaska District, Regulatory Division received a Department of the Army (DA) application from AGDC (file POA-2015-00329) for a permit under Section 404 of the CWA (33 USC 1344) and Section 10 of the Rivers and Harbors Act of 1899 (RHA) (33 USC 403). Under Section 404 of the CWA, the COE has the authority to issue or deny permits for proposed discharges of dredged and/or fill material into waters of the United States. Under Section 10 of the RHA, the COE has authority to issue or deny permits for work and structures in, on, over, or under navigable waters of the United States. The COE would adopt the EIS per 40 CFR 1506.3(c) if, after an independent review of the document, it concludes that the EIS sufficiently provides information to support decision making under its statutory authorities. Regulations implementing Section 404 of the CWA and Section 10 of the RHA are defined in 33 CFR Parts 320–332.

In its regulatory capacity, the COE is neither a proponent nor an opponent of projects seeking DA authorization. As stated in 33 CFR 320.19, the COE conducts a public interest review that seeks to balance a proposed action's favorable impacts against its detrimental impacts. Additionally, as part of the public interest review, and in accordance with 33 CFR 320.4(b)(4), the COE is also required to review actions in accordance with regulations developed by the EPA under the CWA Section 404(b)(1) guidelines, including a determination of the least environmentally damaging practicable alternative (LEDPA). The CWA Section 404(b)(1) guidelines restrict the COE from issuing a permit for any alternative other than the LEDPA. The term practicable means available and capable of being done after taking into consideration cost, existing technology, and logistics, considering the overall purpose of the Project. For the purposes of determining the LEDPA, the COE has determined that the overall Project purpose is construction of the infrastructure necessary to commercialize and transport natural gas resources from the North Slope to sell to communities within Alaska, and for the production and export of LNG to foreign markets.

The COE issued a public notice for AGDC's DA permit application on December 30, 2019 to commence the COE's public interest review process; the comment period on the COE's public notice

[6] The Alaska Oil and Gas Conservation Commission (AOGCC) administers the Alaska Class II UIC permitting program.

expired on February 28, 2020. The COE will prepare a Record of Decision (ROD) prior to finalizing its action concerning the issuance or denial of the requested DA permit.

1.2.5 U.S. Coast Guard

The Coast Guard exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order (EO) 10173; the Magnuson Act of 1950 (50 USC 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC 1221 et seq.); and the Maritime Transportation Security Act of 2002 (46 USC 701). The Coast Guard is responsible for matters related to navigation safety, vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment in or adjacent to navigable waters up to the last valve immediately before the receiving LNG tanks. As appropriate, the Coast Guard (acting under the authority in 33 USC 1221 et seq.) also would inform FERC of design- and construction-related issues identified as part of waterfront safety and security assessments. If the Project is approved, constructed, and operated, the LNG carrier loading facilities and any appurtenances between the LNG carriers and the last valve immediately before the LNG storage tanks would comply with applicable sections of the Coast Guard regulations in *Waterfront Facilities Handling Liquefied Natural Gas* (33 CFR 127) and EO 10173.

As required by its regulations, the Coast Guard is responsible for issuing a Letter of Recommendation (LOR) as to the suitability of the waterway for LNG marine traffic following a Waterway Suitability Assessment (WSA). The process of preparing the LOR begins when an applicant submits a Letter of Intent (LOI) to the local Captain of the Port. AGDC submitted its LOI and associated WSA with the Coast Guard on May 15, 2014. A follow-on WSA was submitted on March 18, 2016. The Coast Guard reviewed the LOI, WSA, and follow-on WSA and issued its LOR on August 17, 2016.

The Coast Guard also has authority over bridges, pipeline crossings, and causeways in or over navigable waters of the United States under Section 9 of the RHA, as amended (33 USC 401); the Act of March 23, 1906, amended (33 USC 491); the General Bridge Act of 1946, as amended (33 USC 525); and the International Bridge Act of 1972 (33 USC 535). The Coast Guard has set forth implementing regulations in 33 CFR Parts 114–118.

1.2.6 Bureau of Land Management

The BLM is the federal agency responsible for certain land-use authorizations on BLM-managed lands. The authority for management of the land and resource development options comes from several statutes, including the Federal Land Policy and Management Act of 1976 (FLPMA), the Mineral Leasing Act of 1920 (MLA), the Alaska Native Claims Settlement Act of 1971 (ANCSA), Title VIII and IX of the Alaska National Interest Lands Conservation Act of 1980 (ANILCA), and the National Trails Systems Act of 1968 (NTSA) (916 USC 1241–1251).

Under FLPMA, the BLM has authority to regulate the use, occupancy, and development of federal public lands and take whatever action is required to prevent unnecessary or undue degradation of these lands (43 USC 1732). In accordance with FLPMA, the BLM manages its Alaska lands and their uses to ensure healthy and productive ecosystems.

Under Section 28 of the MLA (30 USC 185) and 43 CFR 2881.11, the BLM has the authority to issue grants to oil or gas pipelines or related facilities to cross federal lands under BLM jurisdiction or the jurisdiction of two or more federal agencies, except land in the National Park System, land held in trust for Indians, or land within the Outer Continental Shelf. AGDC would need to obtain a Right-of-Way Grant and Temporary Use Permits from the BLM for crossing lands managed by the BLM.

Under ANCSA, the BLM retains interim administration of selected lands. Prior to issuing a lease, permit, or right-of-way on selected lands, the views of the concerned regions or villages shall be obtained and considered. Title VIII of ANILCA establishes procedures for federal agencies to evaluate impacts on subsistence uses and needs, and means to reduce or eliminate such impacts (16 USC 3120). Title IX of ANILCA establishes procedures for federal agencies to grant rights-of-way on lands selected by the State of Alaska under Section 6 of the Alaska Statehood Act of 1958 (916 USC 410hh-3233, 43 USC 1602-1784).

Pursuant to the NTSA, the BLM is the statutorily-designated federal administrator for the Iditarod National Historic Trail (INHT) and is the federal point-of-contact for INHT matters. The BLM must also consider consistency with applicable Resource Management Plans (RMP). Any authorizations by the BLM, such as granting of a right-of-way or authorizing a sale of mineral materials, must be in conformance with the existing RMP. An evaluation of consistency with the applicable RMP potentially affected by the Project is provided in sections 4.9 and 4.10.

In accordance with the MLA, the BLM must respond to a right-of-way application submitted by AGDC to cross federally managed lands. The BLM will decide whether or not to approve, approve with modification, or deny issuance of a right-of-way grant to AGDC for the Project, and, if so, under what terms and conditions. This EIS will be used to identify the required mitigation measures that would apply to the right-of-way grant, mineral material sales, and other authorizations incidental to the Project.

1.2.7 U.S. Fish and Wildlife Service

The USFWS is responsible for ensuring compliance with the Endangered Species Act of 1973 (ESA). Section 7 of the ESA, as amended, states that any project authorized, funded, or conducted by any federal agency should not "…jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined…to be critical…" (16 USC 1536(a)(2)). The USFWS also reviews project plans and provides comments regarding protection of fish and wildlife resources under the provisions of the Fish and Wildlife Coordination Act of 1934 (16 USC 661 et seq.). The USFWS is responsible for the implementation of the provisions of the Migratory Bird Treaty Act of 1918 (MBTA) (16 USC 703), the Bald and Golden Eagle Protection Act of 1940 (BGEPA) (16 USC 688), and the Marine Mammal Protection Act of 1972 (MMPA).

Section 7 of the ESA requires identification of and consultation on aspects of any federal action that may have effects on federally listed species, species proposed for federal listing, and their habitats. The ultimate responsibility of compliance with Section 7 remains with the lead federal agency (i.e., FERC for this Project).

As the lead federal agency for the Project, FERC is consulting with the USFWS pursuant to Section 7 of the ESA to determine whether federally listed endangered or threatened species or designated critical habitat are found in the vicinity of the Project, and to evaluate the Project's potential effects on those species or critical habitats. The USFWS elected to cooperate in preparing this EIS because it has special expertise with respect to environmental impacts associated with the Project. In addition to the ESA, FERC is coordinating with the USFWS regarding the MBTA, the BGEPA, the MMPA, the Fish and Wildlife Coordination Act, other federal trust wildlife resources, and NEPA.

The USFWS has a role as a federal land manager under the CAA. Federal land managers are charged with direct responsibility to protect the air quality and related values (including visibility) of Class I areas and Class II nationally designated protected areas and to consider, in consultation with the EPA, whether proposed industrial facilities would have an adverse impact on these values (42 USC 7475 (c)). The Tuxedni Wilderness within the Alaska Maritime National Wildlife Refuge (NWR) is designated a Class I area, and the Arctic, Kanuti, Yukon Flats, Koyukuk, Selawik, Nowitna, Kenai, Kodiak, and Alaska

Maritime NWRs are considered Class II nationally designated protected areas. The USFWS is responsible for land management within all of these NWRs, a portion of which would be within 186.4 miles (300 kilometers [km]) of Project facilities.[7]

Per the ANILCA 303(1)(B), the purposes for which the Alaska Maritime NWR, including Tuxedni NWR [ANILCA 303(1)(v) Gulf of Alaska (GOA) Unit], Arctic NWR (ANWR) [ANILCA 303(2)(B)]; Kanuti NWR [ANILCA 302(4)(B)]; Kenai NWR [ANILCA 303(4)(B)]; Kodiak NWR [ANILCA 303(5)(B)]; Koyukuk NWR [ANILCA 302(5)(B)]; Nowitna NWR [ANILCA 302(6)(B)]; Selawik NWR [ANILCA 302(7)(B)]; and, Yukon Flats NWR [ANILCA 302(9)(B) and 303(7)(B)] were established and managed are to:

- conserve fish and wildlife populations and habitats in their natural diversity;
- fulfill the international treaty obligations of the United States with respect to fish and wildlife and their habitats;
- provide the opportunity for continued subsistence uses by local residents;
- provide a program of national and international scientific research on marine resources; and
- ensure, to the maximum extent practicable, water quality and necessary water quality within the refuge.

These purposes are integrated into Comprehensive Conservation Plans applicable to each refuge. In addition to ANILCA, each refuge is administered under the National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 USC 668dd-668ee), which serves as the "organic act" for the National Wildlife Refuge System. The National Wildlife Refuge System Improvement Act provides a foundation for the USFWS' biological integrity, diversity, and environmental health policy. Many refuges in Alaska have portions that are congressionally designated as wilderness or possess wilderness characteristics under the Wilderness Act of 1964.

1.2.8 National Park Service

The NPS is a land management agency within the U.S. Department of the Interior (DOI) with jurisdiction of over 80 million acres of federal land in the United States. It manages these lands to protect and preserve natural and cultural resources unimpaired for the enjoyment of future generations. The NPS is responsible for management of lands within the DNPP, Lake Clark National Park and Preserve (NPP), Kenai Fjords National Park, and Gates of the Arctic NPP, all of which would be within 186.4 miles of Project facilities. The NPS has a role as a federal land manager under the CAA. The DNPP is designated a Class I area, while Lake Clark, Kenai Fjords, and Gates of the Arctic are designated as Class II nationally designated protected areas.

The NPS will consider issuance of a right-of-way permit to AGDC that would allow the Project to pass through the DNPP. The route of the Mainline Pipeline would cross the DNPP between MPs 537.1 and 543.1. The Denali National Park Improvement Act (Public Law 113-33), as amended by the John D. Dingell, Jr. Conservation, Management, and Recreation Act (Public Law 116-9), allows the NPS to issue

[7] 300 km is a typical screening distance used by federal land managers to assess potential air quality impacts from a facility on a sensitive area or resource (see section 4.15.5).

right-of-way permits for a high-pressure natural gas transmission pipeline (including appurtenances) under certain conditions (see section 1.6.16).

The NPS, under the National Historic Preservation Act of 1966 (NHPA) (54 USC 306108) and its implementing regulations (36 CFR Part 800), has, at a minimum, a consultative role in the Project's Section 106 review process (see section 1.6.2) regarding Project effects on the Gallagher Flint Station National Historic Landmark and the DNPP.

1.2.9 U.S. Department of Energy

The DOE Office of Fossil Energy (DOE/FE) must meet its obligation under Section 3 of the NGA to authorize the import and/or export of natural gas, including LNG, unless it finds that the proposed import or export would not be consistent with the public interest. By law, under Section 3(c) of the NGA, applications to export natural gas to countries with which the United States has Free Trade Agreements (FTA) that require national treatment for trade in natural gas are deemed to be consistent with the public interest, and the Secretary must grant authorization without modification or delay. In the case of applications to export LNG to non-FTA nations, NGA Section 3(a) requires the DOE/FE to conduct a public interest review and grant authority to export unless the DOE/FE finds that the proposed exports would not be consistent with the public interest. Additionally, NEPA requires DOE/FE to consider the environmental effects of its decisions regarding applications to export natural gas to non-FTA nations.

On July 18, 2014, AGDC filed an application with the DOE, in DOE/FE Docket No. 14-96-LNG, seeking authorization to export LNG to both FTA and non-FTA nations. The DOE issued its *Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Proposed Alaska LNG Project in the Nikiski Area of the Kenai Peninsula, Alaska, to Free Trade Agreement Nations* on November 21, 2014 (DOE/FE Order No. 3554). On May 28, 2015, the DOE issued its *Order Conditionally Granting Long-Term, Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Proposed Alaska LNG Terminal in Nikiski, Alaska, to Non-Free Trade Agreement Nations* (DOE/FE Order No. 3643). DOE/FE Order 3643 would allow AGDC to export a volume up to the equivalent of 929 billion cubic feet per year of natural gas for a term of 30 years. The 30-year term commences on the earlier of the date of first commercial export or 12 years from the date of the Order (May 28, 2027).

The LNG may be exported to any country with which the United States does not have an FTA requiring national treatment for trade in natural gas, which currently has or in the future develops the capacity to import LNG, and with which trade is not prohibited by U.S. law or policy. The authorization is conditioned on the satisfactory completion of the environmental review process to comply with NEPA under FERC Docket Nos. PF14-21-000 and CP17-178-000, and on issuance by DOE/FE of a Finding of No Significant Impact or a ROD pursuant to NEPA. AGDC must also comply with all preventive and mitigation measures required by federal and state agencies for the Project. In addition, AGDC must file with the DOE copies of executed long-term contracts for both natural gas supply and the export of LNG on its own behalf or as an agent for other entities from the proposed Alaska LNG Project.

1.2.10 National Marine Fisheries Service

NMFS is serving as a cooperating agency pursuant to 40 CFR 1501.6 because the scope of the proposed action and alternatives involve activities that have the potential to affect marine resources under their jurisdiction by law and special expertise. As applicable, permits and authorizations are issued pursuant to the ESA (16 USC 1531 et seq.) and the regulations governing the taking, importing, and exporting of threatened and endangered species (50 CFR Parts 222 to 226), as well as the MMPA (16 USC 1361 et seq.) and the regulations governing the taking and importing of marine mammals (50 CFR 216). NMFS has additional responsibilities to conserve and manage fishery resources of the United States, which includes the authority to engage in consultations with other federal agencies pursuant to the Magnuson-Stevens Fishery Conservation and Management Act of 1976 (MSA) and 50 CFR 600 when proposed actions may adversely affect Essential Fish Habitat (EFH).

In accordance with 50 CFR 402, NMFS serves as a consulting agency under Section 7 of the ESA for federal agencies proposing or authorizing an action that may affect marine resources listed as threatened or endangered. As the lead federal agency for the Project, FERC is consulting with NMFS pursuant to Section 7 of the ESA to determine whether federally listed endangered or threatened species or designated critical habitat are found in the vicinity of the Project, and to evaluate the Project's potential effects on those species or critical habitats. FERC initiated formal Section 7 consultation in June 2019 for potential effects on ESA-listed species (see section 4.8.1).

AGDC would be required to obtain Incidental Take Authorizations (ITA) under the MMPA. NMFS received applications from AGDC pursuant to the MMPA for authorization to take marine mammals incidental to construction activities associated with the Project in Cook Inlet (April 2017) and Prudhoe Bay (March 2019). Because NMFS consideration whether to issue ITAs to AGDC under the MMPA is a major federal action[8] triggering NMFS' independent NEPA compliance obligation, when serving as a cooperating agency, NMFS may satisfy this independent NEPA obligation by preparing a separate NEPA document or, if appropriate, by adopting the NEPA document prepared by the lead agency for issuance of an authorization. Therefore, NMFS, in accordance with 40 CFR 1506.3 and 1505.2, intends to adopt this EIS and issue a separate ROD associated with its decision to grant or deny AGDC's request for regulations and a Letter of Authorization (LOA) pursuant to Section 101(a)(5)(A) of the MMPA for construction activities in Cook Inlet and an Incidental Harassment Authorization (IHA) pursuant to Section 101(a)(5)(D) of the MMPA for construction activities in Prudhoe Bay.

The MSA, as amended by the Sustainable Fisheries Act of 1996 (Public Law 104–267), establishes procedures designed to identify, conserve, and enhance EFH for those species regulated under a federal fisheries management plan. Section 305(b)(2) of the MSA requires federal agencies to consult with NMFS on any action authorized, funded, or undertaken that may adversely affect EFH. The EFH consultation process begins with a determination of adverse effect by the action or authorizing (lead) agency. If an action may adversely affect EFH, an EFH assessment is required per 50 CFR 600.920(e). If the lead agency determines that an action would not adversely affect EFH, no consultation is required, and the agency is not required to contact NMFS about their determination.

Because EFH has been designated in the Beaufort Sea, Cook Inlet, and in the watersheds between the marine terminals, the MSA requires coordination between FERC and NMFS to protect, conserve, and enhance EFH. We[9] prepared an EFH assessment for submission to NMFS and completed EFH consultation on September 23, 2019 (see section 4.7.4).

8 Since NMFS's action would authorize take of marine mammals incidental to a subset of the activities analyzed in this final EIS, these components of FERC's proposed action are the subject of the NMFS proposed action. The purpose of NMFS's action, which is a direct outcome of AGDC's request for authorization to take marine mammals incidental to construction activities in Cook Inlet and Prudhoe Bay, is to evaluate AGDC's applications pursuant to the MMPA and 50 CFR 216 and to issue ITAs, if appropriate. The need for NMFS's action is to consider the impacts of AGDC's activities on marine mammals and ultimately allow AGDC to conduct its activities in compliance with the MMPA if the requirements of section 101(a)(5)(A) and (D) are satisfied.

9 The pronouns "we," "us," and "our" refer to the environmental and engineering staff of FERC's Office of Energy Projects.

1.3 PUBLIC REVIEW AND COMMENT

1.3.1 Pre-filing Process and Scoping

Prior to and during the pre-filing process, AGDC[10] contacted federal, state, and local agencies in the area to inform them about the Project and discuss Project-specific issues and concerns. AGDC also created a Public Participation Plan that outlined the tools and actions taken to facilitate stakeholder communications and dissemination of public information. The Public Participation Plan established a single point of contact for stakeholder communications and public information; a Project toll-free number, e-mail address, and mailing address; a publicly accessible website; participation in public community meetings; development of a stakeholder and public/agency correspondence log; posting of relevant information in local newspapers and local libraries; and continued engagement with federal, state, and local officials and community leaders. Public outreach for the Project was initiated prior to the commencement of the 2013 summer field season and the land acquisition associated with the Liquefaction Facilities and is continuing.

As part of the pre-filing process, AGDC hosted a total of 14 open house meetings in the Project area from October 2014 through January 2015. More specifically, during the months of October and November 2014, AGDC held 11 open houses in Nikiski, Tyonek, Anchorage, Healy, Nenana, Minto, Barrow, Fairbanks, Trapper Creek, Wasilla, and Houston, Alaska. In January 2015, AGDC held three open house meetings in Nuiqsut, Kaktovik, and Anaktuvuk Pass, Alaska. The goals of the public open house meetings were to inform landowners, government officials, and the affected communities about the Project and invite them to ask questions and express their concerns. FERC staff participated in the meetings and provided information regarding FERC's environmental review process.

On March 4, 2015, FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Alaska LNG Project and Request for Comments on Environmental Issues* (NOI) that explained the pre-filing process, provided a summary of the Project, outlined a preliminary list of environmental issues identified by FERC staff, requested written comments from the public, and asked other federal, state, and local agencies with jurisdiction and/or special expertise to cooperate with FERC in the preparation of the EIS. The NOI was sent to over 1,850 interested parties, including federal, state, and local officials; agency representatives; conservation organizations; tribal communities; local libraries; and newspapers in the Project area, as well as property owners along the pipeline route and within 0.5 mile of the planned compressor stations and LNG Plant. The issuance of the NOI established a 9-month public scoping period for the submission of comments, concerns, and issues related to the environmental aspects of the Project. The extended 9-month scoping period was in recognition of subsistence harvesting windows observed by communities potentially affected by the Project. The official scoping period for the Project ended on December 4, 2015.

In October 2015, FERC issued two supplemental *Notices of Public Scoping Meetings for the Planned Alaska LNG Project* to notify the communities and relevant stakeholders about the planned scoping meetings. In addition to the formal notices, we created two customized media advisories to further help create awareness among the communities and stakeholders about the planned scoping meetings. The media advisories outlined the key event details of each scoping meeting and were sent to community leaders, radio stations, boroughs, and local media outlets.

During the fall of 2015, FERC held 12 public scoping meetings during the formal scoping period to inform the various communities about FERC's environmental review process and gather key comments

[10] Actions taken by the original Project applicants (AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LLP) are referred to as AGDC's actions for consistency in presentation throughout the document.

and concerns from the communities in the Project area that should be addressed in the EIS. During the scoping meetings, FERC gathered feedback from the local communities, including residents, elected officials, tribal leaders, community leaders, and other interested stakeholders. FERC held meetings in Nikiski, Kaktovik, Houston, Barrow, Trapper Creek, Nuiqsut, Coldfoot, Healy, Tyonek, Nenana, Anchorage, and Fairbanks. A total of about 310 people attended the scoping meetings, including stakeholders, FERC representatives, cooperating agencies, and AGDC. A total of about 69 attendees provided oral comments at the meetings.

On July 27, 2016, FERC issued a *Supplemental Notice Requesting Comments on the Denali National Park and Preserve Alternative for the Planned Alaska LNG Project.* The Notice was issued to solicit feedback from the public and agencies regarding the Denali Alternative, which passes directly through the DNPP entrance area and is closely aligned with the Parks Highway. On August 23, 2016, FERC held a public forum within the DNPP to discuss the Denali Alternative. About 16 people attended the forum, including DNPP staff. In addition to the forum, written comments were submitted during the supplemental scoping period by members of the public and federal, state, and local agencies. The official comment period for the supplemental notice formally closed on September 25, 2016. On August 16, 2019, AGDC adopted the portion of the route through the DNPP as part of the proposed route for the Mainline Pipeline.

Before publication of the draft EIS, we received 248 written comment letters and form letters during the pre-filing process, formal scoping period, and supplemental scoping period, and throughout the preparation of the draft EIS. Written comments were received from federal agencies, state agencies, elected officials, Alaska Native tribes, non-government organizations, affected landowners, individuals, groups, and companies (including a form letter submitted by seven individuals and landowners).

In addition to FERC's formal notices, we issued Project newsletters in September 2015, June 2016, and December 2017 to provide stakeholders information on FERC's environmental review process and instructions on how comments could be filed with the Commission. We also participated in interagency meetings, conference calls, and site visits for the Project to identify issues to be addressed in the EIS. The meetings, conference calls, and site visits provided a forum for the exchange of information, and supported FERC's responsibility to coordinate federal authorizations and associated environmental review of the Project. Transcripts of each scoping meeting, summaries of the meetings and conference calls, and all written comments filed with FERC are part of the public record for the Project and available for viewing on the FERC website (http://www.ferc.gov).[11]

On April 17, 2017, AGDC filed its application with FERC pursuant to Section 3 of the NGA. On May 1, 2017, FERC issued a *Notice of Application* alerting the public that the application is currently under review with the federal agency. This notice opened a defined period for parties to file for intervenor[12] status. FERC Docket No. CP17-178-000 was established for the Project.

1.3.2 Public Review of the Draft and Final Environmental Impact Statement

A *Notice of Availability of the Draft Environmental Impact Statement for the Proposed Alaska LNG Project* was issued on June 28, 2019. The draft EIS was filed with the EPA, and the EPA issued a formal

11 Meeting transcripts can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter the appropriate accession number in the "Numbers: Accession Number" field. Nikiski (20151027-4006); Kaktovik (20151123-4004); Houston (20151028-4014); Barrow (20151123-4005); Trapper Creek (20151123-4002); Nuiqsut (20151123-4006); Coldfoot (20151202-4002); Healy (20151204-4007); Tyonek (20151202-4003); Nenana (20151204-4006); Anchorage (20151119-4012); and Fairbanks (20151202-4001).

12 An intervenor is an official party to the proceeding with certain rights. Intervenors have the right to participate in hearings before FERC's administrative law judges, file briefs, file for rehearing of Commission decisions, have legal standing in a Court of Appeals if they challenge the Commission's final decision, and be placed on a service list to receive copies of case-related Commission documents and filings by other intervenors.

notice of availability in the Federal Register on July 8, 2019, indicating that the draft EIS was available online.

The draft EIS was mailed to 1,341 federal, state, and local government agencies; elected officials; Alaska Native tribal governments and ANCSA Corporations; local libraries and newspapers; property owners that could be affected by Project facilities; individuals requesting intervenor status in FERC's proceedings; and other interested parties (i.e., individuals and environmental and public interest groups who provided scoping comments or asked to remain on the mailing list). The distribution list for the EIS is in appendix A. The public had 90 days after the date of publication in the Federal Register to review and comment on the draft EIS either in the form of written comments and/or at public comment meetings held in the Project area. The comment period closed on October 3, 2019.

The dates and locations of the public comment meetings were provided in a separate notice on July 26, 2019. Public comment meetings were held on September 9, 2019, in Utqiagvik and Trapper Creek, Alaska; September 10, 2019, in Nuiqsut and Houston, Alaska; September 11, 2019, in Healy and Nikiski, Alaska; and September 12, 2019, in Fairbanks and Anchorage, Alaska. The comment meetings provided interested parties with an opportunity to present oral comments on the analysis of the Project's potential environmental impacts, as described in the draft EIS. A total of 35 people commented at the meetings. In addition, 116 comment letters were received in response to the draft EIS. All environmental comments on the draft EIS have been considered during the preparation of this final EIS. A transcript of the comment meetings and copies of each written comment are part of the public record for the Project and can be viewed in appendix CC of this final EIS along with our comment responses. A subject index is provided in appendix BB.

Section 810(a) of ANILCA requires the BLM to evaluate the effects of the alternatives presented in the draft EIS on subsistence activities and hold public hearings if it finds that any alternative may significantly restrict subsistence uses. The BLM held public hearings and solicited public testimony in the potentially affected communities. The dates and locations of these public hearings were provided in the same supplemental notice issued for the draft EIS public meetings. The public hearings conducted by the BLM took place in Utqiagvik, Alaska, on September 9, 2019; Nuiqsut, Alaska, on September 10, 2019; Anaktuvuk Pass, Alaska on September 17, 209; and Kaktovik, Alaska on September 19, 2019.

The Commission's notice of availability for this final EIS has been mailed to the agencies, tribes, individuals, and organizations on the distribution list shown in appendix A. The notice of availability includes information on how the document may be viewed and downloaded from the FERC website. We are filing this final EIS with the EPA for issuance of a formal public notice of availability in the Federal Register. In accordance with the CEQ's regulations implementing NEPA, no agency decision on a proposed action may be made until 30 days after the EPA publishes a notice of availability for this EIS. However, the CEQ regulations provide an exception to this rule when an agency decision is subject to a formal internal process. In such cases, the agency decision may be made at the same time the notice of the EIS is published, allowing both periods to run concurrently. Should the Commission issue an Order authorizing the Project, it would be subject to a 30-day rehearing period. Therefore, the Commission could issue its decision concurrently with the EPA's notice.

1.3.3 Tribal Government-to-Government Consultation and Coordination

As the lead federal agency for this EIS, FERC is responsible for tribal consultation and coordination with federally recognized Indian tribes that could be affected by the Project based on geographic location, tribal resources, or tribal ownership considerations. FERC consulted with tribes in a manner that meets its own requirements (FERC, 2003) and those of the other federal permitting agencies regarding tribal consultation for the Project. FERC sent a letter initiating consultation to 38 tribes and conducted follow-up calls with these tribes. FERC, with the assistance of a BLM official, coordinated consultation meetings with nine tribes stating an interest in consultation. Section 4.13.2 describes the consultation with tribes that has occurred as part of the NHPA Section 106 process.

1.3.4 Issues Raised During Scoping and Public Comment on the Draft EIS

1.3.4.1 Issues Raised Within the Scope of this EIS

This EIS addresses substantive comments submitted to FERC or made at the open houses, scoping meetings, comment meetings on the draft EIS, and interagency meetings. Table 1.3.4-1 summarizes the environmental issues and concerns identified by commenters during the scoping and comment processes and identifies the EIS section where each issue is addressed.

FERC received numerous comments during scoping expressing concern regarding the proximity of the Project facilities to nearby residential properties in the Nikiski area and the potential chemical odor, industrial noise, and traffic residents could experience. In addition, we received comments from Nikiski landowners that expressed concern about the possibility of a decrease in residents' property values due to the proximity of the Project. Comments from the Kenai community included concerns about increased traffic and strains on housing and the public school system from a population increase due to construction workers. Additional concerns from Kenai included noise, lighting, recreational impacts, and safety. Landowners and stakeholders from the Nikiski area expressed concern around AGDC's plans to move the Kenai Spur Highway and the associated impact of this highway relocation on the community. Construction camps and increased crime rates due to construction workers were other concerns raised. Multiple comments were received in support of an alternative LNG terminal site in Valdez and at Port Mackenzie.

We received numerous comments on the Project's potential impact on surrounding wildlife; more specifically, the caribou population and its migration routes, the endangered Cook Inlet beluga whale population, and Cook Inlet fish habitat. At the Nuiqsut scoping meeting, many comments were centered on how the Project could affect local subsistence and the caribou migration on the North Slope, because caribou is the community's main food source. In addition, in multiple scoping meetings, speakers from the fishing community voiced their concerns about how the Project could affect the local fishing industry and if the Project's right-of-way could prevent beach access, particularly near Nikiski. FERC also received comments that expressed concern around the Project's potential impact on surrounding wetland ecosystems, particularly Minto Flats and Lower Susitna. These comments expressed concern that wetlands are sensitive to land disturbance during construction and cannot be restored to their original state. There were also questions around how the changes to the wetlands could cause more carbon to be released into the atmosphere, ultimately resulting in more greenhouse gases being produced.

Comments were received expressing concern about the Project's impact on existing nature reserves or parks, wilderness areas, and areas used for recreational purposes, including the DNPP, Denali State Park, and the Kenai River Special Management Area. Comments noted that the DNPP and Denali State Park are an integral part of the tourism within the region and integral to the local economy and job creation. We received various comments about the safety of the Project.

In the Village of Tyonek scoping meeting, commenters voiced concern around leak detection of the pipeline and pipeline maintenance offshore in winter under the sea ice. Commenters expressed concern about their safety due to the proximity of the Project. We also received multiple comments about how the Project could result in and further contribute to climate change effects. In regard to the Fairbanks community, commenters spoke to the air quality benefits of natural gas and requested the pipeline route be moved closer to Fairbanks to economically support a future off-take pipeline to Fairbanks.

TABLE 1.3.4-1

Environmental Issues and Concerns Raised During Public Scoping and Public Comment on the Draft Environmental Impact Statement

Issue/Concern	EIS Section Addressing Issue
General	
Purpose and need	1.1
Design and location of the pipeline	2.1.3 and 2.1.4
Project schedule	2.3.1
Construction techniques/methods	2.2
Potential in-state gas interconnections	2.1.4 and 4.19.2
Right-of-way clearing and use of right-of-way	2.1.4, 2.2.2, 4.9.1
Dredging Cook Inlet	2.1.5, 2.2.3, 4.3.3
Mitigation and monitoring plans	2.2, 2.4
Alternatives	
Valdez Alternative	3.8.1
Alternative route closer to Fairbanks	3.6.3
Route through the DNPP (former Denali Alternative)	3.6.2, 4.9.4.1
Impact on prehistoric/historic cultural resources and properties	3.6.2
Impact on the Nenana River	3.6.2, 4.3.2.5
Impact on tourism and recreational activities near the DNPP	3.6.2, 4.9.4.1, 4.11.7.2
Traffic-related impacts near the DNPP	3.6.2, 4.12.2.1
Consistency with the Denali Park Improvement Act of 2013	3.6.2
Use of existing right-of-way; Trans Alaska Pipeline System (TAPS) corridor	3.8 and 3.8.1
Investment in renewables instead of the Project	1.3.4
Need for alternative energy resources due to climate change and impact of fossil fuels	1.3.4
Port MacKenzie Alternative	3.8.1
Boulder Point Alternative	3.6
Geology	
Landslides	4.1.3
Gravel extraction and quantity	4.1.2
Seismic risks	4.1.3
Soils	
Erosion and sediment control	4.2.4 and 4.2.5
Impacts on permafrost	4.2.2, 4.2.4, 4.2.5
Soil contamination	4.2.6
Water Quality and Aquatic Resources	
Construction impacts on groundwater	4.3.1
Impacts on streams	4.3.2
Impact of construction timing relative to tides	4.3.3
Construction methods across the shorelines and Cook Inlet	4.3.3
Temperature impacts on water resources	4.3.2 and 4.3.3
Impacts on EFH	4.7.4
Impingement and entrainment of aquatic species during water withdrawals	4.7.1, 4.7.2, 4.7.3, 4.7.4
Maintaining fish passage	4.3.3, 4.7.1, 4.7.4
Ballast water impacts and management	4.7.3 and 4.7.4

TABLE 1.3.4-1 (cont'd)	
Environmental Issues and Concerns Raised During Public Scoping	
Issue/Concern	EIS Section Addressing Issue
Water sources for the Liquefaction Facilities	4.3.4
Expansion of the City of Kenai Water System	4.19
Wetlands	
Impacts on wetlands, particularly Minto Flats and Lower Susitna	4.4.2 and 4.4.3
Permanent placement of granular fill	4.4.2 and 4.4.3
Vegetation	
Impacts on wildlands/forests	4.5.2 and 4.5.3
Invasive species control	4.5.5 and 4.5.8
Wildlife	
Impacts on fish and wildlife habitat	4.6 and 4.7
Effects of dredging on marine species	4.6.3 and 4.8
Impacts on endangered marine wildlife	4.6.3 and 4.8
Marine mammal protection and more specifically impacts on the beluga whale population	4.6.3 and 4.8
Vessel impacts on marine wildlife	4.6.3 and 4.8
Special Status Species	
Potential for impacts on federally listed or proposed threatened or endangered species on their critical habitat, including, but not limited to, the polar bear, beluga whale, northern right whale, and ringed seal	4.8
Land Use and Visual Resources	
Impacts on residential property near the pipeline route	4.9.1
Impacts on recreation and tourism to local communities and natural areas, including Denali State Park and the DNPP	4.9.4 and 4.11.7
Impact of facilities on recreation and the environment	4.9.4
Access limitations to Cook Inlet beach	4.9.4
Impacts on sensitive viewers within the DNPP	3.6.2 and 4.10.2
Impacts of light pollution from facilities	4.10.2
Socioeconomics	
Impacts on communities during and after construction	4.11
Effects on human health	4.17
Impacts on local employment	4.11.2
Impacts on property values/resale ability	4.11.5
Compensation to landowners	4.9.2
Ability of local law enforcement and emergency response services during construction and operation	4.11.6
Impacts of construction camps and personnel on local communities	4.11
Fate of facilities after their intended lifetime	1.7
Job creation	4.11.2
Transportation	
Impacts of new and existing roads	4.12.2.1, all applicable resource sections
Impacts from increased traffic during construction	4.12.2
Impacts of vessel traffic through Cook Inlet	4.12.2
Impacts of increased personnel on local airports	4.12.2
Relocation of Kenai Spur Highway	4.19.2

TABLE 1.3.4-1 (cont'd) **Environmental Issues and Concerns Raised During Public Scoping**	
Issue/Concern	EIS Section Addressing Issue
Cultural Resources	
Impacts on archaeological sites, particularly around the DNPP	3.6.2 and 4.13.5
Subsistence	
Impacts on subsistence hunting/gathering	4.14
Impacts on local hunting on the North Slope, caribou hunting	4.14
Air Quality	
Potential pollution generated by facilities and vessels	4.15.4 and 4.15.5
Effect of air emissions on the environment	4.15.4 and 4.15.5
Noise	
Noise effects of the planned facilities and construction on residents and wildlife	4.6, 4.7, 4.16.3, 4.16.4
Reliability and Safety	
Safety and integrity of the pipeline and related facilities	4.18.10
Effect of seismic activity on pipeline safety	4.1.3 and 4.18.10
Onshore and offshore leak detection and repair, maintenance	4.18.5
Potential for facilities to become terrorist targets	4.18.3.2 and 4.18.10
Cumulative Impacts	
Impacts of greenhouse gases	4.15.4, 4.15.5, 4.19.4
Impact on the climate and related effects	4.15.5, 4.19.4

Commenters asked for clarification between the Alaska LNG Project and the Alaska Stand Alone Pipeline (ASAP) Project. The Alaska Legislature intended ASAP to address in-state gas needs as the primary project objective (Alaska Statute [AS] 31.25.005). The COE was the lead federal agency for the ASAP Project EIS and issued the Final Supplemental EIS on June 22, 2018. On March 4, 2019, the COE and BLM issued a Joint ROD for the ASAP Project**.** Under the ASAP Project, AGDC proposed to construct a 733-mile-long, 36-inch-diameter natural gas pipeline from the North Slope to an existing natural gas distribution system (ENSTAR Natural Gas Company), which serves the south-central region of the state. The ASAP Project does not involve the export of natural gas outside of Alaska. The objectives and regulatory frameworks of the ASAP and Alaska LNG Projects are different, and the projects are therefore evaluated separately. However, given the ability of both projects to deliver natural gas from the North Slope to south-central Alaska, AGDC has stated that the ASAP Project would not be required if the Alaska LNG Project proceeds.

During the comment period on the draft EIS that closed on October 3, 2019, comments on the public review process frequently requested an extension of the comment period, referencing the other EISs concurrently under review in the area and concerns that the document was too long to review in the timeframe given. Other comments requested that additional meetings be held in areas where reroutes had occurred. Residents of Boulder Point expressed concern about the proposed route and asked for additional information on the Cook Inlet West Alternative. Several comments were also received regarding other alternatives (e.g., the Fairbanks Alternative, Port Valdez Alternative, and Port MacKenzie Alternative), information that was missing in the draft EIS, and resource-specific issues throughout the EIS. Responses to these comments are provided in appendix CC.

1.3.4.2 Issues Raised Outside the Scope of this EIS

During the comment processes, some citizens and organizations raised issues that are considered outside the scope of this EIS. Those issues will not be addressed in this EIS because they do not meet the Project purpose and need or we do not consider them to be environmental in nature. Examples of out-of-scope issues include the need to export LNG and the use of alternative energy resources in place of fossil fuels.

The decision regarding the public interest related to exporting LNG from the United States to foreign nations rests with the DOE and is therefore outside FERC's jurisdiction. The Commission explained the background behind the different authorities that the U.S. Congress has assigned to FERC in comparison with the DOE in its *Order Granting Section 3 Authorization* to Sabine Pass Liquefaction, LLC, issued on April 6, 2012 in Docket No. CP11-72-000.[13] While the Commission has the authority to site and approve or disapprove the construction and operation of onshore LNG terminals, the DOE retains the ability to approve or disapprove the import or export of the commodity itself (see section 1.2.9).

The Commission received numerous comments urging that alternative energy sources be explored, which could eliminate the need for the Project. The generation of electricity from renewable energy sources is not a viable alternative for the Project as it does not meet the Project's purpose and need (see section 1.1).

1.4 TRADITIONAL KNOWLEDGE

Traditional knowledge incorporates knowledge of ecosystem relationships and a code of ethics governing appropriate use of the environment. This code includes rules and conventions promoting desirable ecosystem relations, human-animal interactions, and even social relationships, since the latter continues to be established and reaffirmed through hunting and other activities on the land. Traditional knowledge articulates with non-traditional knowledge to form a rich and distinctive understanding of life and the world (Alaska Native Science Commission, 2018). The Director General of the United Nations Educational, Scientific and Cultural Organization (Sreedharan, 2010) defines traditional knowledge as follows:

> *The indigenous people of the world possess an immense knowledge of their environments, based on centuries of living close to nature. Living in and from the richness and variety of complex ecosystems, they have an understanding of the properties of plants and animals, the functioning of ecosystems and the techniques for using and managing them that is particular and often detailed. In rural communities in developing countries, locally occurring species are relied on for many - sometimes all - foods, medicines, fuel, building materials and other products. Equally, people's knowledge and perceptions of the environment, and their relationships with it, are often important elements of cultural identity.*

As included in this EIS, traditional knowledge is information concerning the characteristics of Alaskan natural resources including vegetation, wildlife, and subsistence; and about use or management practices that are passed down from generation to generation and contribute to the cultural, social, and spiritual identity of Alaska Native communities. Traditional knowledge is accrued through observation and experience and shared among members of a cultural group over time, often through oral traditions. Traditional knowledge is valued in many Alaskan communities and can inform resource management actions and decisions. The depth of traditional knowledge comes from inhabiting a location for a long

[13] 139 FERC ¶ 61,039 (2012), III, pages 9–12.

time. It includes detailed knowledge of animals, plants, and the use of appropriate technologies for hunting, trapping, and fishing (Inglis, 1993) that is integrated into a system of practices and beliefs.

The traditional knowledge described in this EIS was collected through community workshop interviews, questionnaires, and a review of ethnographic research. Traditional knowledge workshops were conducted for 17 communities within five regions, including the North Slope, the Yukon River, the Tanana River, south-central Alaska, and the Kenai Peninsula. Of the 17 communities, AGDC conducted workshops for nine study communities and incorporated data from eight study communities that participated in traditional knowledge workshops for the Alaska Pipeline Project in 2012. Interviews were conducted where: 1) at least 50 percent of the community is Alaska Native; 2) a federally recognized tribe is affiliated with the community; 3) the community is within 30 miles of the pipeline corridor; and 4) the community is more than 30 miles from the pipeline corridor, but with subsistence use areas that overlap the pipeline corridor. A total of 305 participants were interviewed at 140 traditional knowledge workshops between 2014 and 2016. In addition to the traditional knowledge data collected in 2012 as part of the Alaska Pipeline Project, data collected in 2013 as part of the Susitna-Watana Hydroelectric Project was also included in this analysis.

Each community's traditional knowledge covers a broad range of topics relevant to the natural and social environments. Information about the natural environment that was acquired during the interviews includes traditional knowledge regarding the ocean and coastal areas (North Slope and Kenai Peninsula regions only); watersheds; soils, permafrost and erosion; storms, winds, and climate; ice and snow; air quality; geologic activity; vegetation; and wildlife and wildlife habitat. Traditional knowledge about culturally important places, subsistence, noise, viewscapes, and social and economic topics was also provided. Other comments collected related to the identification of potential impacts or benefits of the Project, and suggestions for how Project benefits could be maximized or how potential impacts could be lessened. Table 1.4-1 summarizes the environmental issues and concerns identified by participants of the traditional knowledge workshops and identifies the EIS section where each issue is addressed.

Traditional knowledge is used in this EIS to supplement the affected environment descriptions and to inform resource impact analyses and conclusions. Where traditional knowledge is available, this information is included and considered, as appropriate, in the analyses.

The EIS focused on using traditional knowledge that was applicable to the nature of development of the Project and relevant to impacts and mitigation associated with the Project or that contained information about the environment in and around the Project. Much of the information collected in the traditional knowledge workshops aligns with issues and topics typically discussed in an EIS. Therefore, these items are not specifically called out as topics or issues identified through the workshops themselves. However, in some instances, specific information was provided in the workshops that was not readily available from public data sources. These issues and others are identified in table 1.4-1, and specific discussions of the topics from the workshops can be found in the referenced EIS section.

TABLE 1.4-1

Environmental Issues and Concerns Raised During Traditional Knowledge Workshops

Issue/Concern	EIS Section Addressing Issue
Geology	
Earthquakes	4.1.3
Volcanoes	4.1.3
Paleontological resources	4.1.6
Soils	
Impacts on and observed changes to permafrost	4.2.2, 4.2.4, 4.2.5
Erosion	4.2.2, 4.2.4, 4.2.5
Water Resources	
Observations and changes to sea ice, currents, and tides	4.3.3
Marine water quality	4.3.3
Ocean depth	4.3.3
Sea ice	4.3.3
Changes in waterbody levels impacting the ability to access subsistence areas Increased siltation and erosion and water clarity	4.3.2
Rivers drying up, over-run with vegetation, or blocked by logjams in the Minto Flats State Game Refuge	4.3.2
Access to fresh drinking water	4.3.2
Water contamination	4.3.2
Observations and changes to flooding	4.3.2
Wetlands	
Changes observed in wetland areas including the drying and sinking of wetlands	4.4.1
Extent of wetlands in the region	4.4.1
Human impacts on wetlands including off-road vehicle impacts	4.4.1
Importance of wetland areas as wildlife habitat	4.4.1
Changes in Climate	
Temperature increases	4.19.4
Storm and weather changes	4.19.4
Changes in ice and snow levels	4.19.4
Vegetation	
Impacts of ice roads on vegetation, including salt use	4.5.2
Impacts of smog on grass	4.5.2
Impacts of spruce beetle on trees in the region	4.5.2
Decline in pollinators, including bee populations	4.5.6
Subsistence resources and observed changes in vegetation from climate change, including berry harvest	4.5.8 and 4.14
Invasive species, including dandelions and white sweetclover, and effects on native willows due to bank stabilization	4.5.8
Spread of invasive species by people's shoes, vehicle tires, hay, horseback riders, dog mushing, and seed mixes for roadways	4.5.8

TABLE 1.4-1 (cont'd)

Environmental Issues and Concerns Raised During Traditional Knowledge Workshops

Issue/Concern	EIS Section Addressing Issue
Wildlife	
Health and abundance of animal populations including migration routes and habitat:	
Moose	4.6.1
Caribou	4.6.1
Bear	4.6.1
Dall sheep	4.6.1
Wolf	4.6.1
Wolverine	4.6.1
Small land mammals	4.6.1
Importance of waterfowl for subsistence	4.6.2, 4.14
Sei whale population increases in Cook Inlet	4.8.1
Fisheries and Marine Mammals	
Health and abundance of salmon populations	4.7.1
Changes in salmon migration patterns	4.7.1
Decreases in marine benthic invertebrates	4.7.2
Cook Inlet water temperature	4.7.3
Health and abundance of aquatic mammal populations including migration routes and habitat:	
Whale species	4.6.3
Seals	4.6.3
Sea otters and sea lions	4.6.3
Porpoises	4.6.3
Boat traffic and impacts on marine mammals, including noise	4.6.3
Habitat, population levels, and health of marine invertebrates	4.7.2, 4.7.3
Land Use and Visual Resources	
Impacts of past oil and gas development on the land	4.19
The importance of landscape and views as landmarks for travel and navigation	4.10.2
Socioeconomics and Health Impact Assessment	
Impacts on communities during and after construction	4.11, 4.17
Increased cost of living during construction	4.11.5
Effects on human health including mental health	4.17
Job creation and lack of local hiring	4.11.2
Lack of equal employment opportunities for pipeline jobs	4.11.2
Interest in training to qualify for construction jobs	4.11.2
Social problems including increases in drug and alcohol use	4.17
Boat traffic impacts on fishing	4.11.3
Increases in population and lack of housing available for local population	4.11.1, 4.11.5
Transportation	
Impacts of ice roads on the environment	All applicable resource sections

TABLE 1.4-1 (cont'd) **Environmental Issues and Concerns Raised During Traditional Knowledge Workshops**	
Issue/Concern	EIS Section Addressing Issue
Increases in traffic	4.12.2
Cultural Resources	
Historic trails in Project area	4.13.1
Cultural sites in Project area	4.13.1
Air Quality and Noise	
Air pollution generated by facilities, traffic, and vessels in Project area	4.15.4, 4.15.5
Changes in air quality from wildfires	4.15.2
Fugitive dust from roads and facilities	4.15.4
Impact of noise pollution on wildlife including marine mammals	4.16, 4.6.1, 4.6.2, 4.6.3
Noise pollution from facilities, traffic, and vessels in Project area	4.16.3 and 4.16.4
Effect of air emissions on human health and the environment	4.15 and 4.17

1.5 NON-JURISDICTIONAL FACILITIES

FERC is required to consider all factors bearing on the public interest as part of its decision to authorize natural gas export facilities. Occasionally, projects reviewed by FERC have associated facilities that do not fall under the jurisdiction of the Commission. These "non-jurisdictional" facilities may be integral to the project need (e.g., a power plant to be built at the end of a FERC-jurisdictional pipeline); or they may be associated as minor components that would be built as a result of the jurisdictional facilities (e.g., an electric distribution line providing service to a natural gas compressor station).

Non-jurisdictional facilities related to the Project would be constructed, owned, and operated by other companies that are not subject to FERC jurisdiction under the NGA. These other facilities include:

- modifications/new facilities at the PTU;
- modifications/new facilities at the PBU;
- relocation of the Kenai Spur Highway;
- upgrades to the City of Kenai water system;
- in-state gas interconnections; and
- LNG carrier transits to and from the Liquefaction Facilities during operation of the Project.

We discuss these facilities and activities in our cumulative impacts analysis in section 4.19.

1.6 PERMITS, APPROVALS, CONSULTATIONS, AND REGULATORY REQUIREMENTS

In addition to NEPA, FERC and other agencies are required to comply with the requirements of other federal laws that involve consideration of the Project's potential impact on a range of environmental resources. This includes compliance with Section 7 of the ESA, Section 106 of the NHPA, the MBTA, MSA, BGEPA, MMPA, RHA, CWA, SDWA, CAA, FLPMA, MPRSA, Wild and Scenic Rivers Act of 1968 (WSRA), MLA, NTSA, and ANILCA. Each of these statutes has been taken into account in the preparation of this EIS. Other federal agencies must be consulted and/or would issue permits or approvals based on these federal environmental laws before the Project could be constructed. For example, in order to comply with Section 106 of the NHPA, FERC must afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment on the undertaking.

In accordance with Section 313(d) of the Energy Policy Act of 2005 (EPAct), FERC is required to keep a complete consolidated record of all actions or decisions made by agencies undertaking federal authorizations on FERC-regulated projects. On October 19, 2006, in Order No. 687, FERC issued implementing regulations regarding the maintenance of a consolidated record. Section 313(c) of the EPAct requires that FERC establish a schedule for federal authorizations. Pursuant to Order No. 687, FERC issued an initial *Notice of Schedule for Environmental Review of the Alaska LNG Project* on March 12, 2018. On August 31, 2018, FERC issued a *Notice of Revised Schedule for Environmental Review of the Alaska LNG Project* and a *Notice of Anticipated Schedule of Final Order for the Alaska LNG Project*.

While the EPAct amended the NGA to give exclusive authority to FERC to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal, it specified that nothing in the Act was intended to overrule other federal authorities. This includes the protection of the rights of states with federally delegated responsibilities under the CAA and CWA.

Table 1.6-1 lists the major federal, state, and local permits, approvals, and consultations for Project construction and operation. AGDC would be responsible for obtaining all permits and approvals required to construct and operate the Project, regardless of whether they appear in this table. FERC encourages cooperation between applicants and state and local authorities; however, state and local agencies, through the application of state and local laws, may not prohibit or unreasonably delay the construction or operation of facilities approved by FERC. Any state or local permits issued with respect to jurisdictional facilities must be consistent with the conditions of any authorization issued by FERC. Although there may be differences between FERC's and other agencies' permits and conditions, the Project's environmental inspection program would address all environmental or construction-related conditions or other permit requirements placed on the Project.

While the EOs provided in table 1.6-2 do not apply to the Commission as an independent federal agency, they may apply to cooperating agencies that rely on the information provided in this EIS for decision making.

1.6.1 Endangered Species Act

The ESA (16 USC 1531 et seq.) establishes a national policy for conserving threatened and endangered species of fish, wildlife, and plants, and the habitat they depend on. Section 7(a)(2) of the ESA requires federal agencies to ensure that their actions are not likely to jeopardize the continued existence of endangered or threatened species or adversely modify or destroy their designated critical habitat. The USFWS and NMFS jointly administer the ESA and are responsible for listing a species as threatened or endangered, designating critical habitat, developing and implementing protective regulations and recovery plans, and undertaking several other management and conservation efforts pursuant to the ESA. Other management and conservation efforts include monitoring and evaluating the status of listed species, candidate species or species proposed for listing, and recently delisted species, and consulting on federal actions that may affect a listed species or designated critical habitat.

TABLE 1.6-1

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
Federal			
FERC	Order Granting Authorization to Construct, Operate or Modify Facilities Used for the Export or Import of Natural Gas under Section 3 of the NGA	Approves or denies authorization to construct, operate, or modify facilities used for the export or import of natural gas.	Application submitted on 4/18/2017
DOE	Section 3(c) of the NGA 15 USC 717b 18 CFR 153, 157, 375, and 385	Authority to export LNG to FTA nations.	Approved. DOE/FE Order No. 3554 issued 11/21/2014
	Section 3(a) of the NGA 15 USC 717b 18 CFR 153, 157, 375, and 385	Authority to export LNG to non-FTA nations.	Conditionally approved. DOE/FE Order No. 3643 issued 5/28/2015
COE	DA permit under Section 404 of the CWA and Section 10 of the RHA	Approves or denies a permit for discharges of dredged or fill material into waters of the United States and for structures or work in or affecting navigable waters of the United States.	Original application submitted on 04/18/2017 Complete application submitted 12/11/2019. Public Notice issued 12/30/2019
Coast Guard	LOR	Reviews the Liquefaction Facilities and marine transportation component and the suitability of the waterway for LNG carriers.	LOR issued 8/17/2016
	Operations Manual and Emergency Manual required by Section 33 of the CFR	Requires approval by the local Captain of the Port prior to the transfer of LNG.	Pending
	Facility Security Plan required by Section 33 of the CFR	Requires approval by the local Captain of the Port prior to the transfer of LNG.	Pending
	Bridge Permit or Administrative Action under the General Bridge Act of 1946 and other applicable statutes.	Approves or denies permits for the construction of new bridges (temporary or permanent) or causeways or for the reconstruction of existing bridges or causeways across the navigable waters of the United States. Administrative action for modifications to existing bridges that do not change the general configuration or navigational opening.	Six applications submitted as of 4/30/2019
USFWS	Consultation under Section 7 of the ESA	Considers FERC's finding of impact on federally listed and proposed threatened and endangered species and their critical habitat, and provides a Biological Opinion if the action is likely to adversely affect federally listed or proposed species or their critical habitat.	Ongoing
	Consultation under Sections 101(a)(5)(A) and (D) of the MMPA	Approves or denies authorization for incidental, but not intentional, take of marine mammals (including polar bears and sea otters).	Ongoing

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
	Coordination under the MBTA and Section 3 of EO 13186	Assesses impacts and develops avoidance and minimization measures, in coordination with FERC, to limit adverse impacts on migratory birds.	Ongoing
	Coordination under the Bald and Golden Eagle Take Permit pursuant to BGEPA	Assesses impacts and develops avoidance and minimization measures, in coordination with FERC, to limit adverse impacts on eagles.	Ongoing
	Fish and Wildlife Coordination Act	Coordinates regarding the protection of fish and wildlife.	Ongoing
NMFS	Consultation under Section 7 of the ESA	Considers FERC's finding of impact on federally listed and proposed threatened and endangered marine species and their critical habitat.	Ongoing
	Consultation under Sections 101(a)(5)(A) and (D) of the MMPA	Approves or denies authorization for incidental, but not intentional, take of marine mammals.	Ongoing
	Consultation under MSA	Assesses impacts and provides comments to prevent loss of and damage to EFH.	Completed 9/23/2019
	Fish and Wildlife Coordination Act	Coordinates regarding the protection of fish and wildlife.	Ongoing
EPA	CWA, Section 404	Evaluates CWA 404 permit applications for compliance with Section 404(b)(1) guidelines and other statutes and authorities within their jurisdiction.	Ongoing
	CWA Section 401	Considers issuing a Section 401 certification for the COE's CWA Section 404 permit and FERC's Order within the DNPP.	Pending
	CWA, Section 402	Issues NPDES permits authorizing point source discharges of pollutants to waters of the United States within the DNPP. Administers the VGP. Oversees the state APDES permitting program. ADEC assumed authority to administer the wastewater permitting program for discharges to state waters on November 1, 2012, for areas outside the DNPP.	Pending; anticipated submittal 2nd quarter 2020
	CWA, Section 311	Provides a Federal On-Scene Coordinator responsible for direction and monitoring of spills. EPA requires owners/operators to prepare and implement Spill Prevention, Control, and Countermeasure (SPCC) Plans and Facility Response Plans for facilities that store more than 1,320 gallons in aggregate in aboveground tanks with capacity of 55 gallons or more.	Pending
	SDWA, UIC Program under 40 CFR 144	Administers the UIC Program in Alaska for Class I, III, IV, and V wells. There are no Class III or IV wells in Alaska. Class II wells are administered by the Alaska Oil and Gas Conservation Commission (AOGCC).	Pending; anticipated submittal 3rd quarter 2020.

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
	CAA , 42 USC 7401 et seq.	Enforces the provisions of the CAA through Alaska's EPA-approved programs. These include Title V air operating permits and its EPA-approved SIP.	Ongoing
ACHP	Consultation under Section 106 of the NHPA	Provides comments if the Project would affect historic properties.	Ongoing
NPS	Consultation under Section 106 of the NHPA	Provides comments if the Project would affect the Gallagher Flint Station National Historic Landmark and the DNPP.	Ongoing
	Right-of-Way Permit	Considers issuing a right-of-way permit that allows a utility to pass through NPS property.	Application submitted on 10/1/2019
DOT, PHMSA	Special Permits	Considers granting Special Permits for any action that varies from what existing PHMSA regulations allow.	Four Special Permits for the Mainline Pipeline issued on 9/9/2019; application filed on 9/8/2017 for Liquefaction Facilities
	LOD	Determines if the LNG facilities would be capable of complying with location criteria and design standards contained in 49 CFR 193, Subpart B.	Issued 2/4/2020
	Response Plans, Safety, and Operations Documentation	Determines if the pipeline design must conform to the Pipeline Safety Regulations and Safety Statutes established by law and enforced by PHMSA.	Pending
BLM	Purchase of a Mineral Material/Mineral Sales Contract under the Mineral Materials Act, 43 CFR Part 3600	Considers authorizing permit for use of a specific piece of public land for a project and authorizing rights and privileges for a specific use of the land for a specific period of time. The sale of timber is subject to 43 CFR 5402 and will be included in the BLM's ROD and Right-of-Way Grant Terms & Conditions.	Pending
	Right-of-Way Grant; MLA, 30 USC 185 and 43 CFR 2880	Considers grants and temporary use permits for pipelines to transport oil or gas.	Application submitted on 04/17/2017
	Purchase of a Mineral Material/Mineral Sales Contract under the Mineral Management Act	Issues required contracts for material sites on federal land. Removal of rock, crushed rock, or gravel will include a cost per cubic yard fee.	Pending; anticipated submittal 1st quarter 2020
	ANILCA, Title VIII: Section 810 16 USC 410hh-3233; 43 USC 1602–1784; 43 CFR 36	Evaluates and provides a finding of effects of proposed development on subsistence. [c]	Ongoing
	NTSA, 16 USC 1241–1251	Coordinates protection and/or improvement of Trail System.	Ongoing

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
	Consultation under Section 106 of the NHPA	Provides comments if the Project would affect historic properties on BLM lands or the INHT.	
Department of Defense	Letter of Non-objection	Provide comments if the Project could have an impact on the testing, training, or operational activities of any active military installation.	Ongoing
Federal Aviation Administration	Notice for Construction, Alteration, and Deactivation of Airports under 14 CFR 77.13	Issues notices for structures interfering with flight paths during reactivation or construction.	Pending; anticipated submittal 1st quarter 2020
Federal Communications Commission	Radio and Wire Communications Permits and Licenses	Approves or denies a permit for Project activities requiring radio and wire communication and frequencies.	Pending; anticipated submittal in 4th quarter 2020
State			
Alaska Department of Natural Resources (ADNR), Division of Mining, Land and Water	Permit to Appropriate Water, Water Right Certificate of Appropriation under the Alaska Water Use Act	Considers granting a permit for constructing works for an appropriation, or diverting, impounding, withdrawing, or using a significant amount of water from any source (the term significant amount of water is defined in 11 Alaska Administrative Code [AAC] 93.035).	Pending; anticipated submittal 1st quarter 2020
	Temporary Water Use Authorization for Non-permanent Water Use under the Alaska Water Use Act	Considers granting permit for short-term use water withdraws such as for camps, construction, maintenance, and operational activities as well as for gravel mine dewatering.	Pending; anticipated submittal 2nd quarter 2020
	Material Sales Contract and Material Site Reclamation Plans	Considers authorizing purchase of gravel from state lands as a negotiated sale and associated reclamation plans.	Pending; anticipated submittal 2nd quarter 2020
	Temporary Land Use Permit (Uplands and Non-marine Waters, Off Road Travel aka Tundra Travel, and Tidal and Submerged Lands)	Approves or denies permits for temporary activities occurring on state lands, including activities in non-marine waters, uplands, off-road (tundra) travel, and tidal and submerged lands.	Pending; anticipated submittal 2nd quarter 2020
	Recreation Rivers Special Use Permit under the Recreational Rivers Act	Approves or denies a permit for non-recreation activities within the Recreation Rivers Management Area (Deshka River, Alexander Creek, and Yentna).	Pending; anticipated submittal 2nd quarter 2020
	Easements	Approves or denies easements on state lands.	Pending
ADNR, Office of History and Archaeology and State Historic Preservation Office	Cultural, Historical, and Archeological Resources Consultation (Section 106 Review) under the NHPA and Alaska Historic Preservation Act	Approves or denies a cultural clearance for all state permits.	Pending
ADNR, Division of Oil and Gas, State Pipeline Coordinator's Section	Right-of-Way Lease under the Alaska Right-of-Way Leasing Act	Considers leasing state owned or managed lands for transportation pipeline system right-of-way purposes.	Application submitted on 11/15/2019

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
	North Slope Area Special Use Lands (Alaska Division of Lands number [ADL] 50666)	In addition to permitting requirements under 11 AAC 96.010, considers issuance of a permit for motorized vehicle use. The requirement for a permit or authorization would be fulfilled through the issuance of a right-of-way lease.	Application submitted on 11/15/2019
	Dalton Highway Corridor Management Area (AS 19.40.210)	Reviews for compliance with AS 19.40.210, which prohibits off-road vehicles on land within the highway corridor with an exception for off-road vehicles necessary for oil and gas transportation.	Application submitted on 11/15/2019
	Reclamation Plan (AS 27.19.030-040)	Reviews and approves any material site reclamation plan on or off state land except as provided in AS 27.19.050.	Pending
ADNR, Division of Forestry	Open Burning Permit	Approves or denies a permit for the open burning of material (such as slash trees, shrubs, or other organic material or waste materials) on site.	Pending; anticipated submittal 2nd quarter 2020
ADNR, Division of Parks and Recreation	Park Use Permit	Approves or denies a permit for all development activities on State Park Lands and Recreation Areas.	Pending; anticipated submittal 2nd quarter 2020
	Right-of-Way Lease	Considers leasing state owned or managed park and recreation lands for pipeline right-of-way.	Pending; anticipates submittal 2nd quarter 2020.
ADEC, Division of Water Quality	Section 401 Water Quality Certification – Certificate of Reasonable Assurance under CWA Section 401	Considers issuing a Section 401 certification for the COE's CWA Section 404 permit for areas outside the DNPP.	Original application submitted to the COE on 4/18/2017 Complete application submitted to the COE on 12/11/2019 COE Public Notice issued 12/30/2019
	APDES Permit under Section 402 of the CWA	Authorizes discharge of pollutants to state waters under an APDES permit.	Pending; anticipated submittal 2nd quarter 2020
	APDES and Wastewater Disposal Authorization General Permit, AKG320000 – Statewide Oil and Gas Pipeline under Section 402 of the CWA	Approves or denies a Notice of Intent requesting coverage for the Project under the General Permit for inadvertent releases of drilling fluids, domestic wastewater, gravel pit dewatering, excavation dewatering, hydrostatic test water, mobile spill response, and construction/operation stormwater.	Pending; anticipated submittal 2nd quarter 2020
	Domestic and Non-domestic Wastewater Disposal System Plan Review under Section 402 of the CWA (Construction)	Reviews plans to ensure compliance with minimum standards of performance. Permanent operations camps would likely have wastewater treatment systems requiring approval.	Pending; anticipated submittal 1st quarter 2020

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
	UIC Waste Water Disposal	Approves or denies a permit for the disposal of domestic or non-domestic wastewater.	Pending; anticipated submittal 3rd quarter 2020
ADEC, Division of Air Quality	Title V Air Permit under 18 Alaska Administrative Code 50.326	Approves or denies an operations permit for sources that either emit over 100 tons per year of any criteria air pollutant or are subject to certain New Source Performance Standards or and National Emission Standards for Hazardous Air Pollutants subparts obtain an operating permit.	Pending; anticipated submittal 3rd quarter 2023 (GTP); 4th quarter 2023 (Mainline Pipeline stations); 1st quarter 2024 (Liquefaction Facilities)
	Prevention of Significant Deterioration (PSD) Construction Permit for Permanent Facilities	Considers granting a permit for emissions categorized as major for the GTP and Liquefaction Facilities.	Applications submitted on 12/29/17 (GTP) and 05/1/18 (Liquefaction Facilities)
	Minor Construction Permit for Permanent Facilities	Considers granting a permit for emissions categorized as minor for permanent facilities such as compressor stations.	Pending; anticipated submittal 1st quarter 2022 (Mainline Pipeline
	Minor Construction Permit for Temporary Facilities	Considers granting a permit for emissions categorized as minor for temporary facilities such as rock crushers and certain emission generating sources at camps.	Pending; anticipated submittal 3rd and 4th quarter 2020 (GTP); 4th quarter 2020 and 1st quarter 2021 (Mainline Pipeline); 3rd and 4th quarter 2020 (Liquefaction Facilities); 3rd quarter 2020 (PTTL)
	Open Burning Permit	Approves or denies permits for the open burning of material (such as slash trees, shrubs, or other organic material or waste materials) on site.	Pending; anticipated submittal 1st quarter 2021
ADEC, Division of Environmental Health	Approval to Construct and Operate a Public Water Supply System	Approves construction and operation of water treatment systems.	Pending; anticipated submittal 2nd quarter 2020
	Food Service Permit	Approves or denies a permit to allow serving food at permanent construction camps or facilities.	Pending; anticipated submittal 2nd quarter 2020
ADEC, Division of Spill Prevention and Response	Oil Discharge Prevention and Contingency Plan	Approves plans that define how state lands and water would be protected from spill incidents.	Pending; anticipated submittal 2nd quarter 2020
	Contaminated Sites Program	Reviews construction plans and schedules and develops requirements to minimize disruption to institutional control measures at regulated contaminated sites in the Project footprint.	Pending
Alaska Department of Fish and Game (ADF&G)	Title 16 Fish Habitat Permit under the Alaska Fishway Act and Anadromous Fish Act	Approves or denies a permit for all activities within the limits of ordinary high water of any streams with fish presence to prevent adverse effects on anadromous fish or their habitat and prevent the obstruction of efficient passage and movement of fish.	Pending; anticipated submittal 3rd quarter 2020

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
ADF&G, Division of Habitat	Special Area Permit	Approves or denies permits for any field activities that may occur on state critical habitat areas or game refuges.	Pending; anticipated submittal 3rd quarter 2020
	Public Safety Permit	Approves or denies permits to allow a person to kill, destroy, re-locate, or haze wild animals that are creating a nuisance or a threat to public safety.	Pending; anticipated submittal 3rd quarter 2020
Alaska Department of Transportation and Public Facilities (ADOT&PF), Division of Measurement Standards & Commercial Vehicle Enforcement	Oversize and Overweight Permit	Approves or denies permits for transport of oversize/overweight construction materials on ADOT&PF owned roads.	Pending; anticipated submittal 3rd quarter 2020
ADOT&PF	Driveway/Approach Road Permit	Approves or denies permits for construction-access roads that intersect state highways.	Pending; anticipated submittal 3rd quarter 2020.
	Lane Closure Permit	Approves or denies permits for Project activities that require the use of a highway right-of-way for access to or construction and maintenance of a utility facility.	Pending; anticipated submittal 3rd quarter 2020
	Utility Permits Right-of-Way	Approves or denies permits for locations where the pipeline occupies the highway right-of-way either at crossings or longitudinal along a right-of-way.	Pending; anticipated submittal 3rd quarter 2020
	Encroachment Permit	Approves or denies permits for the temporary use of the right-of-way.	Pending; anticipated submittal 3rd quarter 2020
	Special Use Permit	Approves or denies special use permits for right-of-way related activities.	Pending; anticipated submittal 3rd quarter 2020
Alaska Division of Fire and Life Safety (State Fire Marshall's Office)	Building Plan Review; Fire System Permit	Completes review and issues permit for Project facilities and potentially for some construction campsites and any permanent camps or operations centers to ensure fire systems and fuel tanks meet state standards.	Pending; anticipated submittal 3rd quarter 2020
University of Alaska	Right-of-Way Lease	Considers authorizing a lease to access University of Alaska lands.	Pending; anticipated submittal 2nd quarter 2020
Alaska Mental Health Trust Authority	Right-of-Way Lease	Considers authorizing a lease for access to Alaska Mental Health Trust Authority lands.	Pending; anticipated submittal 2nd quarter 2020
Alaska Oil and Gas Conservation Commission	Permit to Drill	Approves or denies permits to drill a well for oil or gas in Alaska.	Pending; anticipated submittal 2nd quarter 2020

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
Native Corporation and Village Corporation lands	Surface Use Permits and Leases	Approves or denies permits for any use of Alaska Native lands.	Pending; anticipated submittal 3rd quarter 2020
Local			
Kenai Peninsula Borough	Code of Ordinances Permits under Title 10 – Health and Safety, Title 21 – Zoning, and Temporary Land Use	Administers regulations created for site development, construction, operation, land use, and use of gravel or timber.	Pending; anticipated submittal 3rd quarter 2020
	Land Use Easement	Considers granting rights-of-way and easements for use of lands for more than 5 years.	Pending; anticipated submittal 3rd quarter 2020
	Right-of-Way Construction Permits under KB 14.40	Issues permits granting permission for construction and use of rights-of-way.	Pending; anticipated submittal 3rd quarter 2020
Matanuska-Susitna Borough	Code of Ordinances Permits under Title 8 – Health and Welfare, Title 11 – Encroachment Permits; Title 17 – Zoning, Title 18 – Port, Title 23 – Real Property, Title 28 – Natural Resource Utilization	Administers regulations created for construction within a flood hazard area, gravel extraction, and borough lands including indoor facilities and outdoor storage areas at Port MacKenzie.	Pending; anticipated submittal 3rd quarter 2020
Denali Borough	Title 4 Real Property Acquisition, Management, and Disposal 4.10.050 Leasing Borough Land 4.10.070 Temporary Use of Borough Lands	Administers regulations created for borrow material extraction and sales, temporary use of borough land, and lease of borough land.	Pending; anticipated submittal 3rd quarter 2020
Fairbanks North Star Borough	Construction in rights-of-way under Service Areas Title Fairbanks North Star Borough Code 14.03.050	Issues permits for excavation and construction on public roads within Road Service Areas Permit application.	Pending; anticipated submittal 3rd quarter 2020
	Temporary Land Use Permit	Approves or denies permits for development projects, environmental and engineering surveys, off-road travel, solid waste disposal, and gravel extraction on Fairbanks North Star Borough lands.	Pending; anticipated submittal 3rd quarter 2020
Fairbanks North Star Borough, Department of Community Planning	Floodplain Permit under Buildings & Construction Title 15.04.040.050; Fairbanks North Star Borough Code 21.40.010.030	Approves or denies permits for construction within a flood hazard area.	Pending; anticipated submittal 3rd quarter 2020
North Slope Borough, Permitting and Zoning Division	Administrative Approvals and Development Permits under North Slope Borough Municipal Code	Approves or denies permits and administrative approvals for any construction, operation, or studies conducted in the North Slope Borough.	Pending; anticipated submittal 3rd quarter 2020
North Slope Borough, Inupiat History, Language, and Culture Division of the Planning Department	Inupiat History, Language, and Culture Clearance under North Slope Borough Municipal Code 19.50.030(F) and 19.60.040(K)	Issues a Certificate of Clearance as a formal approval process to ensure that all sites listed in North Slope Borough's Traditional Land Use Inventory are protected.	Pending; anticipated submittal 3rd quarter 2020

TABLE 1.6-1 (cont'd)

Major Permits, Approvals, and Consultations [a, b]

Agency	Permit/Approval/Consultation	Agency Action	Status
Other			
ARRC	Blanket Permit	Approves or denies permits for any rail yard expansions at existing railroads.	Pending; anticipated submittal 2nd quarter 2020
Alyeska Pipeline Service Company, State Pipeline Coordinator's Section, BLM Authorized Officer, and Joint Pipeline Office	Letter of Non-objection [d]	Issues a letter granting permission to access lands previously leased by Alyeska Pipeline Service Company.	Pending; anticipated submittal 3rd quarter 2020
PBU and PTU	Letters of Non-objection and other use agreements	Issues a letter granted access to operator lease lands.	Pending; anticipated submittal 3rd quarter 2020
Third-Party Utility Companies	Easements/Leases	Considers granting easements and leases for use of lands.	Pending; anticipated submittal 1st quarter 2020

ARRC= Alaska Railroad Corporation

a The federally approved Alaska Coastal Management Program expired on July 1, 2011, resulting in a withdrawal from participation in the Coastal Zone Management Act's National Coastal Management Program. The Coastal Zone Management Act Federal Consistency Provision, Section 307, no longer applies in Alaska.

b Consultations with Alaska Native tribes are discussed in section 4.13.2.

c Additional regulations associated with subsistence are described in section 1.6.17.

d Any non-objection for access to the TAPS rights-of-way would be conditioned on AGDC's promise to mitigate the risks associated with the Project's proximity to TAPS.

TABLE 1.6-2 **Executive Orders**	
Permit/Approval/Consultation	Authorizations
EO 10173 – Regulations Relating to the Safeguarding of Vessels, Harbors, Ports, and Waterfront Facilities of the United States	Federal agencies must safeguard against destruction, loss, or injury from sabotage or other subversive acts, accidents, or other causes of similar nature, of vessels, harbors, ports, and waterfront facilities in the United States.
EO 11514 – Protection and Enhancement of Environmental Quality	Federal government shall provide leadership in protecting and enhancing the quality of the nation's environment to sustain and enrich human life. Federal agencies must initiate measures needed to direct their policies, plans, and programs so as to meet national environmental goals.
EO 11988 – Floodplain Management	Federal agencies must establish procedures to ensure that the potential effects of flood hazards and floodplain management are considered for actions undertaken in a floodplain. Impacts on floodplains are to be avoided to the extent practicable.
EO 11990 – Protection of Wetlands	Federal agencies must avoid short-term and long-term adverse impacts on wetlands whenever a practicable alternative exists.
EO 12898 – Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations	Federal agencies must develop environmental justice strategies to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations (including Native American tribes).
EO 12962 – Recreational Fisheries	Federal agencies must improve the quantity, function, sustainable productivity, and distribution of aquatic resources for increased recreational fishing opportunities to the extent permitted by law and where practicable.
EO 13007 – Indian Sacred Sites	Federal agencies must accommodate access to and ceremonial use of Indian sacred sites by Indian religious practitioners and avoid adversely affecting the physical integrity of such sacred sites.
EO 13045 – Protection of Children from Environmental Health and Safety Risks	Federal agencies must assess environmental health and safety risks that may disproportionately affect children and to ensure their policies, programs, activities, and standards address the disproportionate risks to children.
EO 13112 – Invasive Species	Federal agencies are to prevent the introduction of invasive species, control those that are introduced, and provide for the restoration of native species.
EO 13175 – Consultation and Coordination with Indian Tribal Government	Federal agencies must consult with Indian and Alaska Native tribal governments when considering polices that would affect tribal communities.
EO 13186 – Responsibilities of Federal Agencies to Protect Migratory Birds	Federal agencies must avoid or minimize the impacts of their actions on migratory birds and take active steps to protect birds and their habitat.
EO 13212 – Actions to Expedite Energy-Related Projects	Federal agencies must take appropriate actions, to the extent consistent with applicable law, to expedite projects that will increase the production, transmission, or conservation of energy.
EO 13783 – Promoting Energy Independence and Economic Growth	Federal agencies must review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.

The ESA generally prohibits the "take" of an ESA species listed as endangered unless an exception or exemption applies. NMFS has extended the "take" prohibition to ESA-listed threatened species under its jurisdiction through promulgation of protective rules. The term "take," as defined in Section 3 of the ESA, means to "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct." FERC is required to consult with the USFWS and NMFS (collectively referred to as the Services) to determine whether any federally listed or proposed endangered or threatened species or their designated critical habitat occur in the vicinity of the Project. If FERC determines that these species or habitats could be affected by the Project, FERC is required to prepare a Biological Assessment (BA) to identify the nature and extent of the adverse impact and recommend measures to avoid or reduce potential impacts on habitat and/or species. Section 7(b)(3) requires that at the conclusion of consultation, the consulting agency provide an opinion stating whether the federal agency's action is likely to jeopardize ESA-listed species or destroy or adversely modify designated critical habitat. A similar opinion is included for proposed species or proposed critical habitat if either or both were part of the consultation. If incidental take would be caused by the action and is reasonably certain to occur, and if certain conditions are met, Section 7(b)(4) would require the Services to provide an Incidental Take Statement (with the Biological Opinion).

To initiate formal consultation under Section 7 of the ESA, in conjunction with developing the draft EIS, we prepared a BA for the Project activities (e.g., construction, operation) that may affect listed species or critical habitat, and submitted this BA to the Services. Before initiating formal consultation and with assistance from AGDC, we engaged in early coordination with the Services to seek technical assistance and input regarding the analyses of impacts on threatened or endangered species during BA development. Details about the consultation history and the analyses of impacts on threatened or endangered species is provided in the BA (see section 4.8 for additional details) and will also be included in the final Biological Opinions prepared by the Services. At the time of final EIS completion, our Section 7 consultations with the Services remain in progress. See section 4.8 for a summary of the potential impacts on threatened and endangered species and the status of our compliance with Section 7 of the ESA.

1.6.2 National Historic Preservation Act

Section 106 of the NHPA, as amended (54 USC 3001 et seq.), requires FERC to take into account the effects of its undertakings on historic properties and afford the ACHP an opportunity to comment. The Section 106 process seeks to accommodate historic preservation concerns with the needs of federal undertakings through consultation among the agency official and other parties with an interest in the effects of the undertaking on historic properties, commencing at the early stages of project planning. The goal of consultation is to identify historic properties potentially affected by the undertaking, assess effects, and seek ways to avoid, minimize, or mitigate any adverse effects on historic properties. Historic properties include prehistoric or historic sites, districts, buildings, structures, objects, or properties of traditional religious or cultural importance that are listed in or eligible for listing in the National Register of Historic Places (NRHP). In accordance with the regulations for implementing Section 106 in 36 CFR 800.2(a)(3), FERC is using the services of AGDC and its consultants to prepare information, analyses, and recommendations. However, FERC remains responsible for all findings and determinations. FERC is complying with Section 106, as outlined in 36 CFR 800, by consulting with the Alaska State Historic Preservation Office (SHPO), the ACHP (as necessary), the BLM, the NPS, tribes, and other interested parties, as appropriate, to identify historic properties in the area of potential effects and assess potential effects on historic properties. FERC is using a Programmatic Agreement (PA) to clarify the framework that would be followed to address any potential adverse effects on historic properties where surveys are outstanding. Section 4.13 summarizes the status of FERC's compliance with the NHPA.

1.6.3 Migratory Bird Treaty Act

Migratory birds are species that nest in the United States and Canada during the summer and then migrate south to the tropical regions of Mexico, Central and South America, and the Caribbean for the non-breeding season. Migratory birds are protected under the MBTA (16 USC 703–711). Birds protected under the MBTA include all common songbirds, waterfowl, shorebirds, hawks, owls, eagles, ravens, crows, native doves and pigeons, swifts, martins, swallows, and others, including their body parts (feathers, plumes, etc.), nests, and eggs. The act makes it unlawful to pursue, hunt, take, capture, or kill; attempt to take, capture, or kill; possess, offer to or sell, barter, purchase, deliver, or cause to be shipped, exported, imported, transported, carried, or received any migratory bird, part, nest, egg, or product, manufactured or not, without a permit.

EO 13186 (66 Federal Register [FR] 3853) directs federal agencies to identify where unintentional take is likely to have a measureable negative effect on migratory bird populations and to avoid or minimize adverse impacts on migratory birds through coordination with the USFWS. EO 13186 states that emphasis should be placed on species of concern, priority habitats, and key risk factors, and that particular focus should be given to addressing population-level impacts. On March 30, 2011, the USFWS and the Commission entered into a *Memorandum of Understanding Between the Federal Energy Regulatory Commission and the U.S. Department of the Interior United States Fish and Wildlife Service Regarding Implementation of Executive Order 13186, "Responsibilities of Federal Agencies to Protect Migratory Birds"* that focuses on avoiding or minimizing adverse impacts on migratory birds and strengthening migratory bird conservation through enhanced collaboration between the two agencies. This voluntary memorandum of understanding does not waive legal requirements under the MBTA or any other statutes and does not authorize the take of migratory birds. See section 4.6.2 for the status of our compliance with the MBTA.

1.6.4 Magnuson-Stevens Fishery Conservation Management Act

The MSA was enacted to address impacts on fisheries on the U.S. continental shelf. It established U.S. fishery management over fishes within the fishery conservation zone from the seaward boundary of the coastal states out to 200 nautical miles (i.e., boundary of the U.S. Exclusive Economic Zone [EEZ]). The MSA also established regulations for foreign fishing within the fishery conservation zone and issued national standards for fishery conservation and management to be applied by regional fishery management councils. Federal agencies are required to consult with NMFS with respect to any action authorized, funded, or undertaken—or proposed to be authorized, funded, or undertaken—by such agency that may adversely affect EFH identified under the MSA. If an action is likely to adversely affect EFH, the federal agency must consult with NMFS to identify conservation measures to minimize or avoid adverse impacts. If NMFS identifies conservation measures, the action agency must determine whether it would implement them and provide a formal response if it fails to do so. We prepared an EFH assessment for submission to NMFS and completed EFH consultation on September 23, 2019. See section 4.7.4 for additional information on our compliance with the MSA.

1.6.5 Bald and Golden Eagle Protection Act

The BGEPA prohibits taking without a permit, or taking with wanton disregard any bald or golden eagle or their body parts, nests, chicks, or eggs, which includes collection, molestation, disturbance, or killing. The BGEPA protections include provisions not included in the MBTA, such as the protection of unoccupied nests and prohibition on disturbing eagles. The BGEPA includes limited exceptions to its prohibitions through a permitting process, including exceptions to take bald or golden eagle nests that interfere with resource development or recovery operations. Compliance with the BGEPA is discussed in section 4.6.2.

1.6.6 Marine Mammal Protection Act

Marine mammals—such as seals, whales, sea otters, and polar bears—are protected under the MMPA. Section 101(a) of the MMPA (16 USC 1361) prohibits persons or vessels subject to the jurisdiction of the United States from taking any marine mammal in waters or on lands of the United States or on the high seas (16 USC 1372(a)(l), (a)(2)). Sections 101(a)(5)(A) and (D) of the MMPA provide exceptions to the prohibition on take, which gives NMFS or the USFWS the authority to authorize the incidental but not intentional take of small numbers of marine mammals, provided certain findings are made and statutory and regulatory procedures are met. ITAs may be issued as either (1) regulations and the associated LOA or (2) an IHA. LOAs may be issued for up to a maximum of 5 years and IHAs may be issued for a maximum of 1 year. NMFS has regulatory authority for all marine mammals relevant to the Project with the exception of the sea otter, Pacific walrus, and the polar bear, which are under USFWS authority. AGDC is responsible for obtaining authorizations under the MMPA. Potential impacts on marine mammals are discussed in section 4.6.3.

NMFS promulgated regulations to implement the provisions of the MMPA governing the taking and importing of marine mammals (50 CFR 216) and published application instructions that prescribe the procedures necessary to apply for ITAs. U.S. citizens seeking to obtain authorization for the incidental take of marine mammals under NMFS jurisdiction[14] must comply with these regulations and application instructions in addition to the provisions of the MMPA. Like NMFS, the USFWS implements a process for ITAs. U.S. citizens seeking to obtain authorization for the incidental take of marine mammals under USFWS jurisdiction[15] must comply with USFWS implementing regulations (50 CFR 18), application procedures, and instructions, in addition to the provisions of the MMPA.

Once NMFS (or the USFWS) determines an application is adequate and complete, NMFS (or the USFWS) has a corresponding duty to determine whether and how to authorize take of marine mammals incidental to the activities described in the application. To authorize the incidental take of marine mammals, NMFS (or the USFWS) evaluates the best available scientific information to determine whether the take would have a negligible impact on the affected marine mammal species or stocks and an immitigable impact on their availability for taking for subsistence uses. NMFS (or the USFWS) must also prescribe the "means of effecting the least practicable adverse impact" on the affected species or stocks and their habitat, and on the availability of those species or stocks for subsistence uses, as well as monitoring and reporting requirements.

On April 18, 2017, NMFS received a request from AGDC for regulations and an LOA pursuant to the MMPA for the take of marine mammals incidental to constructing LNG facilities in Cook Inlet, Alaska.[16] NMFS reviews applications to determine whether to issue an authorization for the activities described in the application. On April 11, 2018, NMFS published a Notice of Receipt of AGDC's application in the Federal Register (83 FR 15556). Following the close of the public comment period for the Notice of Receipt, NMFS determined that the potential effects on marine mammals from AGDC's proposed construction activities could result in Level A harassment. Neither AGDC nor NMFS expects serious injury or mortality to result from this activity. However, since AGDC's LNG facility construction activities are expected to last for 5 years, an LOA is appropriate. Therefore, NMFS published a proposed rule for consideration of whether to issue regulations and an LOA to AGDC on June 28, 2019 (84 FR 30991).

NMFS also received an application from AGDC for an IHA pursuant to the MMPA for take of marine mammals incidental to construction activities associated with the Project in Prudhoe Bay. An application was initially submitted to NMFS on March 28, 2019.[17] After receiving comments from NMFS, AGDC submitted a revised IHA application on May 29 and again on September 16, 2019. NMFS is currently reviewing the latest version of the IHA application before determining its adequacy and completeness.

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[14] NMFS has jurisdiction over most marine species (e.g., marine mammals and pinnipeds).

[15] The USFWS has jurisdiction over terrestrial and freshwater species and some marine species (e.g., polar bears, walruses, sea otters and manatees).

[16] AGDC's application for an ITA for construction activities in Cook Inlet is included in AGDC's response to question 119 of our information request dated October 22, 2018 (Accession No. 20181022-5218), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20181022-5218 in the "Numbers: Accession Number" field.

[17] AGDC's application for an ITA for construction activities in Prudhoe Bay is included in AGDC's comments on the draft EIS (Accession No. 20191003-5048), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20191003-5048 in the "Numbers: Accession Number" field.

On May 3, 2018, USFWS received a request from AGDC for an ITA pursuant to the MMPA for the take of marine mammals incidental to constructing LNG facilities in Cook Inlet. USFWS reviews applications to determine whether to issue an authorization for the activities described in the application. After receiving comments from USFWS, AGDC submitted a revised application on June 28, 2018. On August 1, 2019, the USFWS finalized regulations in the Federal Register (Docket Number 2019-16279) authorizing the nonlethal, incidental take by harassment of small numbers of northern sea otters.

1.6.7 Rivers and Harbors Act

The RHA pertains to activities in navigable waters as well as harbor and river improvements. Section 10 of the RHA prohibits the unauthorized obstruction or alteration of any navigable water of the United States. Construction of any structure or the accomplishment of any other work affecting course, location, condition, or capacity of waters of the United States must be authorized by the COE. Section 10 rivers crossed by the Project are discussed in section 4.3.2.

1.6.8 Clean Water Act

The CWA is the primary federal statute regulating the protection of waters of the United States, the goals of which are to prevent, reduce, and eliminate pollution in the nation's waters in efforts to restore and maintain the "chemical, physical, and biological integrity" of these waters. Both the EPA and COE have regulatory authority under this statute. Under the CWA, it is unlawful to discharge any pollutant from a point source into waters of the United States without a permit. Through CWA Section 402, the EPA, or an approved state program, has the authority to issue NPDES permits that authorize wastewater discharges subject to limitations and requirements imposed pursuant to CWA Sections 301, 304, 306, 401, and 403. Accordingly, NPDES permits typically include effluent limits and requirements that require the permittee to (1) meet national standards that reflect levels of currently available treatment technologies; (2) comply with the EPA-approved state water quality standards in state waters; and (3) prevent unreasonable degradation of the marine environment in the territorial seas, the contiguous zone, and the oceans. In Alaska, the NPDES permit program has been delegated to ADEC. However, the EPA retained the CWA Section 402 authority for facilities within the DNPP; facilities operating outside of state waters; facilities that have been issued CWA Section 301(h) waivers; and facilities in Indian Country (Metlakatla Indian Community, Annette Island Reserve).

Section 404 of the CWA regulates the discharge of dredged and/or fill material into waters of the United States, including wetlands. The COE has the authority to issue DA permits for projects that comply with the CWA Section 404(b)(1) guidelines. Proposed activities must demonstrate avoidance and minimization of adverse impacts on waters of the United States, including wetlands, to the extent practicable and, if required, provide compensatory mitigation for unavoidable impacts.

The status of the NPDES and Section 404 permitting reviews are further discussed in sections 4.3.2, 4.3.3, and 4.4. EO 11990, *Protection of Wetlands* and EO 11988, *Floodplain Management* also pertain to the CWA.

Section 401 of the CWA requires that an applicant for a federal permit who conducts any activity that may result in a discharge to waters of the United States must provide the federal regulatory agency with a Section 401 certification. ADEC issues Section 401 certifications (except within the DNPP, where the EPA has certification authority) that declare that the discharge would comply with applicable provisions of the act, including state water quality standards. Sections 4.3.2 and 4.3.3 discuss Section 401 compliance.

1.6.9 Safe Drinking Water Act

The SDWA authorizes the EPA to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water and drinking water sources (i.e., rivers, lakes, reservoirs, springs, and groundwater wells). The EPA works together with ADEC, which has primacy over drinking water regulations in Alaska. State of Alaska regulations, 18 Alaska Administrative Code (AAC) 80, require public water systems to comply with the federal SDWA and amendments for the public health protection of Alaska residents and visitors. The EPA has an oversight role to ensure that the state and federal regulations and requirements are being met.

The SDWA also sets a framework for the UIC Program to control the injection of wastes into groundwater. The EPA administers the UIC Program for Class I, III, IV, and V wells, although there are no Class III or IV wells in Alaska. The UIC Class I injection well permit authorizes the disposal of fluids beneath any aquifers that could serve as current or future underground sources of drinking water. Wastes allowed for injection include treated domestic wastewater, drilling muds and cuttings, well workover fluids, melt and storm water, produced water, and other exempt and non-exempt non-hazardous fluids. Applicants for a Class I UIC permit must submit a permit application (EPA form 7520-6) and supporting information including, but not limited to, topography, geology, hydrogeology, nearby wells, well construction, well operation, monitoring, aquifer exemptions, waste description, and business description.

1.6.10 Clean Air Act

The CAA, as amended, defines the EPA's and federal land managers' responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. Under the CAA, the EPA sets limits on certain pollutants and grants states and federal land managers the authority to limit air pollutant emissions coming from sources such as industrial facilities. ADEC has the authority to enforce the provisions of the CAA through Alaska's EPA-approved programs and issues Title V air operating permits through its EPA-approved operating permit program. ADEC also enforces air quality standards through its EPA-approved SIP. Under the approved SIP, ADEC has the authority to issue air construction permits, including major-source Prevention of Significant Deterioration (PSD) permits. The EPA issued a rule in 2010 finalizing greenhouse gas reporting requirements for the petroleum and natural gas industry (40 CFR 98). See section 4.15 for additional information regarding our compliance with the CAA and SIP.

1.6.11 Federal Land Policy and Management Act

Under FLPMA, the BLM has authority to regulate the use, occupancy, and development of federal public lands and to take whatever action is required to prevent unnecessary or undue degradation of these lands. In accordance with FLPMA, the BLM manages its Alaska lands and their uses to ensure healthy and productive ecosystems. Under Section 503 of FLPMA, the BLM designates right-of-way corridors and considers national and state land-use policies, environmental quality, economic efficiency, national security, and good engineering and technological practices.

1.6.12 Marine Protection, Research and Sanctuaries Act

In 1972, Congress enacted the MPRSA (also known as the Ocean Dumping Act) to prohibit the dumping of material into ocean waters that would unreasonably degrade or endanger human health or the marine environment. The majority of all authorized materials dumped into the oceans today are dredged materials (sediments) removed from the bottom of water bodies in order to maintain navigation channels and berthing areas. The EPA regulates the ocean disposal of certain non-dredged materials under the MPRSA as well. Sections 2.1.5 and 2.2.3 summarize AGDC's proposed methods to dispose of dredged material. The effects of these actions are analyzed in section 4.3.3.

1.6.13 Wild and Scenic Rivers Act

In 1968, the WSRA (Public Law 90-542; 16 USC 1271 et seq.) established the National Wild and Scenic Rivers (WSR) System for preserving rivers that "possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or similar values." Rivers that qualify for preservation under this legislation can be designated by Congress or by the Secretary of the Interior (USFWS, 2014c). Within the WSRA, federal agencies must seek to avoid or mitigate actions that would adversely affect rivers included on the Nationwide Rivers Inventory (NRI). Rivers included on the NRI are free flowing and possess one or more outstandingly remarkable values (ORV) based on the river's hydrology and inventory of its natural, cultural, and recreational resources (16 USC 28.1271). A discussion of the NRI-eligible waterbodies affected by the Project is provided in section 4.9.5.

1.6.14 National Trails System Act

The NTSA (16 USC 1241 et seq.) authorized a national system of trails. The Secretary of the Interior or the Secretary of Agriculture administers each national trail under NTSA authority. The NPS, U.S. Forest Service, and BLM administer the 20 designated national trails. The National Trails System has four classes of trails: national scenic trails, national historic trails, national recreational trails, and connecting or side trails (Johnson, 2016). The Project would cross one federally designated National Historic Trail (the INHT). The BLM is the statutorily designated federal INHT administrator. We discuss the INHT in section 4.9.4.

1.6.15 Alaska National Interest Lands Conservation Act

In 1980, Congress passed ANILCA, establishing more than 100 million acres of federal land in Alaska as new or expanded conservation system units (CSUs). CSU means any unit in Alaska of the National Park System, NWR System, National WSR System, National Trails System, National Wilderness Preservation System, or a National Forest Monument, including additions and expansions to these systems in the future (Alaska Department of Natural Resources [ADNR], 2017i).

Title VIII, Section 810, subtitled *Subsistence and Land Use Decisions*, outlines the requirements for addressing impacts on subsistence uses of resources in the federal land use decision-making process. Additional information on regulations related to subsistence is provided below. Subsistence is discussed in section 4.14.

Title XI of ANILCA establishes a single comprehensive statutory authority for the approval or disapproval of applications for transportation and utility systems through conservation system units on public lands in Alaska. The Denali National Park Improvement Act (Public Law 113-33), as amended by the John D. Dingell, Jr. Conservation, Management, and Recreation Act (Public Law 116-9), exempts a high-pressure gas transmission pipeline, sited in a non-wilderness area, from Title XI of ANILCA. While AGDC's proposed route does cross National Park System Lands through the DNPP, it is sited entirely within a non-wilderness area and, as such, Public Law 116-9 exempts the Project from Title XI of ANILCA.

1.6.16 Denali National Park Improvement Act

On September 18, 2013, Public Law 113-33, the Denali National Park Improvement Act, was enacted and later amended by the John D. Dingell, Jr. Conservation, Management, and Recreation Act (Public Law 116-9), which allows for a natural gas transmission pipeline in non-wilderness areas within the boundary of the DNPP. An NPS permit would only be issued if regulations and laws applicable to the utility rights-of-way in NPS units are followed and if the right-of-way route is the route through the Park with the least adverse environmental effects on the Park.

1.6.17 Subsistence Regulations

The federal government and the State of Alaska regulate subsistence harvesting under a dual management system. The federal government recognizes subsistence priorities on federal public lands for rural residents, while the state considers all residents to have an equal right to participate in subsistence hunting and fishing when resource abundance and harvestable surpluses are sufficient to meet the demand for all subsistence and other uses. The consequence of this management system is that subsistence users must often consult both federal and state regulations for the lands upon which they hunt and fish to identify harvest limits. Federal subsistence regulations apply to federally qualified subsistence users on federal public lands, including federal subsistence fisheries. State regulations apply to state subsistence fisheries and hunts on all Alaska lands and waters, including lands of Alaska Native Corporations established under ANCSA. Alaska residents may hunt and fish under state regulations and harvest limits unless pre-empted by federal law. In certain national parks and monuments, subsistence harvest may be restricted to federally qualified subsistence users, such as resident zone community residents.[18]

1.6.17.1 Federal Regulations

With the enactment of ANILCA, Congress protected about 100 million acres of public land in Alaska. ANILCA, Title VIII, defines "subsistence uses" as "customary and traditional uses by rural Alaska residents of wild, renewable resources for direct personal or family consumption as food, shelter, fuel, clothing, tools, or transportation; for the making and selling of handicraft articles out of nonedible byproducts of fish and wildlife resources taken for personal or family consumption; for barter, or sharing for personal or family consumption; and for customary trade" (Section 803). ANILCA also establishes a subsistence priority for rural Alaskans on federal public lands and waters (Section 804) and provides for a system of regional advisory councils to insure the participation of rural residents in subsistence management (Section 805). Section 810 of ANILCA requires an evaluation of subsistence needs to be completed for a federal decision to lease or permit the use of federal lands. The evaluation requires a determination of effects of such use, the availability of other lands for the proposed use, and an assessment of alternatives that would reduce or eliminate the proposed use of federal lands needed for subsistence purposes. The BLM is the responsible federal agency for conducting this review for the Project. Section 811 ensures reasonable access to subsistence resources on federal public lands, including the use of snowmobiles, motorboats, and other means of surface transportation traditionally employed for subsistence purposes, subject to applicable regulations. Subsistence harvests cannot be commercially exploited.

1.6.17.2 State Regulations

Under Alaska state law, subsistence is defined as the "noncommercial customary and traditional uses" of fish and wildlife for subsistence (AS 16.05.258). Subsistence includes the consumption as food, shelter, fuel, clothing, tools, or transportation, for the making and selling of handicraft articles out of nonedible by-products of fish and wildlife resources taken for personal or family consumptions; and for the customary trade, barter, or sharing for personal or family consumption (AS 16.05.940 33).

The state distinguishes subsistence harvests from personal use, general hunting, sport, or commercial harvests based on where the harvest occurs, and the resource being harvested, not where the harvester resides (as is the case under federal law). State law provides for subsistence hunting and fishing regulations in areas outside the boundaries of "nonsubsistence areas," as defined in state regulations (5 AAC 99.015). A nonsubsistence area is defined in the regulations as "an area or community where

[18] Resident zone communities are communities and areas near a national park or monument that contain significant concentrations of rural residents who, without using aircraft as a means of access for purposes of taking fish or wildlife for subsistence uses (except in extraordinary cases where no reasonable alternative existed), have customarily and traditionally engaged in subsistence uses within a national park or monument (36 CFR 13.430).

dependence upon subsistence is not a principal characteristic of the economy, culture, and way of life of the area of community" (5 AAC 99.016).

Activities permitted in nonsubsistence areas include general hunting and personal use, sport, guided sport, and commercial fishing. There is no subsistence priority in these areas; therefore, no subsistence hunting or fishing regulations manage the harvest of resources. Nonsubsistence areas in Alaska include the areas around Anchorage, Matanuska-Susitna Valley, Kenai, Fairbanks, Juneau, Ketchikan, and Valdez (Wolfe, 2000).

1.7 FUTURE PLANS AND ABANDONMENT

AGDC has stated in its application that it has no plans that would result in the future expansion of the Project. In order to expand Project facilities, AGDC would have to file a new and separate application with FERC, and the proposal outlined in the application would be considered a new undertaking. The new, separate application would be subject to an independent environmental review by FERC staff, with appropriate input from stakeholders, and the Commission would have to issue a separate authorization if it found the proposal acceptable. The authorization could contain new and different environmental conditions.

AGDC states that the life of the Project is 30 years. AGDC does not have plans to abandon the facilities. While the design life and the amount of gas reserves available on the North Slope may extend beyond 30 years, analysis beyond the Project lifespan is considered speculative given the dynamic nature of the environment. Generally, options for abandoning facilities include converting the facilities for a different use or carrying a different product, leaving them in place (e.g., the pipeline is purged of material, capped, but left in the ground), removing them (e.g., aboveground facilities and pipe are physically removed), or a combination of one or more of these options. Regardless, future Project-related activities—such as permit renewals, decommissioning, or abandonment of the facilities—would warrant a new evaluation under NEPA, providing an opportunity for agencies and the public to review and evaluate the proposed activities. The federal land-managing agencies would need to evaluate any proposed abandonment under the terms of the Right-of-Way Grant. The BLM must consider the final disposition of the pipeline facilities in accordance with 43 CFR 2886 and would require AGDC to address termination and restoration issues.

2.0 PROJECT DESCRIPTION

2.1 PROPOSED FACILITIES AND LAND REQUIREMENTS

2.1.1 Proposed Facilities

The Alaska LNG Project would involve the construction and operation of Gas Treatment, Mainline, and Liquefaction Facilities.[1] Figure 1-1 depicts these facilities. U.S. Geological Survey (USGS) topographic-based maps identifying the locations of the facilities are provided in appendix B. Aerial photographic-based maps depicting the facilities can be accessed on our website at www.ferc.gov.[2]

The key components of each facility are identified below. Detailed descriptions of these components are provided in sections 2.1.3, 2.1.4, and 2.1.5. Once operational, AGDC states that the Project facilities would each have a nominal design life of 30 years.

- Gas Treatment Facilities
  - GTP
  - West Dock Causeway
  - gravel mine
  - water reservoir
  - PBTL
  - PTTL
  - additional work areas
- Mainline Facilities
  - Mainline Pipeline
  - aboveground facilities
  - additional work areas
- Liquefaction Facilities
  - LNG Plant
  - Marine Terminal
  - additional work areas

2.1.2 Land Requirements

Constructing the Project would require the use of about 35,474 acres of land. While AGDC would maintain about 8,507 acres for Project operation, a total of approximately 16,069 acres of land would be permanently affected by the Project. Table 2.1.2-1 summarizes Project land requirements by Project component. Construction impacts are those that would occur during Project construction. Operational impacts are those that would be associated with the operation of the Project facilities (e.g., the operational

[1] The Project information in this section is based on the information provided in Resource Report 1 in AGDC's FERC application and responses to FERC information requests, which are available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "General Search" from the eLibrary menu and enter the "Docket No." excluding the last three digits (i.e., CP17-178), and follow the instructions.

[2] The aerial photographic-based maps were included as appendix A to Resource Report 1 in AGDC's FERC application (Accession No. 20170417-5343). Additional aerial maps depicting a route change (i.e., the adoption of the Denali Alternative) were provided by AGDC in a supplemental filing (Accession No. 20191003-5149). Both map sets can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5343 or 20191003-5149 in the "Numbers: Accession Number" field.

right-of-way for a pipeline facility or an aboveground facility). If a facility or an area used during construction would not be used to operate the Project, then no operational impacts are included. Permanent surface alterations are those that could extend beyond the life of the Project, including material sites and areas where granular fill would be placed during construction. See section 4.0 for additional discussion of temporary and permanent impacts.

2.1.3 Gas Treatment Facilities

The Gas Treatment Facilities would be on state land designated for oil and natural gas development within the North Slope Borough. The Gas Treatment Facilities would include a new GTP and associated facilities in the PBU and would receive natural gas from the PBTL and the PTTL. The GTP would treat/process the natural gas for delivery into the Mainline Pipeline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU gravel pads. As listed above, the Gas Treatment Facilities would also include a modification of the West Dock Causeway and construction of a gravel mine and water reservoir. Construction of the Gas Treatment Facilities would require 3,090 acres, of which 1,341 acres would be maintained by AGDC for Project operation. Of these 3,090 acres, 1,036 acres would be permanently affected by the Gas Treatment Facilities. Figure 2.1.3-1 provides an overview of the Gas Treatment Facilities.

2.1.3.1 GTP

The feed gas produced from the PTU and the PBU contains carbon dioxide (CO_2), hydrogen sulfide (H_2S), water, and other impurities that require removal prior to liquefaction. The GTP would remove these byproducts from the natural gas, then chill, compress, and send out processed natural gas into the Mainline Pipeline. The byproducts removed from the natural gas would be transported by pipelines to the PBU for injection into the production field via existing or new wells as part of the PBU Major Gas Sales (MGS) Project, which is not subject to the jurisdiction of the Commission (see section 1.5 for a description of non-jurisdictional facilities). Information on the PBU MSG Project, including the byproduct pipelines, is provided in section 4.19.2.2.

About 284 acres of land would be required for construction and operation of the GTP and operations center and camp. AGDC would use the operations center and camp during construction, commissioning, and operation of the GTP and its ancillary facilities. The operations center and camp would be fully self-sustaining with its utilities on the same pad. During construction, the camp would house 1,510 construction workers per year. During operation, the center would accommodate about 125 workers. AGDC states that the center and camp could expand to accommodate a maximum capacity of 1,680 beds during maintenance periods, if required. The communication towers to support the GTP would be at the operations center and camp. The towers would be about 150 feet in height and require lights for aviation safety. Figure 2.1.3-2 provides an overview of the GTP.

The GTP would have three gas treatment systems. Each system would contain multiple units assembled in a sequence (see figure 2.1.3-3) and would process about 1.3 billion cubic feet (Bcf) per day of sour feed gas. The feed gas inlet facilities would combine the natural gas from the PBTL with the natural gas from the PTTL before entering the treatment system so that there would be one gas stream. Before entering the PBTL and PTTL, the PBU and PTU feed gas would pass through gas flow measuring meters.

TABLE 2.1.2-1

Estimated Land Requirements for Project Construction and Operation by Facility Type

Facility Name	Land Affected During Construction [a] (acres)	Land Affected During Operation (acres)	Land Affected with Permanent Surface Alterations (acres) [b]
Gas Treatment Facilities [c]			
GTP [d]	284	284	284
West Dock Causeway [e]	253	0	253
Gravel mine	141	141	141
Water reservoir	35	35	35
PBTL	7	7	<1
PTTL			
Right-of-way	1,696	609	<1
Aboveground facilities	<1	<1	<1
Construction camps	97	0	97
Additional temporary workspaces	18	0	0
Ice pad and ice pad access roads	206	0	0
Pipe storage yards	28	0	28
Helipad	<1	<1	<1
Associated transfer pipelines	80	70	<1
Additional temporary work areas			
Access roads	243	193	193
Pioneer camp [f]	0	0	0
Subtotal	**3,090**	**1,341**	**1,036**
Mainline Facilities [g]			
Mainline Pipeline			
Onshore [h]	12,475	5,016	2,630
Offshore [i]	5,070	330	14
Aboveground Facilities			
Compressor stations	233	233	233
Heater station	23	23	23
Meter stations	0	0	0
Launcher/receivers [j]	0	0	0
Cathodic Protection System [k]	0	0	0
Mainline valves (MLV) [l]	8	8	8
Mainline material offloading facility (MOF) [m]	6	0	6
Additional work areas			
Additional temporary workspace	1,636	0	466
Access roads	2,999	631	3,000
Helipads and airstrips [n]	4	4	4
Construction camps [o]	840	0	840
Contractor, pipe, double joining yards	674	0	674
Railroad spurs and work pads	48	0	48
Disposal sites [p]	230	0	230
Material sites [p]	5,855	0	5,855
Subtotal	**30,101**	**6,245**	**14,031**

TABLE 2.1.2-1 (cont'd)

Estimated Land Requirements for Project Construction and Operation by Facility Type

Facility Name	Land Affected During Construction [a] (acres)	Land Affected During Operation (acres)	Land Permanently Affected with Permanent Surface Alterations(acres) [b]
Liquefaction Facilities			
LNG Plant [c]	902	902	902
Marine Terminal			
Product loading facility	19	19	19
Marine Terminal MOF (plus shoreline protection) [q]	30	0	<1
Marine Terminal MOF dredge area	51	0	0
Additional work areas			
Material site [r]	0	0	0
Offshore dredged material disposal area	1,200	0	0
Construction camp	81	0	81
Subtotal	**2,283**	**921**	**1,003**
Total	**35,474**	**8,507**	**16,069**

Note: The sum of the addends may not equal the totals in all cases due to rounding.

[a] Construction acreage includes operational areas.

[b] As discussed in section 4.0, a permanent impact would occur as a result of any activity that modifies a resource to the extent that it would not return to pre-construction conditions during the life of the Project, which AGDC defines as 30 years. This includes impacts that would occur within the construction and/or operational footprints of the Project.

[c] Meter stations would be at the GTP and LNG Plant. These acreages do not represent new disturbance and are not included in the totals presented in the table. The Point Thomson Meter Station associated with the PTTL is not included in this total.

[d] A construction/operations camp would be on a pad connected to the GTP pad.

[e] West Dock Causeway includes the causeway expansion (118 acres), the module staging area (87 acres), Dock Head 4 (31 acres), the breach bulkheads (3 acres), and the screeding areas (14 acres). These numbers include both open water and upland areas.

[f] The pioneer camp is an existing facility with 30 acres of impact.

[g] Although granular fill would be used for access roads, campsites, pipe storage yards, and the construction right-of-way, and not removed after construction is completed, the impact from granular fill is only reported as the permanently maintained footprint for operation (in the Land Affected During Operation column).

[h] Right-of-way widths vary by construction mode and method; the permanent right-of-way width is 53.5 feet for operation. Includes travel and bypass lanes as temporary construction footprints.

[i] Includes the area needed for pipelay (12 acres) and anchoring the offshore pipelay barge, including cable anchor drop (4 acres), cable anchor drag (19 acres), and cable anchor sweep (5,035 acres).

[j] The launchers and receivers would be within other aboveground facilities and would not require additional land.

[k] The cathodic protection system would be completely within the permanent right-of-way or at the planned aboveground facilities (i.e., MLVs, compressor stations, and a heater station).

[l] MLVs would be constructed within the footprints of other aboveground facilities or within the Mainline Pipeline right-of-way. The acreages shown represent the footprints of the stand-alone MLVs within the Mainline Pipeline right-of-way but do not represent new disturbance because they are already included in the onshore Mainline Pipeline acreage.

[m] AGDC would construct the Mainline MOF, and although it would be a permanent facility, it would not be used by AGDC during Project operation.

[n] The acreages presented for helipads and airstrips only encompass the 19 standalone permanent helipads. The area of impact for the remaining 9 permanent helipads is included in the acreages presented for the compressor stations and heater station. The 20 temporary helipads are encompassed within the acreage for construction camps.

[o] This number is an approximation based on information provided by AGDC in various information request responses.

[p] The material sites and disposal sites would be reclaimed according to reclamation plans to be developed in coordination with the appropriate land management agencies.

[q] The MOF is a total of 28.3 acres, but 17.0 acres are included within the MOF dredging footprint.

[r] The material site is an existing facility.

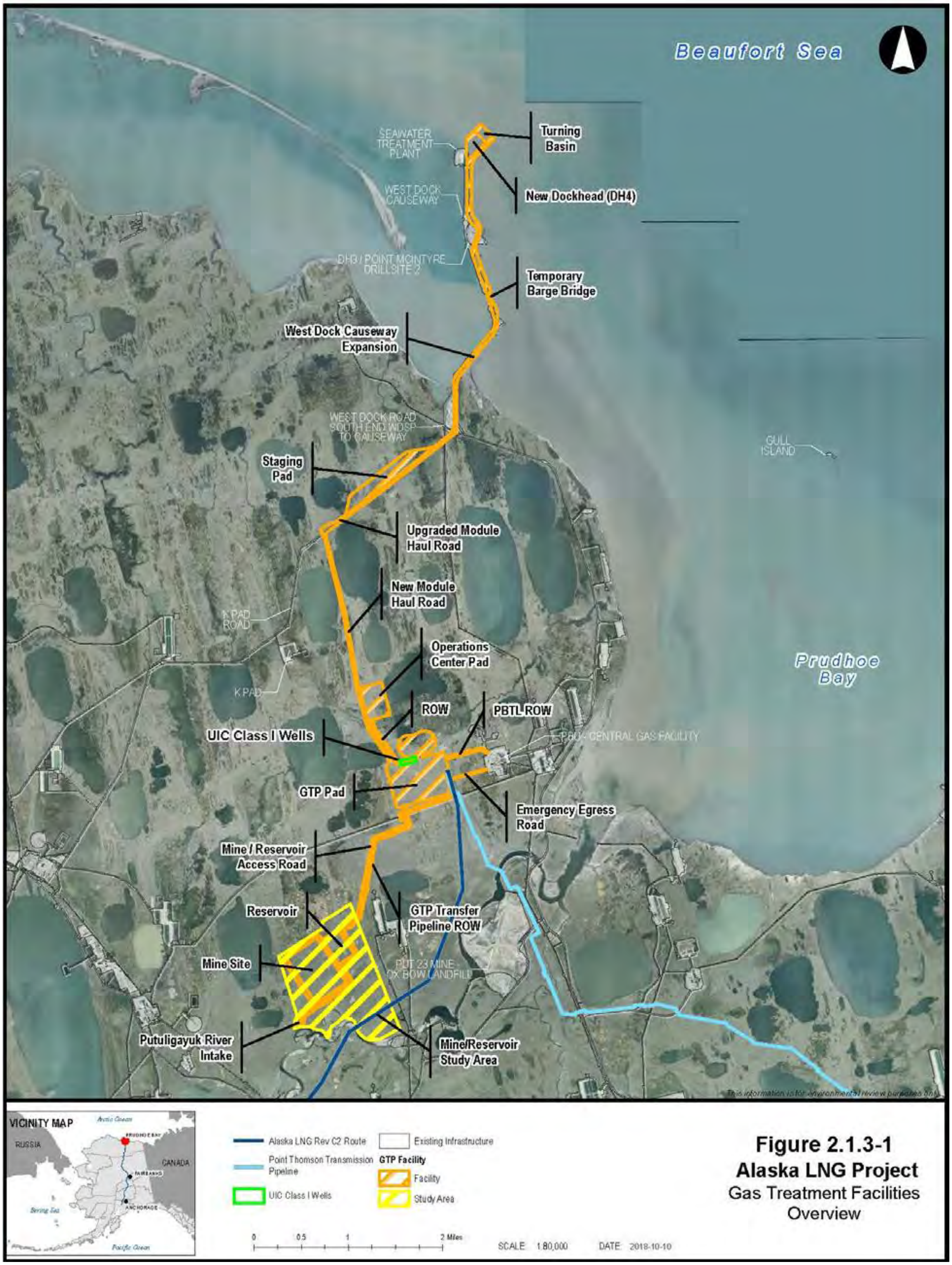

Figure 2.1.3-1
Alaska LNG Project
Gas Treatment Facilities Overview

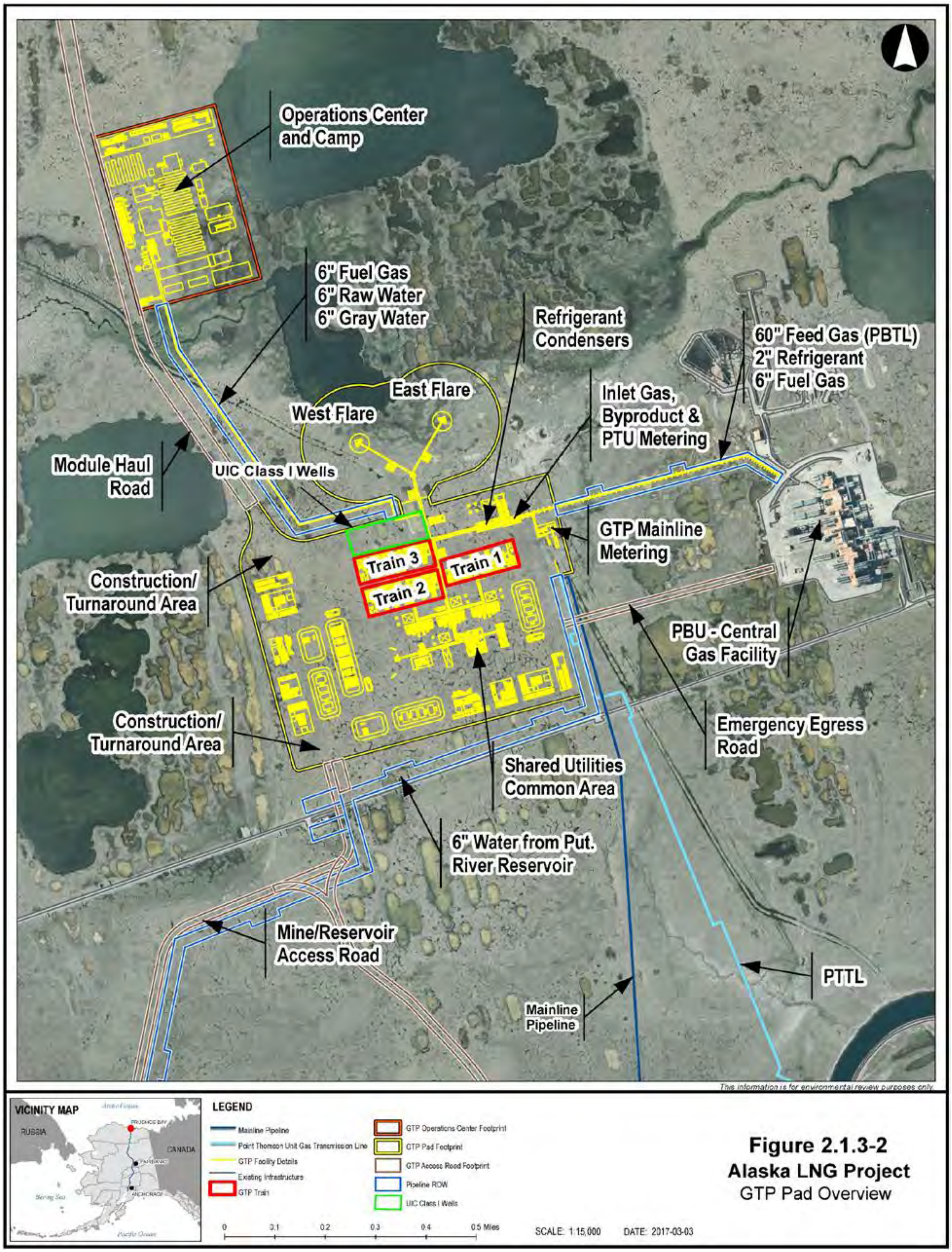

Figure 2.1.3-2
Alaska LNG Project
GTP Pad Overview

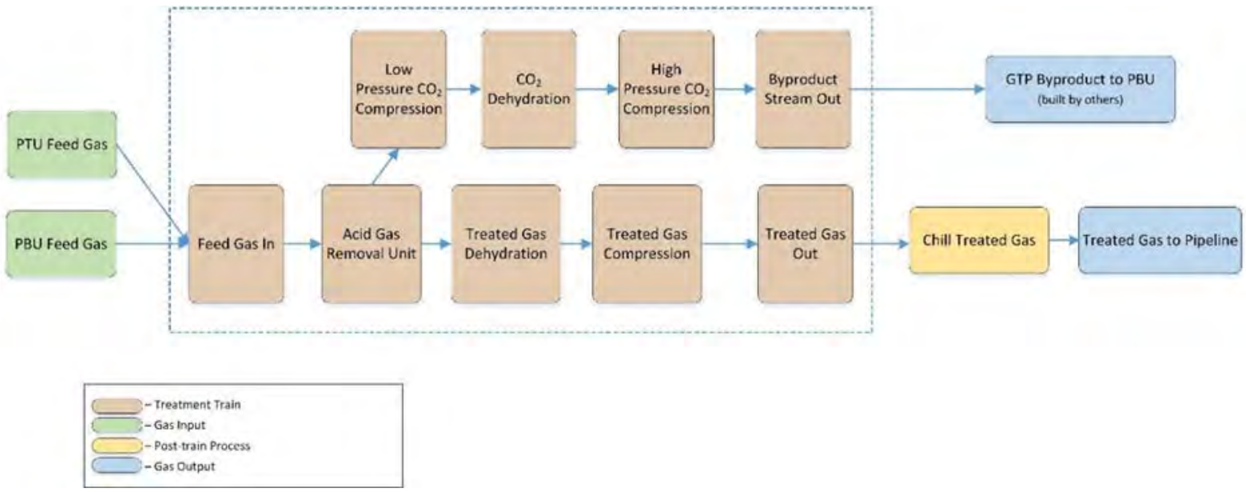

Figure 2.1.3-3 Process Block Diagram of a GTP Train

There would be one acid gas removal unit per system. This unit would remove CO_2 and H_2S from the sour feed gas to meet LNG specifications with the use of an amine solution and packed absorber tower. The gaseous stream of CO_2 and H_2S would be combined into a single GTP byproduct stream and sent to the PBU Treated Gas Distribution System. There would also be one treated gas dehydration unit per system. The unit would use glycol in a packed absorber tower to extract water from the natural gas stream. Extracted water would be disposed of in UIC Class 1 wells at the GTP pad (see additional discussion below).

One treated gas compression unit per system would compress the treated natural gas to adequate pressure so that it enters the Mainline Pipeline at the necessary operating pressure. Each treated gas compressor would have a nominal rating of about 50,000 horsepower (hp). Emissions would be controlled using dry low emissions combustors.

Treated compressed natural gas would be cooled to 30 degrees Fahrenheit (°F) prior to entering the Mainline Pipeline using a propane refrigerant for chilling. The treated natural gas would flow from the chillers through a metering station and into the Mainline Pipeline.

The GTP would have two flare stacks (east flare and west flare) that extend 220 feet high. The purpose of the stacks is to flare excess hydrocarbons and CO_2 produced at the GTP as part of normal plant operations. AGDC would implement a safety boundary in a 600-foot radius around each flare's base. This boundary would allow any workers to move to safer locations or seek shelter inside a module during a flare event. Due to the remote area, AGDC proposes to use signage along the gravel road connecting the GTP pad to the flare to restrict access.

During construction, the GTP would operate using low-voltage, temporary power generators and mobile power generators before the permanent site generators and utilities are in service. For operation, the GTP would include a self-sustaining electrical power generation system using six natural gas turbines with a combined capacity of between about 267,000 and 299,000 hp. The GTP pad would receive its power via buried cables. The gravel pad would be of sufficient thickness to reduce the potential for heat transfer to the underlying permafrost. Insulation board placed under the cable trench area would also mitigate heat transfer from the power cable. Aboveground power cables would provide power to the two remote GTP facilities, the operations center, and water reservoir site. Power to the operations center would be provided via cable in cable trays along the utility pipe rack. Power to the water reservoir would be provided by cable along the water supply pipeline supports.

During construction, AGDC would truck in water and store it on site until a water reservoir and the pumping stations necessary to support the operations camp are established. Potential water sources near the GTP for construction and hydrostatic testing include freshwater from the Putuligayuk and Sagavanirktok Rivers, the North Slope Borough's water system, and naturally occurring lakes in the area. During operation, water from the newly constructed reservoir would support the facilities. To meet drinking water standards, a packaged potable water treatment system would treat the water.

AGDC plans to submit applications to the EPA in the 3rd quarter of 2020 for authorization under the SDWA to construct and operate two UIC Class 1 injection wells at the GTP for disposal of liquid waste streams from the Gas Treatment Facilities (e.g., process liquid waste from dehydration of natural gas).[3] The wells would be about 6,000 to 7,000 feet in vertical depth and would be subject to authorization by the EPA as Class I industrial injection wells for injection of non-hazardous and Resource Conservation and Recovery Act (RCRA)-exempt liquid waste streams. Prior to completion of the UIC wells, AGDC would use a sanitary treatment system to treat the sanitary/domestic waste stream, while other liquid waste streams from construction would be disposed of at existing North Slope Borough disposal facilities. AGDC would install the UIC wells on the northwest corner of the GTP site near the flare area; the approximate location of the area in which the wells would be installed is depicted on figures 2.1.3-1 and 2.1.3-2. Well design and construction would prevent injected wastewaters from leaking from the injection zone. The well casings would be steel or fiberglass reinforced plastic for the full depth of the well in accordance with EPA permit requirements. Due to the North Slope location of the wells, steel would be the preferred material. Information on the liquid waste streams that would be injected into the wells is provided in section 2.5.1.2.

2.1.3.2 West Dock Causeway

The West Dock Causeway is an existing nearly 2.5-mile-long solid fill gravel causeway docking facility along the northwest shore of Prudhoe Bay. It is currently operated by BP Exploration (Alaska), Inc. (BP Exploration) to receive offloaded heavy marine cargo to support Prudhoe Bay oilfield development.[4] The causeway operates during the seasonal ice-free window, which occurs once sea ice conditions improve to 30-percent ice cover or less, generally beginning around August and ending in September.

The existing West Dock Causeway lacks the facilities to receive the GTP modules, which are 90 feet wide and 300 feet long and would weigh about 9,000 tons. Therefore, AGDC would modify the West Dock Causeway by constructing Dock Head 4 to facilitate delivery of the multiple GTP modules as well as other equipment, materials, and supplies. Delivery of the major components of the GTP facilities would occur during six summer sealift seasons.

West Dock Causeway construction would include the following improvements.

- Permanent sheet piling and fill covering 31 acres. The dock face would be about 1,000 feet wide and elevated about 8 feet above sea level. The Dock Head 4 pad surface would require 1.8 million cubic yards of granular fill.

[3] The Project Waste Management Plan identifies the anticipated waste streams, volumes of waste, and waste disposal options for the Gas Treatment, Mainline, and Liquefaction Facilities. See section 2.2 for instructions to access this plan.

[4] We understand that BP has agreed to sell its Alaska businesses, including BP Exploration, to Hilcorp Alaska, with the transaction scheduled to be completed in 2020, subject to state and federal regulatory approvals. As of the publication of this final EIS, the sale is pending and BP Exploration remains the owner of West Dock Causeway.

- Subsea scraping (i.e., screeding) of the turning basin. This would be required to allow barge delivery to Dock Head 4, disturbing about 14 acres.[5] No additional screeding to maintain navigational depths at Dock Head 4 would be required during the proposed 6-year sealift period.

- Permanent sheet piling and fill on each end of the existing 650-foot-long channel between Dock Heads 2 and 3, disturbing 3 acres to accommodate a barge bridge.

- Two barges ballasted together to the sea floor for the six summer sealift seasons (two pre-construction and four construction sealifts).

- Widening existing segments of West Dock Causeway through the placement of granular fill to a width of 125 feet about 800 feet from land to Dock Head 2 and about 4,500 feet from Dock Head 2 to Dock Head 3, and filling a parallel 125-foot-wide roadway from Dock Head 3 to Dock Head 4, for 118 acres of impact.

- A new 87-acre module staging area abutting the west side of the K Pad Access Road and south of an existing West Dock Causeway staging area. AGDC would use this area to place the module units removed from the barges prior to moving the modules to the facility site. Following construction, the module staging area would remain in place for future use by the Project, including equipment deliveries, vehicle turnarounds, and decommissioning and dismantling the facility.

Following its construction and use by AGDC for the Project, Dock Head 4 would remain in place. It would be maintained and operated by BP Exploration.[6]

2.1.3.3 Gravel Mine

To support construction of the Gas Treatment Facilities, AGDC would build a 141-acre gravel mine. Construction would use about 6.9 million cubic yards of granular fill, of which about 4.4 million cubic yards would come from the new gravel mine and the remainder from the excavation of the water reservoir and from the existing Putuligayuk Mine site (Put-23 Mine). The 141-acre mine site would be about 1.4 miles south of the GTP adjacent to the Putuligayuk River and about 700 feet from the existing Put-23 Mine. AGDC has contacted owners of the existing gravel mine, North Slope Borough, and the ADNR, and confirmed the mine would be able to provide granular fill.

2.1.3.4 Water Reservoir

AGDC proposes to build a 35-acre water reservoir with a depth ranging from 35 to 60 feet with a capacity of 250 million gallons that would serve as a year-round water supply for GTP operation. AGDC estimates that the 250 million gallons represents a 2-year water supply for the GTP that would support process and potable water demands. Material excavated from the water reservoir would be used as granular fill for the Gas Treatment Facilities. Pumps would draw water out of the Putuligayuk River during spring breakup at permitted flow rates through protective fish screens (3/32-inch maximum opening size) into a 1.1-mile-long, 14-inch-diameter pipeline that would deliver water from the river to the reservoir. A 5-mile-long, 6-inch-diameter water supply pipeline would transport water from the reservoir to the GTP. Both pipelines would be aboveground on vertical support members (VSMs). One pump station would pump the water from the river using two motor driven pumps, and a second pump station would pump the water from the reservoir to the GTP.

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5 Subsea scraping (screeding) levels, pushes, or moves sediments on the sea floor to create a flat surface. Unlike dredging, sediments are not excavated from the seabed during screeding; therefore, screeding does not require disposal of excavated spoil.

6 Or by Hilcorp Alaska if BP Exploration's Alaska businesses are acquired by Hilcorp.

2.1.3.5 PBTL

The PBTL would be a 1.0-mile-long, 60-inch-diameter aboveground natural gas pipeline built on VSMs using a 120-foot-wide construction right-of-way with a 100-foot-wide permanent right-of-way. The PBTL would transport natural gas from the PBU Central Gas Facility (CGF) to the GTP. AGDC would install the PBTL during the winter. Working from temporary ice roads and work pads for construction, the PBTL would be installed 7 feet above the tundra surface on about 46 VSMs (average spacing of about 115 feet between each VSM), which would disturb less than 1 acre of land. The PBTL would begin at the edge of the existing PBU CGF pad and proceed west to the tie-in point at the GTP. The VSMs would also hold a 6-inch-diameter fuel gas line and a 2-inch-diameter refrigerant (propane) line. There would be one meter station (PBU Meter Station) collocated with the PBU CGF. The PBTL would carry sour gas (i.e., gas with small concentrations of H_2S). PBTL construction would comply with the National Association of Corrosion Engineers (NACE) MR0175 Sour Service Specification to mitigate for internal corrosion and stress cracking.

2.1.3.6 PTTL

The PTTL would be a 62.5-mile-long, 32-inch-diameter aboveground natural gas pipeline built on VSMs using a 100-foot-wide right-of-way for construction with an 80-foot-wide right-of-way for operation. The PTTL would begin at the PTU central pad and travel parallel to the existing Point Thomson export pipeline until Badami, Alaska, where it would parallel the Badami Sales Oil Pipeline until the East Sagavanirktok River, then head northwest and follow existing infrastructure into the Prudhoe Bay area. AGDC would install the PTTL during the winter. Like the PBTL, AGDC would install the PTTL 7 feet aboveground on about 6,250 VSMs (with an average spacing of 53 feet between each VSM). No other pipelines or utilities would be installed on the same VSMs as the PTTL.

The existing PTU central pad would house the PTU Meter Station and a pig launcher. The existing GTP inlet would house a pig receiver. The PTTL would require three Mainline valves (MLV) along the pipeline to monitor pressure and, in the event of a pipeline rupture, automatically close the valves. The PTTL right-of-way would disturb about 1,696 acres during construction and 609 acres for operation. The permanent land impacts associated with the PTTL right-of-way would be less than 1 acre. Like the PBTL, the PTTL would carry sour gas; therefore, construction of the PTTL would also comply with the National Association of Corrosion Engineers MR0175 Sour Service Specifications.

2.1.3.7 Associated Transfer Pipelines

Associated transfer pipelines for the Gas Treatment Facilities include the following:

- a fuel gas pipeline (about 1.8 miles of 6-inch-diameter pipe) delivering fuel gas from the PBU CGF to the GTP and GTP operations camp;
- a propane pipeline (about 0.6 mile of 2-inch-diameter pipe) taking propane from the PBU CGF to the GTP for use in the GTP refrigeration system;
- a Putuligayuk River pipeline (about 1.1 miles of 14-inch-diameter pipe) delivering water from the Putuligayuk River to the reservoir; and
- a supply water pipeline (about 5 miles of 6-inch-diameter pipe) taking water from the reservoir to the GTP and GTP operations camp.

A new elevated pipeline system would be built for the PBU CGF to GTP pipelines. The PBTL, propane pipeline, and fuel gas pipeline would share the same route (and be built on the same VSM system where contiguous) from the general area of the northwest corner of the PBU CGF to the general area of the northeast corner of the GTP. About 348 VSMs would be required for the transfer pipelines. Collectively, the approximately 9 miles of new transfer pipelines would affect about 80 acres of land during construction and about 70 acres of land during operation.

2.1.3.8 Additional Work Areas

Permanent Access Roads

AGDC would use five permanent access roads totaling 13.2 miles to support construction and operation of the Gas Treatment Facilities (see table 2.1.3-1). Four of these roads, totaling 8.4 miles, would be new roads constructed by AGDC. The GTP would require a main access road and an emergency egress road. The new main access road would also provide access to the gravel mine and water reservoir in the spring, summer, and fall. In winter, an ice road, reconstructed each year, would allow wintertime access between these facilities. AGDC would construct an emergency egress road on the east side of the GTP pad and would connect it to the existing PBU CGF. Widening and extending the existing West Dock Causeway would allow delivery and transport of facility modules.

TABLE 2.1.3-1

Access Roads Associated with the Gas Treatment Facilities

Access Road Location	Status	Approximate Width (feet)	Road Length (miles)	Permanent Disturbance (acres)
Main access and gravel mine/water reservoir access road (gravel)	New	85	3.0	32
Gravel mine/water reservoir access road (ice)	New	165	2.5	0 [a]
New module haul road (gravel)	New	150	2.5	45
West Dock Causeway expansion (gravel)	Existing	125	4.8	112
Emergency egress road (gravel)	New	70	0.4	4
Total		**N/A**	**13.2**	**193**

N/A = Not applicable

[a] This ice road would be reconstructed each year during Project operation, but would not result in a permanent ground disturbance.

Ice Roads

Ice roads would be necessary for GTP infrastructure construction, including winter construction of the pipelines / transfer lines (see table 2.1.3-2). Most ice roads constructed on the North Slope are typically operational between the middle of February (sometimes as early as January) through early April. Prior to spring breakup, cuts across the ice roads would facilitate sheet flow and breakup. AGDC would rebuild the gravel mine site and water reservoir perimeter roads each year during construction/mining operations. Coast Guard permits are not required for ice road crossings of navigable waterways if the roads are removed prior to spring breakup.

The PTTL would require a temporary full-length ice road along the construction right-of-way and two lay-down ice work pads to store materials and provide fabrication space for pipeline construction. Additionally, AGDC would build 52 temporary ice ramps and turnouts for multiple access points to the right-of-way. Table C-1 in appendix C provides a list of the temporary ice roads to be built for the PTTL.

TABLE 2.1.3-2

Temporary Ice Roads for Construction of the Gas Treatment Facilities

Ice Road Purpose/Use	Estimated Width (feet)	Estimated Length (miles) / Area (acres)	Estimated Construction Duration	Estimated Volume of Water per Season (gallons) [a]
Gravel mine/water reservoir service vehicle access road	40	2.1 miles / 10 acres	One season	5.3 million
Gravel mine site perimeter road	40	2.0 miles / 10 acres	Four seasons	21.3 million
Water reservoir perimeter road	40	1.0 mile / 5 acres	Four seasons	7.5 million
Pipeline crossing construction ice pads	NA	Length varies / About 5 acres	One season	2.8 million
Construction right-of-way / ice road for the PBTL [b]	120	0.7 mile / 10 acres	Two seasons	6.1 million
Construction right-of-way / ice road for utility lines [c]	120	1.1 miles / 16 acres	One season	9.5 million
Construction right-of-way / ice road for Putuligayuk River intake line (from Putuligayuk River to water reservoir)	110	0.8 mile / 11 acres	One season	8.7 million
Construction right-of-way / ice road for water line from water reservoir to GTP Pad	110	4.0 miles / 53 acres	One season	34.5 million

NA = Not available

[a] Preliminary estimates based on planned design. Estimated amounts for maintenance water are included.

[b] Includes fuel gas and propane lines on shared VSMs with PBTL between the PBU CGF and GTP pad.

[c] Includes electrical/cable trays, fuel gas line, grey water return line, and water line between the GTP and operations camp.

Pioneer Camp

Two years prior to construction, AGDC would open a 30-acre pioneer camp, housing 600 personnel, to support the Gas Treatment Facilities. AGDC intends to use an existing granular pad in the PBU or the Deadhorse area. The temporary pioneer camp would be self-sustaining with power generation, a fuel storage tank, water treatment, and sewage treatment. Water for camp use would be trucked to the pioneer camp until the new reservoir is established. Treated wastewater (e.g., black and grey water) associated with the pioneer camp would be disposed of in previously permitted UIC wells.

2.1.4 Mainline Facilities

The Mainline Pipeline route would start at the GTP and generally follow the existing Trans Alaska Pipeline System (TAPS) crude oil pipeline and adjacent highways south to Livengood, Alaska. From Livengood, the Mainline Pipeline would generally head south–southwest (adjacent to the Minto Flats State Game Refuge [SGR]) to Trapper Creek. It would then follow the Parks Highway (including about 6.1 miles through the DNPP between about MPs 537.1 and 543.1) and Beluga Highway, and then turn south–southeast around Viapan Lake. It would then cross Cook Inlet entering near Beluga Landing and exiting at a landing near Suneva Lake on the northern part of the Kenai Peninsula. The permanent Mainline Facilities also include eight compressor stations, one heater station, MLVs, and permanent access roads at various locations along the Mainline Pipeline route. Construction of the Mainline Facilities would require about

30,101 acres, of which 6,245 acres would be maintained by AGDC for Project operation. Of the 30,101 acres, about 14,031 acres would be permanently affected by the Mainline Facilities.

2.1.4.1 Mainline Pipeline

The 806.9-mile-long Mainline Pipeline would cross several boroughs and census areas (see table 2.1.4-1). The Mainline Pipeline would be buried with the exception of two aerial waterbody crossings, four aboveground crossings of active faults, and the offshore portion in Cook Inlet, which would be laid on the seabed. Installation would occur in four construction spreads with lengths ranging from 191.8 miles (Spread 2) to about 208.9 miles (Spread 1) (see section 2.2.2). There would be separate specialized construction crews to construct the pipeline across specific waterbody or wetland features as well as aboveground facilities.

TABLE 2.1.4-1

Boroughs or Census Areas Crossed by the Mainline Pipeline

Borough or Census Area	Begin Milepost	End Milepost	Approximate Length (miles) [a]
North Slope Borough	0.0	184.4	184.4
Yukon-Koyukuk Census Areas	184.4	423.9	239.5
Fairbanks North Star Borough	423.9	426.3	2.4
Yukon-Koyukuk Census Areas	426.3	488.6	62.3
Denali Borough	488.6	575.4	87.1
Matanuska-Susitna Borough	575.4	755.3	179.9
Kenai Peninsula Borough	755.3	806.6	51.3
Total			**806.9**

[a] Total miles are based on the Mainline Pipeline centerline and may not exactly match estimated milepost numbers. The straight-line distance between consecutive mileposts may be greater than or less than 5,280 feet due to changes in elevation and adoption of route alternatives and variations. The mileposts should be considered reference points only.

AGDC proposes to use construction right-of-way widths that vary from 65 to 185 feet wide for the onshore portion of the Mainline Pipeline depending on construction methods and modes. Descriptions of AGDC's proposed construction right-of-way modes are provided in section 2.2.2. AGDC proposes to use a 53.5-foot-wide permanent right-of-way during operation of the onshore portion of the pipeline. Construction of the onshore portion of the Mainline Pipeline would require 12,475 acres, and operation would require 5,016 acres. Ninety-four percent of the onshore portion of the Mainline Pipeline would be sited on federal, state, borough, and municipal land of various holdings, with the remainder of the pipeline on privately owned and Alaska Native lands.

Offshore, the Cook Inlet crossing is a 27.3-mile-long pipeline segment between Beluga Landing South on the western shore of Upper Cook Inlet and Suneva Lake on the eastern side of the inlet. AGDC would use lay barges moored in place and propelled by winches attached by cable to an array of large anchors to construct the pipeline. The offshore portion would disturb about 5,070 acres during construction. The subtidal impact would consist of about 5,035 acres for cable sweep, 19 acres for anchor drag, 12 acres for pipelay, and 4 acres for anchor drop. The operational easement for the offshore pipeline would encompass 330 acres.

Portions of the Mainline Pipeline would be collocated with existing linear corridor infrastructure. The Mainline Pipeline would be parallel to and within 100 feet of an existing pipeline, roadway, and/or electric transmission utility right-of-way for about 163.7 miles or about 20 percent of its total length. AGDC identified fiber optic lines, TAPS, TAPS fuel gas line, Dalton Highway, George Parks Highway (Parks Highway), and overhead power lines as existing adjacent rights-of-way. Table C-2 in appendix C provides detailed milepost (MP) locations where the Mainline Pipeline would be collocated with or adjacent to existing rights-of-way. Another 128.2 miles (16 percent) of the Mainline Pipeline would be in areas designated for use as a utility corridor by the BLM, and 6.1 miles of the Mainline Pipeline route through the DNPP (between about MPs 537.1 and 543.1) would cross an area where a high-pressure natural gas transmission pipeline is authorized to occur.

AGDC would design the Mainline Pipeline in compliance with 49 CFR 192 Subpart C, which addresses pipe grade, pipe wall thickness, pipe strain base, pipe materials, and other design aspects. AGDC has requested five special permits from PHMSA to construct, operate, and maintain the Mainline Pipeline (see section 1.2.2). The special permits would address strain-based design, use of multi-layer external coating, MLV spacing, and crack arrestor spacing (see table 2.1.4-2). Detailed descriptions of the special permit proposals, along with a reference to PHMSA's assessment of the special permit applications, are provided in section 4.18.

TABLE 2.1.4-2

Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards Exceptions

Regulation	Explanation
49 CFR Part 192.103, 192.105, 192.317, and 192.620	Strain Based Design – AGDC developed a strain based design permit application for seven areas where time-dependent ground movement (e.g., frost heave or thaw settlement) could result in longitudinal strains that exceed 0.5 percent of the pipe material's yield strength.
192.112(b)(2)(iii), 192.112(b)(3)	Crack arrestor spacing – AGDC would produce a Fracture Control Plan that details the Project's compliance with the requirements in 49 CFR 192.112(b), with the exception of the crack arrestor spacing requirements in 192.112(b)(3). As part of the Fracture Control Plan, to ensure a robust design and reduce the probability of fracture initiation, material requirements for pipe body and seam welds would be specified to achieve a large through-wall critical flaw length.
192.179(a)(4)	MLV spacing – AGDC would vary the spacing between MLVs in remote locations.
49 CFR 192.112(f)(1) and (2)	Multi-layer coating – AGDC would utilize three layer polyethylene coatings, which consist of a fusion bonded epoxy (FBE) layer, a copolymer adhesive layer, and a polyethylene outer layer.

2.1.4.2 Mainline Aboveground Facilities

The Mainline Facilities include eight compressor stations, one stand-alone heater station, two meter stations, multiple MLVs, multiple pig launcher/receiver stations, cathodic protection systems, a material offloading facility (Mainline MOF), and gas interconnections for in-state deliveries. Construction of the new aboveground facilities would require 270 acres, all of which would be permanently affected by the Project and 264 acres of which would be maintained by AGDC for operation. Depending on site conditions, the granular fill pads for the aboveground facilities would vary in thicknesses. For northern locations (e.g., MPs 0.0 to 517.6), thermopiles with air space are the proposed foundations to mitigate heat transfer from facilities to underlying permafrost. South of MP 517.6, driven steel piles are the proposed foundations.

Lighting at aboveground facilities would meet regulatory requirements, codes, and standards. In addition, AGDC has indicated that lighting would address guidance provided by the USFWS to reduce potential impacts on birds and other wildlife from light trespass and upward directed light.

Compressor Stations

The compressor stations would use natural gas-fired engines to maintain pressure within the Mainline Pipeline to deliver the contracted volumes of natural gas to the Liquefaction Facilities. The compressor station sites generally would consist of a developed, fenced area within a larger parcel of land that otherwise remains undeveloped. The compressors themselves would be housed in buildings designed to attenuate noise and allow for operational and maintenance activities. Other structures on the site would include living quarters (camps); administrative, maintenance, storage, and communications buildings; potable water, wastewater, and solid waste systems; helicopter pads; and pig launcher/receiver facilities. Natural gas engine-driven power generators would generate electric power for the compressor stations. Gas cooling and heating equipment would be required at several of the compressor stations north of MP 517.6. Wastewater (e.g., black and grey water) generated at the compressor stations would be treated with sewage treatment facilities approved by ADEC. The specific volumes, types, frequencies, rates, treatments, and disposal mechanisms for wastewater discharges from the sewage treatment facilities at the compressor stations, as well as the approximate locations of potential outfalls and discharge points, would be determined by AGDC as construction plans are finalized and through the acquisition of the required permits for the discharges. Any debris generated at the site would be removed and taken to an approved disposal facility.

When compressed, natural gas increases in temperature to a point that could potentially affect the soil surrounding the pipeline exiting the station. As natural gas moves through the pipeline after compression, the temperature of the natural gas would generally decrease. AGDC would manage the natural gas temperature in the Mainline Pipeline as described below.

- From MPs 0.0 to 180.0, the pipeline gas temperature would be kept below freezing temperatures using gas-to-gas exchangers and aerial coolers throughout the year because this area is in continuous permafrost.

- From MPs 180.0 to 567.0, the pipeline gas temperature would range from below freezing in the winter to above freezing in the summer to account for seasonal variation in ground temperatures. In this area of discontinuous permafrost, the in-line temperature would have a 32°F year-round average.

- From MPs 567.0 to 806.6, the pipeline gas temperature would be maintained above-freezing temperatures by using indirect fired natural gas heaters (see discussion in next section).

The location of each compressor station and the amount of compression required were determined by hydraulic modeling of the gas flow. Table 2.1.4-3 identifies the compressor station locations. Further information about construction and operational procedures for the compressor stations is provided in sections 2.2.2.4 and 2.5.2.2, respectively. With the exception of the Ray River Compressor Station, each compressor station would permanently affect 30 acres of land. The Ray River Compressor Station would affect 23 acres. Construction and operation of the eight compressor stations would require about 233 acres.

Heater Station

Heating stations are similar to compressor stations with power generators, instrumentation, utility, and power gas systems. AGDC would construct one stand-alone gas heater station at Theodore River (MP 749.1) as well as install gas heaters at the Rabideux Creek Compressor Station. Similar to compressor stations, the heater station would house its construction and operation workers in an adjacent camp. The camp would be fully self-sustaining with power generation, water wells, water treatment, and sewage treatment. Wastewater (e.g., black and grey water) generated at the heater station would be treated with sewage treatment facilities approved by ADEC. The specific volume, type, frequency, rate, treatments, and disposal mechanism for wastewater discharges from the sewage treatment facilities at the heater station, as well as the approximate locations of potential outfalls and discharge points, would be determined by AGDC as construction plans are finalized and through the acquisition of the required permit for the discharge. Any debris generated at the site would be removed and taken to an approved disposal facility. The Theodore River Heater Station would require 23 acres of land for construction and operation.

TABLE 2.1.4-3

Project Compressor Stations

Compressor Station	Type	Milepost	Size (acres)	Borough or Census Area	Horsepower	Equipment [a]
Sagwon	Compressor station with cooling	76.0	30	North Slope Borough	68,000	• Three compressor turbines • Four power generators • Two auxiliary utility glycol heaters • One waste incinerator
Galbraith Lake	Compressor station with cooling	148.5	30	North Slope Borough	42,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Coldfoot	Compressor station with cooling	240.1	30	Yukon-Koyukuk Census Area	42,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Ray River	Compressor station with cooling	332.6	23	Yukon-Koyukuk Census Area	42,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Minto	Compressor station with cooling	421.6	30	Yukon-Koyukuk Census Area	42,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Healy	Compressor station with cooling	517.6	30	Denali Borough	42,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Honolulu Creek	Compressor station without cooling	597.4	30	Matanuska-Susitna Borough	33,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator
Rabideux Creek	Compressor station without cooling	675.2	30	Matanuska-Susitna Borough	33,000	• One compressor turbine • Three power generators • Two auxiliary utility glycol heaters • One waste incinerator • Five indirect-fired gas heaters

[a] AGDC would operate the Mainline Facilities from a gas control center with the capability to monitor and control the facilities, including remotely starting and stopping compressor units (see section 4.18). If any of the single-unit compressor stations needed to be taken down during operation (e.g., due to an outage or for maintenance), AGDC would temporarily reduce the Mainline Pipeline's throughput (gas flow). AGDC would also have a minimum of one spare compressor unit available for switch-out, if needed.

Meter Stations

Meter stations contain equipment to measure the volume of gas removed from or added to a pipeline system at receipt and delivery points. A typical meter station consists of a graveled area with building(s) that enclose the measurement equipment. Two meter stations would be constructed for the Project, one at the GTP at MP 0.0 (GTP Meter Station) and one at the LNG Plant at MP 806.6 (Nikiski Meter Station). The GTP and Nikiski Meter Stations would be within the footprint of the other facilities (i.e., the GTP and LNG Plant) such that no additional land would be necessary beyond that associated with the other, larger facilities. The area occupied by each of the meter stations within the GTP or LNG Plant would be less than 3 acres.

Mainline Valves

MLVs consist of aboveground and underground piping and valves that control and segment the flow of gas within the pipeline for safety, operation, and maintenance purposes. Regulatory and operational requirements determine valve placement. AGDC has submitted a Special Permit application to PHMSA regarding valve spacing. More information on this permit can be found in section 4.18.

Operating the Mainline Pipeline would require the installation of 30 MLVs (see table 2.1.4-4). MLVs would be at the GTP, at each of the eight compressor stations and the heater station, and at the LNG Plant. The remaining 18 MLVs would be stand-alone facilities installed within the Mainline Pipeline right-of-way. These stand-alone facilities would permanently convert a total of 8 acres to an industrial use within the Mainline Pipeline right-of-way. Each MLV site would include a blowdown valve, a pipeline break control system, and an adjacent helipad.

Based on comments received from the EPA, AGDC evaluated an alternative design for the MLVs that included using an elevated, pile-supported structure. AGDC determined that due to the increased exposure of the pipe with associated integrity and safety concerns, as well as increased operational maintenance requirements of a pile supported pad, an elevated, pile-supported structure is not the preferred design for the MLVs.

TABLE 2.1.4-4

Project Mainline Valves

Mainline Valve Number	Milepost	Borough or Census Area	Mainline Valve Number	Milepost	Borough or Census Area
MLV 1 [a]	0.0	North Slope Borough	MLV 15 [b]	517.6	Denali
MLV 2	36.7	North Slope Borough	MLV 16	534.8	Denali
MLV 3 [b]	76.0	North Slope Borough	MLV 18	546.5	Denali
MLV 4	112.0	North Slope Borough	MLV 19	572.2	Denali
MLV 5 [b]	148.5	North Slope Borough	MLV 20 [b]	597.4	Matanuska-Susitna
MLV 6	194.1	Yukon-Koyukuk Census Area	MLV 21	625.8	Matanuska-Susitna
MLV 7 [b]	240.1	Yukon-Koyukuk Census Area	MLV 22	648.2	Matanuska-Susitna
MLV 8	286.1	Yukon-Koyukuk Census Area	MLV 23 [b]	675.2	Matanuska-Susitna
MLV 9 [b]	332.6	Yukon-Koyukuk Census Area	MLV 24	703.7	Matanuska-Susitna
MLV 9A [c]	356.2	Yukon-Koyukuk Census Area	MLV 25	725.9	Matanuska-Susitna
MLV 10	378.0	Yukon-Koyukuk Census Area	MLV 26 [d]	749.1	Matanuska-Susitna
MLV 11 [b]	421.6	Yukon-Koyukuk Census Area	MLV 27	766.0	Kenai Peninsula
MLV 12	444.9	Yukon-Koyukuk Census Area	MLV 28	793.3	Kenai Peninsula
MLV 13	467.1	Yukon-Koyukuk Census Area	MLV 29	799.9	Kenai Peninsula
MLV 14	493.0	Denali	MLV 30 [e]	806.6	Kenai Peninsula

TABLE 2.1.4-4 **Project Mainline Valves**					
Mainline Valve Number	Milepost	Borough or Census Area	Mainline Valve Number	Milepost	Borough or Census Area

[a] Collocated with the GTP.
[b] Collocated with a compressor station.
[c] This MLV was added to the Project as part of PHMSA's review of AGDC's Special Permit for Mainline Valve Spacing application (see section 4.18).
[d] Collocated with the Theodore River Heater Station.
[e] Collocated with the LNG Plant.

Launchers and Receivers

Launchers and receivers are facilities where internal pipeline cleaning and inspection tools, known as "pigs," are inserted or retrieved from the pipeline. Launchers/receivers generally consist of a 20- to 30-foot segment of aboveground piping that tie into the pipeline below the ground surface. A launcher would be installed at the GTP Meter Station; combined sets of launchers/receivers would be installed at each compressor and heater station; and a receiver would be installed at the Nikiski Meter Station. No additional land would be required for the pig launchers and receivers beyond that associated with the other, larger facilities.

Cathodic Protection Systems

Cathodic protection systems help prevent corrosion of underground pipeline facilities. These systems typically include an aboveground transformer-rectifier unit and an associated anode ground bed underground. Select compressor stations, meter stations, and MLV sites would have cathodic protection system facilities (e.g., ground beds and rectifiers).

AGDC would install its cathodic protection system completely within the permanent pipeline right-of-way, including the pipeline segment across Cook Inlet, or at the aboveground facilities (i.e., MLVs, compressor stations, and heater station). Placed within the permanent right-of-way, installed test stations would be in proximity to the edge of the trench line. AGDC would install cathodic protection system deep wells at the MLV and compressor/heater station locations, where required. These wells would be set up for the vertical anode bed and would have a component that extends aboveground. The well locations for the cathodic protection system would be either within the outline of the MLV pad or within the boundary of the stations.

Mainline MOF

AGDC would construct a Mainline MOF consisting of a pier and roll-on/roll-off (RO/RO) ramp on the west side of Cook Inlet (MP 766.0) to support onshore and offshore pipeline construction (see figure 2.1.4-1). The Mainline MOF would provide a marine offloading and backhaul loading point for construction equipment and consumables, fuel, camp components, line pipe, and other construction materials as well as personnel. AGDC would place fuel tanks on the dock to refuel barges. The specially designed fuel tanks would be made of stainless steel and have protective layers to prevent spills. About 6 acres of land would be required to construct the MOF. The pier would be 450 feet long running parallel to the shoreline and 310 feet wide extending into the Cook Inlet. The RO/RO ramp would be about 80 by 120 feet and allow barge delivery. Both the pier and ramp would consist of anchored sheet pile walls backed by granular fill. Two new 30-foot-wide access roads would cut through the existing shoreline bluff and lead to the pipeline right-of-way. No dredging would be necessary to construct or operate the Mainline MOF.

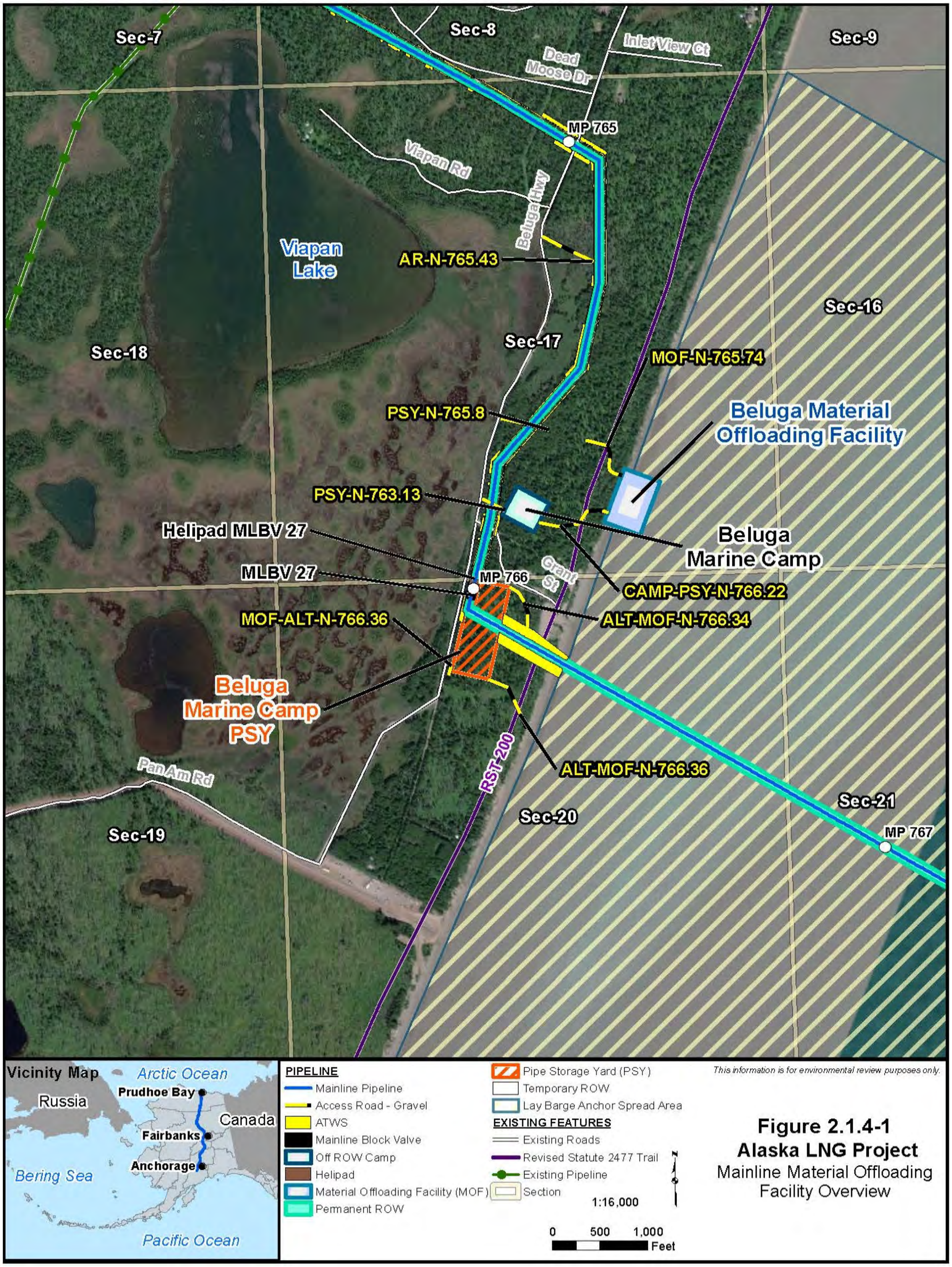


Figure 2.1.4-1
Alaska LNG Project
Mainline Material Offloading Facility Overview

The Mainline MOF would be used during the ice-free season in Cook Inlet. An average of 67 marine vessels per year would arrive at the Mainline MOF, with the peak year occurring in Year 2. AGDC states that the Mainline MOF would remain in place after construction, but it would not be used by AGDC to support Project operation. In comments on the draft EIS, the State of Alaska[7] said that ADNR policy does not allow lessees to abandon docks. Therefore, AGDC would be required to maintain the Mainline MOF under the right-of-way lease for the facility, remove the Mainline MOF following construction, or transfer responsibility for maintenance of the Mainline MOF to a third party by entering into a tideland lease under AS 38.05.070 or as otherwise approved by the Commissioner of the ADNR.

Gas Interconnections

AGDC proposes to install three gas interconnections with an isolation valve along the Mainline Pipeline to allow for future in-state deliveries of natural gas at the following locations (see figure 1-1):

- MP 441.2, to serve the Fairbanks area;
- MP 764.3, connecting to the existing ENSTAR pipeline system to serve the Anchorage/Matanuska-Susitna Valley area; and
- MP 806.6, to serve the existing ENSTAR pipeline system in the Kenai Peninsula area.

Because the gas interconnections would be installed within the operational right-of-way of the Mainline Pipeline, no additional land would be required. The facilities needed to take the gas from these locations would not be under FERC's jurisdiction. AGDC states that there is no specific limit to the potential interconnections available to in-state users upon the execution of binding gas delivery commercial agreements. Additional discussion of the in-state gas interconnections is provided in section 4.19.2.

2.1.4.3 Additional Work Areas

Additional Temporary Workspaces

In some situations, constructing the Mainline Pipeline would require the use of additional temporary workspaces (ATWS). Conditions typically requiring ATWS include:

- roadway, railroad, waterbody, wetland, or other utility crossings;
- sites of construction constraints that require special construction techniques, such as directional micro-tunneling (DMT) entry and exit locations or pipe bends;
- areas requiring extra trench depth;
- spoil storage areas;
- areas where organic layer segregation occurs, with the organic or surface layer defined by AGDC as the top 12 inches of soil (or less) where the majority of soil organic material resides;

[7] The State of Alaska comments included comments from representatives of ADNR, ADEC, Alaska Department of Fish & Game (ADF&G), Department of Commerce, Community, and Economic Development (ADCCED), Alaska Department of Health and Social Services (ADHSS), Alaska Department of Transportation and Public Facilities (ADOT&PF), and Alaska Department of Public Safety.

- locations with soil stability concerns;
- truck turnarounds;
- hydrostatic test water withdrawal and discharge locations; and
- staging and fabrication areas.

AGDC would place its ATWS outside but adjacent to the Mainline Pipeline construction right-of-way. ATWS for the Mainline Pipeline would affect about 1,636 acres of land during construction, resulting in 466 acres of permanent impact. After pipeline installation, ATWS would be restored following the Project Revegetation Plan (see section 2.2 for how to access this plan). Table C-3 in appendix C identifies AGDC's proposed ATWS locations.

Access Roads (Gravel and Ice) and Ice Pads

AGDC would use existing public and private roads and construct new roads to access construction workspaces. If necessary, improvements to existing private roads would be through widening and/or grading, gravelling, installing or replacing culverts, or clearing tree limbs to accommodate the Project's large and heavy construction equipment and material. As with the Gas Treatment Facilities, to construct the Mainline Pipeline, AGDC would construct new roads to access the Project work area. The roads would be either native material, granular fill, or temporary use of snow/ice, depending on the intended traffic load and duration and timing of use. Following construction, AGDC would leave gravel and culverts in place at waterbody crossings unless removal is required by COE permitting. Except for those roads made from snow and/or ice, any road constructed to support construction would remain in place after construction unless the landowner or land management agency asks for its removal. For purposes of the analysis, we have assumed that AGDC would not remove any of the temporary use roads following construction; therefore, impacts associated with these roads would be permanent.

Winter construction on spreads north of the Brooks Range would require roads and work pads constructed of snow and ice in the tundra and in wetland vegetated areas of continuous permafrost. These roads and work pads would use materials such as compacted snow, ice aggregate, mixtures of snow and water, manufactured snow, and/or ice created by flooding the tundra surface to achieve design thickness and width.

AGDC would require the use of 649 roads to access construction workspace (see table C-1 in appendix C). Of the 649 access roads, 160 are existing roads, of which 132 would require no improvements and 28 would require improvements for use by the Project. AGDC would build 489 new roads. Fifty-one access roads would require new culverts to maintain stream flow. For culverts, AGDC would develop a Fisheries Conservation Plan for the Project that incorporates a design and maintenance plan based on the *Anadromous Salmonid Passage Facility Design* (NMFS, 2011a) for fish-bearing streams (see section 4.7.1). Additional information on culverts is provided in sections 4.3.2 and 4.7.1. AGDC would construct 31 ice roads between MPs 0.6 and 86.6 as well as 2 ice roads at MPs 475.9 and 476.1. AGDC would use an estimated 557 million gallons of water to construct these ice roads. Following construction, AGDC would use 16 newly constructed access roads for permanent access to its facilities.

AGDC would use granular fill to expand or improve existing access roads, construct new roads for temporary use during Project construction, and build permanent access roads for Project operation. The granular fill would be obtained from approved material sites off the right-of-way. As noted, AGDC would leave the temporary granular fill roads in place after construction unless the landowner or land management agency requests that the roads be removed as part of the land lease agreements. Granular fill or culverts at waterbody crossings would be removed if required by COE permitting for the Project. Access road construction would disturb about 3,000 acres of land, with 631 acres maintained to support operation.

Helipads and Airstrips

Forty-eight new helipads would be installed using granular fill along the Mainline Facilities during construction, 28 of which would be permanently maintained by AGDC and used during Project operation. Of the 28 helipads, 9 would be in the footprint of compressor stations and the heater station. The remaining 19 permanent helipads would be constructed at MLV sites, affecting a total of 4 acres during Project construction and operation. An additional 20 helipads would be constructed at temporary construction camps and would not be used during operation, but impacts at these sites (e.g., placement of granular fill) would be permanent. The acres associated with the temporary and permanent helipads at construction camps, compressor stations, and the heater station are included with these larger facilities.

During construction, AGDC would use 23 existing airports and airfields to transport personnel and equipment to the Project area. The main airstrips would include Deadhorse, Fairbanks, and Anchorage. Other airstrips would include Beluga, Galbraith, Dietrich, Coldfoot, Prospect Creek, Five Mile Camp, Kenai, and Livengood. No Project-related improvements at the airports or airstrips are anticipated. Tables C-4 and C-5 in appendix C list the Project helipads and airstrips AGDC has identified and their nearest Mainline Pipeline mileposts.

Construction Camps

AGDC would erect construction camps in 46 locations to support construction (see table 2.1.4-5). A total of about 840 acres would be required for construction camps for a period of 3 to 8 years. Construction camps would be a permanent impact because the granular fill pads used for each camp would be left in place following construction. Each construction camp would operate as a self-sustaining unit with fuel storage, power generation, water treatment, food preparation, and wastewater treatment facilities.

Camp sizes would vary depending on the construction activity and locations they would be supporting. AGDC has identified three types of camps: pioneer, Mainline, and facility camps. Pioneer camps would open 2 to 3 years before Mainline Pipeline construction to house personnel involved in development of construction infrastructure, such as developing material sites and building Mainline and facility camps, access roads, and storage and staging areas. These camps would occupy about 4 acres each and house about 120 workers in skid-mounted units. Mainline camps would each occupy about 35 acres and house about 1,200 workers in temporary housing units. Facility camps would each occupy about 8 acres and house about 240 workers in skid-mounted or temporary housing units. A temporary wastewater treatment plant at each construction camp would process and discharge wastewater (e.g., black and grey water) in accordance with ADEC requirements. The specific volumes, types, frequencies, rates, treatments, and disposal mechanisms for wastewater discharges from the wastewater treatment facilities at each construction camp, as well as the approximate locations of potential outfalls and discharge points, would be determined by AGDC as construction plans are finalized and through the acquisition of the required permits for the discharges. Any debris generated at the site would be removed and taken to an approved disposal facility.

TABLE 2.1.4-5

Construction Camps Associated with the Mainline Facilities

Facility Name	Milepost	Type of Camp [a, b]	Acres [b]	Duration of Use (years)
Prudhoe Bay	0.6	Mainline	35	4.25
Franklin Bluffs	43.7	Mainline	35	4.25
Sagwon Compressor Station	76.0	Facility	8	4.25
Happy Valley	86.4	Mainline	35	4.25
Galbraith Lake Special Design Area (SDA) – Atigun [c]	143.0	Mainline/Pioneer	35	0.25
Galbraith Lake Compressor Station	148.5	Facility	8	3.25
Dietrich	205.9	Mainline/Pioneer	35	5
Koyukuk DMT [c]	205.9	Pioneer	4	0.25
Coldfoot Compressor Station	240.1	Facility	8	4.25
Coldfoot	241.1	Mainline	35	4.25
Prospect [b]	279.0	Mainline	35	3
Old Man	305.7	Mainline	35	3
Ray River Compressor Station	332.6	Facility	8	4.25
Ray River Pipe Storage Yard [c]	332.6	Pioneer	4	3
Five Mile	353.7	Mainline/Pioneer	35	3.25
Yukon DMT [c]	353.7	Pioneer	4	0.25
Livengood	401.0	Mainline	35	5
Wilbur Creek Pipe Storage Yard [c]	407.2	Pioneer	4	5
Minto Compressor Station	421.6	Facility	8	3
Murphy Dome [c]	441.2	Pioneer	4	5
Dunbar	456.1	Mainline/Pioneer	35	5
Tanana DMT	456.1	Pioneer	4	0.25
Rex	498.6	Mainline	35	0.25
Healy Compressor Station	517.6	Facility	8	3
Healy [c]	528.9	Mainline/Pioneer	35	3.25
SDA Nenana at Moody [c]	528.9	Pioneer	4	1.25
SDA Lynx Creek Crossing [c]	528.9	Pioneer	4	1.25
52-2-064-2 FP	551.3	Pioneer	4	2.25
Cantwell	567.5	Mainline	35	0.75
35-4-033-2 FP	582.2	Pioneer	4	1.75
Honolulu Creek Compressor Station	597.4	Facility	8	1.5
Hurricane	606.6	Mainline	35	1.5
35-4-025-2 FP	607.0	Pioneer	4	2
35-3-010-1 FP	637.5	Pioneer	4	2
Chulitna	647.8	Mainline	35	0.75
Logged Pipe Storage Yard [c]	672.0	Pioneer	4	3.25
Chulitna DMT [c]	672.0	Pioneer	4	0.25
Rabideux Creek Compressor Station	675.2	Facility	8	3.25
Susitna	693.7	Mainline/Pioneer	35	1.25
Deshka DMT [c]	693.7	Pioneer	4	0.5
Sleeping Lady	744.9	Mainline	35	3

TABLE 2.1.4-5 (cont'd)				
Construction Camps Associated with the Mainline Facilities				
Facility Name	Milepost	Type of Camp [a, b]	Acres [b]	Duration of Use (years)
Theodore River Heater Station	749.1	Facility	8	3
Beluga Marine	765.8	Mainline/Pioneer	35	0.5
Shorty Creek - Shore Crossing [c]	765.8	Pioneer	4	0.25
Kenai	803.5	Mainline/Pioneer	35	2.5
Suneva Lake -Shore Crossing [c]	803.5	Pioneer	4	1

SDA = Special Design Area

[a] AGDC would place pioneer camps in areas associated with aboveground facilities. Each pioneer camp footprint would overlap with the aboveground facility.

[b] For the camps listed as Mainline/Pioneer, it is assumed that the pioneer camp footprint would overlap with the Mainline camp.

[c] These camps were included at a later date and are not represented on the Project maps provided in appendix B.

Contractor Yards, Pipe Storage Yards, and Rail Yards and Spurs

AGDC would use 30 contractor yards (collocated with construction camps or pipe storage yards) for staging, material storage, and other contractor support associated with the Mainline Pipeline and the PTTL. Forty-six pipe storage yards would be along the Mainline Pipeline and PTTL. AGDC would set up two additional yards where welders would join single 40-foot lengths of pipe into 80-foot or double joints of pipe. One of these double joining yards would be off Pittman Road, northwest of Wasilla, and one would be near Fairbanks.

During construction, a total of 674 acres would be used for yards, including 474 acres for pipe storage yards and 200 acres for double joining yards. Pipe storage yards would be about 6 to 15 acres in size. Pipe would typically be delivered from the double joining yards, in double-jointed (80-foot nominal, 76-foot estimated) lengths. Exceptions would include single joints for concrete coated crossings, test manifolds, steep terrain, valve pumps, and other locations, and possibly joints for use in the stress-based design areas.

The Project would transport pipe and major equipment to the appropriate work area using the Alaska Railroad system. To support the railroad transport, AGDC would construct eight rail yards or siding areas. A rail spur to each of these sidings would facilitate the unloading of Project material onto a newly built granular fill pad. Construction would use about 48 acres of land for railroad sidings and rail spurs. While AGDC would not remove these facilities following construction, they are not proposed for use during Project operation. AGDC would truck materials from the railyards to the appropriate pipe and/or contractor yards if the railyards do not otherwise intersect a Project work site.

Table C-6 in appendix C provides a list of the contractor yards, pipe storage yards, and rail yards and spurs associated with the Mainline Facilities, and the distance and direction from the nearest Mainline Pipeline milepost.

Disposal Sites

Waste material generated during construction includes construction wastes from packing of material and supplies, camp refuse, sanitary waste, and construction debris (i.e., excavated material such as vegetation, rock, ice-rich soils, soils with fines content greater than 45 percent, stumps, blast rock, and acid rock drainage material). As described in the Project Gravel Sourcing Plan and Reclamation Measures, Project disposal sites would be used for the disposal of construction debris. These disposal sites would require about 230 acres at 109 locations with 31 sites on Spread 1, 44 sites on Spread 2, 20 sites on Spread 3, and 14 sites on Spread 4. Land associated with disposal sites would be permanently affected by the Project. Table C-7 in appendix C identifies the disposal sites proposed by AGDC by spread. Wastes from packing materials, supplies, camp refuse, and other garbage would either be burned in an incinerator on site, where allowed, or transported to existing permitted waste disposal facilities in accordance with applicable regulations. A summary of wastes and estimated quantities from construction is provided in the Project Waste Management Plan.

Material Sites

Material sites would provide the various construction materials (e.g., sand, gravel, and stone) required for Project construction, including base material for aboveground facility pads, temporary construction facilities (e.g., work pads), access roads, and other uses. AGDC's estimates that about 19.7 million cubic yards of granular fill would be needed for the Mainline Facilities, including volumes for right-of-way stabilization, bedding and padding of the pipe, weight bags and slope stabilization, aboveground facility pads, access roads, construction camps, and pipe storage yards. For more details on granular fill volumes by construction activity, see section 4.1.2.

AGDC identified 153 material sites (including both primary and alternate locations) for the Project, of which 68 would be new sites (see table C-8 in appendix C). Material sites would encompass about 5,855 acres. AGDC would use about 60 percent of the granular fill between MPs 0.0 and 400.7 on construction Spreads 1 and 2. Land associated with material sites would be permanently affected by the Project (except in cases where a landowner requires site reclamation).

2.1.5 Liquefaction Facilities

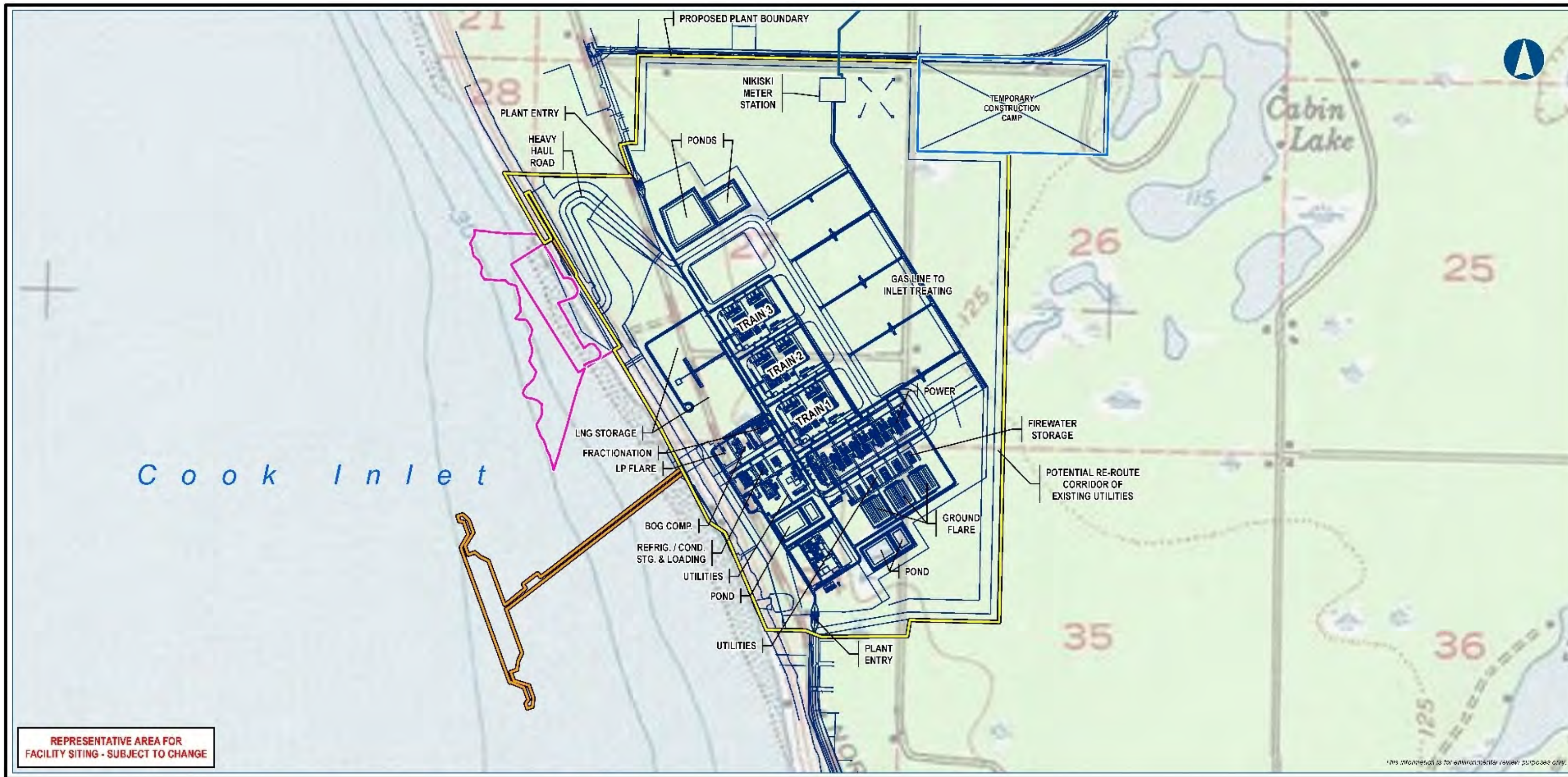
AGDC would construct the Liquefaction Facilities on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula. The Liquefaction Facilities would be comprised of two components: the LNG Plant and the Marine Terminal. About 2,283 acres would be disturbed during construction of the Liquefaction Facilities, of which 921 acres would be maintained for Project operation. Of the 2,283 acres, about 1,003 acres would be permanently affected. Figure 2.1.5-1 shows the proposed Liquefaction Facilities. Wastewater would be treated at on-site treatment facilities prior to discharge to Cook Inlet according to the effluent requirements described in the APDES individual permit.

2.1.5.1 LNG Plant

The LNG Plant would consist of three liquefaction trains, a meter station, LNG storage tanks, flares, power plants, water supplies, associated infrastructure, and ATWS (see figure 2.1.5-2). Construction and operation of the LNG Plant would require 902 acres. The existing Kenai Spur Highway would be relocated to accommodate the LNG Plant (see sections 1.5 and 4.19.2.3). All areas required for LNG Plant construction would also be used for operation. The LNG Plant includes the area required by regulation for safety and vapor dispersion zones. Operation of the LNG Plant would result in discharges of treated wastewater, boiler blowdown waters, reverse osmosis reject water, and site stormwater to Cook Inlet.

Inlet Receiving

The LNG Plant feed gas would enter through the meter station on the site's northern boundary. The meter station would include isolation valves, above-grade piping, an instrument building, a meter run building, a gas chromatograph, pig receiver, and flow metering. Constructed on a granular fill pad, the meter station would be powered from the on-site LNG power plant. Prior to liquefaction, the feed gas would pass through an inlet filter to separate any liquids. The feed gas would then be pre-treated to remove water and potential mercury (see below).



Legend
- Alaska LNG Rev C2 Route
- LNG Plant Generalized Plot Plan Features
- LNG Plant Operations Area
- LNG Plant Construction Camp
- Marine Terminal Footprint Operations Area
- Temporary MOF and MOF Dredging Area

0 1,000 2,000 Feet

1:17,000

Figure 2.1.5-1
Alaska LNG Project
Liquefaction Facilities

Figure 2.1.5-2
Alaska LNG Project
LNG Plant Overview

LEGEND
- LNG Property Boundary
- LNG Facility Features
- LNG Train 1
- LNG Train 2
- LNG Train 3

0 500 1,000 Feet

SCALE: 1:12,500 DATE: 2017-02-27

Mercury Removal and Dehydration

To prevent corrosion of aluminum equipment, mercury would be removed from the feed gas by absorption in mercury removal beds. AGDC would replace the mercury removal beds by the end of their service life. Maintenance and safety procedures would cover the proper replacement and disposal of spent materials. After exiting the mercury removal system, the natural gas would pass through the dehydration beds, which would consist of molecular sieve dehydration vessels that remove water vapor. Each dehydration unit would consist of six molecular sieve vessels, five operating in water adsorption mode and one in regeneration/standby mode. These beds would work in parallel with the heavy hydrocarbon removal column once the gas steam has passed through a dehydration unit.

In comments on the draft EIS, the State of Alaska requested information on disposal methods for mercury. AGDC has said that removal and disposal of mercury absorption beds would be performed in accordance with applicable regulations by a qualified third-party contractor. Mercury absorption beds would be disposal of at an EPA-permitted hazardous waste landfill or treated at a permitted thermal treatment site where the material is destroyed in high-temperature kilns with proper scrubbing of exhaust gases. AGDC's Project Waste Management Plan identifies anticipated quantities of waste from operation of the Liquefaction Facilities, including for mercury absorption beds. Instructions for accessing this plan are provided in section 2.2.

Liquefaction

Following pre-treatment, three liquefaction-processing units, or trains, would liquefy the natural gas. AGDC would use the Propane Precooled Mixed Refrigerant (AP_C3MR™) Process, an Air Products and Chemicals, Inc. patented technology. In this process, the treated natural gas would be pre-cooled in successive stages of propane chilling. Subsequent cooling and liquefaction would occur by heat exchange against mixed refrigerant in the main cryogenic heat exchanger. Prior to entering the main cryogenic heat exchanger, the mixed refrigerant would be cooled/partially condensed. The refrigeration for this pre-cooling would occur by multiple stages of propane chilling.

Each of the three liquefaction trains would include two refrigerant compression strings installed in parallel, driven by two natural gas turbines. The propane and mixed refrigerant would be cooled using air coolers. Fans would pull the air over tube bundles, in turn cooling within the tube bundles. Air-cooled LNG plants are influenced by air temperature variation. The air cooler inlet air-dry bulb design temperature would vary between a low ambient of 2°F and a high ambient of 61°F.

Liquefaction Process

Figure 2.1.5-3 depicts the liquefaction process. The main processes are summarized in the subsections below. The three liquefaction trains would feed into a single unit consisting of three distillation columns to remove ethane, propane, and butane and stabilize the condensate product. This process is called fractionation. AGDC would re-inject ethane and propane into the feed gas to maximize LNG production. A small amount of ethane and propane would be used for refrigerant. The remaining condensate would be sent to the condensate storage tank and transported by truck to nearby industrial customers.

LNG Storage Tanks

Two LNG storage tanks, each with a net capacity of about 63.4 million gallons, would store the LNG produced by the three liquefaction trains. The storage tanks would be designed to meet the requirements of the NFPA Standard 59A, PHMSA's regulations at 49 CFR 193, and other applicable standards (see figure 2.1.5-4 for a typical LNG storage tank design).

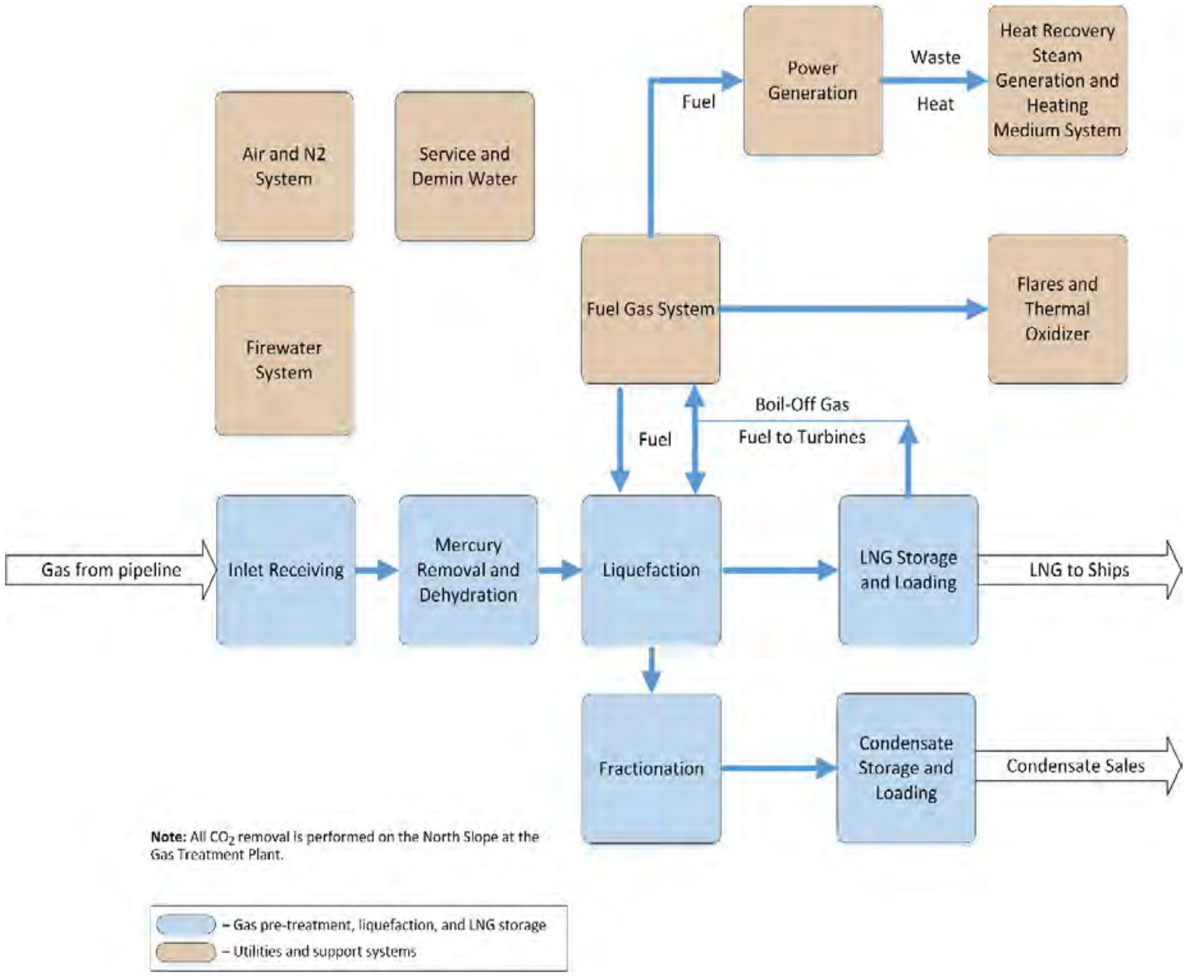
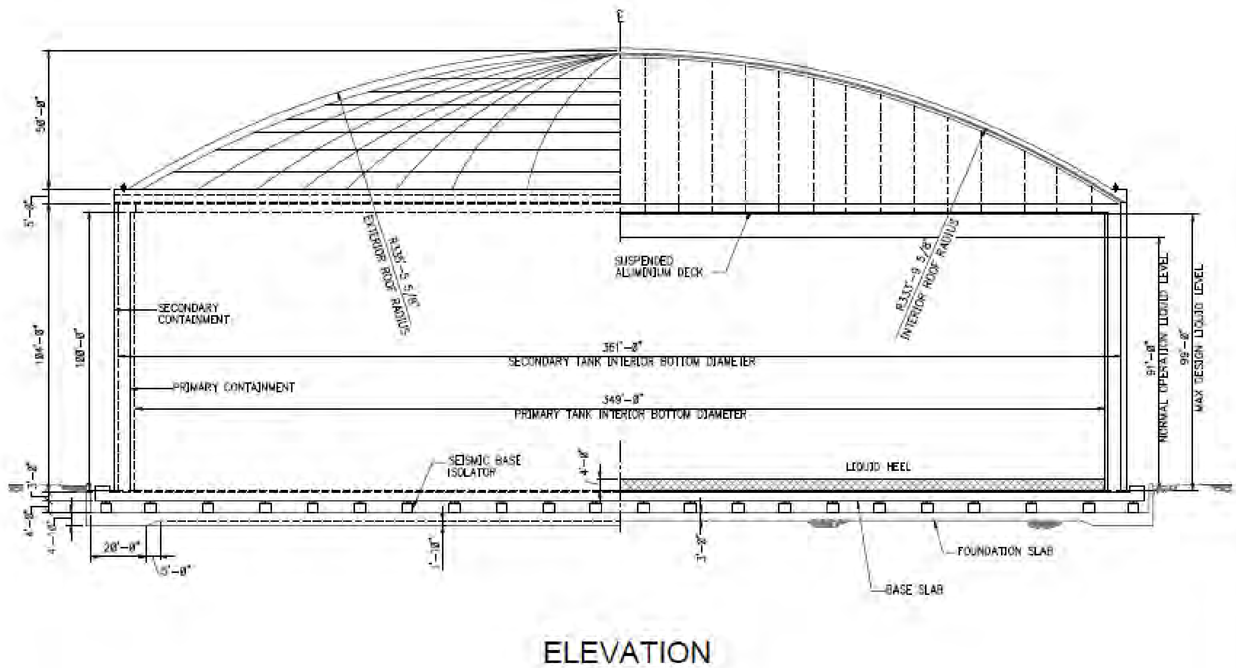


Figure 2.1.5-3 Liquefaction Process Block Diagram

Figure 2.1.5-4
Alaska LNG Project
LNG Tank Typical Drawing



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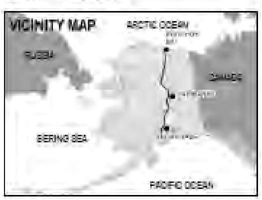

PRELIMINARY & SUBJECT TO CHANGE. ALL DRAWINGS AND DIMENSIONS TYPICAL

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The two LNG storage tanks would be full-containment tanks with a self-supporting primary container and a secondary container. The primary, inner container would store the LNG under normal operating conditions. The secondary container would be capable of holding the maximum quantity of LNG and controlling the vapor resulting from the unlikely occurrence of product leakage from the inner container. The tanks would be designed with a precast concrete inner tank with a 9-percent nickel bottom and a precast concrete outer tank. The tanks would have an outside diameter of 361 feet and would be 159 feet tall (top of the foundation slab to top of the dome roof). Each of the tanks would provide storage capacity of 3 to 4 days of production.

Fuel Gas System and Boil-Off Gas Compression

The Fuel Gas System would be a common system for both continuous use and applicable intermittent fuel gas use and would supply both high pressure and liquefied petroleum fuel gas. The expected fuel consumption would range from 5.1 billion to 5.4 billion British thermal units per hour and 0.8 to 1.2 billion British thermal units per hour, respectively, during normal operation.

The boil-off-gas (BOG) (vaporized LNG) generated from the Liquefaction Facilities, including LNG lines, LNG loading pumps, storage tanks, and LNG loading operations, would be compressed and routed to the fuel gas system. BOG generated in excess of fuel gas demand would be recycled to the natural gas stream entering the liquefaction process. BOG from the LNG storage tanks and loading operations would provide the majority of the overall plant fuel needs for operation, including power generation.

Flares

A flare stack is a gas combustion device primarily used for burning off flammable gas released by pressure relief valves. The purpose of a pressure relief and flare system is to protect plant systems from overpressure during start-up, commissioning, shutdown, plant upsets, and emergency conditions. Upset events that require flaring or depressurizing are not planned and the control system is designed to prevent such events. Planned flaring is associated with system cool down and maintenance shutdown scenarios.

AGDC would install two flare systems, including a ground flare on the LNG Plant and a low-pressure flare near the Marine Terminal. The ground flare system would be a multipoint ground flare with a radiation fence about 52 feet high. The ground flare's radiation fence area would encompass about 14 acres. The ground flare would not be directly visible to the public due to shielding by radiation fencing.

The low-pressure flare would be on shore adjacent to the Marine Terminal. It would be about 200 feet high and would support marine operations. The flare ignites only when the over-pressure valve opens and when a flammable gas mixture is present at the flare tip. This is a safety overpressure system and not designed for use during normal operation. This flare would be visible to the public.

Ancillary Facilities

Ancillary facilities include power supply, cathodic protection, diesel fuel, water supply, condensate storage facilities, communications facilities, a consolidated building complex, and other utilities and support systems.

<u>Power Supply</u>

The Homer Electric Association would provide electric power during construction. AGDC would coordinate with the Homer Electric Association to construct a connection to the existing power line along the Kenai Highway. AGDC would operate its own centralized essential power back up system consisting of diesel generators connected together powering only the systems necessary to maintain plant safety during power failure. During operation, power would be generated by the BOG as indicated above.

Cathodic Protection System

The design for cathodic protection of the facilities is an impressed current cathodic protection system for the jacketed structure supports and steel pilings. The individual pile and jacketed structures would be bonded to each other to form an electrically continuous steel structure. Due to the large tidal range, and the presence of moving ice during the winter months on Cook Inlet, a secondary system for cathodic protection would consist of an additional steel pipe encasement over the nearshore zone during operation.

Diesel Fuel System

Diesel would fuel backup generators, air compressors, and firewater pumps for the LNG Plant. The diesel fuel tank would be an aboveground tank of low temperature carbon steel that would hold 7,138 gallons within a secondary containment system.

Water Supply Systems

Fresh water from the City of Kenai water system would supply the LNG Plant, but improvements to this system would be required (see sections 1.5 and 4.19.2.4). These improvements include:

- two new 12-inch-diameter water wells and yard piping at the Wellfield 2 site;
- expansion of the existing water treatment plant capacity from 1.5 million to 2.5 million gallons per day;
- construction of two new distribution pump houses;
- replacement of 500 feet of distribution piping at Wellfield 2; and
- construction of 6.1 miles of new 16-inch-diameter water distribution pipeline connecting the west end of the existing City of Kenai system with the LNG Plant.

For Project operation, the water supply system would consist of lift pumps with intake screens, two freshwater storage tanks with a total storage of over 1.4 million gallons, freshwater tank feed lines, and a supply line to the firewater tanks.

A water treatment system would include a cartridge filter in combination with reverse osmosis and electro deionization to produce high quality demineralized water for high-pressure steam generation. Freshwater would be treated through multiple processes to meet the various water service needs in the plant. These include demineralization water, potable water, and utility water. Reverse osmosis reject water would be discharged to Cook Inlet, as noted in section 2.1.5.1.

Firewater System

A firewater tank would provide the primary firewater supply for the facility and have sufficient water to fight the largest credible fire for 4 hours. The tankage would hold about 1.2 million gallons, which is two times the amount required by the NFPA 59A (fire-fighting capacity for at least 2 hours). The lines along the trestle would be freeze-protected to ensure flow year-round.

Condensate Storage Facility

About 42,000 gallons per day of condensate, including extracted pentane and heavier hydrocarbons removed from the natural gas stream by the liquefaction process, would be hauled off the facility by truck (about five to six trucks with an 8,000-gallon capacity per truck per day). The condensate product would first be stored on site in a condensate storage tank.

Communications Facilities

Site communications systems would include a permanent communication tower (about 150 feet high) and fiber optic and structured cabling, telephone, radio, and meteorological systems. The communication tower would be lit in accordance with Federal Aviation Administration (FAA) requirements. These facilities would not require additional areas of disturbance, as they would be placed on developed areas within the LNG Plant.

Consolidated Building Complex

A consolidated building complex would provide offices, conference space, a maintenance/shop area, emergency response area, warehouse, and laboratory area. It would also include areas for climate-controlled storage, dispensing material for daily operations, and office facilities for warehouse personnel. The laboratory area would contain equipment capable of analyzing refrigerants, processing gas, fuel gas, and LNG, and performing liquid hydrocarbon and water analysis.

2.1.5.2 Marine Terminal

The Marine Terminal would be constructed adjacent to the LNG Plant in Cook Inlet and would allow LNG carriers to dock and load LNG. The terminal would include a product loading facility (PLF) and a temporary MOF, referred to as the Marine Terminal MOF (see figure 2.1.5-5).[8] The Marine Terminal would require about 49 acres during construction and 19 acres for fixed facilities during operation.

Product Loading Facility

The PLF would consist of two berths for docking the LNG carriers, the piping necessary to deliver LNG from shore to the LNG carriers, and the equipment to dock LNG carriers. This would be a permanent facility for the duration of the Project export operations. The berths would be in natural water depths greater than -53 feet mean lower low water (MLLW) and about 1,600 feet apart. No dredging would be required for the PLF. Each berth would have four breasting dolphins to assist moored LNG carriers by absorbing loads generated by sea state conditions as well as by serving as mooring points to restrict movement of the vessel. The breasting dolphins would have a pre-cast concrete deck (platform) with railings for personnel engaged in the mooring process and for emergency release mooring hooks and winch. In addition, each berth would have six concrete pre-cast mooring dolphins with mooring hooks that would secure the vessel alongside the berth during cargo loading operations.

The berths would facilitate the docking of LNG carriers ranging in size between 125,000 and 216,000 cubic meters (m^3). The estimated number of vessels per month ranges between 17 and 30 (204 and 360 per year), with an average of 21 vessels per month, assuming a nominal 176,000-m^3 LNG carrier design vessel. An LNG carrier could enter or leave the berth while loading operations are occurring at the other berth.

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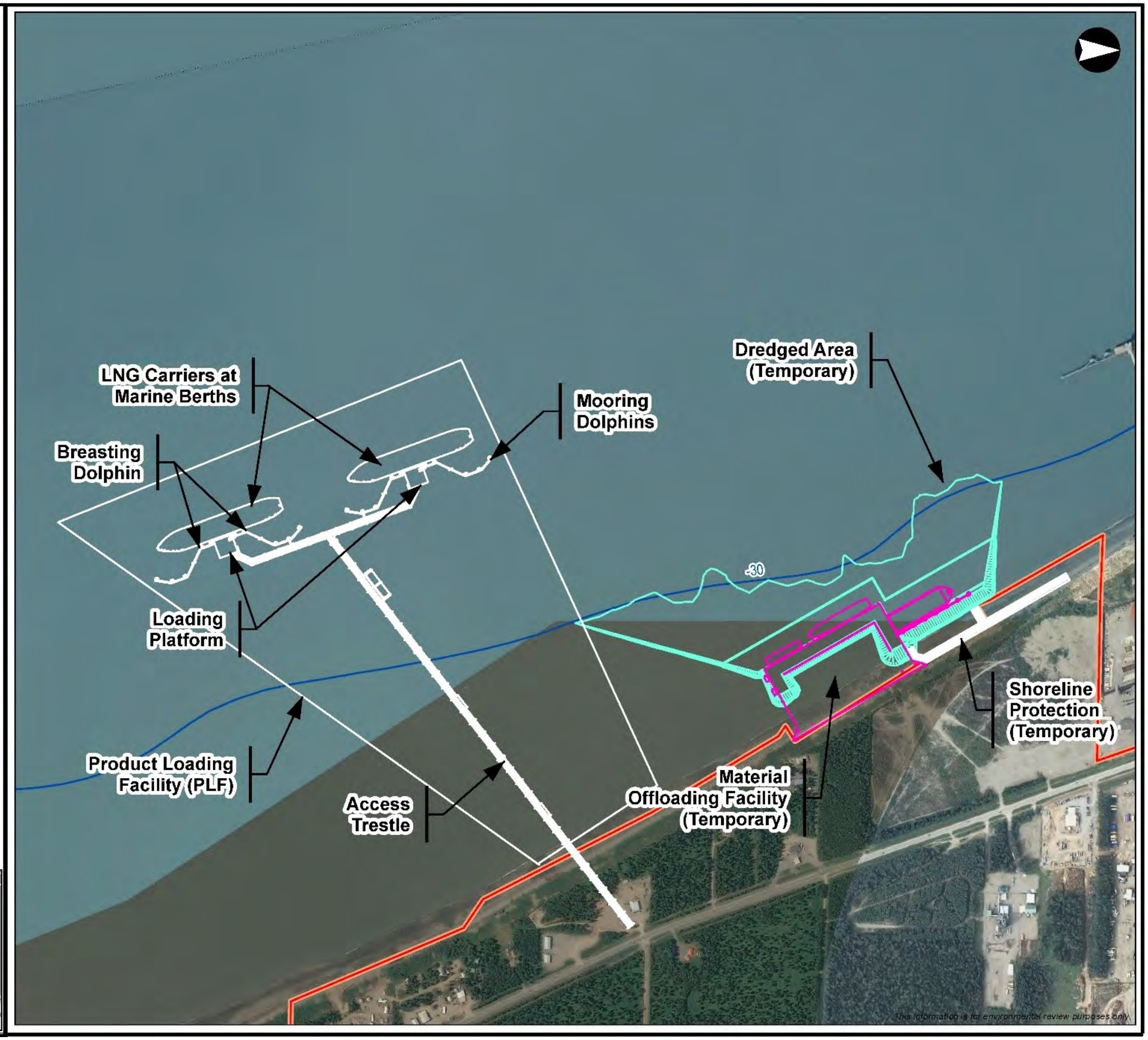
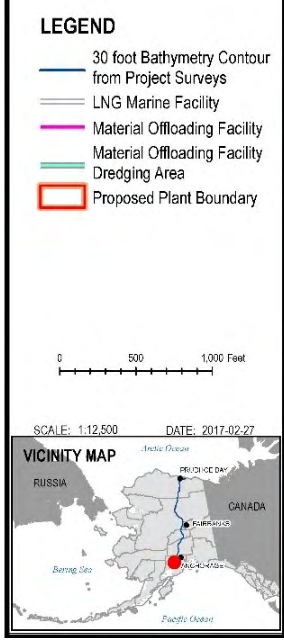
[8] The dredging area depicted on figure 2.1.5-5 is discussed in section 2.1.5.2.

Figure 2.1.5-5
Alaska LNG Project
Marine Terminal





The loading platforms would be connected to each other and to the shore by means of a single access trestle, which would be a steel jacket structure with decking connecting the storage tanks onshore to the loading platforms at the offshore end of the trestle. The trestle would extend out 3,300 feet to eliminate the need for dredging. The trestle would support pipe rack modules and a roadway (side by side) from the shoreline to the loading platforms. The trestle support piles would be spaced at 120 feet. The roadway would be one-lane and a standard width of 15 feet with bypass bays (roadway width of 30 feet) at three locations along the trestle. The trestle would slope down from the top of the bluff (about +116 MLLW) to the berths (about +50 MLLW), as measured from the top of the piles.

LNG Carriers

The ships that transport LNG are specially designed and constructed to carry LNG for long distances. LNG carrier construction is highly regulated and consists of a combination of conventional ship design and equipment with specialized materials and systems designed to contain liquids stored at a temperature of -260 °F.

LNG carriers are constructed with double hulls, which increase the structural integrity of the hull system and provide protection for the cargo tanks in case of an accident. The space between the inner and outer hulls is used for water ballast. Sufficient ballast water capacity must be provided to permit the ship safe transit under various sea conditions. Typically, a ballast control system, which permits simultaneous ballasting during cargo transfer operations, is also incorporated into each LNG carrier. This allows the LNG carrier to maintain a constant draft during all phases of its operation to enhance performance. A typical LNG carrier would discharge about 9 million to 12 million gallons of ballast water into Cook Inlet during loading operations.

LNG carriers calling at the Marine Terminal would comply with all federal and international standards regarding LNG shipping. As such, ships that transport LNG from the Marine Terminal would be fitted with an array of cargo monitoring and control systems. These systems would automatically monitor key cargo parameters while the ship is at sea and during cargo operations at the unloading facilities. The system includes provisions for pressure monitoring and control, temperature monitoring of the cargo tanks and surrounding ballast tanks, emergency shutdown of cargo pumps and closing of critical valves, monitoring of tank cargo levels, and gas and fire detection.

Marine Terminal MOF

The Marine Terminal MOF would consist of two berths and a dock, which would be used during construction of the Liquefaction Facilities to enable direct deliveries of equipment modules, bulk materials, construction equipment, and other cargo to minimize the transport of large and heavy loads over road infrastructure. The dock would be about 1,050 feet long and 600 feet wide, which would provide sufficient space for cargo discharge operations and accommodate 200,000 square feet of staging area. The dock would have an outer wall consisting of combi-wall (combination of sheet piles and pipe piles) tied back to a sheet pile anchor wall and sheet pile coffer cells, backfilled with granular fill. Berths at the MOF would include one Lift-on/Lift-off (LO/LO) berth and one RO/RO berth.

Cargos would be unloaded at the RO/RO berth or the LO/LO berth. The LO/LO berth would allow crane and derricks to load and unload ships, and the RO/RO berth would allow wheeled cargo to roll on and off the vessel. The MOF could receive multiple vessels to its docks, and these vessels could remain at the MOF over a period of several days while equipment and materials are unloaded.

AGDC estimates that the Marine Terminal MOF would require about 6,000 feet of sheet piling and 136 piles. The dock would require about 600 feet of sheet piling in Cook Inlet. The Marine Terminal MOF would require intermittent pile driving during construction Years 1 and 2. AGDC proposes to use vibratory hammers and impact hammers to install the piles.

Constructing the Marine Terminal MOF would require dredging in Cook Inlet to create a ship maneuvering area (see figures 2.1.5-5 and 2.1.5-6). AGDC proposes to dredge a 51-acre maneuvering area. The estimated dredge volume for the Marine Terminal MOF totals about 800,000 cubic yards, which includes:

- 165,000 cubic yards for MOF foundation preparation (conducted over two construction seasons);
- 492,000 cubic yards for dredging of the MOF berths and the approach; and
- 143,000 cubic yards of over-dredge tolerance for MOF berths and approach.

The dredging would occur during Years 1 and 2 of construction. Additionally, about 140,000 cubic yards of maintenance dredging for the Marine Terminal MOF would be conducted between Years 3 and 7 of construction. The Marine Terminal MOF would be designed with a nominal design life of 10 years. AGDC proposes to remove the Marine Terminal MOF when the Liquefaction Facilities are in operation.

AGDC would use existing dock facilities at Arctic Slope Regional Corporation's Nikiski Fabrication Facility and Rig Tenders Marine Terminal facilities without major modification as a "Pioneer MOF." The Pioneer MOF would support construction prior to completion of the Marine Terminal MOF and during peak construction periods. In addition to making use of the existing dock facilities, AGDC would also use the facilities for laydown areas and storage and office space.

2.1.5.3 Additional Work Areas

Offshore Dredged Material Disposal Areas

AGDC proposes a new offshore-unconfined aquatic dredged material disposal site to accommodate the total volume of material dredged for the Marine Terminal MOF. AGDC has identified two potential sites and plans to permit both for potential use by the Project (see figure 2.1.5-7). One open-water disposal location (DP1) would be about 4 miles west of the MOF. DP1 was selected because it is in relatively deep water (between -60 and -85 feet MLLW) with strong currents (over 6.5 knots peak flood and over 5.5 knots peak ebb), which would disperse dredged sediment placed at the site and prevent mounding of the material. An alternative open water disposal location (DP2) would be in deeper water (between -85 to -110 feet MLLW). Dredged material transport and placement would require a total of 1,200 acres. As discussed in section 4.3.3, AGDC conducted sediment dispersion and deposition modeling, which showed that either site could accommodate the anticipated volume of dredged material from the Project. The disposal site location would be subject to COE approval and concurrence from the EPA.

Construction Camp

A construction camp would be used to accommodate the workforce required to build the Liquefaction Facilities and would include dormitories, a cafeteria, recreation rooms, and other amenities. The construction camp would be on about 81 acres of land adjacent to the LNG Plant. The construction camp would have a design life of about 6 years, and its installation would be one of the first on-site activities. Prior to camp construction, Project personnel (less than 300 persons) would stay in local accommodations.

The workforce size would peak at 4,400 persons. The camp design would be modular with the ability to add additional accommodations. The construction camp would be adjacent to the LNG Plant site to prevent the need for off-site traffic and road crossings during shift changes. This would minimize impacts on local traffic and reduce the risk of potential traffic accidents for workers and residents.

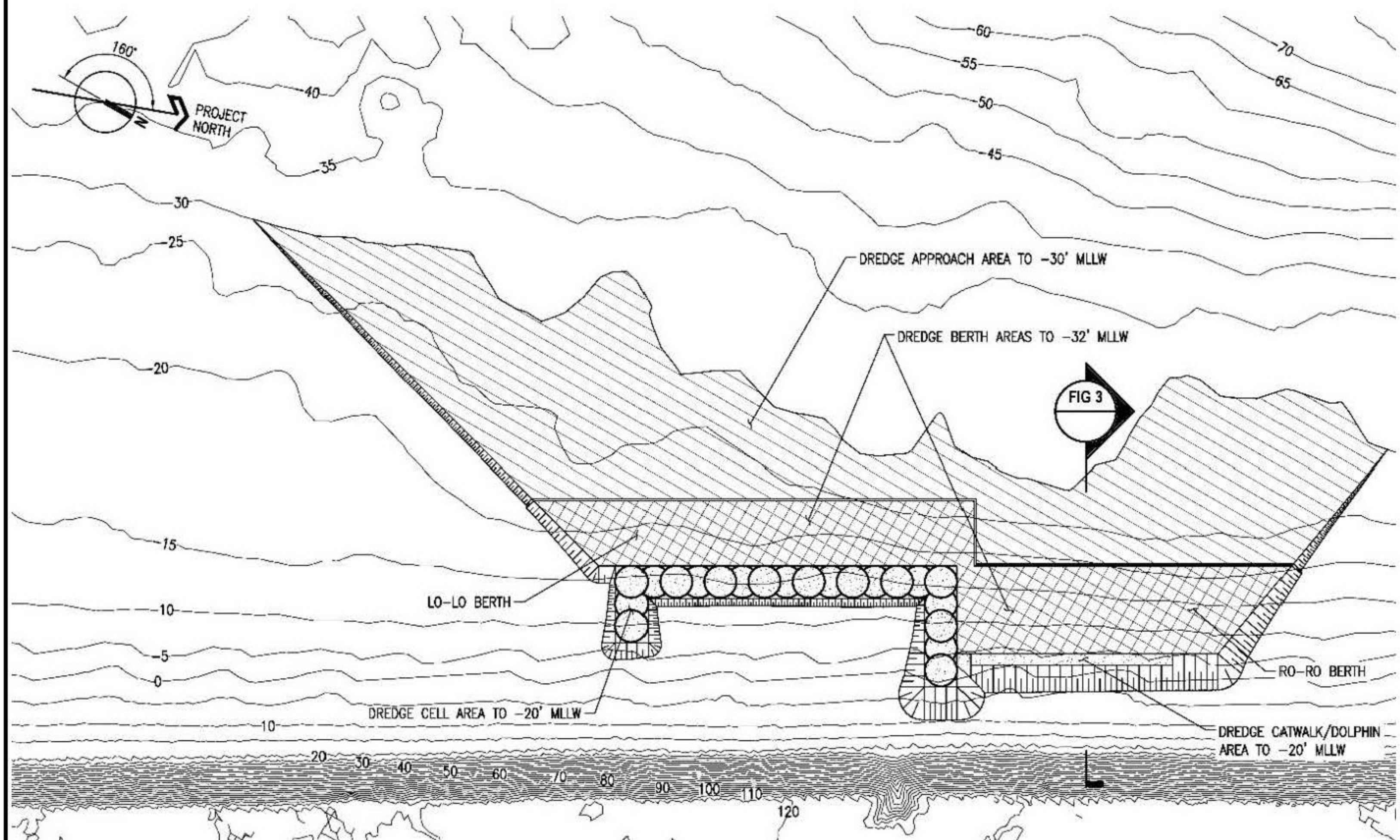


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Figure 2.1.5-6

Alaska LNG Project

Terminal Material Offloading
Facility Dredge Footprint

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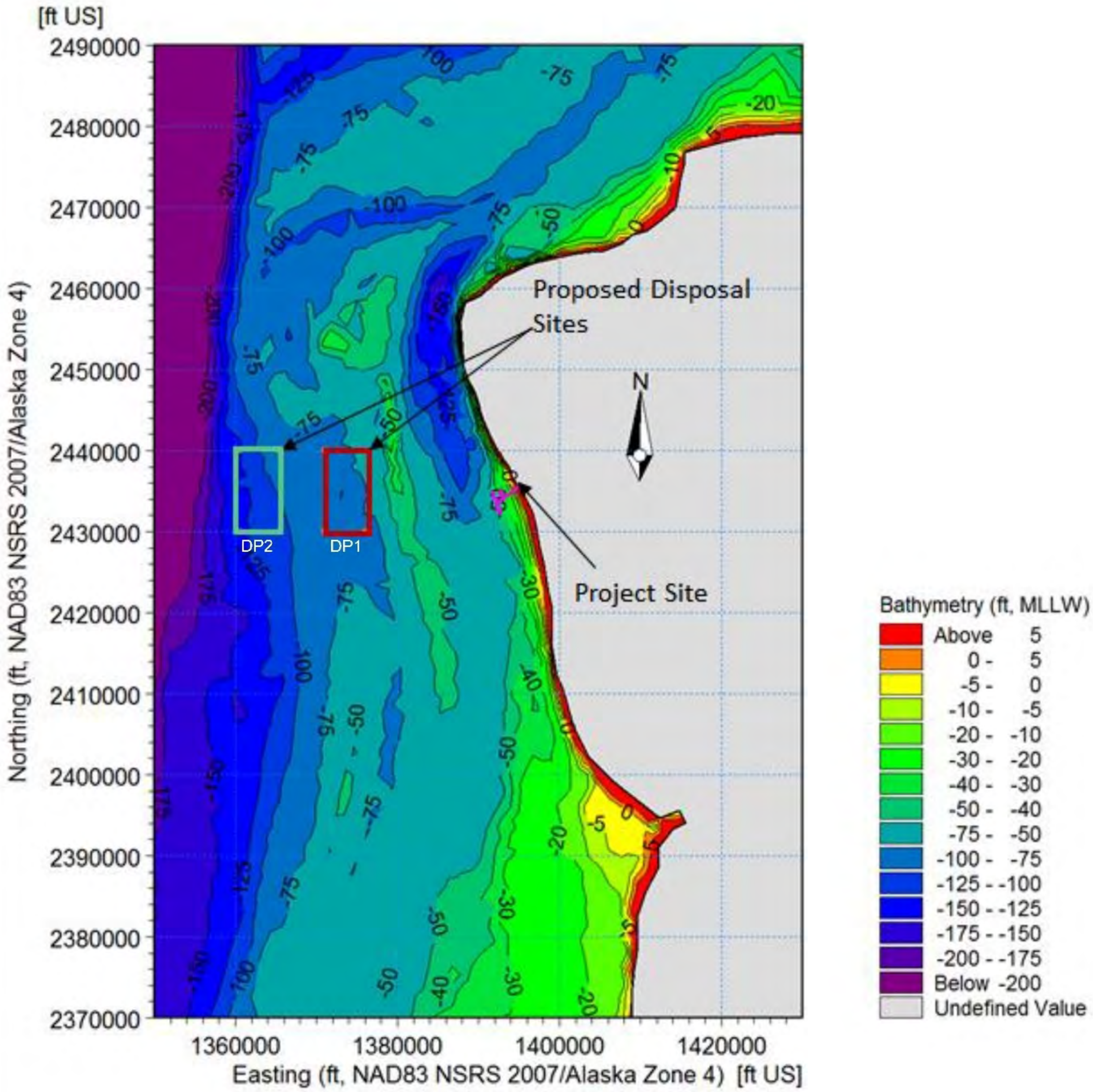

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Figure 2.1.5-7
Alaska LNG Project
Marine Terminal Material Offloading Facility
Dredged Material Disposal Locations

DATE: APRIL 14, 2017

Heavy Haul Road

AGDC would construct a dedicated heavy haul road for the transit of large heavy modules from the Marine Terminal MOF to their permanent foundations. The 18-acre, approximately 3,500-foot-long road would be constructed from the shoreline to the top of the bluff. To minimize the area used for the heavy haul road up the bluff from the MOF, AGDC would arrange the road with a "Z" shape. Rather than use space on a wide swept bend, the module transport would change direction by reversing to navigate the road. The heavy haul road would be coarse hot-mix asphalt over a crushed aggregate base to withstand the heavy loads and provide a weather-resistant surface.

Material Sites

Construction of the Liquefaction Facilities would require about 4.7 million cubic yards of granular fill. The fill would be used in concrete production and as base material on building pads, access roads, and temporary laydown and staging areas. AGDC's geophysical and geotechnical investigations at the LNG Plant site indicate that the site would provide a significant portion of the necessary material. About 1.0 million cubic yards would be cut from the heavy haul road and reused to build the Marine Terminal MOF. The eastern portion of the site would provide the remaining granular fill. Processing of the granular fill would be required to meet the engineering purpose, which AGDC would do on site. Additionally, AGDC has indicated that multiple existing quarries within 20 miles of the Liquefaction Facilities could provide additional granular fill if necessary.

Additional Temporary Workspaces

AGDC identified ATWS at the LNG Plant and Marine Terminal for parking; stockpiles of aggregate and sand, the organic layer, and snow; on-site offices and shops; warehouse areas; chemical storage areas; concrete batch plants; wash facilities; and laydown areas. ATWS would be within the LNG Plant site and the Marine Terminal MOF area. The affected area for ATWS is included in the total acres for the LNG Plant and Marine Terminal MOF.

2.2 CONSTRUCTION PROCEDURES

In its application and subsequent filings, AGDC provided plans describing how it would construct and maintain the Project. These plans also include measures to avoid or minimize potential impacts on the environment. The environmental avoidance and impact minimization measures identified in AGDC's plans are based on our *Upland Erosion Control, Revegetation and Maintenance Plan* (FERC Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (FERC Procedures).[9] AGDC has adopted these plans, referred to as the Project Plan and Procedures,[10] with a number of proposed modifications.

FERC allows applicants to request modifications to the FERC Plan and Procedures; however, an applicant must specify in its application any individual measures it considers unnecessary, technically infeasible, or unsuitable due to local conditions, and describe alternative measures it proposes to implement.

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[9] The FERC Plan and Procedures are a set of construction and mitigation measures that were developed in collaboration with other federal and state agencies and the natural gas pipeline industry to minimize the potential environmental impacts of the construction of pipeline projects in general. They are performance based, which allows applicants to incorporate adaptive management strategies to remain in compliance. The FERC Plan can be viewed on the FERC Internet website at http://www.ferc.gov/industries/gas/enviro/plan.pdf. The FERC Procedures can be viewed on the FERC Internet website at http://www.ferc.gov/industries/gas/enviro/procedures.pdf.

[10] The Project Plan was included in appendix D of AGDC's Resource Report 7 (Accession No. 20170417-5345). The Project Procedures were included in a June 11, 2018 response to FERC information request No. 135 dated February 15, 2018 (Accession No. 20180611-5159). AGDC filed updates to the Project Plan and Procedures on September 18, 2019, in response to Staff Recommendations 27 and 33, respectively, in the draft EIS (Accession No. 20190918-5098). Both documents are available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20190918-5098 in the "Numbers: Accession Number" field.

The applicant must also explain how the proposed alternative measures would achieve a comparable level of mitigation as FERC's measures.

We have reviewed AGDC's proposed modifications to our Plan and Procedures and the supporting justifications. The proposed Project Plan and Procedures include numerous minor wording changes that do not require our specific approval. We determined that other modifications were acceptable as proposed by AGDC or acceptable assuming our recommendations from the draft EIS would be incorporated into the final versions of the plans; we also determined that one requested modification to the Project Plan is unnecessary.

On September 18, 2019, AGDC filed updates to the Project Plan and Procedures that incorporate our revisions and recommendations from the draft EIS. The accepted modifications to the Project Plan and Procedures are identified in tables D-1 and D-2, respectively, of appendix D. These tables include the original text from FERC's Plan and Procedures, the modified text in the Project Plan and Procedures, and AGDC's justifications supporting the modifications. The proposed modification to the Project Plan that we determined to be unnecessary is provided in table D-3 of appendix D.

In addition to the Project Plan and Procedures, AGDC prepared other plans identified in table 2.2-1 that it would implement to reduce environmental impacts.

2.2.1 Gas Treatment Facilities

2.2.1.1 GTP

The GTP would be constructed on granular fill pads of sufficient thickness to reduce the potential for heat transfer to the permafrost and reduce against damage/disturbance to the tundra. Site preparation work would include pile driving, installing buildings, road widening, GTP pad construction, support pipeline construction, and water reservoir construction. The majority of the GTP facility would consist of modules transported to the site via seagoing vessels and then transported from the dock to the site. Sealift vessels would anchor temporarily at the Prudhoe Bay Operations Staging Area (PBOSA), about 5 miles north of the West Dock Causeway and landward of Reindeer Island. Each sealift year, about 9 to 12 tugs and barges would anchor temporarily. The remaining facility components would be constructed on site.

AGDC would use spotting aircraft to assist barges during sealifts by flying the sealift route from the Bering Strait north to Prudhoe Bay. AGDC states that these flights would be intermittent to assess sea and ice conditions along the barge route.

Water would initially be trucked in from existing water supply facilities or a nearby permitted water source until the dedicated GTP water reservoir is operational. Two new Class I UIC injection wells would be developed by AGDC adjacent to the GTP pad after receiving EPA permit authorization for the wells program. AGDC would construct the wells in accordance with EPA's UIC program and Alaska Oil and Gas Conservation Commission regulations. Prior to completion of the two new Class I UIC injection wells, wastewater and other select liquid wastes from the GTP would be disposed of at existing North Slope Borough disposal facilities, as discussed in section 2.1.3.1.

Ice roads would be necessary in the first winter of construction to connect the gravel mine and water sources to the GTP pad site. In addition, ice roads would be required for the water pipeline, which would be on VSMs. The gravel mine site and water reservoir ice roads would be rebuilt each year during construction/mining operations.

TABLE 2.2-1

Construction and Restoration Environmental Plans

Plan Name	Brief Description of Plan	Resources Addressed	Location of Plan on Docket [a]
Air Transport Plan	Details the planned number of Project-related aircraft operations at the proposed airports and airstrips.	Transportation	Included in response to FERC information request No. 168 dated 05/24/2019 (Accession No. 20190524-5248).
Ballast Water Management Plan	Describes applicable requirements for vessel operators for ballast water management systems.	Marine Waters; Marine Mammals; Fisheries Resources; Threatened, Endangered, and Other Special Status Species	Included in response to FERC information request No. 27 dated 05/03/2019 (Accession No. 20190503-5051).
Blasting Plan	Describes the measures to be taken during Project construction to ensure that blasting operations are safely carried out in accordance with the manufacturers' prescribed safety measures and in compliance with applicable federal, state, and local regulations.	Geological Resources; Soils and Sediments; Groundwater Resources; Freshwater; Wetlands; Terrestrial Wildlife; Fisheries Resources; Cumulative Impacts	Included in response to FERC recommendation No. 31 of the draft EIS (Accession No. 20190918-5098).
DMT Inadvertent Release Contingency Plans	Describes the procedures to be followed should an inadvertent fluid release occur during DMT activities.	Geological Resources; Groundwater Resources; Freshwater; Wetlands; Vegetation; Fisheries Resources; Threatened, Endangered, and Other Special Status Species	Included in response to FERC information request No.13 dated 12/13/2019 (Accession No. 20191213-5043).
Emergency Response-Vessel Assurance Execution Plan	Defines a set of standards for ensuring safe marine transportation that contractors would be required to meet in order to provide their services to the Project.	Marine Waters	Included in response to FERC information request No. 126 dated 08/31/2017 for Resource Report 3 (Accession No. 20180102-5212).
Fire Prevention and Suppression Plan	Describes measures to ensure that fire prevention methods comply with federal, state, and local regulations.	Vegetation	Included as appendix G to Resource Report 8 in AGDC's FERC Application (Accession No. 20170417-5345).
Fugitive Dust Control Plan	Describes the procedures to be used to minimize fugitive dust during construction.	Geological Resources; Soils and Sediments; Freshwater; Wetlands; Vegetation; Fisheries Resources; Land Use, Recreation, and Special Interest Areas; Subsistence; Air Quality; Public Health and Safety; Cumulative Impacts	Included in response to FERC information request No. 81 dated 03/30/2018 (Accession No. 20180330-5172).
Gravel Sourcing Plan and Reclamation Measures	Describes the material requirements, sources, extraction protocols, transportation logistics, and reclamation measures during construction and reclamation.	Geological Resources; Soils and Sediments; Groundwater Resources; Fisheries Resources	Included in response to FERC information request No. 36 dated 11/19/2018 (Accession No. 20181119-5181).
Groundwater Monitoring Plan	Describes the process to monitor the quality of groundwater resources during construction in the event that dewatering occurs.	Groundwater Resources; Water Use; Landfills, Mines, and Hazardous Waste Sites; Cumulative Impacts	Included in response to FERC information request No. 83 dated 05/11/2018 (Accession No. 20180511-5130).
Health, Safety, Security, and Environment Plan	Provides the Project-wide health and safety objectives and performance criteria for construction contractor compliance in developing Project-specific Health and Safety Plans.	Hazardous Waste Sites	Included in response to FERC information request No. 151 dated 05/03/2019 (Accession No. 20190503-5051).

TABLE 2.2-1 (cont'd)

Construction and Restoration Environmental Plans

Plan Name	Brief Description of Plan	Resources Addressed	Location of Plan on Docket [a]
Invasive Species Prevention and Management Plan	Describes preventative and control measures, along with monitoring and performance standards, to avoid and/or minimize the introduction and spread of non-native invasive plant species during construction and operation on BLM and state lands.	Wetlands; Vegetation	Included in response to FERC information request No. 107 dated 11/20/2018 (Accession No. 20181120-5161).
Journey Management Plan	Describes the process to be followed at the West Dock Causeway for planning and safely undertaking road transport activities to avoid conflicts with existing traffic.	Transportation	Included in response to FERC information request No. 167 dated 05/24/2019 (Accession No. 20190524-5248).
Lighting Plan	Describes the measures to be followed by the Project to provide adequate lighting for the prevention of accidents and compliance with Occupational Safety and Health Administration requirements while reducing visible light disturbance to the public and wildlife, as practicable, and reducing the potential for light pollution, including backscatter into the sky.	Terrestrial Wildlife; Avian Resources; Fisheries Resources; Threatened, Endangered, and Other Special Status Species; Visual Resources	Included in response to FERC information request No. 104 dated 01/02/2018 (Accession No. 20180102-5212).
Marine Mammal Monitoring and Mitigation Plan for Construction of the Alaska LNG Project in Cook Inlet	Describes measures to be implemented during in-water construction activities (e.g., noise mitigation measures) in Cook Inlet to comply with the MMPA and ESA.	Marine Mammals; Fisheries Resources; Threatened, Endangered, and Other Special Status Species;	Included in response to FERC information request No. 120 dated 05/03/2019 (Accession No. 20190503-5051).
Marine Mammal Monitoring and Mitigation Plan for Construction of the Alaska LNG Project in Prudhoe Bay	Describes measures to be implemented during in-water construction activities (e.g., noise mitigation measures) in Prudhoe Bay to comply with the MMPA and ESA.	Marine Mammals; Fisheries Resources; Threatened, Endangered, and Other Special Status Species;	Included in response to FERC information request No. 120 dated 05/03/2019 (Accession No. 20190503-5051).
Migratory Bird Conservation Plan	Describes the procedures to be implemented during Project construction, operation, and maintenance for avian protection.	Avian Resources; Threatened, Endangered, and Other Special Status Species; Cumulative Impacts	Included in response to FERC information request No. 117 dated 10/22/2018 (Accession No. 20181022-5218).
Noxious/Invasive Plant and Animal Control Plan	Describes preventative and control measures to be used to avoid and/or minimize the introduction and spread of non-native invasive plant and animal species during construction and operation.	Wetlands; Vegetation; Fisheries Resources; Threatened, Endangered, and Other Special Status Species; Cumulative Impacts	Included in response to FERC information request No. 1e dated 04/27/2018 (Accession No. 20180427-5256).
Open Burning Plan	Describes measures to be taken during construction to control burning activities that comply with federal, state, and local regulations.	Air Quality; Cumulative Impacts	Included in response to FERC information request No. 10 dated 11/01/2017 (Accession No. 20171101-5285).

TABLE 2.2-1 (cont'd)

Construction and Restoration Environmental Plans

Plan Name	Brief Description of Plan	Resources Addressed	Location of Plan on Docket [a]
Paleontological Resources Management Plan	Describes the procedures to be used to protect paleontological resources in accordance with NEPA, FLPMA, Paleontological Resources Preservation Act of 2009, and FERC guidelines.	Geological Resources	Included as appendix E to Resource Report 6 in AGDC's FERC Application (Accession No. 20170417-5338).
Paleontological Resources Unanticipated Discoveries Plan	Describes the procedures to be used to reduce the potential for damage to these resources in the event that unanticipated paleontological resources are encountered during construction.	Geological Resources	Included as appendix D to Resource Report 6 in AGDC's FERC Application (Accession No. 20170417-5338).
Pipeline Right-of-Way Operational Monitoring and Maintenance Plan	Describes the procedures to be used to ensure safe operation of the Mainline Pipeline.	Geological Resources; Soils and Sediments; Groundwater Resources	Included in response to FERC information request No. 70 dated 05/11/2018 (Accession No. 20180511-5130).
Plan for Unanticipated Discovery of Cultural Resources and Human Remains	Describes the procedures to be used in the event that previously unreported historic properties or human remains are found during construction.	Cultural Resources	Included as appendix F to Resource Report 4 in AGDC's FERC Application (Accession No. 20170417-5338).
Polar Bear and Pacific Walrus Avoidance and Interaction Plan	Provides guidance to avoid or minimize adverse effects on and human interaction with polar bears and Pacific walrus during construction and operational activities on the North Slope and Beaufort Sea. This plan would be finalized upon receipt of MMPA authorizations.	Threatened, Endangered, and Other Special Status Species	Included in response to FERC information request No. 135 dated 11/19/2018 (Accession No. 20181119-5181).
Recreational and Commercial Fishing Construction and Mitigation Plan	Provides mitigation measures that would reduce impacts on commercial and recreational fishers.	Socioeconomics, Land Use	Included in response to FERC information request No. 163 dated 05/24/2019 (Accession No. 20190524-5248).
Restoration/ Revegetation Plan	Appendix B of the Project Restoration Plan; describes the procedures, performance standards, and performance goals for restoring construction areas.	Soils and Sediments; Freshwater; Wetlands; Vegetation; Avian Resources; Terrestrial Wildlife; Threatened, Endangered, and Other Special Status Species; Land Use, Recreation, and Special Interest Areas; Visual Resources; Socioeconomics; Cumulative Impacts	Included in response to FERC information request No. 107 dated 11/20/2018 (Accession No. 20181120-5161).
Spill Prevention, Control, and Countermeasure Plan	Describes the management procedures for the prevention and cleanup of releases of fuels, lubricants, and coolants, as well as potentially hazardous materials to be implemented during construction.	Soils and Sediments; Groundwater Resources; Freshwater: Marine Waters; Wetlands; Vegetation; Avian Resources; Marine Mammals; Fisheries Resources; Marine Benthic Invertebrates; Plankton; Threatened, Endangered, and Other Special Status Species; Landfills, Mines, and Hazardous Waste Sites; Public Health and Safety; Cumulative Impacts	Included in response to FERC information request No. 38 dated 11/20/2018 (Accession No. 20181120-5161).

TABLE 2.2-1 (cont'd)

Construction and Restoration Environmental Plans

Plan Name	Brief Description of Plan	Resources Addressed	Location of Plan on Docket [a]
Stormwater Pollution Prevention Plan	Describes the potential sources of pollution that could reasonably be expected to affect the quality of stormwater discharges from Project construction and the practices to be used to reduce the pollutants in stormwater discharges, and assures compliance with the terms and conditions of the Alaska Construction General Permit.	Soils and Sediments; Freshwater; Marine Waters; Water Use; Wetlands; Vegetation; Avian Resources; Marine Mammals; Fisheries Resources; Threatened, Endangered, and Other Special Status Species; Cumulative Impacts	Included in response to FERC information request No. 35 dated 05/31/2019 (Accession No. 20190531-5299).
Traffic Mitigation Plan	Describes the measures to be implemented to mitigate for potential traffic impedance during construction.	Land Use, Recreation, and Special Interest Areas; Socioeconomics; Transportation	Included as appendix N to Resource Report 8 in AGDC's FERC Application (Accession No. 20170417-5345).
Unanticipated Contamination Discovery Plan	Describes the processes to be followed by the Project in the event that undocumented or unanticipated contaminated material is found during construction.	Geological Resources; Soils and Sediments; Groundwater Resources; Marine Waters; Landfills, Mines, and Hazardous Waste Sites; Public Health and Safety	Included in response to FERC information request No. 153 dated 05/3/2019 (Accession No. 20190503-5051).
Waste Management Plan	Describes the procedures to be implemented for managing hazardous and non-hazardous solid and liquid wastes generated by the Project.	Soils and Sediments; Freshwater; Marine Waters; Water Use; Wetlands; Vegetation; Terrestrial Wildlife; Avian Resources; Marine Mammals; Fisheries Resources; Threatened, Endangered, and Other Special Status Species; Land Use, Recreation, and Special Interest Areas; Landfills, Mines, and Hazardous Waste Sites; Socioeconomics; Public Health and Safety	Included in response to FERC information request No. 37 dated 11/19/2018 (Accession No. 20181119-5181).
Water Use Plan	Describes the different uses of water resources during construction, including information about water volumes, source locations, discharge locations, and any proposed treatments.	Water Use; Fisheries Resources	Included in response to FERC information request No. 92 dated 11/20/2018 (Accession No. 20181120-5161).
Water Well Monitoring Plan	Describes the potential effects on water wells near the Project construction footprint and the monitoring that would occur to ensure impacts on wells are avoided or minimized.	Groundwater Resources; Water Use; Cumulative Impacts	Included in response to FERC information request No. 72 dated 11/19/2019 (Accession No. 20181119-5181).
Wetland Mitigation Plan	Describes strategies being considered to mitigate permanent wetland impacts from the Project.	Wetlands; Cumulative Impacts	Included as appendix O to Resource Report 2 in AGDC's FERC Application (Accession No. 20170417-5357).
Wildlife Avoidance and Interaction Plan	Describes the avoidance and interaction plan for wildlife.	Threatened, Endangered, and Other Special Status Species; Public Health and Safety	Included in response to FERC information request No. 1a dated 06/11/2018 (Accession No. 20180611-5159).

TABLE 2.2-1 (cont'd)

Construction and Restoration Environmental Plans

Plan Name	Brief Description of Plan	Resources Addressed	Location of Plan on Docket [a]
Winter and Permafrost Construction Plan	Describes the procedures and processes to be implemented to manage summer, winter, and shoulder season construction on permafrost. The plan discusses soil stabilization measures to be implemented to limit thermal and erosional degradation of the permafrost.	Soils and Sediments; Groundwater Resources; Water Use; Wetlands; Avian Resources; Fisheries Resources	Included as appendix M to Resource Report 1 in AGDC's FERC Application (Accession No. 20170417-5339).

[a] Plans can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter the appropriate accession number in the Numbers: Accession Number" field.

Service pipelines, including the water reservoir supply, raw water supply, grey water return, and treated fuel gas pipelines, would be required for the GTP. These pipelines would be supported on a shared VSM pipeline support system between the PBU CGF and GTP; therefore, the construction procedures for these pipeline facilities are the same as described for the PBTL and PTTL. The GTP pipelines and components would be hydrostatically tested. AGDC would discharge the hydrostatic test water to the UIC wells. Additional information on hydrostatic testing of the GTP pipelines and other components is provided in section 4.3.4.4.

2.2.1.2 West Dock Causeway

Construction at the West Dock Causeway would require leveling the offshore area (i.e., subsea screeding), installing sheet piling and placing granular fill behind the sheet piling, installing mooring dolphins, and placing a temporary barge bridge ballasted to the seafloor to span the 650-foot-wide channel between Dock Heads 2 and 3 on a seasonal basis. AGDC would conduct the initial work on the Dock Head 4 expansion from barges. Following construction of the dock deck, AGDC would install the remaining equipment, including the mooring dolphins, from the deck.

The existing bridge across the 650-foot-wide channel/breach between Dock Heads 2 and 3 is limited to single-lane, light vehicle traffic at a width of 20 feet and with an approximate load limit of 100 tons. A bridge with capacity to support the modules would be required for the Project. A temporary barge bridge consisting of two barges ballasted to the sea floor would span the gap. AGDC would place the barges before the beginning of the open-water season (typically before August) for seasonal fish migration. On average, the ice-free window occurs about early August through September. The barge bridge would provide up to three areas for fish passage through the bridge. Pre-work would be performed a year before the first season of deliveries to prepare the seafloor and install breasting-dolphins for the barge bridge support. The surface would be prepared using minimal fill and placement of gabion mattresses (a rock filled wire mesh structure) to prevent scour. The 650-foot-wide channel breach–bridge area would be screeded (e.g., to level with a straight edge). AGDC would remove the barge bridge at the end of each season (typically October) for the six seasons of construction, and the surface would need to be prepared again prior to each season.

AGDC would use ice trenching and grading at the West Dock Causeway to prepare the seabed. Ice trenching and grading would require the use of a trencher for cutting ice, an excavator for removing ice, a second excavator, and haul units. The ice would initially be cut with the trenchers; the excavators would then follow to remove the ice and expose the seafloor. AGDC would begin this work after the ice becomes grounded, which typically occurs on or before February 1.

The Project-related vessel traffic during construction would consist of one sealift per year for 6 years. Each sealift would be scheduled to occur during the ice-free period. Table 2.2.1-1 provides a summary of the estimated number of barges and modules per sealift season to be delivered to Dock Head 4.

TABLE 2.2.1-1

Estimated Number of Barges and Modules per Sealift Season at the West Dock Causeway

Year	Number of Barges	Number of Modules
Pre-construction Sealift -1	9	57
Pre-construction Sealift -2	9	8
Year 4 Sealift	12	17
Year 5 Sealift	12	15
Year 6 Sealift	10	10
Year 7 Sealift	9	9
Total	**61**	**116**

2.2.1.3 Gravel Mine and Water Reservoir

The gravel mine and water reservoir would be developed simultaneously. The material excavated to develop these facilities would be used for GTP construction. The water reservoir and gravel mine site would be accessed via temporary ice roads constructed in the winter (January to May) of the first construction season. Construction activities would occur year-round.

Gravel mine and water reservoir development would occur in three separate removal activities: removal of organic materials, removal of inorganic overburden, and removal of suitable granular fill. During removal activities, blasting would be done in accordance with the Project Gravel Sourcing Plan and Reclamation Measures. The blast method used in North Slope gravel mining is a form of cast blasting. Cast blasting moves (or casts) a significant amount of material into a spoils pile. Temporary erosion and sediment control measures would be used in accordance with the Project Plan, APDES General Stormwater Permit, and applicable state mine permit stipulations.

Development of the sites would start with excavating an area to its full depth to serve as a sump to manage melt water within the site. Following excavation, material would be loaded and hauled off for its intended purpose. Overburden would be stockpiled in berms along the perimeter of the reservoir and mine site for re-use during reclamation, to decrease thermal degradation of surrounding permafrost, and to provide a visual cue to snowmachines travelling in the area. After completion of the water reservoir, water from the Putuligayuk River would fill the reservoir.

2.2.1.4 PBTL and PTTL

Construction of the PBTL and PTTL gas transmission lines would use similar measures. The pipelines would be installed on VSMs connected to a horizontal support member. AGDC would construct the PTTL using two construction spreads over one winter season, while the PBTL would be constructed using one construction spread over two winter seasons. AGDC would build a full-length 120-foot-wide ice road for the PBTL and a full-length 100-foot-wide ice road for the PTTL. The PTTL would include two lay-down areas to store materials and provide fabrication space. In addition, an ice road from Prudhoe Bay to Point Thomson would be built to transport Project materials and construction equipment from one end of the PTTL construction right-of-way to the other, without interfering with construction activities on the right-of-way. In addition to the ice travel lane, AGDC estimates that it would require 52 spur ice roads to access the PTTL right-of-way. Because active hunting areas are present along the proposed PTTL route, AGDC would use X65 grade steel for the pipe with 0.5-inch wall thickness, which is considered bullet resistant for rifle calibers and ammunition typically used in the North Slope area.

The PTTL centerline would cross 106 waterbodies, all of which would be aerial crossings. The Sagavanirktok River (West Channel) crossing would use the existing bridge and would not require any new in-stream supports. The Shaviovik, Kadleroshilik, and Sagavanirktok (Main Channel) Rivers would be crossed using in-stream supports of pile pier foundations. Some PTTL crossings would require VSMs to be sited within a waterbody (e.g., a river, lake, or pond).

Water would be drawn for ice roads, ramps, and pads from designated water sources near the pipeline alignment. Once the winter work pads and access roads are in use, they would require maintenance to repair damage caused by tracked equipment. Maintenance would include grading and adding compacted snow, ice and water, and, in certain cases, ice aggregate as fill. Work crews would decommission winter snow and ice work pads and roads at the end of each winter season in accordance with land use and fish habitat permits.

Once the ice travel lane is established, VSMs would be installed. Stringing crews would haul VSMs and crossbeams from the lay-down areas to the work pad along the right-of-way. Drilling crews would drill the holes for the VSMs. Each construction spread could require multiple rotary air drills working simultaneously. The baseline design provides for a minimum embedment of each VSM of 26 feet to extend below the tundra surface to resist uplift and settlement. The VSMs would have an aboveground height of 7 feet.

When sufficient VSMs have been installed, field welding of the pipeline would begin. The pipe would be strung west to east based on a standard side boom configuration (lay to the left). A stringing crew would haul pipe from the lay-down areas and place it on skids along the work pad. The pipe would then be welded using qualified procedures. Qualified and certified examination inspectors would perform non-destructive testing of welds. Welds would meet specification and applicable code requirements prior to coating. Following inspection, the pipe would be lifted onto the VSMs.

The PTTL and meter station would require about 14.2 million gallons of water for hydrostatic testing. Another 14.2 million gallons of water would be required for hydrostatic testing of the PBTL and other GTP pipelines and components, including the propane, water reservoir, raw water supply, and treated fuel gas pipelines for the Operations Center. AGDC has proposed using the Badami Reservoir, Kadleroshilik River, and Sag Mine Site C for PTTL test water. The PBTL would use the same water sources as the GTP. Temporary water use authorizations issued by the ADNR and fish habitat permits issued by the Alaska Department of Fish & Game (ADF&G) would dictate permissible withdrawal amounts for the Project. AGDC would discharge test water into the same basin as the water source withdrawal; no inter-basin transfer of water would occur. AGDC plans to conduct its testing in summer seasons and to discharge the water into uplands and wetlands in accordance with applicable federal and state permit requirements.

2.2.2 Mainline Facilities

The Mainline Facilities would be constructed under various seasonal and terrain conditions. The majority of the pipeline would be constructed onshore in both summer and winter seasons with the 27.3 miles of offshore pipe in Cook Inlet laid in the ice-free season. Mainline Pipeline construction would be divided into four pipeline construction spreads to be built over a 2-year period, as shown in table 2.2.2-1. AGDC does not anticipate laying pipe with the support of helicopters.

AGDC proposes to use a baseline construction right-of-way width of 110 feet, as shown on its construction right-of-way drawings (see figures 2.2.2-1 to 2.2.2-5). The minimum right-of-way for the Mountain Grade Construction Mode (Mode) (figure 2.2.2-6) would be 65 feet, not including the width of the cut slope, which would vary depending on terrain. In addition, AGDC proposes to use a by-pass lane and a travel lane in many areas, resulting in a construction right-of-way width as large as 145 to 185 feet for about 88 percent of the pipeline route, depending on the construction mode (see additional discussion below).

As shown in table 2.2.2-1, the northern spreads (Spreads 1 and 2) encompass the first 400.7 miles from Prudhoe Bay to Livengood. This area contains mostly continuous permafrost and occurs within an arctic climate. The southern spreads (Spreads 3 and 4) encompass the southern 405.9 miles, which includes the 27.3-mile offshore Cook Inlet section. Excluding the offshore section, Spreads 3 and 4 encompass 378.6 miles of pipe, 13.3 miles of which is on the Kenai Peninsula. Spread 3 is mostly in discontinuous permafrost with a subarctic climate, whereas Spread 4 is mostly in non-permafrost but with isolated or sporadic areas of permafrost and a northern climate, with a variable maritime climate on the southern end.

TABLE 2.2.2-1

Construction Spreads for the Mainline Pipeline

Spread Number	Geographic Area	Begin Milepost	End Milepost	Total Length	Starting Location	Ending Location	Proposed Pipelay (miles) [a]	
							Year 1	Year 2
1	North Slope	0.0	208.9	208.9	GTP	North side of the Dietrich River Crossing No. 3	114.7	94.2
2	Interior Alaska	208.9	400.7	191.8	North side of the Dietrich River Crossing No. 3	Livengood; south side of Elliott Highway	139.0	52.8
3	Alaska Range	400.7	607.4	206.7	Livengood; south side of Elliott Highway	Hurricane Camp	119.0	87.7
4	South-Central	607.4	806.6	199.2	Hurricane Camp	LNG Plant, MLV 30	97.8	101.4
						Total	**470.5**	**336.1**

[a] Years 1 and 2 of construction refer to the construction sequence specific to each spread, rather than a specific calendar year. Pipeline construction for Spreads 3 and 4 would begin in the fourth quarter of Year 2 and continue into the fourth quarter of Year 4. Pipeline construction for Spreads 1 and 2 would begin in the fourth quarter of Year 3 and continue into the fourth quarter of Year 5.

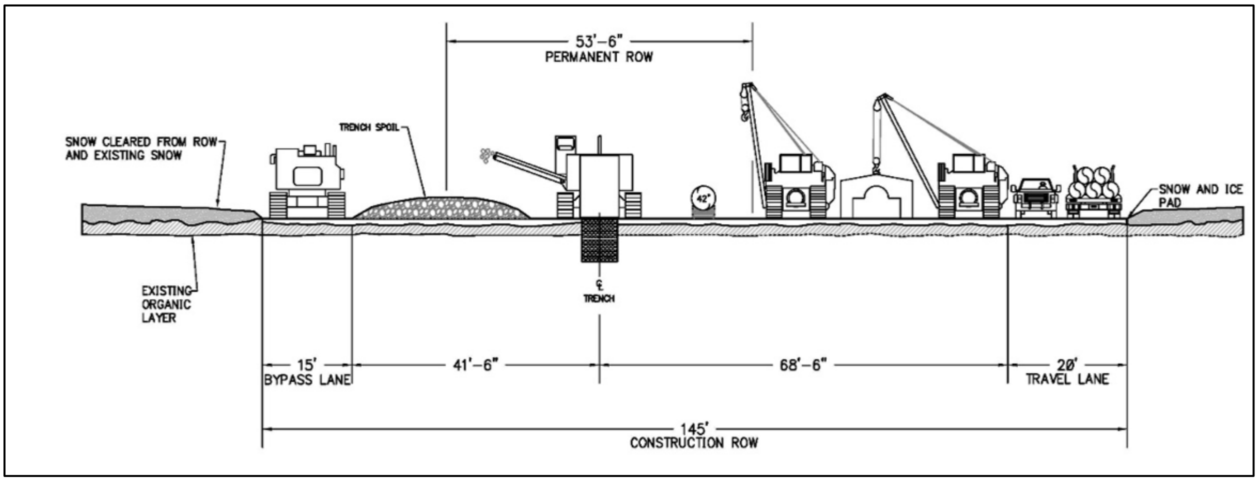

Figure 2.2.2-1 Right-of-Way Construction Mode 1–Ice Work Pad over Permafrost in Flat Terrain

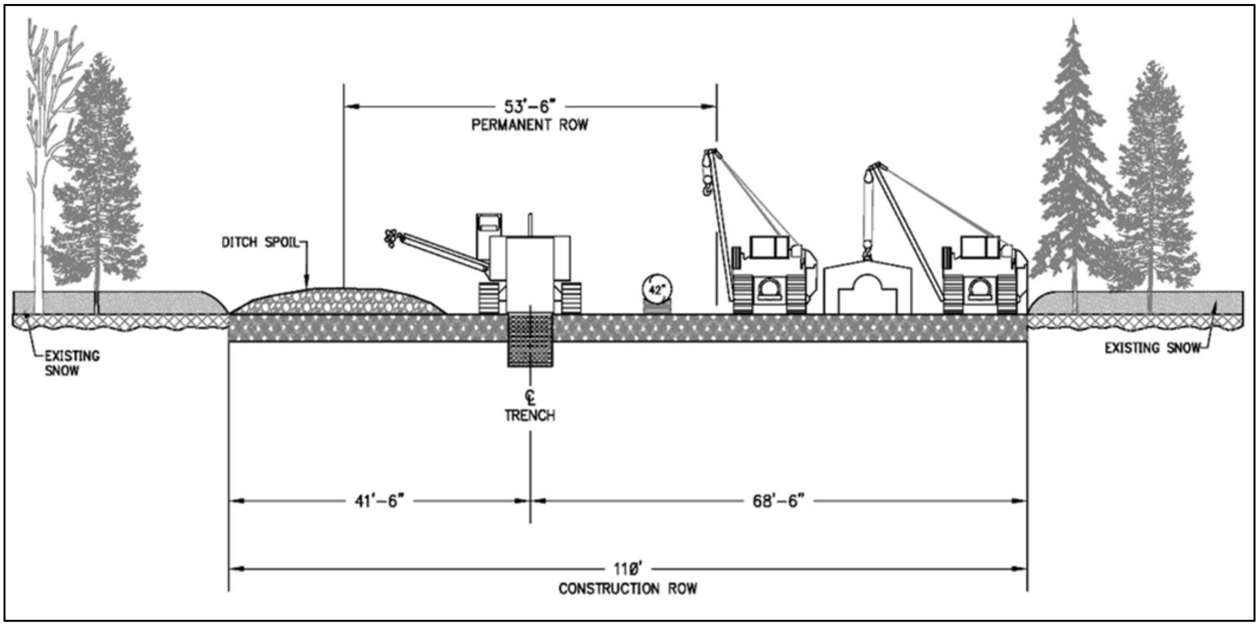

Figure 2.2.2-2 Right-of-Way Construction Mode 2–Winter Frost Packed in Non-permafrost or Thaw-Stable Permafrost

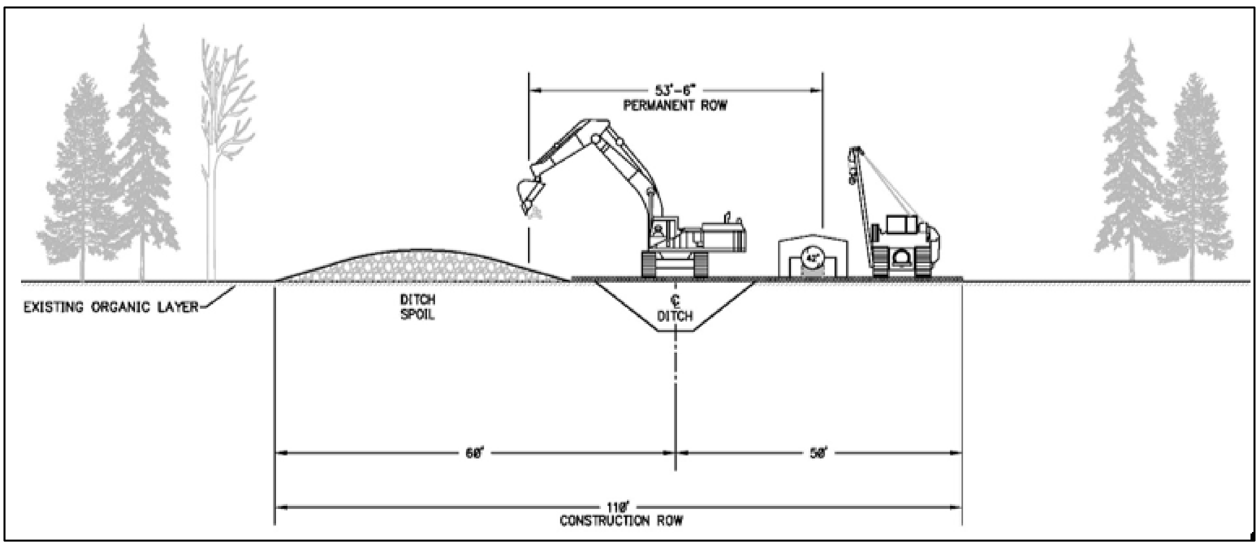

Figure 2.2.2-3 Right-of-Way Construction Mode 3–Matted Summer Wetlands

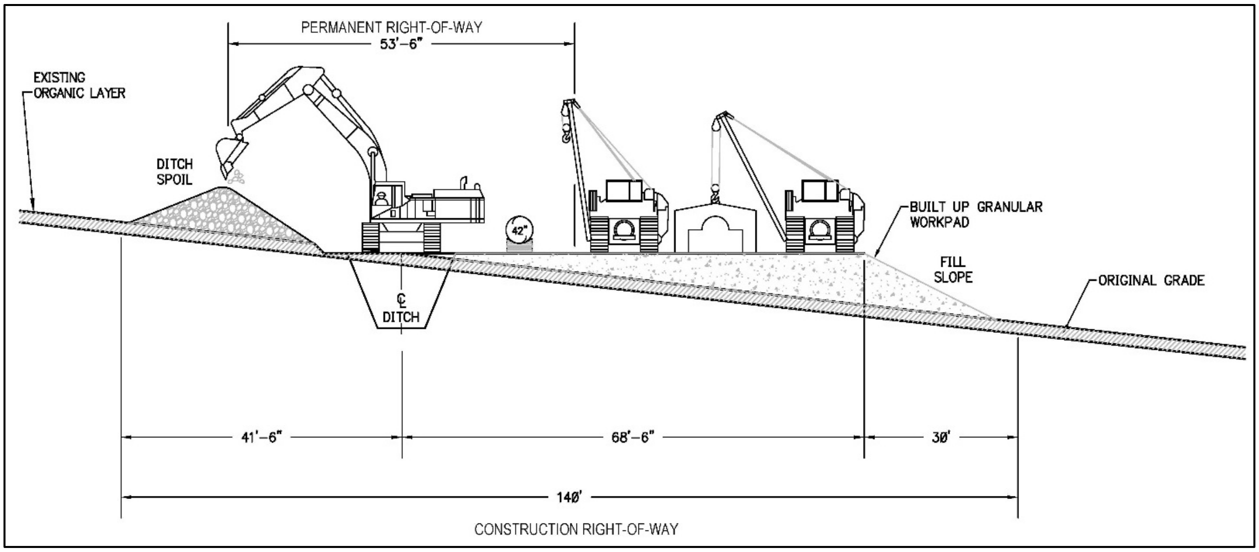

Figure 2.2.2-4 Right-of-Way Construction Mode 4–Granular Work Pad over Thaw-Sensitive Permafrost or Thaw-Stable Permafrost with a Thick Organic Mat

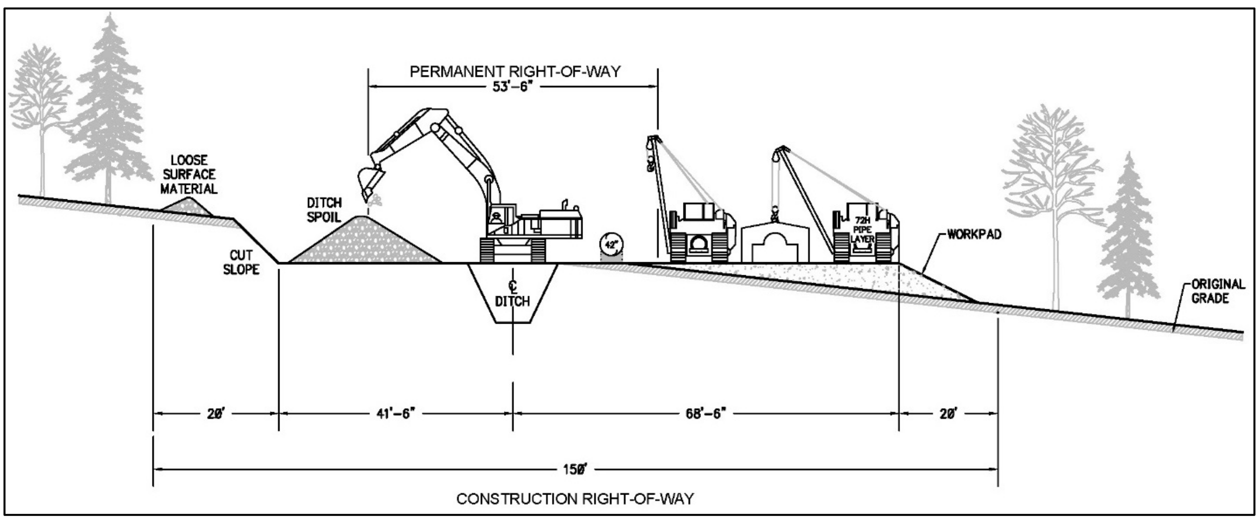

Figure 2.2.2-5 Right-of-Way Construction Mode 5A–Graded

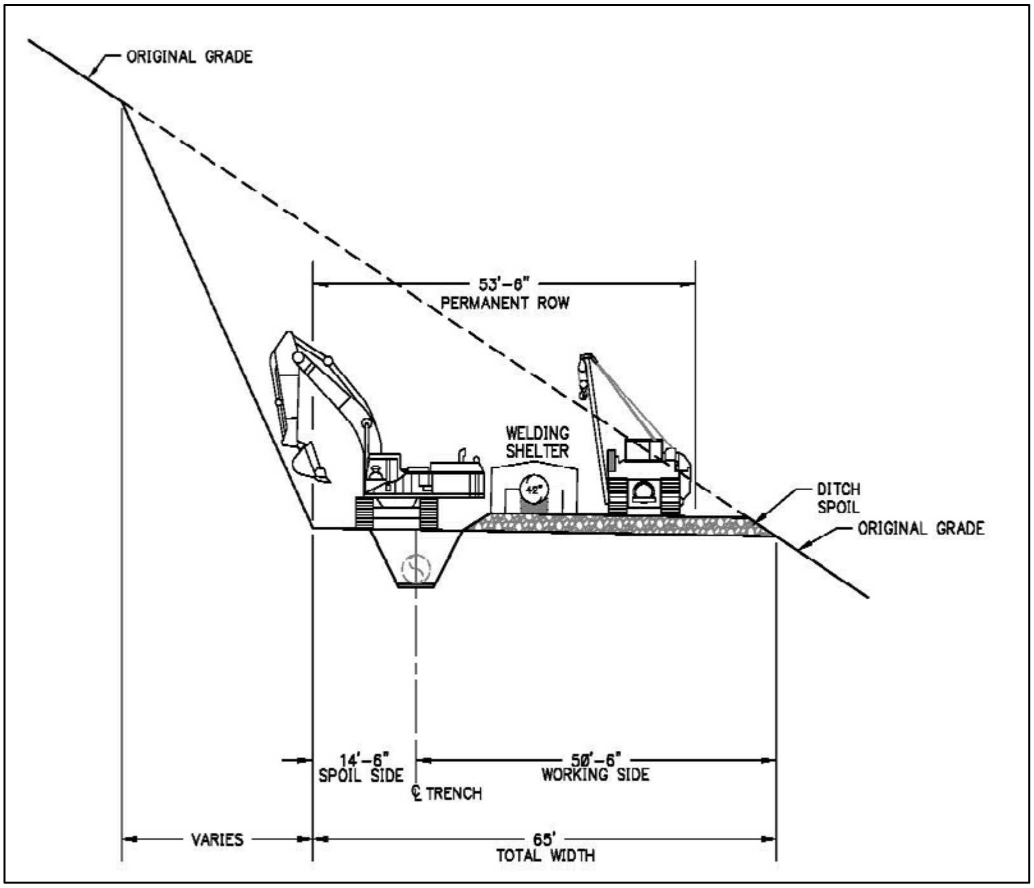

Figure 2.2.2-6 Right-of-Way Construction Mode 5B–Mountain Grade

For construction, AGDC divided the construction year into winter and summer seasons, which encompass the shoulder (spring and fall) seasons. Summer construction season occurs from May 1 through September 30 and winter construction season from October 1 through April 30. Spring (April to May) and fall (October to November) are the designated shoulder seasons. AGDC noted that shoulder seasons present scheduling difficulties, as the timing of seasonal change can be variable. Generally, May north of the Brooks Range and April south of the Brooks Range are breakup months when rivers and streams begin flowing again. During this time, right-of-way conditions would be sloppy, and productive right-of-way work could be limited. Conversely, the fall shoulder months could be unseasonably warm in various years or become colder earlier in other years. Depending on the weather, the fall shoulder season could extend the summer construction schedule for pipelay.

Table 2.2.2-2 identifies AGDC's proposed construction mode, right-of-way width, construction season, and a general description of the mode and its application area for the onshore portion of the Mainline Pipeline. Table C-9 in appendix C provides details of the construction right-of-way mode by construction spread and milepost. AGDC's selection of the construction modes presented in table C-9 of appendix C are based on terrain, soils, and the construction season.

2.2.2.1 General Construction Procedures

Construction of the Mainline Pipeline and associated facilities would generally be completed using sequential installation techniques, which include survey and staking; clearing; grading; trenching; pipe stringing, bending, and welding; lowering-in and backfilling; hydrostatic testing; commissioning; and cleanup and restoration (see figure 2.2.2-7). These construction techniques would generally proceed in an assembly line fashion with construction crews moving down the right-of-way as work progresses.

During winter construction when little natural light is available for much of the day, artificial lighting, such as lighted equipment and portable light towers, would be used for clearing and subsequent construction activities. If nighttime lighting is needed, the light would be directed toward the center of construction activities and shielded if there are nearby homes or businesses. In spite of these measures, there could be times when the Project route could temporarily appear as a brightly lit area when viewed from nearby locations during nighttime construction. The Project Lighting Plan is discussed in section 4.10.2.

Surveying and Staking

Helicopters would transport early surveyors to the right-of-way to commence staking the limits of the construction right-of-way, the trench centerline, ATWS, and other approved work areas. AGDC would mark approved access roads and the limits of approved disturbance on any access roads requiring widening using temporary signs or flagging. Environmentally sensitive areas (e.g., waterbodies, cultural resources, and sensitive species habitat) would also be marked in this initial step, where appropriate. This includes staking known archaeological sites, wetland areas, and water crossing boundaries, as well as other environmentally sensitive areas that would require protection during the construction process. AGDC would conduct wetland surveys along the construction right-of-way prior to construction (see section 4.4.1 for additional discussion regarding these surveys). The field review information would be incorporated into the construction alignment sheets to allow appropriate staking of the construction right-of-way. Existing underground utilities would be located and flagged prior to construction.

Clearing

Clearing activities would typically occur in the winter season and would begin 1 to 3 years prior to each scheduled construction season. Clearing would include removing trees and brush (but would not include grubbing or removing root structures) mainly using heavy equipment. Additional handwork with power saws would also be required. Except for sites with aboveground facilities where the cleared workspace would be grubbed, root structures would remain until the season of right-of-way construction.

Access to the right-of-way for personnel and equipment would be required for clearing. Winter access would include the installation of snow-fill and log-fill ramps, as well as bridges and culverts where required for crossing drainages and watercourses. Summer access could also include bridges and culverts and the use of mats, log corduroy, geotextile fabric, or combinations of these, that would be overlain with natural material to allow heavy construction equipment and support vehicles to cross, subject to permit conditions.

Temporary erosion control measures would be installed in accordance with the Project Plan. The non-salvaged vegetation would be used for rollback, erosion control, access control, or riprap. Any open burning would be conducted in accordance with applicable state and local regulations and Project plans. Note that the region of Fairbanks is a non-attainment area; therefore, any open burning would only occur if allowed under Alaska Department of Environmental Quality regulations.

TABLE 2.2.2-2

Construction Right-of-Way Modes Associated with the Onshore Mainline Pipeline

Right-of-Way Mode	Construction Right-of-Way Width [a]	Construction Season and Miles [b,c,d]	Description	Application Area
1 Ice work pad over permafrost in flat terrain	145 feet; includes a 15-foot bypass lane and 20-foot travel lane.	Winter – 56.6 miles	Typically, a 6-inch layer of ice creating a work pad over permafrost in flat terrain with ample water sources.	About 7 percent of the right-of-way in the Beaufort Coastal Plain.
2 Winter frost packed in non-permafrost or thaw-stable permafrost	110 feet; optional use of 15-foot bypass lane and 20-foot travel lane.	Winter – 69.4 miles	Frost packed work pads over flat permafrost and over flat non-permafrost wetlands.	About 9 percent of the right-of-way.
3 Matted summer wetlands	110 feet; optional use of 15-foot bypass lane and 20-foot travel lane.	Summer – 0.6 mile	Matting for short, flat, isolated, and saturated wetlands to provide a stable work surface.	Less than 1 percent of the right-of-way in wetlands in the Ray Mountains, Tanana-Kuskokwim Lowlands, and the Alaska Range Subregions.
4 Granular work pad over thaw-sensitive permafrost or thaw-stable permafrost with a thick organic mat	140 feet; optional use of 15-foot bypass lane and 20-foot travel lane.	Winter – 111.7 miles Summer – 179.2 miles	Granular work pads over thaw-sensitive permafrost terrain, including those with wetlands, and over thaw stable soils with a thick organic layer to create a stable work surface.	About 37 percent of the right-of-way.
5A Graded	150 feet; optional use of 15-foot bypass lane and 20-foot travel lane.	Winter – 123.5 miles Summer – 225.5 miles	Conventional grading cut and granular fill in thaw stable permafrost and non-permafrost terrain with cross slopes greater than 2 percent, including those with wetlands.	About 45 percent of the right-of-way.
5B Mountain grade	65 feet; mountain grade area	Summer – 1.4 miles	Steep side slope grading cut and fill in areas where the right-of-way would be cut or notched into the hillside.	Less than 1 percent of the right-of-way in the Brooks Range Subregion and all subregions south.

[a] Construction miles do not include a total of about 11.6 miles where the Mainline Pipeline would cross waterbodies, adjacent riparian areas, and wetlands where AGDC did not assign one of the construction modes. In these areas, construction techniques would follow the Project Procedures.

[b] Optional travel lanes are not depicted in drawings for Modes 3, 4, and 5A.

[c] The sum of the addends may not equal the totals in all cases due to rounding.

[d] Construction miles include only the onshore miles. There are an additional 27.3 miles of offshore pipeline.

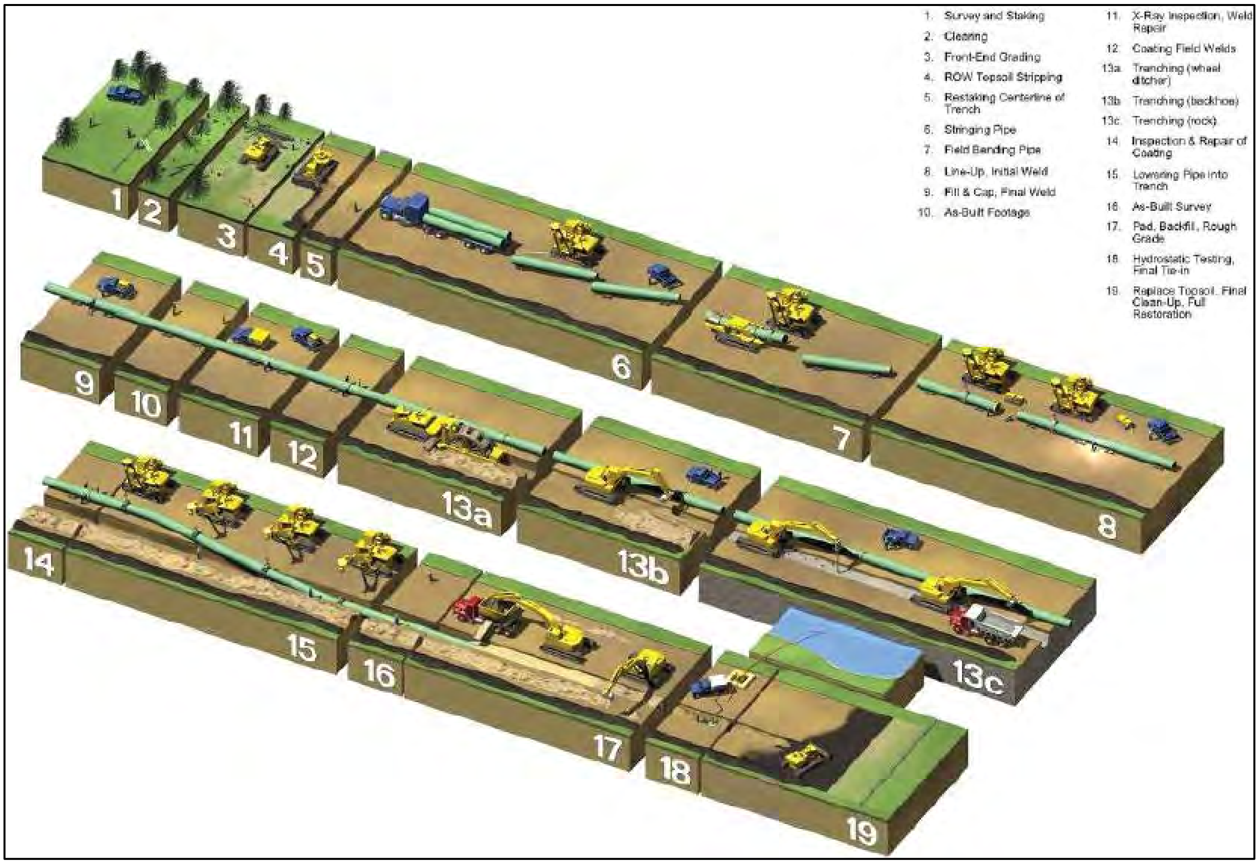

Figure 2.2.2-7 Construction Sequence for the Mainline Pipeline

Grading

Work surface grading is necessary in uneven areas to level the work surface for the safe use of heavy equipment during construction. Grading is also necessary to level side slopes across the work surface. Temporary erosion control measures would be used in accordance with the Project Plan.

Winter grading activities would use frozen soil conditions to support construction equipment and vehicles. For thaw-stable soils, right-of-way preparation activity could begin by driving frost into the ground to support heavy construction equipment. For thaw-sensitive soils, initial preparation activities could include installation of granular fill or snow/ice working surfaces as applicable for the right-of-way mode selected. AGDC would apply snow/ice to working surfaces in thaw-sensitive tundra areas on the Arctic Coastal Plain. Snow and loose surface material could be windrowed over the trench line to reduce seasonal or mechanical penetration of frost. This material would be bladed away just prior to trenching activities.

In areas where rock is at grade, the surface would be ripped with ripper tractors if practical. If the rock cannot be ripped, it would be drilled and blasted after removal of any loose surface material. Bucket-wheeled or chain trenchers could also be used instead of ripper tractors. Blasting could also be necessary in permafrost soils. Grading of rock areas could be undertaken a season or more in advance of construction.

Winter Work Pads and Access Roads

In certain tundra and wetland areas, winter work pads would be required. Winter work pads and roads would be constructed of compacted snow, ice aggregate, mixtures of snow and water, manufactured snow, or ice created by flooding the tundra surface to achieve a design thickness and width.

Access roads to water sources and material sites would be needed to construct ice roads and work pads. These access roads would allow collection of ice aggregate from the frozen surfaces of approved waterbodies as well as allow collection of fill material for the work pads. Once the winter work pads and access roads are in use, they would require maintenance, including grading and adding compacted snow, ice and water, and, when needed, ice aggregate as fill. Work crews would decommission winter snow and ice work pads and roads at the end of each winter season in accordance with land use and fish habitat permits.

Erosion Control

During construction, stabilizing work sites would reduce surface erosion and siltation. Stabilization work would follow the Project Plan, in which installation and maintenance of temporary and permanent environmental mitigation measures would depend on site-specific conditions and needs. For erosion control efforts, installation of temporary slope breakers and trench plugs, surface drainage ditches, sediment barriers, erosion-control mulch, matting, or synthetic bales, and other means would mitigate and control surface erosion.

After initial disturbance, soil erosion control measures would be installed. These measures would be left in place and repaired, replaced, and supplemented as needed in accordance with the Project Plan, Procedures, and Revegetation Plan. Additional information regarding erosion and sediment control measures is provided in the Project Plan and APDES General Permit AKG320000 – Statewide Oil and Gas Pipelines.

Pipe Stringing and Bending

Hauling and stringing of individual pipe joints (i.e., placing joints of pipe end-to-end along the right-of-way in preparation for laying) would take place as grading progresses. In certain trench soil conditions, such as those requiring drilling and blasting, pipe stringing would take place after trenching. Individual pipe lengths would be nominally 40 or 80 feet in length.

Individual sections of pipe would be bent to conform to the contours of the ground after the joints of pipe sections are strung alongside the trench. Workers would use a track-mounted, hydraulic pipe-bending machine to bend the pipe. Where multiple or complex bends are required, bending would be conducted at the pipe fabrication factory, and the pipe would be shipped to the Project area pre-bent. In areas requiring blasting, pipe stringing and bending would occur after trenching.

Welding

Pipe joints would be welded together and placed on temporary supports at the edge of the trench. Production welding would be performed using a mechanized welding system, but manual welding (i.e., shielded metal arc welding or stick welding) would also be used. AGDC would use welders who are qualified according to applicable standards in 49 CFR 192 Subpart E, American Petroleum Standard 1104, and other requirements.

Qualified and certified non-destructive examination inspectors would perform non-destructive testing of welds. Each weld would be subject to ultrasonic and/or radiographic inspection. If testing indicates a weld does not meet design criteria, the weld would be repaired or cut out and replaced, and the new weld would be re-inspected. Welds would meet applicable code requirements prior to coating.

Once the welds are made and tested, a coating crew would coat the area around the weld before the pipeline is lowered into the trench. Prior to application, the coating crew would thoroughly clean the bare pipe with a power wire brush or sandblast machine to remove dirt, mill scale, and debris. The crew would then apply the coating and allow the coating to dry. The pipeline would be inspected electronically for faults or voids in the coating and would be visually inspected for scratches and other defects.

In both summer and winter periods of construction, pipe would be welded and coated ahead of trenching, except where blasting is required. This sequence results in the trench remaining open for only a short time before the welded pipe sections are lowered into the trench. During winter periods, the trench would be less likely to fill with snow and the spoil material would be less likely to freeze. During summer periods, the trench would be less likely to fill with water if a rainstorm event occurs.

Trenching

The pipeline trenches would be excavated with bucket wheel or chain trenching machines or track-mounted excavators. Track-mounted mechanical rippers, rock hammers, or rock trenchers would be used to fracture and excavate rock or frozen soil. Drilling and blasting would be required where other means of excavation are not practical. AGDC would stockpile the excavated material along the right-of-way on the side of the trench away from construction traffic.

The trench associated with the onshore portion of the Mainline Pipeline would be excavated to a depth that would provide sufficient cover over the pipeline in accordance with the provisions for buried pipelines as established in 49 CFR 192.327 "Cover" and 192.328 "Additional construction requirements for steel pipe using alternative maximum allowable operating pressure." These provisions specify that the pipeline have a minimum of 36 inches of cover based on the Project's pipeline design in all conditions. Typically, the trench depth would range from 6 to 8 feet deep, depending on the substrate and resource being crossed, and the trench width would be between 5 and 6 feet. AGDC notes that, in accordance with Title 17 AAC 15.201(c), the minimum depth of cover would be 4 feet at road crossings and 10 feet at railroad crossings as specified by the Alaska Railroad Corporation standards. Excavations could be deeper in certain locations, such as at road and stream crossings. Less cover would be provided in rocky areas and additional cover would be provided at road and waterbody crossings.

Blasting would be required in areas where mechanical equipment cannot break up or loosen the bedrock. In these areas, AGDC would implement its Project Blasting Plan. Additionally, site-specific plans would be developed by blasting subcontractors prior to blasting and would include the schedule and timing of blasts. Blasting would not begin until landowners and tenants have been provided notice to protect property and livestock. Blasting mats or padding would be used where necessary to prevent fly rock from scattering. All blasting activities would be performed in compliance with federal, state, and local codes, ordinances, and permits; manufacturers' prescribed safety procedures; and industry practices. Impacts of blasting on various resources and details about the measures to mitigate the impacts of blasting on these resources are discussed in section 4.

Lowering-In and Backfilling

The trench would be inspected for rocks and other debris that could damage the pipe or protective coating before the pipe would be lowered into the trench. Trench dewatering could be necessary to inspect the bottom of the trench in areas where water has accumulated. Trench water discharges would be directed to well-vegetated areas and away from waterbodies and dry washes to minimize the potential for runoff and sedimentation. In areas with rock or areas where soils contain frozen soil lumps, boulders, or cobbles, foam pillows or imported select fill bedding material could be placed as bedding on the trench bottom before the pipe sections are lowered into the trench. AGDC estimates that it would place about 2 million cubic yards of granular fill obtained from the material sites to pad the trench. Suitable padding material would be placed around the pipe to protect the pipe and coating from damage. Other pipe protection measures such as a rock-shield material could be installed before the lowering in of the pipe. The pipe would be lowered into the trench by a series of side-boom tractors (tracked vehicles with hoists on one side and counterweights on the other), which would lift the pipe and place it on the bottom of the trench.

Suitable material excavated during trenching would be backfilled. In areas where excavated material is unsuitable for backfilling (e.g., soil with high ice content or containing large rocks), additional fill could be required. AGDC would obtain this additional fill material from the Project's material sites. Crowning of the top of the trench could be needed to compensate for future subsidence.

We received a comment from the State of Alaska that use of ice-rich backfill materials combined with the absence of erosion control measures can lead to permafrost degradation. AGDC has stated that while frozen material would be used to backfill the trench depending on right-of-way mode and season of construction, mitigation measures would be implemented to minimize impacts associated with permafrost degradation, such as thaw settlement. As discussed in more detail in section 4.2.5.2, these measures would include ensuring sufficient thickness of thaw-stable backfill to compensate for thaw settlement, providing an insulating layer on the right-of-way, controlling gas temperatures to limit changes in permafrost temperatures, monitoring of the right-of-way during operations, and creating post-construction rehabilitation plans for additional surface preparation or revegetation efforts, as needed.

Rock excavated from the trench could be used to backfill the trench only to the top of the existing bedrock profile. Spoil or rock that is not returned to the trench would be handled as construction debris.

Hydrostatic Testing

AGDC would hydrostatically test 20-mile-long sections of the pipeline to ensure the system is capable of withstanding the operating pressure. Hydrostatic testing involves filling the pipeline with water to a designated test pressure and maintaining that pressure. Actual test pressures and durations would be consistent with the requirements of 49 CFR 192. Any detected leaks would be repaired and the section of pipe re-tested.

Potential water sources for pipeline hydrostatic testing include streams crossed by the pipeline right-of-way and nearby lakes and parallel streams. Anticipated volumes and potential sources of test water would follow the Project Water Use Plan as discussed in section 4.3.4. Pressure test plans for each construction spread would list permitted water sources, permitted water volumes, and conditions for water withdrawals and discharge as specified by regulatory/permitting authorities.

The Mainline Pipeline would be hydrostatically tested in the summer season. Hydrostatic testing would begin in May and continue through October. Heaters, enclosed shelters, and boilers would be utilized as necessary when ambient temperatures drop below freezing. AGDC has stated that the test water would not contain any additives. AGDC would discharge the water to one of the Class I injection wells to be installed at the GTP, the GTP reservoir, wetlands and uplands along the route, and Cook Inlet. Hydrostatic test water discharged to surface waters would be subject to NPDES or APDES permitting. Additional information on hydrostatic testing of the Mainline Pipeline, including anticipated water sources and discharge locations, is provided in section 4.3.4.4.

Cleanup and Restoration

In both summer and winter construction, initial cleanup would begin after backfilling of the trench is complete. Cleanup would continue as weather and ground surface conditions allow, in accordance with the Project Plan and Procedures as well as the Project Revegetation Plan. Winter cleanup activities and stabilization work would be completed during subsequent winter seasons, as necessary, but final cleanup could also occur during summer months. Summer remedial work could be required following winter construction to re-establish erosion control measures and address surface water drainage or final grade issues.

Surface cross-drainage patterns would be re-established. This could involve re-mobilizing construction personnel and equipment during the following construction season to specific areas to re-establish drainage patterns where grading of the initial backfill is required.

During cleanup and restoration, AGDC would install markers showing the location of the pipeline. The markers would identify the owner of the pipeline and convey emergency information in accordance with applicable governmental regulations, including PHMSA safety requirements. Special markers providing information and guidance for aerial patrol pilots would also be installed.

Any property damaged during construction, such as fences and gates, would be restored by AGDC to its original or better condition in accordance with individual landowner agreements. Access road improvements would only be removed after construction if requested by the landowner or land management agency. Granular fill or culverts at waterbody crossings would be removed if required by COE permitting for the Project. Non-hazardous construction debris would be disposed of in designated debris sites or per easement agreements. However, we note that while an easement agreement may designate alternative disposal of construction debris, it may only be left on site if it is a beneficial re-use in accordance with sections II.B.17 and III.E of the Project Plan.

2.2.2.2 Special Construction Procedures

Construction through areas containing sensitive resources (e.g., permafrost, wetlands, and waterbodies) or in areas with construction constraints (e.g., residential areas, road/railroad/utility crossings, steep or side slopes, fault crossings, and rocky areas) would require construction techniques that differ from the standard measures described above. Construction of the offshore portion of the Mainline Pipeline would also require special construction techniques. General procedures are described below and specific procedures are further discussed in section 4, as applicable.

Permafrost

Between the Arctic Coastal Plain and the Alaska Range to the south, roughly 580 miles of the 806.9-mile-long Mainline Pipeline would cross continuous or discontinuous permafrost terrain. Permafrost terrain would be crossed during winter, summer, and shoulder construction seasons. AGDC states that its construction methods are based on those developed during construction of TAPS, Alaska's North Slope oilfields, and northern Alaska highways. AGDC developed a Project Winter and Permafrost Construction Plan, which identifies construction, restoration, and mitigation measures specific to permafrost areas. These measures include:

- selecting an appropriate construction mode based on permafrost type, topography, and construction season;
- constructing in thaw-sensitive permafrost during winter;

- working from granular or ice work pads; and
- placing insulation on slopes to control the rate of permafrost thawing and/or minimize thermal degradation.

Additional information on construction in permafrost areas is provided in section 4.2.

Granular Fill

The terms "granular" and "gravel" in this document are in reference to coarse-grained particles (consisting of a combination of gravels, sands, and fines) and characterize fill materials deemed suitable for construction. AGDC proposes to use granular fill in locations during Project construction to provide structural support for equipment to travel over permafrost terrain, thus providing a stable surface between equipment and the underlying permafrost. AGDC would use granular fill in areas where the underlying ground is thaw-sensitive permafrost to stabilize the Mainline Pipeline right-of-way, ATWS areas, and access roads. AGDC would place the granular fill between 1 and 3 feet deep to construct a pad. The specific amount of granular fill in any location would depend on the permafrost thaw-susceptibility as well as the construction season, with the summer construction season requiring the deepest fill (up to 3 feet) to prevent rutting. In the North Slope region, the granular fill would be placed to a depth of 5 feet, which is the accepted minimum industry standard.

Granular fill over the trench line could be thinner than that placed on the working side to provide a level surface for excavators or trenchers. No granular fill would be placed in the spoil area, allowing trench spoil to be placed on the native vegetative mat. During backfilling, AGDC would move trench spoil back to the trench. After the pipeline is lowered-in and the trench backfilled, the thicker section of granular fill would be spread from the working side across the trench to provide a uniform cover over the surface. Following construction, the compacted granular fill would be ripped to mitigate the compaction effects of construction traffic, graded to facilitate drainage, covered with any available growth media, and scarified to allow revegetation. AGDC would fertilize and/or seed in areas where the interim performance standard of 30-percent pre-disturbance live canopy cover over a 3-year period does not occur.

AGDC estimates that granular fill would remain following construction on 6,171 acres along the Mainline Pipeline. This acreage includes areas where the fill is spread on the right-of-way, ATWS areas, and access roads. AGDC intends to work with landowners where access roads would be built to determine if they would prefer to have the granular fill roads removed following construction.

The expected duration of settling, saturating, and revegetating of the granular fill areas would vary with location and moisture (water content) in soils/permafrost near the surface. In regions south of the Brooks Range, areas of discontinuous permafrost would settle more rapidly than the three northernmost subregions with continuous permafrost (Brooks Range, Brooks Foothills, and Beaufort Coastal Plain) due to shorter, cooler summers in and north of the Brooks Range.

Roads, Pipeline, and Utility Crossings

The Mainline Pipeline would cross numerous roads, pipelines, and utilities between the GTP and the Liquefaction Facilities. Construction across paved roads, highways, and unpaved roads would be in accordance with Project-specific specifications and the requirements of road crossing permits and approvals. Authorities with jurisdiction over roads and highways to be crossed by the pipeline, including Alaska Department of Transportation and Public Facilities (ADOT&PF), have been consulted to determine acceptable crossing methods. AGDC would obtain crossing permits prior to construction.

Road and Railroad Crossings

Pipeline construction across public and private roads and railroads would be based on site-specific conditions and crossing permits. AGDC would cross major roads and railroads using trenchless methods, such as bore. For road crossings where the pipeline cannot be installed by bore, AGDC would excavate a trench across the road. In such cases, AGDC would build a temporary bypass or bridge to reduce impacts on traffic until the pipeline is installed and the road surface restored. The minimum depth of cover would be 4 feet for road crossings and 10 feet for railroad crossings. For information on the Project Traffic Mitigation Plan, see section 4.12.2.

Utility Crossings

TAPS is a 48-inch-diameter major oil pipeline in Alaska that is both buried and aboveground on pipe support structures. The Mainline Pipeline generally parallels TAPS for about 400 miles from the North Slope to Livengood, occasionally crossing the TAPS pipeline, work pads, and access roads. The Mainline Pipeline also parallels a 149-mile-long buried TAPS fuel gas line system extending from the North Slope to fuel pump stations north of the Brooks Range.

The Mainline Pipeline would cross the TAPS pipeline at 11 locations and the fuel gas line at 5 locations. There is one location where the TAPS and fuel gas line would be crossed simultaneously. AGDC attempted to minimize the TAPS and fuel line crossings and identified these crossings as the only alternative due to natural features such as mountains and rivers, or due to the TAPS alignment in relation to the Dalton Highway. AGDC identified locations where it would not be possible for the Mainline Pipeline to remain on one side of the Dalton Highway due to physical or natural features and must therefore cross over the TAPS pipeline to cross the highway.

At crossing locations where TAPS (or the fuel gas pipeline) is belowground, AGDC proposes to install the Mainline Pipeline either by boring beneath the existing pipeline or by trenching and burial depending on the depth of the TAPS pipeline (or fuel gas pipeline) at the crossing location. In locations where the Mainline Pipeline would be installed above TAPS, a berm may be required to cover the Mainline Pipeline depending on the depth of the TAPS pipeline at the crossing location. Berms would be designed with a minimum of 3 feet from the top of the Mainline Pipeline to the surface of the berm. For crossings where TAPS is aboveground, AGDC would bury the Mainline Pipeline beneath TAPS, with a minimum of 4 feet of cover maintained over the Mainline Pipeline. These crossings would be made at the midpoint between two support structures and as perpendicular to the TAPS alignment as practicable. The Mainline Pipeline would maintain a minimum 20-foot-separation distance between its outer diameter and all VSMs. AGDC would comply with the TAPS Maintenance and Repair Manual when working near the TAPS pipeline.

Surface water runoff near the TAPS right-of-way could result in concentrated surface flow, scouring, erosion, and sedimentation, in which case additional mitigation measures would be implemented to minimize impacts on TAPS infrastructure. Proposed mitigation would include immediate backfilling and regrading; installing permanent erosion controls as necessary; and right-of-way monitoring. AGDC would use best management practices (BMPs) prior to, during, and following construction activities with an emphasis of avoiding and minimizing impacts on the TAPS. We received scoping comments raising concern about the crossing of TAPS and about the close proximity of Project facilities to TAPS. We address these issues in section 4.18.

The Mainline Pipeline would cross both buried and overhead utilities. Prior to grading and construction activities, AGDC would notify the utility owner and survey the crossings. AGDC would obtain third-party agreements and crossing permits prior to construction at each crossing location. AGDC would consult with the utilities' owners and construct its facilities to ensure that the existing utilities' cathodic protection system and the Project's cathodic protection system are non-interfering.

Wetland Crossings

The Mainline Pipeline centerline would cross 325.4 miles of wetlands affecting about 5,684 acres (see section 4.4). The construction techniques used in wetlands would depend on site-specific conditions at the time of construction, including season and weather conditions, the degree of soil saturation, the presence and extent of permafrost, soil stability, and wetland type. Wetland crossings would follow the measures described in the Project Procedures and federal and state permit requirements.

For wetlands, AGDC would use all construction modes, except for Mode 5B. The mode selected would be based on the location and construction season. Modes 1 (ice work pads) and 2 (frost packed) would not strip the organic layer because construction would occur in winter. Mode 3 (matted summer wetlands) would be used for summer wetland areas and would involve stabilizing the work surface using timber mats, which would be removed following construction. Mode 4 (granular fill work pads) would be used for flat or sloping terrain that is underlain by fine-grained thaw-sensitive permafrost, thaw-stable permafrost with a thick organic mat, or other organic or fine-grained soils. AGDC proposes to place granular fill on the undisturbed top layer. Mode 5A would be used in areas of graded cross-slopes, and fill would be installed to construct a stable working surface.

After the pipeline is lowered-in and the trench backfilled, granular and cut fill placed in wetlands (Modes 4 and 5A) would remain in place permanently. Erosion controls installed along the edge of the construction right-of-way would protect adjacent wetlands or uplands.

Construction across wetlands typically requires ATWS on each side of the wetland to stage construction, fabricate the pipeline, and store materials. FERC's Procedures require that ATWS for wetland crossings be a minimum of 50 feet from the wetland edge unless approval for a reduced setback is granted by FERC. AGDC has identified locations where a 50-foot setback between ATWS and wetlands cannot be maintained and has requested modifications to our Procedures to allow use of these ATWS areas (see section 4.4.3).

Waterbody Crossings

The Mainline Facilities would have 669 waterbody crossings, of which 553 would be along the Mainline Pipeline right-of-way, 102 would be along access roads, and 14 would be for additional work areas (e.g., material sites, pipe storage yards, and disposal sites) (see section 4.3.2). Waterbody crossings would be constructed in accordance with the measures described in AGDC's application and federal, state, and local permits, as well as the Project Procedures and site-specific waterbody crossing plans (where applicable). Surface water resources are addressed further in section 4.3, and aquatic resources are addressed in section 4.7. Potential impacts on fisheries resources and agency consultations regarding construction-timing restrictions for waterbodies are also discussed in section 4.7.

Open-cut waterbody crossing techniques (e.g., wet-ditch open-cut, dry-ditch open-cut, and frozen-cut) or trenchless methods (DMT or aerial span) typically require ATWS on each side of the waterbody to stage construction, fabricate the pipeline, and store materials. FERC's Procedures require that these extra workspaces be a minimum of 50 feet from the waterbody edge unless approval for a reduced setback is granted by FERC. AGDC has identified locations where a 50-foot setback between ATWS and waterbodies cannot be maintained, and has requested modifications to our Procedures to allow use of these ATWS areas (see section 4.3.2).

Sediment barriers would be installed immediately after initial disturbance of the waterbody or adjacent upland. Sediment barriers would be properly maintained throughout construction and reinstalled as necessary until replaced by permanent erosion controls or until restoration of adjacent upland areas is complete and revegetation has stabilized the disturbed areas.

For waterbodies without flow at the time of construction, AGDC would utilize the general construction methods described in this section 2.2. After backfilling, the streambanks would be re-established to approximate pre-construction contours and stabilized. Erosion and sediment control measures would be installed across the construction right-of-way to reduce streambank erosion and prevent upland sediment transport into the waterbody.

To prevent sedimentation due to equipment traffic through waterbodies, AGDC proposes to install temporary bridges on 43 waterbodies along the Mainline Pipeline right-of-way. Three of these waterbodies were deemed navigable by the Coast Guard and would therefore require Coast Guard bridge permits prior to construction (see section 4.3.2). AGDC proposes to install temporary bridges across 9 waterbodies for Mainline Pipeline access road crossings. Of these crossings, one is across a navigable waterbody that would require a Coast Guard bridge permit. Each bridge would be a steel prefabricated structure about 16 feet wide and of varying lengths. Each bridge would be designed to accommodate normal to high streamflow (storm events) and would be maintained to prevent soil from entering the waterbody and prevent restriction of flow while the bridge is in use. All construction equipment would be required to use the bridges, except for the clearing equipment used for equipment bridge installation. Temporary bridge bulkheads would be placed in the waterbody during clearing or right-of-way preparation and used until the bridge is removed. AGDC proposes to use a select waterbody temporary bridge deck that could be removed more than once based on the construction schedule and activity. Table 2.2.2-3 summarizes the waterbodies with temporary bridges as well as the number of access roads requiring temporary bridges by construction spread.

TABLE 2.2.2-3

Temporary Bridges Across Waterbodies and Temporary Access Roads by Construction Spread

Spread Number	Geographic Area	Begin Milepost	End Milepost	Total Length (miles)	Number of Temporary Bridges	Bridge Length Range (feet)	Number of Access Roads Requiring Temporary Bridges	Range of Bridge Length (feet)
1	North Slope	0.0	208.9	208.9	6	30–60	1	40
2	Interior Alaska	208.9	400.7	191.8	11	30–80	1	150
3	Alaska Range	400.7	607.4	206.7	14	30–300	3	20–150
4	South-Central	607.4	806.6	199.2	12	20–120	4	60–300
Total					**43**		**9** [a]	

[a] Three additional access roads could require either a temporary bridge or a culvert. Two of the crossings would be in Spread 1 and one would be in Spread 2.

<u>Open-Cut Construction Methods</u>

AGDC would follow the timing requirements in permits and would implement the erosion control methods and bank stabilization and revegetation measures described in the Project Plan and Procedures to reduce short- and long-term impacts on waterbodies. Table 2.2.2-4 identifies the crossing methods AGDC would use by FERC waterbody classification type.

TABLE 2.2.2-4

Number of Waterbody Crossings by FERC Classification and Crossing Method Along the Mainline Pipeline Right-of-Way

FERC Class [a]	Crossing Method [b]	Summer Construction	Winter Construction
Minor	Wet-ditch open-cut	140	3
	Dry-ditch open-cut	46	26
	Frozen-cut	N/A	238
Subtotal		**186**	**267**
Intermediate	Wet-ditch open-cut	50	1
	Dry-ditch open-cut	27	9
	Frozen-cut	N/A	N/A
Subtotal		**77**	**10**
Major	Wet-ditch open-cut	1	1
	Dry-ditch open-cut	N/A	3
	Buried trenchless	5	N/A
	Aerial span	1	1
	Offshore construction (Cook Inlet)	1	N/A
Subtotal		**8**	**5**
Total		**271**	**282**

N/A = Not applicable.

[a] Based on FERC's Procedures (2013), the definition of "waterbodies" includes any natural or artificial stream, river, or drainage with perceptible flow at the time of crossing and other permanent waterbodies such as ponds and lakes. A minor waterbody is less than or equal to 10 feet wide at the water's edge at the time of crossing; an intermediate waterbody is greater than 10 feet wide but less than or equal to 100 feet wide; and a major waterbody is greater than 100 feet wide at the water's edge at the time of crossing.

[b] Waterbodies that are dry or frozen to the bed would be crossed using standard upland construction techniques in accordance with the Project Plan. Waterbodies that are flowing would use open-cut crossing techniques in accordance with the Project Procedures. Crossing methods are defined as wet-ditch open-cut, dry-ditch open-cut (i.e., dam and pump, flume, and channel diversion), frozen-cut, and trenchless (i.e., DMT or aerial span).

Wet-Ditch Open-Cut Construction Method

The wet-ditch open-cut construction method involves trench excavation, pipeline installation, and backfilling in a waterbody without controlling or diverting streamflow (i.e., the stream flows through the work area throughout the in-stream construction period). With the wet-ditch open-cut method, the trench is excavated across the stream using track hoes or draglines working within the waterbody, on equipment bridges, and/or from the streambanks. Once the trench excavation across the entire waterbody is complete, a prefabricated section of pipe is lowered into the trench. The trench is then backfilled with the previously excavated material. Following pipe installation and backfilling, the streambanks are re-established to approximate pre-construction contours and stabilized. Erosion and sediment control measures are then installed across the right-of-way to reduce streambank and upland erosion and sediment transport into the waterbody.

Dry-Ditch Open-Cut Construction Methods

Dry-ditch open-cut construction methods involve conventional trenching of channels that are either dry (contain no discernible flow) or flowing at the time of crossing. A dry-ditch crossing of a flowing waterbody requires the installation of a flume, dam-and-pump, or channel diversion to isolate the majority of the stream flow from the trench construction. The flume method involves diverting the flow of water across the construction work area through one or more flume pipes placed in the waterbody. After the flume pipes are placed in the waterbody, sand bags or equivalent dam diversion structures are installed in the waterbody upstream and downstream of the trench area. These devices dam the stream and direct the water flow through the flume pipes thereby isolating the water flow from the construction area between the dams. A backhoe reaches under the flume pipe to dig the trench. The flume pipes and dams typically remain in place during pipeline installation and until final cleanup of the streambed and banks is completed.

The dam-and-pump method is similar to the flume crossing method except that pumps and hoses are used instead of flumes to move water across or around the dammed construction work area. The technique involves damming the stream channel, installing a pump upstream of the crossing, and running a discharge hose from the pump across the construction area to a discharge point downstream of the construction area. Water flow is maintained throughout the dam-and-pump operation until the pipeline is installed and the streambed and banks are restored and stabilized.

The channel diversion method is a type of flow isolation that can be used in conjunction with the flume or dam-and-pump techniques or as a standalone method. The technique is used at braided stream crossings or streams with secondary floodplain channels where flow can be diverted to existing channels (e.g., historic channels or newly created channels). Similar to the flume method, sand bags or equivalent diversion structures are installed in the waterbody to direct flow to a different channel and remain in place until final cleanup of the streambed and banks is completed.

Frozen-Cut Construction Methods

The frozen-cut method involves construction when the waterbody is frozen to the streambed and there is no flowing water. Upland construction techniques are used at these crossings. If the waterbody is not frozen to the streambed and has flowing water, a dry-ditch open-cut crossing method would be employed. See section 2.2.2.1 for more information on trenching methods proposed by AGDC.

<u>Trenchless Construction Methods</u>

Directional Micro-tunneling

The DMT method is a trenchless construction method that uses micro-tunneling. This method allows for the trenchless installation of a prefabricated pipeline segment simultaneously with the drilling of a borehole or micro-tunnel. The pipeline segment is installed behind a large cutter head on a drill. A pipe thruster is used in this process to grab ahold of the circumference of the pipe and lead it through the borehole behind the cutter head as drilling is completed. DMT provides continuous borehole support, creating more opportunity for drilling across non-stable soil surfaces and eliminating the need for surface conductor casings. The process involves remote guidance for laying the pipe instead of a direct pipelay method. The process uses a direct micro-tunneling boring machine, which has a steering capability and results in the pipe having a curved alignment once installed. The DMT process uses a shallow angle for drilling, leading to a shallow burial depth for the pipe segment.

The DMT method uses a slurry referred to as drilling fluid, which is composed of about 65-percent water and 30-percent bentonite, a naturally occurring clay mineral that can absorb up to 10 times its weight in water (the remaining 5 percent consists of additives such as barium sulfate, calcium carbonate [chalk], or hematite). Bentonite-based drilling fluid is a non-toxic, non-hazardous material that is also used to construct potable water wells throughout the United States. The drilling fluid is pumped under pressure through the inside of the drill pipe and flows back (returns) to the drill entry point along the outside of the drill pipe. The purpose of the drilling fluid is to lubricate the drill bit and convey the drill cuttings back to the drill entry point where the fluid is reconditioned and re-used in a closed circulating process. Drilling fluid also forms a cake on the rock surface of the borehole, which helps to keep the drill hole open and maintains circulation of the drilling fluid system. Because the drilling fluid is pressurized, it can be lost, resulting in an inadvertent release or "hydrofracture." This occurs if the drill path encounters fractures or fissures in the substrate that offer a path of least resistance. It can also occur near the drill entry and exit points where the drill path has the least amount of ground cover.

The potential for an inadvertent release is low using the DMT process. If a loss occurs, the volume of fluid lost would depend on various factors, including the size of the fissure/fracture, the permeability of the geologic material, the viscosity of the drilling fluid, and the pressure of the drilling system. A reduction in drilling pressure (or loss of returns to the drilling rig altogether) would indicate that a release could be occurring. The release may not be evident from the ground surface if the fluid moves laterally. For a release to be evident there must be a fissure/fracture or other pathway extending vertically from the borehole to the surface. The migration of fluids could also occur horizontally, for instance in folded or fractured formations or in proximity to shallow groundwater, such as perched aquifers/seeps/springs. AGDC has prepared a DMT Inadvertent Release Contingency Plan (DMT Plan) for each DMT crossing, which includes preventative and responsive measures such as the installation of containment structures and staging of response equipment at the entrance and exit points of the drill.[11]

DMT activities would take place on a continuous 24-hour per day, 7-day per week schedule. It is estimated that each DMT crossing for the Project would take about 8 weeks to complete. This estimate is based on 3 weeks of drilling (assuming advancement of 5 feet per hour over a 20-hour drill workday while on site), 2 weeks to mobilize and prepare the site, 2 weeks to demobilize, and 1 week of contingency for inadvertent releases. AGDC proposes five waterbody crossings using the DMT construction method (see table 2.2.2-5). For more information on these crossings, see section 4.1.5.

TABLE 2.2.2-5

Directional Micro-tunneling Crossings Associated with the Mainline Pipeline

Waterbody Name	Beginning Milepost	Entry and Exit Length (feet)	Drill Direction	Drill Depth (feet)	Season
Middle Fork Koyukuk River	211.1	2,625	North	72	Summer
Yukon River	356.5	2,668	North	100	Summer
Tanana River	473.0	3,124	South	66	Summer
Chulitna River	641.8	2,661	North	83	Summer
Deshka River	704.7	1,299	North	33	Summer

Aerial Span

Aerial span crossings would be used for two waterbodies along the Mainline Pipeline due to their difficult terrain or geologic fault lines (see table 2.2.2-6). The aerial span crossings would involve placing the pipeline on bridges installed across the waterbody. Aerial span construction methods would result in no impacts on the waterbodies crossed because there would be no in-water work and no structures placed in the water. The Nenana River No. 3 and Nenana River No. 5 crossings, both major waterbody crossings, would be attached to the span crossing above clearances established by the Coast Guard.

[11] Impacts from the loss of drilling muds on surface waters are addressed in the APDES General Permit. The permit provides coverage for inadvertent releases to waters of the United States as a contingency to fluids released to surface waters and grants a 500-meter mixing zone to comply with turbidity limits.

TABLE 2.2.2-6 **Aerial Span Crossings of Waterbodies Associated with the Mainline Pipeline**					
Waterbody Name	Milepost	Aerial Length (feet)	Reason	Type of Aerial Crossing	Season
Nenana River No. 3	532.1	1,102	Difficult terrain	Triple span; plate girder bridge	Summer
Nenana River No. 5	537.1	626	Difficult terrain	Existing pedestrian bridge (triple span; steel girder bridge)	Winter

Offshore Construction Procedures

Prior to construction, AGDC or its construction contractor would conduct a pre-installation bathymetric survey of the seabed to support final engineering design and installation of the offshore pipeline. This survey would locate existing utilities, such as subsea cables and other pipelines, along and near the proposed Mainline Pipeline route. Final designs for crossing existing utilities would be developed after the survey in consultation with the applicable utility operators. Generally, concrete pads, sacks, or mattresses would be used to separate the Mainline Pipeline and other existing utilities at these crossings. In comments on the draft EIS, the State of Alaska noted that the Mainline Pipeline would cross a new natural gas pipeline, referred to as Tyonek West, which was built in 2018 between the existing Tyonek Platform and Ladd Landing.

The Cook Inlet offshore crossing would be laid in the ice-free season. AGDC proposes to avoid conflicts with other waterway and nearshore users to the extent practicable, including commercial, subsistence, and recreational vessels and activities. Hydrostatic testing would occur shortly after installation of the pipeline on the seafloor.

The Mainline Pipeline would be buried at the Cook Inlet shoreline crossings to avoid potential impacts of shallow water hazards, such as ice, vessel keels, and beach erosion or soil scour, which could create unsupported spans along the pipeline. The offshore pipeline would require two nearshore (land to water) pipeline installations and 27.3 miles of offshore pipeline lay (see figure 2.2.2-8). The western shoreline installation would be at Beluga Landing South, and the eastern shoreline installation would be near Suneva Lake. For the shoreline approaches, the Mainline Pipeline would be buried from the shoreline out to a depth such that the top of the pipe would be sufficiently protected from major hazards. This depth is expected to be from about -35 to -45 feet MLLW.

The nearshore trenches would be excavated by amphibious or barge-based excavators to trench from the shoreline to the transition water depth. A backhoe dredge could also work in the nearshore area. Shore pull operations would be performed during periods of high tides, allowing the pipeline to be pulled into place using water buoyancy to facilitate the pull. Shore pull operations could be halted during low tide periods. AGDC does not intend to backfill the offshore area of the nearshore crossings nor bury the pipe in Cook Inlet. Following pipeline installation for each shoreline approach, AGDC expects the trench to naturally backfill within a matter of several days. If the trench does not naturally backfill, however, then manual backfilling would be required.

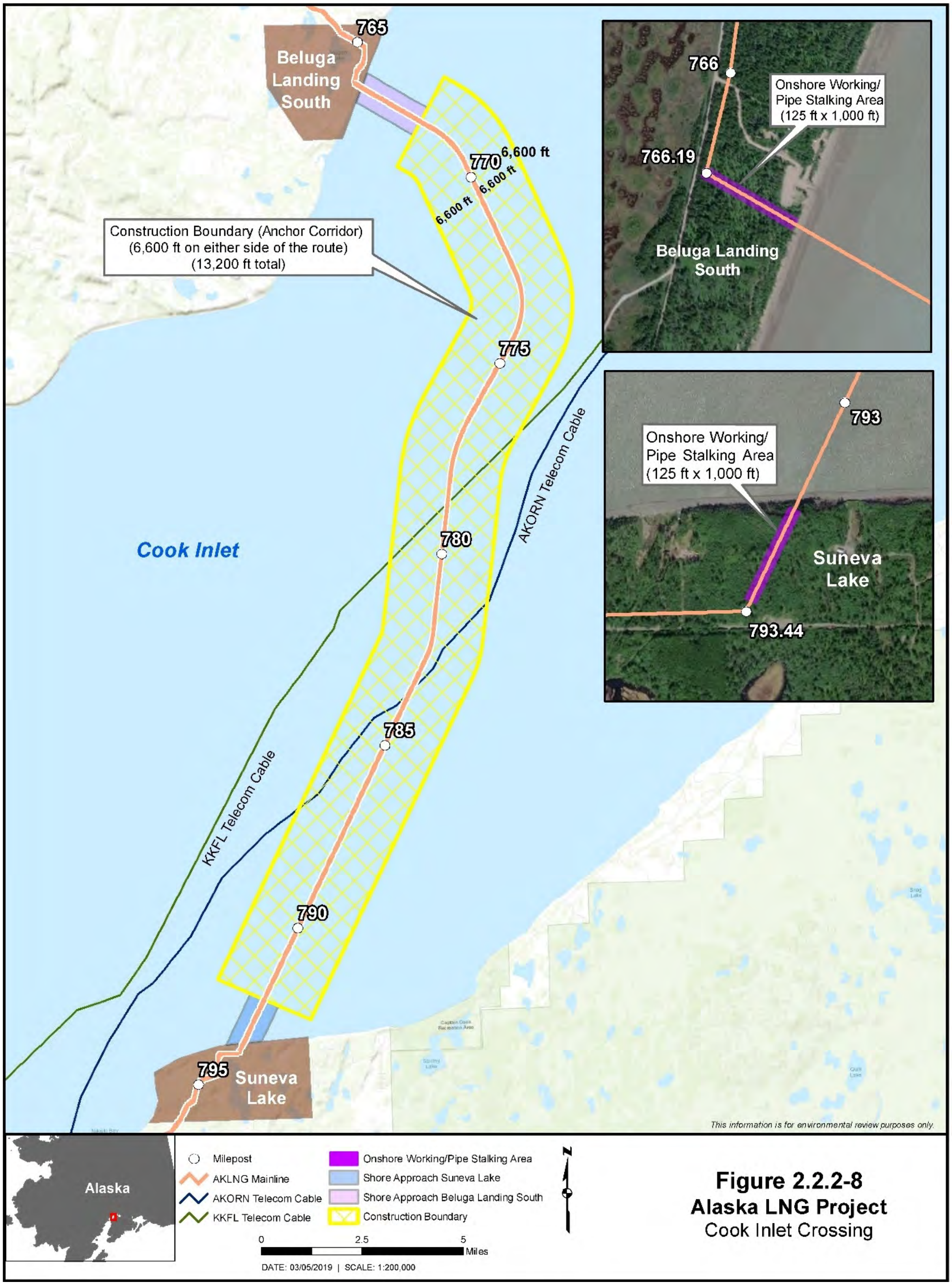

Figure 2.2.2-8
Alaska LNG Project
Cook Inlet Crossing

The offshore lay would require an offshore pipelay barge that would weld 40-foot-long sections of concrete coated pipe together and then lower them to the seafloor. As each pipe joint is welded and lowered, the pipelay vessel would move by pulling on its anchors. The pipelay barge would deploy about 12 anchors, each about 15 feet wide. Tugboats would reposition the anchors at 2,500-foot intervals in the direction of movement. The anchors would create a seafloor disturbance from the anchor drop, anchor drag, and cable anchor sweep. As anchors are lowered to the seafloor, the weight of the anchor would create an anchor drop mark. The anchor would drag until it embeds in the seafloor, creating about a 3-foot berm for about 10 feet per anchor. As the pipelay barge advances, tugboats would lift the anchors from the sea floor, and as the anchor lifts, its cable would "sweep" across the seafloor. Upon completion of the pipelay of the pipe originating at each shore, the pipeline sections would be in a water depth sufficient to complete an above-water weld tie-in. AGDC estimates that there would be 636 anchor drops, affecting about 5,070 acres.

Mid-line buoys would be used on anchor lines directly over existing subsea infrastructure or in places where the anchor cable would have the potential to drag over existing utilities. Anchor cables that would not contact known infrastructure would not have mid-line buoys. AGDC plans to use mid-line anchor buoys on the four anchors positioned off the sides of the pipelay barge to ensure the anchor cables do not strike when crossing the two known submarine telecom cables in Cook Inlet. Similar measures would be required for the Tyonek West pipeline.

In the Boulder Point area onshore, the pipeline right-of-way and associated workspaces would be graded following pipeline installation and trench backfilling to maintain pre-construction drainage patterns and reduce the effects of bluff erosion. After completion of major construction work, the organic layer (removed and segregated during installation) would be placed along the right-of-way. Erosion control would be installed at the bluff face to stabilize the area. No beach access would be provided to the public through the Mainline Pipeline right-of-way, with access controlled by gates/security.

AGDC would coat the offshore pipeline with 3.5 inches of concrete coating for on-bottom stability as well as protection from impacts on the pipeline. The concrete density would be 190 pounds per cubic foot. AGDC states that the concrete coating would protect the pipeline from shipping related impacts (e.g., anchor or container drops) and natural features (e.g., boulders), and would be in compliance with the cover requirement in CFR 192.327(f)(2).

AGDC reviewed current and future shipping traffic in Upper Cook Inlet and studied the potential impact on the 42-inch-diameter pipeline from anchor drops with anchor sizes of 20 and 29 tons. The results of AGDC's study showed that the concrete coated pipeline installed on the seabed without burial would absorb the impact energy expected from the dropped anchors and withstand the force of a dragged anchor. AGDC additionally evaluated the potential damage to the pipeline in the event a container (common cargo on ships) with a mass weight of 31 tons or a 10-ton boulder moving at 4.8 knots strike the pipeline, and determined that the concrete coating would protect the pipeline. AGDC also conducted an evaluation of the potential for ice to affect the unburied pipeline, and determined that the pipeline would withstand a direct ice contact under unburied conditions assuming that the driving forces would be wind and current only.

Based on the studies conducted, AGDC concluded that external damage to the Mainline Pipeline from anchor drop/drag, dropped container, trawl gear, ship sinking/grounding, boulders, or ice would not be expected with the proposed concrete weighted coating, and that the pipeline would be safe without burial.

In a March 2017 letter to AGDC, PHMSA said that a pipeline crossing of Cook Inlet—whether installed below the natural bottom or supported by stanchions and held in place by anchors or concrete coating, as described by CFR 192.327(f)(2)—would need to meet applicable crossing and depth of cover standards. PHMSA has reviewed the technical information and responses provided by AGDC relative to the design. With regard to 49 CFR 192.327(f)(2), PHMSA is satisfied that AGDC would mitigate any future pipeline safety conditions. Should mitigation of safety conditions (e.g., free spans) be required after detailed design is completed, or determined to be necessary during Project construction or operation, additional environmental analysis by FERC and other permitting agencies may be required depending on the proposed scope and anticipated impacts of implementing the mitigation measures.

Fault Crossings

AGDC identified four active faults (Northern Foothills Thrust Fault, Park Road Fault, Denali Fault, and Castle Mountain Fault) that would be crossed by the Mainline Pipeline using aboveground construction. Three additional fault areas (Stampede-Little Panguingue Creek, Healy Creek, and Healy Faults) would require further detailed design to determine the best installation method for the Mainline Pipeline. These areas have had no recent activity and may be only potentially active. Table 2.2.2-7 identifies the geologic area to be crossed and the proposed crossing method.

AGDC is proposing to cross the active faults using aboveground crossing methods as shown in Table 2.2.2-7. AGDC would use load distributing shoes that would slide on the supporting cross beams in response to ground movement. Each crossing configuration would differ based on the type of fault crossed. Design considerations for the shoes and beams would include determining the appropriate size and length to accommodate the expected range of movement of the pipeline and to provide for adequate support. If a pipe shoe should slide off a support beam during a seismic event, the shoe and pipeline would drop a short distance to the ground, which would be unlikely to cause damage to the pipeline. This concept is similar to the design used by TAPS where it crosses the Denali Fault at TAPS MP 589. Alternatively, a second design approach would be to construct the pipeline in a shallow, sloped-wall trench with loose, well-drained granular fill. This would allow for large strains and deformation to occur without pipe rupture. Similar to the "shoe design," the pipeline berm would be aligned across the fault zone in an orientation that minimizes the direct axial stress/strain induced into the pipeline. The Park Road fault crossing would be a conventional aboveground crossing, meaning the pipeline would be placed on aboveground "sleeper" supports.

AGDC would use permanent gravel roads connecting the fault crossing granular fill pad to the nearest road system for year-round access in case of fault movement and the need for field repairs. The Park Road fault would be reached via an access road connecting the Parks Highway to the permanent right-of-way less than 0.2 mile north of the fault crossing. AGDC would monitor the Mainline Pipeline right-of-way at fault crossings annually, keeping it free from brush and re-grading as needed to maintain access.

TABLE 2.2.2-7

Geologic Fault Crossings and Construction Methods Associated with the Mainline Pipeline

Fault Name	Milepost Range	Crossing Length (feet)	Crossing Method
Northern Foothills	500.0–500.6	3,010	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad.
Stampede-Little Panguingue Creek	520.0–521.0	5,280	To be determined following detailed design.
Healy Creek	522.4–522.5	6,000	To be determined following detailed design.
Healy	526.9–527.0	520	To be determined following detailed design.
Park Road	537.7–537.8	600	Conventional aboveground crossing.
Denali	560.3–561.5	6,336	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad.
Castle Mountain	743.2–743.4	1,056	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad.

Atigun Pass Summit

At MP 168.7, the Atigun Pass Summit presents a narrow route segment with limited construction options. At this pinch point in the topography, the existing TAPS pipeline and the Dalton Highway limit the possible locations for the Mainline Pipeline. AGDC proposes to install the Mainline Pipeline between TAPS and the Dalton Highway, which would bring the Mainline Pipeline adjacent to the Dalton Highway, allowing for improved access during construction and operation. Because of its high elevation (about 5,000 feet), snow load, steep grades, and avalanche danger, AGDC would construct this section of the Mainline Pipeline in the summer with a reduced right-of-way width. AGDC would use a mini-spread set up working from the south end of the section in the upper Dietrich River through the Chandler Shelf and Atigun Pass to the north base of the pass.

The Mainline Pipeline through this section would parallel the TAPS pipeline corridor. Construction on the slopes would require a coordinated effort with winch bulldozers holding equipment in place. Upon completion of the pipe installation, erosion control measures such as water diversion ditches, terracing, retaining structures, and other engineered methods for slope stabilization would be installed. Near the summit, the Mainline Pipeline would cross over the buried TAPS using the open-cut trench method. The open-cut would create a shallow trench (e.g., near ground level) above the buried TAPS and would require a granular fill berm to provide sufficient depth of cover over the Mainline Pipeline as well as provide protection from pipe movement. Granular fill would be brought in to build up a graded berm to cover the Mainline Pipeline. The thickness of the berm and placement of the Mainline Pipeline within it would ensure adequate vertical separation between the pipelines. AGDC would take measures to maintain a separation distance of 3 feet between the pipelines. At this location, preliminary information received from the Alyeska Pipeline Service Company indicates the TAPS pipeline is buried under 9 feet of cover. The berm would consist of select compacted material around the pipe and coarse granular fill/cobble on the surface as a means of erosion control and mechanical protection.

The Mainline Pipeline would cross the Dalton Highway, the main highway for the region, four times in this area. All crossings would be installed by boring beneath the road to minimize highway closures, but construction through Atigun Pass would require temporary lane closures on the highway in three locations. On the north side of Atigun Pass, along the Dalton Highway, there would be a northbound lane closure from near the top of the pass at highway MP 244.3 to just before the downhill section at highway MP 244.9. At the bottom of the south side of Antigun Pass, in a relatively flat area, there would be a southbound lane closure between highway MPs 242.2 and 242.4. The southernmost lane closure is for northbound lanes in the Dietrich Valley between highway MPs 235.0 and 235.6. Each of these lane closures would include rerouting traffic into the lane that remains open. While the lane closures would result in slower and more congested traffic, they would not require extensive reroutes.

2.2.2.3 Winter Construction Procedures

AGDC developed a Winter and Permafrost Construction Plan that outlines the steps for Mainline Pipeline construction during winter conditions, including ice work pad construction and frost packing (see table 2.2-1). In some areas, winter construction would require working from ice work pads or frost packed pads as discussed below.

Ice Work Pads

Construction of an ice work pad would be accomplished by combining snow with water and sometimes ice chips to a specified depth and width. Suitably constructed ice work pads can support heavy loads and pipeline construction equipment without damage to underlying vegetation. An ice work pad area is constructed by driving equipment across the area to pack the colder frost lower and push up the soil moisture. Once an area is sufficiently frozen, a water layer is sprayed across the area to develop an ice work pad. Use of ice work pads (Mode 1) would avoid stripping surface organics from the area outside of the trench line to minimize disturbance of the organic layer. In addition to the equipment working area, the trench line would be covered by the ice work pad and no other preparation would be required. For continuous chain trenching, the trencher would dig in one pass through the ice work pad and tundra to the full trench depth in the mineral soil.

In the spring, resource agencies would monitor weather and tundra conditions and issue a notice closing tundra travel to unapproved equipment. Prior to the tundra travel closing date, trench spoil would be placed back into the ditch and crowned (i.e., using excavated spoil to create a slight mound over the backfilled pipe trench) to allow for future thaw settlement. Erosion and sediment control devices and other mitigation measures would be installed along the trench line to control surface drainage and/or allow movement of water across the crown (see section 4.2.5.2).

Frost Packed Pads

Frost packing (Mode 2) would be used on flat terrain underlain by saturated non-permafrost soils or thaw stable permafrost soils overlain by a saturated vegetative mat. Frost packing prevents soils that may not have the strength to support construction equipment from rutting or mixing with subsoils during construction. Frost packed pads would reduce impacts on soils and vegetation by maintaining plant root structure and associated surficial organic layers in place.

Frost packing would generally be limited to flatter terrain because of safety concerns with operating heavy equipment on frozen, sloping ground. To complete frost packing, equipment would be driven across the area, thus driving the soil temperature down while pushing the moisture to the surface. Frost packed pads can be affected by above-freezing weather temperatures. In fine-grained, thaw-sensitive permafrost soils, snow cover would be used and supplemented with available water sources to create a packed or hardened snow travel surface above the vegetation. Just as with ice work pads, organic layer salvage or layering organic material over the trench line would not be required in areas using frost packed pad construction.

2.2.2.4 Aboveground Facilities

Compressor Stations and Heater Station

Compressor and heater station construction would begin with access road and work pad installation. The work pad, access road, and foundation construction phasing would be dependent on the permafrost conditions at each site. The work pads at the permafrost sites would be constructed of granular fill of sufficient thickness to reduce the potential for heat transfer to the permafrost. Work pads at non-permafrost sites would be constructed of granular fill of sufficient thickness to provide adequate bearing capacity for equipment and wheel loads. Construction of the aboveground facilities would occur year-round depending on the construction plan. Vegetation clearing would be conducted in accordance with the clearing windows identified in the Project Migratory Bird Conservation Plan.

The granular fill for the work pads would be imported for the permafrost sites. Granular fill for the non-permafrost sites would be a combination of imported and on-site material where available. After completion of the work pad, a permanent perimeter fence and access gate would be installed. The compressor station and heater station facilities would consist of both stick-built and modular units configured for specific station types.

Facility structures would be supported on pile foundations with identical foundation layout and structural connections regardless of soil and permafrost conditions. Piles would be between 18 and

24 inches in diameter and embedded about 40 feet below grade, with 10 feet of stickup and a total length of 50 feet. AGDC estimates that each station would contain between 859 to 1,822 piles. The stations would be elevated above the work pad elevation, which is especially important at permafrost sites to provide an airspace between the structure and the ground surface to serve as a thermal break and minimize thawing in permafrost areas.

Electrical, water, wastewater, and communication utilities would be both above- and belowground to connect facilities. Belowground electrical and communication cable would be installed in trenches 2 to 4 feet deep. Belowground water and wastewater utilities for permafrost sites would consist of insulated arctic pipe or insulated utilities. The buried utilities for permafrost sites would be contained within the constructed work pad, with no excavations penetrating the original tundra surface. Water and wastewater utilities at non-permafrost sites would be buried at 8 to 10 feet below grade, which is a typical burial depth to prevent seasonal freezing in south-central Alaska.

Compressor and heater station access roads would be constructed to provide site access from the public road system. Access roads to support construction traffic would be built and serve as long-term access to the sites following construction. Roads would be installed with appropriately sized drainage culverts to be maintained by AGDC to ensure proper drainage. Each facility would contain a granular fill pad around the facility to provide a safety buffer as well as a level working surface.

Meter Stations

The two meter stations required for the Mainline Facilities would be constructed on granular fill pads developed as part of the GTP and LNG Plant sites. Following the installation of piles, building skids would be installed along with a scrubber, meter runs, and piping. Site work would follow the same process as described above for the compressor stations and heater station.

Mainline Valves

MLVs would be prefabricated and tested prior to installation and installed after pipeline hydrostatic testing is complete. Upon completion, the MLV site would be fenced and granular fill placed around the MLV to provide a safety buffer.

Launchers and Receivers

Launchers and receivers would be constructed concurrently with compressor and meter stations using similar construction methods.

Mainline MOF

AGDC would install 670 feet of steel sheet piling, including an anchor wall complete with tie-rods, for the Mainline MOF. Vibratory and impact type pile driving hammers would install the sheet piling. The pile driving would not be a continuous activity. Pile driving would require about 25 days over a 60-day period in April and May to be completed. The sheet pile would be about 70 to 80 feet long and embedded about 50 feet into the Cook Inlet seafloor. Behind the steel sheet piling, AGDC would place fill material obtained from local sources.

Gas Interconnections

The assemblies required for the gas interconnections would be prefabricated and tested prior to installation after pipeline hydrostatic testing is complete. Upon completion, the gas interconnection sites would be fenced.

2.2.2.5 Additional Work Areas

Access Roads

Access roads would be required during construction of the pipeline and aboveground facilities to transport equipment, material, pipe, and personnel to the right-of-way, compressor stations, material sites, and other locations. For public roads to be used during construction of the Project, the need for road improvements would be evaluated by AGDC. Many of the existing non-public roads would require modifications to accommodate large and heavy construction equipment and material and use agreements with the applicable landowner and/or land-managing agency. Where existing roads are not readily available, or do not provide adequate access, the Project would construct new temporary and permanent access roads using available native material, imported granular fill, or snow/ice depending on the location, traffic load, duration, and timing of use.

Helipads and Airstrips

Where helipad sites are required outside of the construction sites for the construction camps, contractor yards, compressor and heater station facilities, and select MLVs, each site would be cleared and leveled. Helipads pads using granular fill, where necessary, would be constructed. Certain sites could be sufficiently stable to allow helicopter operations without the use of a granular fill pad. The Project would use existing airstrips.

Material Sites

For the development of new material sites, each site would be surveyed and staked, trees and brush would be cleared, and an access road would be constructed. The site would be evaluated for asbestos and other contamination, if required. Existing material sites that have already been evaluated for asbestos and other contaminants would not require further evaluation. The material sites would be developed in accordance with any permit requirements related to site preparation.

AGDC would use the best available information to identify naturally occurring asbestos at material sites, construction areas, and existing roads and pads proposed for use. A sampling and testing plan conducted in accordance with 17 AAC 97.020 would be implemented for areas with potential to contain naturally occurring asbestos. If a material test is determined to have an asbestos content equal to or greater than 0.25 percent using the bulk test method, a site-specific monitoring and mitigation plan would be developed and submitted to the ADOT&PF for approval.

2.2.2.6 Post-Construction Maintenance

AGDC would conduct follow-up inspections and monitor disturbed areas until the performance standards specified in the Project Revegetation Plan are met and temporary erosion control devices can be removed. FERC staff would continue oversight of the Project area after construction by reviewing AGDC's annual monitoring reports and conducting field compliance inspections. AGDC would be required to continue revegetation efforts until performance standards have been met, as stated in the Project

Revegetation Plan, which would be reviewed and require approval by FERC, the COE, the NPS, and the BLM.

2.2.3 Liquefaction Facilities

The Liquefaction Facilities would require the following temporary facilities during construction:

- construction camps and other infrastructure to support the construction workforce;
- infrastructure to support construction (e.g., concrete batch plants, construction equipment storage, construction camps, offices, warehouses, construction fuel storage tanks, water source and temporary potable water plant, temporary domestic wastewater treatment plant, construction power, communication tower and radio base station, and laydown areas);
- Pioneer MOF to handle offloading of aggregate and bulk construction materials and equipment for the Liquefaction Facilities;
- material sites;
- disposal areas for construction debris and for blast rock; and
- a Marine Terminal MOF.

2.2.3.1 LNG Plant

Construction at the LNG Plant would start with ADOT&PF permanently redirecting traffic to the newly constructed Kenai Spur Highway segment. See section 4.19.2 for more information on the Kenai Spur Highway relocation. The surveyed facility would be fenced prior to the start of construction activities. In accordance with the Project Plan and Procedures, AGDC would install temporary erosion and sediment controls along the property line and at existing primary property outfalls.

Site clearing would start at the property line, moving across the site. The organic layer would be stripped and stockpiled for re-use on site, as needed. Debris and grubbed material would be collected and disposed of at an approved off-site disposal facility in compliance with local requirements. Cut, fill, and rough grading operations would occur on the eastern portion of the site. Lower areas of the site would have fill added to construct a level pad and foundations.

In parallel with the cut, fill, and rough grading operations, work on the Marine Terminal, MOF, and heavy-haul roads would begin. Construction would occur in accordance with the Project Plan to prevent erosion and sedimentation from storm events and construction activities. During construction, stormwater runoff would be directed to designated, graded, sediment catch basins that would outflow via one of three outfalls into Cook Inlet, in accordance with the Stormwater Pollution Prevention Plan (SWPPP).[12] Undisturbed areas within the site would retain their existing natural drainage. The construction area would include wash-down areas to remove soil from vehicles before they exit the site.

During construction, access roads within the LNG Plant footprint would change to address construction activity needs. Roads stabilized with native soils or granular fill would be graded and compacted periodically to maintain a safe travel surface. The heavy haul road from the Marine Terminal

12 AGDC notes that a Project-wide final SWPPP would be prepared the year of construction with the construction contractor.

MOF would consist of coarse hot-mix asphalt over a crushed aggregate base to withstand the heavy loads and provide a weather-resistant surface.

Foundation Construction

The techniques used to construct structural foundations would be based on geotechnical information about the soil bearing capacity of the selected site. Critical equipment and structures, such as process equipment and pipe racks, would have foundations constructed of reinforced concrete designed according to standard engineering practices. The concrete foundations and earthworks would meet settlement criteria per American Concrete Institute 376 and FERC guidelines. The top 7 feet of existing ground would be replaced by granular fill. Foundations for processing equipment and large machinery would typically be completed and cured before equipment and modules arrive on site.

Liquefaction Trains

The LNG trains would be designed, constructed, operated, and maintained in accordance with PHMSA's *Federal Safety Standards for Liquefied Natural Gas Facilities*, 49 CFR 193, and the NFPA 59A LNG Standards. Each LNG train would consist of multiple process modules fabricated off site and transported to the Marine Terminal MOF. Vessels would arrive at the Marine Terminal MOF in a certain order to enable efficient assembly of the LNG trains. The modules would be offloaded from vessels at the Marine Terminal MOF and moved into final position using self-propelled module transporters. The transporters would move each process module sequentially into position and then lower each module onto its foundation. Smaller modules would be lifted off the vessels, transported to site, and then set in place by crane.

Liquefaction Storage and Processing Facilities

The LNG storage tanks would be constructed using conventional construction techniques. Following installation of the foundation, construction of the tank base and post-tensioning of the outer concrete container wall would occur. In parallel with construction of the outer concrete container wall, the steel dome roof and suspended deck would be constructed on temporary supports inside the outer container of each storage tank. The bottom carbon steel vapor liner would then be installed. On top of the outer concrete container wall, the steel dome roof compression ring would be cast into the concrete, and then the steel dome roof would be air-raised into position and secured to the compression ring.

To ensure that the tanks are capable of operating at the design pressure, AGDC would complete testing according to NFPA 59A (2001 edition) and the applicable provisions in American Petroleum Institute (API) Standard 620. Pneumatic testing of the outer tanks would occur. Hydrostatic testing of the inner tank would occur during the summer. The process would commence with one tank. If timing allows, test water would be transferred to the other tank when it is mechanically complete. Hydrostatic testing would use water obtained from the City of Kenai or salt water from Cook Inlet. If Cook Inlet water is used, in advance of filling each tank, a screened hose would withdraw the water and the water tested to ensure that the water meets ADNR requirements. On completion of testing, test water would be discharged into Cook Inlet via an outfall; this discharge would be subject to an APDES permit.

At the prefabrication yards, integrity testing would be done in a controlled environment. Testing of LNG piping would be in accordance with NFPA 59A (2001) and American Society of Mechanical Engineers (ASME) standards to confirm integrity of the completed systems.

2.2.3.2 Marine Terminal

The Marine Terminal construction activities would occur both offshore and onshore. The offshore construction activities would use the ice-free working windows in Cook Inlet. The onshore construction work would occur year-round. In the first year, construction would establish a laydown area for the cantilever bridge (overhead construction) system at the top of the Marine Terminal MOF shoreline bluff where the access trestle begins and establish a road cut to access the MOF from the bluff.

The Marine Terminal MOF would use a combi-wall of pilings and sheets backfilled with granular fill that would tie to a sheet pile anchor wall. As pilings are set, fill material would be stabilized with erosion and sediment control measures as necessary. As the ice season approaches, the MOF offshore work would be stabilized for the winter months.

Offshore work, including the Marine Terminal MOF, the PLF trestle, and heavy-lift module installations, would occur from Years 1 to 5 and in Year 7 of construction. The PLF trestle work would be supported on steel-jacketed (quadrupod) structures. The 10-foot-diameter quadrupod units would be installed from barges and anchored with four 48-inch anchor piles. The prefabricated topsides would be 120-foot spans lifted with a dedicated heavy lift derrick barge. The marine spreads would work the areas from opposite ends to avoid vessel conflict.

During the final stages of construction, modules would be offloaded at the MOF and transported via the beach access road onto the trestle. Installation would start from offshore and work inward. Heavy lifts would consist of 160-foot-long roadway/pipe rack modules and platform modules. Quadrupod piles, roadways, pipe racks, and platforms as modules would be fabricated off site and delivered for installation via barge.

The Marine Terminal MOF would require dredging during the first and second season of marine construction. During the first season, mechanical dredge equipment would remove sediment placed in split hull or scow/hopper barges and transport the material to the dredged material disposal area. Decanting/dewatering of the dredged material in the barges at the dredge site would be conducted to maximize the amount of dredged material in each barge. A workboat would carry personnel between land and the dredging vessel fleet. Up to three deck/material barges also maneuvered by tugs would be used to support the dredge equipment with fuel, equipment, and other supplies. A survey vessel would conduct a hydrographic survey prior to, during, and after dredging.

Hydraulic or mechanical dredging would be conducted during the second season. For a hydraulic dredger, the dredged material would be pumped from the dredge area as a slurry to the dredged material disposal location or pumped into split-hull barges for decanting and transport to the disposal site. The split-hull barges would release the dredged material beneath the water surface at the disposal site. A floating or semi-submerged pipeline system could also be used for dredged material transport. A booster pump could be required depending on the distance between the dredge area and dredged material disposal area. A typical dredge fleet for hydraulic dredging would include the hydraulic suction cutterhead dredge, a working boat, a tending tug, a derrick barge, and a barge mounted booster pump with onboard power plant.

Maintenance dredging would occur in Years 3 and 7. A total volume of 140,000 cubic yards of material would be excavated. Both dredging methods would employ a real-time kinematic global positioning system (GPS) for station keeping and a cutterhead or bucket position to maintain desired dredge depths in the correct areas. The dump scows and tugs or, alternatively, the trailing suction hopper dredge, if used, would use a differential GPS station to track along with a data-logger and data relay used for real-time or near-real-time monitoring of the dredged material movement and disposal. A survey vessel would conduct a hydrographic survey prior to, during, and after dredging.

Given the total volume of dredging planned and the potential for additional maintenance dredging, a new offshore-unconfined aquatic disposal site, in relative proximity to the dredging area, is AGDC's preferred option for dredged material disposal.

2.2.3.3 Restoration

Areas disturbed by construction of the Liquefaction Facilities would be stabilized with temporary erosion controls until construction is complete unless covered by equipment, granular fill, or other covering. The Project Plan and Procedures describe erosion control and soil stabilization measures to be used during restoration. Following construction, sites affected by construction would be permanently stabilized by application or establishment of granular fill, concrete, asphalt, or revegetation/landscaping.

The Marine Terminal MOF would be removed at the end of construction. The removal would require permits from the COE and ADEC. Excavated material would be hauled off site for disposal at an authorized disposal facility and metal materials would be sent to recycling facilities. AGDC is not proposing any in-water disposal of material from the Marine Terminal MOF. The shoreline area would be restored to original contours by grading crews. Geotubes used to construct the Marine Terminal MOF would be opened and the fill material used by the grading crews during restoration, as applicable.[13] The MOF access road would remain in place.

2.3 CONSTRUCTION SCHEDULE AND WORKFORCE

2.3.1 Construction Schedule

Project construction and commissioning would take about 8 years to complete with two phases of construction. The first phase (6 years) would involve installation of the LNG Plant, Marine Terminal, Mainline Facilities, GTP trains, PBTL, and PTTL, to a point that would allow transport and export of the first production of LNG. The second phase (2 years) would include completion of the remaining Project facilities (additional trains and compressor stations) required for full production. Table 2.3.1-1 summarizes the proposed Project schedule. Table 2.3.1-2 provides an overview of activities that would occur during each year of construction.

TABLE 2.3.1-1

Project Construction Schedule

Facility	Duration (years)
Gas Treatment Facilities	7.5
Mainline Facilities [a]	6.25
Liquefaction Facilities	6.75

[a] Includes the Mainline Pipeline and associated aboveground facilities

[13] Geotubes are tubes of geotextile fabric filled with sediment.

TABLE 2.3.1-2

Construction Activities by Year

Year	Activities
1	• Liquefaction Facilities construction infrastructure development (camps, granular material, access, etc.), site preparation activities, piling, and foundation installation • Marine Terminal site preparation activities, Marine Terminal MOF construction and dredging • GTP construction infrastructure development (camps, granular material, access, etc.), site preparation activities, and field-erected equipment installation • Construction infrastructure development (camps, borrow sites, access, and pads) for Mainline Pipeline Spreads 1 to 4; site preparation activities (right-of-way construction) for Spreads 2 to 4
2	• Liquefaction Facilities construction infrastructure development, site preparation activities, piling, foundation installation • Liquefaction Facilities LNG tank construction • Marine Terminal site preparation activities, Marine Terminal MOF dredging and completion • GTP construction infrastructure development, site preparation activities, and field erected equipment installation • Construction infrastructure development and site preparation activities for Mainline Pipeline Spreads 1 to 4; pipeline construction for Spreads 3 and 4 • Pre-construction sealift offload
3	• Liquefaction Facilities construction infrastructure development, site preparation activities, piling, and foundation installation • Liquefaction Facilities LNG tank construction and LNG Train 1 and 2 installation and interconnection • Marine Terminal MOF maintenance dredging and trestle, berth, and quadropod installation • Marine Terminal trestle, berth, PLF module berth, and mooring dolphin installation • GTP construction infrastructure development, site preparation activities, and field erected equipment installation • PBTL construction • Construction infrastructure development, site preparation activities, and pipeline construction for Mainline Pipeline Spreads 1 to 4; Spreads 3 and 4 hydrostatic testing and final tie-in (summer months only) • Offshore pipeline construction, including hydrostatic testing and tie-in • PTTL Spreads 1 and 2 construction infrastructure development (ice road construction), site preparation activities, and pipeline construction • Pre-construction sealift offload
4	• Liquefaction Facilities site preparation activities, piling, and foundation installation • Liquefaction Facilities LNG tank construction and LNG Trains 1 and 2 installation and interconnection • Marine Terminal trestle, berth, PLF module berth, and mooring dolphin installation • GTP construction infrastructure development, site preparation activities, and field erected equipment installation • Sealift No. 1 module offload • PBTL construction • Mainline Pipeline Spreads 1 and 4 site preparation activities and Spreads 1 to 4 pipeline construction, hydrostatic testing, and final tie-in (summer months only) • Mainline aboveground facilities construction • Offshore pipeline construction, including hydrostatic testing and tie-in • PTTL Spreads 1 and 2 construction infrastructure development, site preparation, pipeline construction, hydrostatic testing, and final tie-in
5	• Liquefaction Facilities LNG tank construction; LNG Train 1 installation and interconnection; LNG product loading trestle mechanical completion, commissioning and start-up; Trains 2 and 3 installation, interconnection, and pre-commissioning • Marine Terminal PLF installation • Sealift No. 2 module offload • Mainline Pipeline Spreads 1 and 2 pipeline construction, hydrostatic testing, and final tie-in (summer months only) • Mainline aboveground facilities construction • Fill Mainline Pipeline and commissioning/start-up of facilities with GTP gas • Project commissioning: first LNG product, GTP Train 1 start-up

TABLE 2.3.1-2 (cont'd) **Construction Activities by Year**	
Year	Activities
6	• Liquefaction Facilities LNG product loading trestle mechanical completion; Trains 1 and 2 installation, interconnection, commissioning and start-up; Train 3 installation, interconnection, pre-commissioning, and mechanical completion • Sealift No. 3 module offload • Mainline aboveground facilities construction • Fill Mainline Pipeline and commissioning/start-up facilities with GTP gas • Project commissioning: first LNG product, GTP Train 1 start-up (continued)
7	• Liquefaction Facilities Trains 2 and 3 commissioning and start-up • Marine Terminal MOF maintenance dredging, MOF reclamation/demobilization • Sealift No. 4 module offload • Mainline aboveground facilities construction • Project commissioning: intermediate LNG product, GTP Train 2 start-up
8	• Marine Terminal MOF reclamation/demobilization (continued) • Project commissioning: full LNG product, GTP Train 3 start-up

2.3.1.1 Gas Treatment Facilities

GTP

GTP infrastructure development and site preparation work would begin in Year 1 and continue into mid-Year 4 of construction. Materials for these activities would be delivered to the GTP during the two pre-construction sealifts (Years 2 and 3). Infrastructure would include camps, granular material, and GTP site access. Site preparation activities would include installing sheet piling, installing initial building components, road widening, GTP pad construction, service pipeline construction, and water reservoir construction. The gravel mine and water reservoir would be developed simultaneously; the material excavated from these sites would be used for GTP construction. The water reservoir and gravel mine site would be accessed via temporary ice roads constructed in the winter of Year 1.

GTP facility modules and gas treatment trains would be delivered to the site during the four construction sealifts (Years 4 to 7). GTP train construction would commence in Year 4, and conclude with commissioning and start-up of the final GTP train in mid-Year 8.

West Dock Causeway

Pre-work would be performed a year before the first season of deliveries to prepare the seafloor and install breasting-dolphins for the barge bridge support. Six sealifts (two pre-construction and four construction) would occur annually during the ice-free period between Years 2 and 7. Prior to each sealift, the offshore area would be leveled and the temporary barge bridge would be placed between Dock Heads 2 and 3.

PBTL and PTTL

PBTL construction would take place over two winter construction seasons (Years 3 and 4). Tie-ins and cleanup would be completed before the end of the second winter season. Hydrostatic testing, dehydration, tie-ins, and restoration activities associated with the PBTL would occur the following summer.

Construction of the PTTL would occur over the course of one winter construction season (Year 3). AGDC proposes to construct the PTTL using two pipeline spreads that would operate simultaneously. Tie-ins and cleanup would be completed before the end of the winter season. Hydrostatic testing, dehydration, tie-ins, and restoration activities associated with the PTTL would occur the following summer.

2.3.1.2 Mainline Facilities

Mainline Pipeline

The construction schedule for the Mainline Pipeline (and additional work areas) would span up to 57 months for any one spread (Years 1 to 5). This includes 30 months of site preparation activities and 15 to 27 months for pipelay. Table 2.2.2-1 identifies the construction schedule by construction spread. Although the start and end dates imply continuous construction activities would occur on each spread, that is not the case. Construction at any single point would typically last between about 6 and 12 weeks, but could be longer depending on the rate of progress, weather, terrain, and other factors.

The pipeline construction crews would typically work 6 days per week. Work conducted beyond daylight hours could include stream crossings, final tie-in welds, buried trenchless crossings, and bore crossings, where construction would occur 24 hours a day. In addition, extended work hours could be required to complete the compressor stations.

The Mainline Pipeline pipelay would be staggered with the two southern spreads (Spreads 3 and 4) starting first. The two northern spreads (Spreads 1 and 2) would begin following the start of construction in the southern spreads, with overlap in the construction schedules. Overall, AGDC estimates it would lay about 54 percent of the pipe in the summer and 46 percent in the winter.

<u>Summer Construction</u>

Summer construction work would start after soils have dried enough to support construction equipment without rutting or damaging roads, and continue until freezing soil and water conditions occur in September or October. Summer construction season lasts longer in the southern region (Spreads 3 and 4) than in the northern region (Spreads 1 and 2). North of Atigun Pass, the summer construction season would be mid-May through September. In interior Alaska, summer construction season would be early May through early October. In south-central Alaska and the Kenai Peninsula, the summer construction season would be early April until late October.

<u>Winter Construction</u>

The winter construction season would be short due to the time needed for the active layer to freeze under the access pads prior to ice pad construction or for organic layers to freeze hard enough to allow for deeper frost packing. AGDC intends to lay about 60 miles of pipe on the North Slope north of the Brooks Range, 40 miles in interior Alaska, and 36 miles in south-central Alaska during the winter seasons. At the end of the winter season, when spring “breakup” arrives in Alaska, streams and rivers would be swollen, drainages often diverted due to aufeis, and the construction right-of-way that was once frozen hard would be muddy in a matter of days depending on the temperature and orientation of the terrain to the sun. AGDC would install and/or clean up temporary or permanent erosion and sediment control measures prior to spring breakup. These erosion control measures would be cleaned and inspected in accordance with the SWPPP.

Aboveground Facilities

The aboveground facilities would be constructed over a 3-year period (Years 3 to 5). Each would require about 1 year for construction. Each meter station would be constructed in about 1 year, with workers housed at the closest Mainline Pipeline camp. Dedicated crews installing MLVs, launchers and receivers, cathodic protection systems, and gas interconnections would require about 3 months to complete its work at each site.

2.3.1.3 Liquefaction Facilities

Construction of the Liquefaction Facilities would begin after acquisition of necessary property rights, permits, and authorizations. Construction would commence with site preparation activities (e.g., clearing, grubbing) and infrastructure development. These activities would require a 2-year, 9-month period (Years 5 to 7) to complete and would include the Marine Terminal MOF construction, trestle/PLF substructure installation, and site cut and fill work.

AGDC proposes to construct many of the major facilities for the LNG Plant off site and have each delivered by vessel over a 3-year period. Other major facilities would be built on-site. On-site facilities, including the LNG storage tanks, would be erected over the course of 3 to 4 years. The commissioning of the tanks and processing units would occur as natural gas is delivered to the site.

2.3.2 Project-Wide Materials and Equipment Delivery

Logistical activities include the transporting of personnel, equipment, construction materials, and supplies to construction sites via sea, road, rail, and/or air transportation infrastructure. Logistics activities would begin prior to Project infrastructure construction, subject to necessary regulatory approvals.

The majority of materials and equipment would be unloaded and enter Alaska through the following points of entry:

- marine ports, including the Ports of Alaska, Seward, Whittier, and Valdez;
- Project marine docks, including the Mainline MOF, Marine Terminal MOF, and West Dock Causeway – Dock Head 4; and
- over land, including the Alaska (ALCAN) Highway, U.S.–Canada border crossing.

Air transportation would be used for the movement of workers, supplies, and equipment destined for remote areas of Alaska because of the large distances between cities and the limited highway and railroad infrastructure. Most Project-related air travel would be associated with worker movements during scheduled rotation periods. The Project would use Anchorage International, Fairbanks International, Kenai Municipal, and Deadhorse Airports as regional hub airports for the transportation of Project personnel. Mainline Pipeline transport would also occur over land via the Dalton Highway. Busing from Fairbanks and Prudhoe Bay is the primary mode for transporting personnel to and from work sites at the beginning and end of each construction season for the northern spreads. Airports would only be used to augment the busing. Additional information on transportation is provided in section 4.12.

2.3.3 Construction Workforce

In total, an average of about 4,322 workers would work each year during the approximately 8-year construction phase of the Project. Table 2.3.3-1 provides the duration and average workforce number by facility. Workers for the Gas Treatment and Mainline Facilities would be housed in construction camps; workers for the Liquefaction Facilities would be housed in a construction camp or live in close proximity to the work site.

TABLE 2.3.3-1		
Project Workforce by Facility		
Facility	Duration of Construction (months)	Estimated Average Workforce
Gas Treatment Facilities	90	854
Mainline Facilities	75	1,047
Liquefaction Facilities	81	1,789
Overall Project Management Staff	90	633
Total	**336**	**4,322**

2.4 ENVIRONMENTAL INSPECTION, COMPLIANCE MONITORING, AND POST-CONSTRUCTION MONITORING

2.4.1 Environmental Inspection

Prior to construction, AGDC would provide contractors with Project design documents, including environmental alignment sheets, and copies of all applicable federal, state, and local permits. All Project personnel would receive training on environmental permit requirements and the Project's environmental specifications. The environmental training program would be designed to provide focused training sessions to each trainees' respective role and responsibilities. AGDC would provide environmental training before a contractor or AGDC employee is allowed on a work area, and training records would be kept to demonstrate training activities.

AGDC would hire Environmental Inspectors (EI) who would report to a Chief Inspector. The EIs' duties would be consistent with section II.B of the Project Plan. Each EI would be trained and responsible for ensuring that construction of the Project complies with the construction procedures and mitigation measures identified in AGDC's application, the FERC authorization, other environmental permits and approvals, and environmental requirements in landowner easement agreements. EIs would have peer status with all other activity inspectors. EIs would have the responsibility and authority to stop activities that violate the environmental conditions of the FERC authorization, other permits, or landowner/land management agency requirements, and to order appropriate corrective actions. The EIs would also be responsible for advising the Chief Inspector when conditions (such as wet weather) make it advisable to restrict construction activities. EI duties include maintaining status reports and training records. FERC would receive regular construction status reports filed by AGDC.

AGDC would have at least one EI at both the Gas Treatment and Liquefaction Facilities. In the Project Plan, AGDC proposes to have at least one EI for each Mainline Pipeline construction spread during construction and restoration activities. The Project Plan obligates AGDC to ensure that the number and experience of the EIs assigned to each construction spread would be appropriate for the length of the spread and the number/significance of resources affected. In comments on the draft EIS, AGDC further said that it typically would have one Lead EI and one support EI per spread and would adjust staffing up or down based on factors such as length and location of spread, spread access and visibility, spread topography, number of sensitive areas on a spread, and schedule.

For the Project, numerous EIs would be necessary to conduct daily inspections of the construction and restoration activities due to limited access; length of the construction spreads; and the long distance between the right-of-way, camps, compressor stations, and off right-of-way work areas. Prior to construction, AGDC would be required to submit an Implementation Plan for our review and approval that identifies the number of EIs assigned per spread and describes how they would ensure that sufficient personnel are available to assure the Project complies with the construction procedures and mitigation measures.[14] When we review the Project Implementation Plan, we would consider the number and qualifications of the EIs identified by AGDC and determine whether they are appropriate for this Project.

2.4.2 Compliance Monitoring

AGDC has agreed to fund a Third-Party Compliance Monitoring Program (CM Program) that would be implemented under the direction of FERC staff. Under the CM Program, Compliance Monitors (CM) representing FERC staff would be present on each construction spread or site on a full-time, continuous basis. The number of CMs would be determined by FERC staff. The CMs would observe construction procedures and mitigation measures and provide regular feedback on compliance issues to FERC staff and to AGDC's environmental inspection team. Construction progress and environmental compliance would be tracked and documented by the CMs. Other objectives of the CM Program are to facilitate the timely resolution of compliance issues in the field; provide continuous information to FERC staff regarding noncompliance issues and their resolutions; review, process, track, and approve certain variance requests, as discussed below; and assist FERC staff in making determinations regarding the proper implementation of measures identified in the approved Project Plan and Procedures.

Should AGDC receive Commission approval for the Project, any changes to the authorized Project that AGDC may request would require approval from FERC staff. Project changes could involve route realignments, shifting or adding new ATWS or staging areas, adding additional access roads, modifying construction methods, or implementing adaptive management strategies in the event originally proposed minimization or mitigation measures are ineffective due to site-specific field conditions. We have developed a variance process for evaluating and approving or denying such requested changes. The CM Program would allow the CMs to assist FERC in screening and processing variance requests made during construction and restoration.

In addition to the EIs and CMs, FERC staff would conduct periodic field inspections during Project construction and restoration. FERC staff would have the authority to stop any activity that violates an environmental condition of the FERC authorization issued to AGDC. Other federal, state, and local agencies could also monitor the Project to the extent determined necessary by the respective agency.

2.4.3 Post-construction Monitoring

AGDC would conduct follow-up inspections and monitoring of disturbed areas. AGDC developed a Project Revegetation Plan along with a Noxious/Invasive Plant and Animal Control Plan (Invasives Plan) and an Invasive Species Prevention and Management Plan (ISPMP) to guide restoration of the pre-construction plant communities and protect the natural environment (see table 2.2-1). The Revegetation Plan defines the Project's restoration performance standards, performance periods, specific restoration practices, and monitoring plan. According to NPS requirements, the segment of the Mainline Pipeline within the DNPP would need to follow and comply with the *Native Plant Revegetation Manual for Denali National Park and Preserve* (Densmore et al., 2000).

During restoration, AGDC would file annual reports with FERC that document any problems identified during the inspections or by landowners, and describe the corrective actions taken to remedy those problems. Additionally, monitoring and management of non-native invasive species (NNIS) would occur before, during, and after construction through the performance period.

[14] The Project Implementation Plan describes how an applicant would implement the construction procedures and mitigation measures identified in its application and supplements, in the EIS, as well as in the environmental conditions of the FERC authorization. See Environmental Recommendation No.6 in section 5.0.

After construction, FERC, cooperating agencies, and/or other agencies would continue to conduct oversight inspection and monitoring to assess restoration success. If it is determined that the success of any restoration activity is inadequate, AGDC would use an adaptive management approach, in coordination with the appropriate agencies, to identify and implement corrective measures, such as seeding and fertilization.

In addition to monitoring the progress of vegetation restoration, we recognize that during and after construction, unforeseen issues or complaints could develop, and it is important that landowners have an avenue to contact AGDC's representatives. Should the Project be approved, we would ensure that landowner issues and complaints received during and after construction are resolved in a timely and efficient manner.

2.5 OPERATION, MAINTENANCE, AND SAFETY PROCEDURES

AGDC would operate and maintain the Project in accordance with PHMSA regulations in 49 CFR 192, the Commission's guidance at 18 CFR 380.15, and the maintenance provisions of the Project Plan and Procedures. As required by 49 CFR 192.615, AGDC would establish a Pipeline Right-of-Way Operational Monitoring and Maintenance Plan (Pipeline Operation and Maintenance Plan) that includes procedures to minimize the hazards in a natural gas pipeline and an emergency response program. The program would outline the potential hazards associated with Project facilities; the communication protocols with fire, police, and public officials; and prevention measures undertaken to minimize community impacts.

2.5.1 Gas Treatment Facilities

The Gas Treatment Facilities would include a gas control center and an operations center (both placed on the GTP pad). The gas control center would monitor and control operations and include a work permit area, break/lunch room, rest/change rooms, and numerous offices. Operation of the PTTL, the PBTL, and other transfer lines would be monitored from the gas control center. The operations center would include a site office space, a lab, a warehouse, and a maintenance shop.

Workers would be trained for proper handling, storage, disposal, and spill response of hazardous fluids, and a Spill Prevention, Control, and Countermeasure (SPCC) Plan would be implemented prior to operation. Storage tanks and containers for fuels and hazardous liquids at the facility would be constructed with appropriately sized secondary containment. Oil-filled operational equipment would be addressed in a manner consistent with the requirements of 40 CFR 112. Table 2.5.1-1 identifies the Gas Treatment Facilities storage tanks.

TABLE 2.5.1-1

Storage Tanks Planned for Liquids at the GTP

Tank	Tank Type	Volume (gallons)	Tank Material
Raw water storage tank	API 650 Tank	846,720	Carbon steel epoxy-lined with cathodic protection
Raw water storage tank	API 650 Tank	846,720	Carbon steel epoxy-lined with cathodic protection
Three firewater diesel day storage drums	NA [a]	NA [a]	Carbon steel
TEG makeup storage tank	API 650 Tank	NA [a]	Carbon steel epoxy-lined with cathodic protection
AGRU™ solvent storage tank	API 650 Tank	1,120,896	Carbon steel with post weld heat treatment
AGRU™ fresh solvent storage tank	API 650 Tank	169,176	Carbon steel
Diesel fuel storage tank	API 650 Tank	NA [a]	Carbon steel epoxy-lined with cathodic protection

API = American Petroleum Institute; TEG = triethylene glycol; NA = Not available (AGDC has not provided information on storage container type or volume for this tank).

During operation, snow removal would follow typical North Slope practices. Snow on the GTP pad would be pushed to the west side of the pad to minimize drifting. Locations that are not practical to clear to the west would be pushed off adjacent areas of the pad and/or staged on previous construction laydown space/module movement paths, maintaining a minimum distance from flow lines, valves, or well houses to avoid contact, damage, or movement of lines.

2.5.1.1 Flare System

The Gas Treatment Facilities would not generate any continuous process or utility flow sources to flare or vent, except from limited pilot/purge streams. In general, protection systems would be designed to minimize potential flaring/venting flow rates to reduce impacts. The flare system would be for startup, emergency, pre-commissioning, commissioning, shutdown, or upset conditions.

2.5.1.2 Waste Disposal Injection Well

Collected liquid waste streams would be disposed of in the two UIC Class I injection wells that would be installed on the GTP pad. Although the injection wells would be configured as spares to each other, both would normally operate.

AGDC would treat grey water prior to disposal in the injection wells; all other liquid waste streams would be injected untreated down the injection wells. A wastewater treatment facility would be on the operations center pad to treat black and grey water. AGDC would design the wastewater treatment facility to meet applicable codes and standards, regulations, and the permit requirements for the UIC Class I wells.

During operation, waste streams with continuous flow would be collected in a common closed-drain collection drum, and piped to and injected into one of the two injection wells at a rate of approximately 190 gallons per minute (gpm). This waste stream would consist of:

- grey water from the wastewater treatment plant (about 59 percent of continuous flow);
- reverse osmosis reject water (about 8.5 percent of continuous flow);
- backwash water from potable water treatment (about 6.5 percent of continuous flow); and
- process water from the three gas processing trains (about 26 percent of continuous flow); this stream would be greater than 99-percent water, with trace quantities (parts per million) of hydrocarbons, CO_2, H_2S, and triethylene glycol.

The common closed drain collection drum would also be connected to other process waste streams that have intermittent flow. These waste streams would contain substances intrinsically derived from operations associated with the production of natural gas, including oily water, sour water, amine, triethylene glycol, hydrocarbons, and trace amounts of CO_2 and H_2S (i.e., RCRA exempt). The closed-drain collection drum additionally would receive liquid waste from an open drain system, which would capture utility station spent water (e.g., wash water) and leaks and spills within modules. These additional waste streams would be piped to, and injected into, one of the injection wells, intermittently increasing the injection rate to about 225 gpm and the pressure up to 2,000 pounds per square inch gauge. To prevent freezing in the wells, diesel, a mixture of methanol/water, or other fluid that is miscible with disposal fluids, could be injected into the inactive well during winter.

We received a comment from the EPA regarding the volume of liquid waste streams from Project operation at the GTP. AGDC's Project Waste Management Plan identifies the following estimated volumes of liquid waste from operation of this facility:

- black and grey wastewater – 18,204,375 gallons per year (gpy);
- industrial wastewater – 1,550,155 gpy;
- truck wash water - 1,825,000 gpy; and
- other wastewater – 437,270 gpy.

Estimated quantities of process wastewater associated with natural gas production have not been determined.

2.5.1.3 Water Supply System

Water would be provided to the Gas Treatment Facilities from a water reservoir to be developed during construction. The reservoir water would flow into the GTP at a rate of about 190 gpm. The water would be split between the process water treatment system and the potable water treatment systems. About 60 gpm of process water and about 130 gpm of potable water would be treated for use at the Gas Treatment Facilities.

2.5.1.4 Operations Center

Continuous monitoring and operation of the Project facilities would be conducted through the Supervisory Control and Data Acquisition (SCADA) system, which is a computer system used for gathering and analyzing data from real-time systems and operating remote facilities. The SCADA system would compile pipeline-operating data (e.g., pressure, temperature, flow, compressor data, and vibration) from Project facilities and be managed by workers in the on-site Operations Center, and transmitted to the Gas Control Center.

2.5.1.5 PTTL and PBTL

The PTTL and PBTL would be compliant with National Association of Corrosion Engineers MR0175 Sour Gas Service Specification to provide mitigation for internal corrosion and stress cracking in the event of a process upset or the unplanned introduction of free water into the system. Cathodic protection would not be required since the PTTL and PBTL would be constructed aboveground; however, atmospheric corrosion control would still be required per 49 CFR 192.479 to 481.

2.5.2 Mainline Facilities

2.5.2.1 Mainline Pipeline

The pipelines and related aboveground facilities would be designed, constructed, operated, and maintained in accordance with standards that comply with regulations defined in 49 CFR 192 and any applicable Special Permits, which would follow 49 CFR 190.341. AGDC has received Special Permits for the following: exemption from the requirements of 49 CFR 192.103 in regions of discontinuous permafrost to allow Strain-Based Design of select segments of the pipeline; relief from 49 CFR 192.179 for mainline block valve and crack arrestor spacing in Class 1 locations; and exemption from 49 CFR 192.112(f)(1) in pipeline segments built to comply with the Alternative Maximum Allowable Operation Pressure (Alternative MAOP) to utilize a three-layer polyethylene coating.

As required by 49 CFR 192.615, a Pipeline Operation and Maintenance Plan and an emergency plan would be prepared that includes procedures to minimize the hazards in a natural gas pipeline emergency. As a part of pipeline operation and maintenance, regular patrols would inspect the Mainline Pipeline right-of-way. The patrol program would include periodic aerial and ground patrols of the Mainline Facilities to survey surface conditions on and adjacent to the pipeline right-of-way. The search would identify evidence of leaks, unauthorized excavation activities, erosion and washout areas, sparse vegetation, damage to permanent erosion control devices, exposed pipe, missing markers and signs, new residential developments, and other conditions that might affect the safety or operation of the pipeline.

AGDC would maintain a liaison with the appropriate fire, police, and public officials as part of the emergency operating procedures. Communications would include the potential hazards associated with the facilities in their service area and prevention measures undertaken; the types of emergencies that could occur on or near the new pipeline facilities; the purpose of pipeline markers and the information contained on them; pipeline location information; recognition of and response to pipeline emergencies; and emergency contact procedures.

Project operational staff would monitor the cathodic protection system as required by PHMSA regulations. Periodic cathodic protection system surveys would be conducted, including monitoring the test stations along the right-of-way. Access for the surveys would be through use of the Project's permanent access roads and right-of-way. Based on the survey results, the Project would adjust the system to maintain the integrity of the pipeline. Workers would record the survey activities and appropriate corrective actions, as applicable. Further, monitoring of cathodic protection system deep wells would be part of the Project's SCADA system.

In addition to the survey, inspection, and repair activities, Mainline Pipeline operation would include right-of-way maintenance. AGDC would conduct maintenance of the pipeline right-of-way according to the measures outlined in the Project Plan and Procedures. The right-of-way would revegetate after restoration, but larger shrubs and brush could be removed near the pipeline periodically. The frequency of the vegetation maintenance would be in accordance with the Project Revegetation Plan. Routine vegetation maintenance clearing of the permanent right-of-way would not be done more frequently than every 3 years. To facilitate periodic corrosion and leak surveys, a corridor not exceeding 10 feet in width centered on the pipeline would be maintained annually in an herbaceous state.

Pipeline facilities would be clearly marked at line-of-sight intervals and at crossings of roads, railroads, and other key points. The markers would clearly indicate the presence of the pipeline and provide a telephone number and address where a company representative could be reached in the event of an emergency or prior to any excavation in the area of the pipeline by a third party.

2.5.2.2 Aboveground Facility Operation and Maintenance

AGDC would operate the aboveground facilities in accordance with PHMSA requirements and standard procedures designed to ensure the integrity and safe operation of the facilities and to maintain firm natural gas transportation service. Standard operations at compressor stations include the calibration, maintenance, and inspection of equipment; the monitoring of pressure, temperature, and vibration data; and traditional landscape maintenance such as mowing and the application of fertilizer. Standard operations also include the periodic checking of safety and emergency equipment and cathodic protection systems.

Natural gas engine driven power generators would power each of the compressor stations. Each station would have three power generating units except for Sagwon, which would have four power generating units. The nominal power demand would be 2,300 kilowatts (kW) and an engineering rating of 1,150 kWs.

AGDC notes that it would need an average of one helicopter trip per month to MLVs or compressor or heater stations to transport personnel for planned maintenance, routine checks, calibration of equipment and instrumentation, inspection of critical components, and servicing and overhauls of equipment. Overall, operations would generate an average of one helicopter trip per month per helipad.

2.5.3 Liquefaction Facilities

The Liquefaction Facilities would be operated and maintained in accordance with applicable federal and state requirements. Pursuant to the provisions of the Natural Gas Pipeline Safety Act amended in 2011 (Public Law 112-90, 49 USC 60101), the facilities would be operated and maintained in accordance with 49 CFR 193, *Federal Safety Standards for Liquefied Natural Gas Facilities* (and as referenced in 49 CFR 193, the NFPA 59A LNG Standards) as modified by Special Permits. AGDC has requested a Special Permit seeking relief from 49 CFR 193.2167 and 49 CRF 193.2173 for its construction of a pipe-in-pipe design for the LNG rundown and LNG quench lines (see section 1.2.2). The Marine Terminal would be operated and maintained in accordance with 33 CFR 127, *Waterfront Facilities handling Liquefied Natural Gas and Liquefied Hazardous Gases.*

The design of the Liquefaction Facilities would contain control systems that include monitoring systems, process alarms, and control and isolation valves. Alarms would have visual and audible notifications to warn operators that process conditions could be approaching design limits. Operators would undergo extensive training prior to operating the Liquefaction Facilities, and would have the capability to take action to address and mitigate an incident should one occur.

The facility full-time maintenance staff would conduct routine maintenance and minor overhauls. Major overhauls and other major maintenance would be handled by outside maintenance personnel specifically trained to perform the required activities. All scheduled and unscheduled maintenance would be entered into a computerized maintenance management system.

2.5.3.1 Spill Containment System

AGDC's spill containment systems would be designed to convey spills away from process equipment into impoundment systems. The design of all spill containment systems would meet the requirements of 49 CFR 193 and NFPA 59A (2001 Edition) (see section 4.18.5). All spill containment systems would be equipped with detection devices that would activate an automated alarm alerting the operator in the event of a spill. All hazardous fluids would be contained within spill containment systems. The State of Alaska commented that some state spill containment and spill response regulations are more stringent than federal rules, and that any petroleum storage tanks with greater than 10,000 gallons of storage capacity would be regulated by ADEC under AS 46.04.030 and 18 AAC 75 Articles 1 and 4.

The Liquefaction Facilities would be designed and operated in compliance with applicable ADEC and EPA requirements for hazardous materials, including liquids. Personnel would properly handle, store, and dispose of hazardous materials, including liquids, as well as provide spill response. Storage tanks and containers for fuels and other hazardous liquids at the facility would have appropriately sized secondary containment. Oil-filled operational equipment would be addressed in a manner consistent with the requirements of 40 CFR 112. Table 2.5.3-1 identifies the storage tanks planned for the facility.

TABLE 2.5.3-1 **Liquefaction Facility Storage Containers for Fuels and Other Liquids**			
Tank	Type	Volume (gallons)	Material
Diesel day tank (fire water - fresh water)	Horizontal vessel	340	Low temperature carbon steel
Firewater tank	Fixed cone roof tank	1,200,000	Low temperature carbon steel
Condensate storage tank	Fixed cone roof tank, API 650	476,000	Low temperature carbon steel
Offspec condensate storage tank	Fixed cone roof tank, API 650	127,000	Low temperature carbon steel
LNG storage tank	Full containment double wall	63,401,280	Reinforced / pre-stressed concrete
LNG storage tank	Full containment double wall	63,401,280	Reinforced / pre-stressed concrete
Diesel storage tank	Fixed cone roof tank	7,138	Low temperature carbon steel
Air compressor diesel day tank	Horizontal vessel	NA	To be determined by vendor
High purity liquid nitrogen storage & vaporizer package (vessel 1)	NA	1,428	To be determined by vendor
High purity liquid nitrogen storage & vaporizer package (vessel 2)	NA	1,428	To be determined by vendor
Slop oil tank	Horizontal vessel, ASME Sect. VIII, Div. 1	NA	Low temperature carbon steel / SS internal
Fresh water tank	Fixed cone roof tank	731,000	Low temperature carbon steel
Fresh water tank	Fixed cone roof tank	731,000	Low temperature carbon steel
Clarified water clearwell tank	Fixed cone roof tank	24,000	Low temperature carbon steel
Filtered water storage tank	Fixed cone roof tank	204,000	Low temperature carbon steel
Reverse Osmosis permeate tank	Fixed cone roof tank	99,000	Low temperature carbon steel
Potable water storage tank	Fixed cone roof tank	85,000	Low temperature carbon steel
Demineralized water tank	Fixed cone roof tank	476,000	Low temperature carbon steel
Steam condensate tank	Fixed cone roof tank	119,000	Low temperature carbon steel
Equalization tank	Fixed cone roof tank	339,000	Low temperature carbon steel

API = American Petroleum Institute; ASME = American Society of Mechanical Engineers; NA = Not available (AGDC has not provided information on storage container type or volume for this tank).

2.5.3.2 Hazard and Fire Detection System

In the event that a release should occur at the Gas Treatment or Liquefaction Facilities, an Integrated Control and Safety System would be in place. The elements of the system would include: flammable gas detectors, low oxygen detectors (nitrogen, H_2S), high and low temperature detectors, and smoke detectors. Additionally, the system would have manual local emergency shut down activation push buttons and automatic emergency shut down activation features. The other aboveground facilities would be designed to minimize the release of LNG and other flammable materials and to mitigate potential impacts on the public and personnel.

The Integrated Control and Safety System would provide the means to monitor for and alert operators of hazardous conditions throughout the Gas Treatment and Liquefaction Facilities resulting from fire, combustible gas leaks, and low temperature LNG spills. The detection of these hazardous conditions by the Integrated Control and Safety System would result in local audio and visual (e.g., strobe light) signals with various alarms and colors depending on the detected hazard. The Integrated Control and Safety System would be independent of the process control system. When appropriate, the Integrated Control and Safety

System would have the capability to initiate automatic shutdown of specific equipment and systems and could activate the wider emergency shut down system response.

2.5.3.3 Firewater and High Expansion Foam System

The firewater system installed at the Liquefaction Facilities would be designed, tested, and maintained to meet NFPA 59A (2001), 11, 13, 14, 15, 20, 22, 24, 25, 30, and 750 requirements (see section 4.18.5). During operation, the firewater system would be routinely tested. As part of the routine testing, the firewater system would run for about 30 minutes, but there would not be any water discharges. The system design incorporates a recycling loop for the water that is continually circulating to keep water lines from freezing.

At the Liquefaction Facilities, high-expansion foam systems would add protection as a fire suppressant and for controlling vapors released from an accidental LNG spill. Blanketing spills with high-expansion foam is an effective method for reducing and controlling fire intensity and decreasing LNG vapor generation. In comments on the draft EIS, the State of Alaska said that any discharge of Class B fire suppression foams to the environment would require a notification to ADEC and could trigger a requirement for site characterization or cleanup.

2.5.3.4 Emergency Shutdown System

The emergency shutdown system could isolate, shut down, and/or depressurize the appropriate element upon mechanical malfunction or process upset. The emergency shutdown system would initiate an emergency shutdown due to an unplanned event such as loss of process control, process containment, or fire in the facility. The emergency shutdown system would be designed to protect personnel, the environment, and the facility in the event of upset emergency conditions such as fire (local or plant-wide), combustible or toxic fluid leak, mechanical failure of equipment, etc. The system would be separate and independent from process equipment shutdown/interlock systems, which protect the mechanical integrity of the equipment. The emergency shutdown system trip switches would have the capability for remote operation. Manual push buttons and emergency stop switches would be located throughout the facility.

2.5.3.5 Ballast Water Discharge and Cooling Water Use

In accordance with Coast Guard regulations (33 CFR 151, subpart D and 46 CFR 162.060 on *Standards for Living Organisms in Ships' Ballast Water Discharged in U.S. Waters; Final Rule* (77 FR 17254 [Mar. 23, 2012]) and *Navigation and Vessel Inspection Circular 01-18*), LNG carriers are required to install and operate a ballast water management system that meets applicable ballast water discharge standards. In addition to ballast, LNG carriers would require water for cooling the main engine/condenser, diesel generators, and fire main auxiliary and hotel services. Descriptions of the ballast water management and cooling systems on the LNG vessels that would call at the Marine Terminal are provided in section 4.3.3.

2.5.3.6 Marine Traffic Along the Waterway

One or more marine pilots would board the LNG carriers. The pilot would board and disembark the LNG carrier at the pilot station west of the Homer Spit by pilot launch. The pilot's duty is to advise the LNG carriers master on the safe transit to and from the terminal and for docking/undocking operations.

Five assist tugs would support transit of the LNG carriers, with four of the tugs assisting the LNG carriers during berthing operations. The five tugs would include three 90-ton-minimum certified effective static bollard pull (i.e., the static force exerted on a fixed tow line at zero speed), Azimuth Stern Drive tugs, as well as two tugs that are slightly larger with more skeg (i.e., sternward extension of the keel), bollard pull (about 120 tons), and towing and ice mitigation capability. Tugs used to support berthing and mooring of LNG carriers would anchor near Nikiski when not assisting an LNG carrier. A frequently used anchoring site to the south of the Marine Terminal (Kachemak Bay) would be available for anchorage of tugs while performing standby duty and while off duty.

When ice is present in Cook Inlet, the LNG carriers would implement an ice management system to support safe and reliable LNG carrier transit in Cook Inlet and maneuverability at the Marine Terminal. The ice management system would include met ocean and ice monitoring, analysis, and forecasting; ice management operational planning and management; data management and communications system; and ice-breaking tugs. Support tugs would be ice class and would assume the additional responsibilities of patrol/scouting, ice clearing, and ice breaking during winter months.

2.6 OPERATIONS WORKFORCE

The Project would be operated in compliance with federal and state workforce regulations and programs.

2.6.1 Gas Treatment Facilities

Operation and maintenance of the Gas Treatment Facilities would require about 125 on-site workers stationed at an adjacent operations camp. During periods of maintenance or peak operations, the camp's facilities would be arranged to accommodate the additional required workers. About 170 permanent support workers based in AGDC's Anchorage office would support operation of the Gas Treatment Facilities.

2.6.2 Mainline Facilities

Operation and maintenance of the Mainline Pipeline facilities would require about 225 workers. These employees would seek local housing near their work sites. Additionally, about 105 permanent support workers would live in Anchorage.

2.6.3 Liquefaction Facilities

Operation and maintenance of the Liquefaction Facilities would require about 310 workers. Of these, AGDC estimates that about 240 workers would live off site in the Nikiski and Kenai/Soldotna areas with 70 support workers living in the Anchorage area. In addition, workers brought in for maintenance or peak operation at the LNG Plant would obtain local temporary housing.

3.0 ALTERNATIVES

As required by NEPA and Commission policy, and in cooperation with the COE per its responsibilities under the CWA and RHA and the BLM per its responsibilities under the MLA and other statutes, we identified and evaluated reasonable alternatives to the Project and its various components to determine whether any such alternatives would have significant environmental advantages over the proposed action. Specifically, we evaluated the No Action Alternative, system alternatives, Gas Treatment Facilities alternatives, Mainline Pipeline route and aboveground facility alternatives, Liquefaction Facilities alternatives, and additional work area alternatives.

Our evaluation of the alternatives is provided in the following sections. The purpose of our evaluation is to determine whether an alternative would be preferable to the proposed action. Using evaluation criteria, as discussed in greater detail below, we generally consider an alternative to be preferable to a proposed action if the alternative meets the stated purpose of the Project, is technically and economically feasible, and offers a significant environmental advantage over a proposed action. The alternatives were reviewed against the evaluation criteria in the sequence presented below. If the alternative would not meet the Project's purpose/objective or is not feasible, we did not employ the third criterion (i.e., a comparison of the impacts of the alternative on resources to the impacts of the proposed action on resources).

The first consideration for including an alternative in our analysis is whether or not it could satisfy the stated Project objective (also referred to as the Project purpose). The Project objective is to commercialize North Slope natural gas reserves by treating and liquefying the gas and then exporting it to foreign markets while also providing for in-state deliveries. The three identified delivery points are Fairbanks, south-central Alaska (Anchorage), and the Kenai Peninsula. An alternative that cannot achieve the Project objective cannot be considered an acceptable replacement for the Project.

Many alternatives are technically and economically feasible. Technically practical alternatives generally require the use of common construction methods. An alternative that would require the use of a new, unique, or experimental construction method may be feasible, but may not be technically practical because the required technology is not available or is unproven. Economically practical alternatives would result in an action that generally maintains the price-competitive nature of the proposed action. Generally, we do not consider the cost of an alternative as a critical factor unless the added cost to design, permit, and construct the alternative would render the project economically impractical.

To determine if an alternative provides a significant environmental advantage, we evaluate the impacts on environmental resources, including any impacts that may be unique to that alternative. The impacts are then compared to the impacts of the corresponding segment or site of the proposed action. We also consider the degree of impact anticipated on each resource. We then balance the overall impacts and all other relevant considerations to determine if an alternative would provide a significant environmental advantage to the proposed action. Ultimately, only an alternative that we determine has substantial advantages would compel us to shift the impacts from the current set of landowners to a new set of landowners. We would not be compelled to do this for an alternative that is, in our determination, equal to, or only provides minor advantages over the proposed action.

When making a decision on whether to issue its permit, the COE must determine whether the proposed Project is the LEDPA pursuant to the CWA Section 404(b)(1) guidelines. The term practicable means available and capable of being done after taking into consideration cost, existing technology, and logistics in light of the overall purpose of the Project. The COE may only permit discharges of dredged or fill material into waters of the United States that represent the LEDPA, so long as that alternative does not have other significant adverse environmental consequences.

Our evaluation of alternatives is based on Project-specific information provided by AGDC[1], affected landowners, and other concerned parties; desktop and site-specific environmental information as described below; input from other local, state, and federal agencies; and our expertise and experience regarding the siting, construction, and operation of natural gas facilities and their potential impact on the environment. Comments provided to the Commission about possible alternatives have been considered and addressed, as appropriate.

To ensure a consistent environmental comparison, and to normalize the comparison of alternatives to a proposed action, we generally use desktop sources of information (e.g., publicly available data, geographic information system (GIS) data, aerial imagery, USGS topographic maps, etc.) and assume similar footprints (e.g., acreage disturbed) and general workspace requirements. Where appropriate, we also use site-specific information, such as surveys or detailed designs. Our environmental analysis and this evaluation use quantitative data (e.g., acreage or mileage) to compare factors such as total length, amount of collocation, and land requirements. Our evaluation also considers impacts on both the natural and human environments. Impacts on the natural environment include wetlands, forested lands, and other common environmental resources. Impacts on the human environment include residences, roads, utilities, resource use, and land use. We consider the competing interests and differing nature of impacts that can result from an alternative. For example, impacts on the natural environment could compete with impacts on the human environment. We also consider other factors that are relevant to a particular alternative and discount or eliminate factors that are not relevant or could have less weight or significance.

3.1 NO ACTION ALTERNATIVE

The CEQ regulations for implementing NEPA (40 CFR 1502.14(d)) require the Commission to consider and evaluate the No Action Alternative. If the No Action Alternative is selected by the Commission, the proposed facilities would not be constructed and the associated environmental impacts from the Project would not occur. Additionally, the opportunity to commercialize North Slope natural gas would not be realized and in-state deliveries of natural gas through interconnections would not be achieved.

By law, under Section 3(c) of the NGA, applications to export natural gas to countries with which the United States has FTAs that require national treatment for trade in natural gas are deemed to be consistent with the public interest, and the DOE/FE must grant authorization without modification or delay. In the case of applications to export LNG to non-FTA nations, NGA Section 3(a) requires the DOE/FE to conduct a public interest review and grant authority to export unless the DOE/FE finds that the proposed exports would not be consistent with the public interest. Additionally, NEPA requires the DOE/FE to consider the environmental effects of its decisions regarding applications to export natural gas to non-FTA nations.

On November 21, 2014, the DOE/FE issued DOE/FE Order No. 3554, in which it authorized AGDC to export LNG by vessel to FTA countries. On May 28, 2015, the DOE/FE issued Order No. 3643, providing conditional export authorization for non-FTA countries. The authorization is contingent on both AGDC's satisfactory completion of the environmental review process and its on-going compliance with any and all preventive and mitigating measures imposed at the proposed Liquefaction Facilities by federal or state agencies.

[1] Actions taken by the original Project applicants (AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LLP) are referred to as AGDC's actions for consistency in presentation throughout the document.

For the non-FTA conditional authorization granted under Section 3(a) of the NGA, the DOE/FE made preliminary findings that exports from the Project were not inconsistent with the public interest, provided the Project successfully completes the environmental review.

In this particular case, options for alternative sources for production are generally limited to the North Slope. Therefore, if the Project is not constructed, AGDC or other applicants would likely develop a new project or projects to transport natural gas from the PTU and PBU for export in foreign commerce and for in-state deliveries. It is reasonable to expect that under such scenarios, exports of LNG from one or more other future LNG facilities designed to export North Slope gas would be authorized by the DOE and eventually constructed. Any expansion of existing systems or construction of new facilities would result in specific environmental impacts that could be less than, similar to, or greater than those associated with the proposed Project. Because the impacts for any replacement project capable of exporting similar volumes are likely to be comparable to those described in section 4.0 of this EIS, we conclude that in addition to not meeting the Project objective, the No Action Alternative is also not likely to provide a significant environmental advantage. Therefore, we dismiss it from further consideration.

For NMFS, denial of an ITA constitutes the NMFS No Action Alternative. This is consistent with the NMFS statutory obligation under the MMPA to either (1) deny the requested authorization, or (2) grant the requested authorization and prescribe mitigation, monitoring, and reporting requirements. Thus, under the No Action Alternative, NMFS would not issue the regulations and an LOA pursuant to 101(a)(5)(A) to AGDC for construction activities in Cook Inlet and an IHA pursuant to Section 101(a)(5)(D) of the MMPA to AGDC for construction activities in Prudhoe Bay.

3.2 SYSTEM ALTERNATIVES

System alternatives would make use of other existing or proposed facilities to meet the stated objectives of the Project. A system alternative would make it unnecessary to construct all or part of the Project, although modifications or additions to existing or proposed facilities could be required. These modifications or additions would result in environmental impacts that could be less than, similar to, or greater than those associated with Project construction and operation. The purpose of identifying and evaluating system alternatives is to determine whether the environmental impacts associated with Project construction and operation could be avoided or reduced by using existing facilities while still meeting the objectives of the proposed action.

A viable system alternative to the Project would have to:

- commercialize natural gas resources on the North Slope during the economic life of the PBU and PTU gas fields;
- bring cost-competitive LNG from Alaska to foreign markets; and
- provide interconnections along the pipeline to allow for in-state gas deliveries, benefiting Alaska gas users and supporting long-term economic development.

Despite abundant supplies of natural gas on the North Slope, most of the state's gas production cannot be brought to market due to a lack of natural gas pipeline infrastructure. ENSTAR Natural Gas Company (ENSTAR) operates nearly 500 miles of gas transmission lines in Alaska, but these pipelines are all in south-central Alaska in the vicinity of Cook Inlet. The Fairbanks area lacks a direct-source gas transmission pipeline, instead receiving LNG via truck from the Titan LNG liquefaction plant at Point MacKenzie. Only one other LNG facility exists in Alaska, the Kenai LNG Terminal, which is discussed below. Ultimately, this lack of pipeline facilities greatly restricts the opportunity to use existing infrastructure to meet the Project objectives.

We identified and evaluated three system alternatives, as described below.

3.2.1 Existing and Proposed Alaska System Alternatives

An existing LNG export terminal, the Kenai LNG Terminal, is in Nikiski about 0.5 mile north of the proposed Liquefaction Facilities site. This facility, currently owned and operated by Trans-Foreland Pipeline Company, LLC, began operating in 1969 and had the capacity to export about 1.3 MMTPA. The majority of the gas supplied to the Kenai LNG Terminal came from the North Cook Inlet Gas Field. The plant has been continuously maintained in a warm idle state and has not shipped any LNG since 2015. In March 2019, Trans-Foreland Pipeline Company, LLC filed an application with FERC to return certain portions of the plant to active status, which would enable it to receive a shipment of LNG and cool LNG storage tanks; however, the liquefaction portion of the plant would not be returned to active status. Because the capacity of the Kenai LNG Terminal is not sufficient to accommodate the 20-MMTPA design capacity of the Project, it would be unable to meet the Project objective in its current configuration. Expanding the Kenai LNG Terminal would not be feasible because there is insufficient land available and the site is surrounded by other existing industrial facilities. Therefore, expanding the Kenai LNG Terminal to meet the Project purpose is not feasible.

The State of Alaska-sponsored proposed ASAP Project is designed to deliver natural gas from the North Slope to south-central Alaska, serving as many communities as practicable. The ASAP Project would include a gas conditioning facility on the North Slope; an approximately 733-mile-long, 36-inch-diameter pipeline providing up to 0.5 Bcf/day of natural gas; and a 30-mile-long, 12-inch-diameter lateral pipeline to Fairbanks. The ASAP Project would not include an LNG export terminal and would not be capable of delivering LNG from Alaska to foreign markets. Therefore, because it could not meet the Project objective as proposed, it is not a feasible system alternative to the Project.

Modifying the ASAP Project to meet the objectives of the proposed Project would require the construction of an LNG export terminal and associated facilities and a significant expansion of the ASAP Project pipeline, including the construction of compressor stations along the route. As indicated in section 1.0, AGDC would design the Mainline Facilities to transport up to 3.7 Bcf/day of natural gas. To transport this volume of gas, the ASAP Project pipeline would either need to be redesigned or “looped.” Looping would involve constructing a parallel pipeline adjacent to the proposed ASAP Project pipeline. Even with the looping, AGDC would need to construct at least 70 miles of additional pipeline to extend the ASAP pipeline to an export facility. Constructing a pipeline “loop,” additional pipeline, and associated facilities (compressor stations) would result in significant additional environmental impacts. These impacts, and those resulting from the construction of the necessary LNG facilities, would be similar to those of the proposed Project, and therefore would not provide a significant environmental advantage.

In October 2019, Qilak LNG announced plans to partner with ExxonMobil to construct an offshore LNG liquefaction facility on Alaska’s North Slope that would ship LNG to Asian markets. The project would use ice-breaking tankers to navigate arctic sea ice, which would allow for year-round LNG carrier transits to and from the liquefaction facility. According to preliminary publicly available information, the project would be designed to export 4 MMTPA of LNG (compared to 20 MMTPA for the proposed Project). An 80-percent reduction in export volumes would be expected to reduce royalty and tax revenues to the State of Alaska proportionately.

The environmental impacts of the Qilak LNG Project have not been assessed. Because it would not require a pipeline to reach a liquefaction facility in southern Alaska, the Qilak LNG Project would have fewer terrestrial environmental impacts than the proposed Project. The relative scope of impacts on the marine environment from the Qilak LNG Project relative to the proposed Project are unknown, but we note that the former would require an offshore pipeline to connect the production facilities on the North Slope to the offshore LNG liquefaction facility in addition to the liquefaction facility itself. We also note that the Qilak LNG Project would require year-round LNG carrier transits to and from Prudhoe Bay, whereas no vessel traffic is anticipated in Prudhoe Bay for the Project during operation.

Because the Qilak LNG Project would not provide for in-state deliveries of natural gas, it would not meet one of the Alaska LNG Project's objectives. Modifying the project to meet this objective would require the construction of a pipeline from the North Slope to southern Alaska, similar to the ASAP Project as discussed above. For all these reasons, the Qilak LNG Project, if modified to meet the Alaska LNG Project's objectives, would not provide a significant environmental advantage over the proposed Project.

3.2.2 Existing and Proposed Canadian and Contiguous United States System Alternatives

On the coasts of Canada and the contiguous United States, a number of existing and proposed LNG export terminals could be expanded or modified to export additional LNG. Any of these facilities would need additional liquefaction infrastructure and potentially expanded docking facilities to meet the additional export capacity requirement of the Project. Any new LNG terminal would have large impacts from development of the facility. More importantly, using one of the existing or proposed LNG export terminals would require constructing a much longer pipeline from the North Slope to one of these facilities.

Several LNG export terminals have been proposed in British Columbia, Canada. The length of pipeline from the GTP to one of these LNG export terminals would be at least 1,200 miles, or 400 miles longer than the Mainline Pipeline. We estimate that the additional 400 miles would add about 6,452 acres of land disturbance. Another LNG export terminal, the Jordan Cove LNG facility, has been proposed in Coos Bay, Oregon. Use of this site would require an even longer pipeline than the Canadian LNG export sites to connect the facility to the GTP.[2] Therefore, we conclude that none of these alternatives would offer a significant environmental advantage.

3.2.3 Natural Gas Export via Pipeline

We evaluated an alternative that would use a pipeline to export natural gas to markets outside North America. As described in section 1.1, a key Project objective is to commercialize North Slope gas by exporting LNG to foreign markets. Excluding Canada, the nearest foreign market to the Project is in Asia, more than 2,000 miles from Alaska. Subsea pipeline construction to Asian markets would require crossing the northern Pacific Ocean, which has an average depth of 13,000 feet (NOAA, 2017e). We are not aware of any subsea pipelines constructed at this water depth, and even if it were feasible to construct, the costs would be prohibitive, which would render this alternative economically infeasible. Moreover, unlike the transportation of natural gas via LNG carriers, which provides delivery flexibility (because tankers can travel to any port that has an LNG import terminal), delivery by pipeline is limited by the pipeline route, and additional international pipelines would likely need to be constructed if more than one country or market is served. Constructing a natural gas pipeline to a foreign market is neither technically nor economically practical, nor would it offer a significant environmental advantage over the proposed Project, and therefore we did not consider it further.

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[2] This pipeline would connect the GTP to the existing gas transmission systems operated by TransCanada in the Pacific Northwest, which could then deliver gas to the proposed Pacific Connector Pipeline and the Jordan Cove LNG facility in Coos Bay.

3.3 GAS TREATMENT FACILITIES ALTERNATIVES

AGDC has proposed to locate its GTP at the beginning of the proposed Mainline Pipeline route on the North Slope. We received feedback during interagency meetings recommending that our analysis explain why the GTP site could not instead be sited away from the North Slope.

Locating the GTP site at the pipeline terminus at or near the Liquefaction Facilities would not meet one of the Project's objectives, because the in-state gas interconnections along the Mainline Pipeline would not receive pipeline-quality gas. Therefore, to meet the Project objective, an alternative GTP site off the North Slope would need to be positioned upstream of the first in-state gas interconnection.[3] Moreover, moving the GTP away from the North Slope would reduce efficiencies and increase costs. Without additional pipeline infrastructure, the Project would not be able to provide the GTP byproduct stream to the PBU for reinjection into the production field (see the description of the PBU Major Gas Sales (MGS) Project in section 4.19.2.2).

Raw gas is typically treated before entering transmission pipeline systems to remove impurities that cause internal corrosion, thereby minimizing the exposure of the pipe to corrosive forces. The raw gas produced from the PBU and PTU contains CO_2, H_2S, and water. Water in the gas stream can condense, reacting with CO_2 or H_2S to form an acid that collects in low spots and causes internal corrosion (PHMSA, 2008). The presence of H_2S has been shown to reduce the fatigue life of offshore risers by about a factor of 10 (Pipeline and Gas Journal, 2010). Corrosion issues would be exacerbated by fluctuations in the gas stream's chemical composition (Nyborg, 2005). Locating the GTP at the beginning of the Mainline Pipeline allows the system to transport dry "pipeline-quality" gas suitable for domestic and industrial consumption for its entire length, which reduces internal corrosion risks. Consequently, moving the GTP downstream and outside the North Slope region could compromise the integrity of all upstream pipeline segments. Therefore, alternatives further downstream are not technically practical for long-term pipeline operation and are not considered further.

During scoping, the EPA recommended that the EIS evaluate alternative GTP sites and facility configurations. Accordingly, we evaluated alternatives for the GTP and associated facilities. The factors considered for the GTP are different from those considered for a pipeline route because an aboveground facility such as the GTP is a fixed location rather than a linear facility. Additionally, unlike a pipeline, an aboveground facility is visible during operation and, in most cases, generates noise and air emissions. For the GTP, we also considered property size and availability. Based on the proposed design, the size of a site alternative should be at least 284 acres.

In addition, the sites should be far from geological hazards (e.g., known faults). Sites ideally would use industrial and commercial properties and avoid sensitive land uses including Alaska Native allotments, national parks, wilderness areas, wildlife refuges, national preserves, rare or sensitive habitats, and national forests.

3.3.1 GTP Alternative Sites

In response to scoping comments and to determine whether impacts on wetlands and other resources might be reduced, while maintaining a location in reasonable proximity to the PBU CGF, we

[3] As currently identified, the first gas interconnection is near MP 441 to serve the Fairbanks area. During scoping, some commenters expressed the hope that natural gas may eventually become available to communities on the North Slope. While not currently identified as a gas interconnection, locating the GTP off the North Slope would likely preclude this as a future possibility.

evaluated four alternative North Slope locations as potential GTP sites. Key technical siting criteria for identifying alternative sites included:

- availability of a land parcel of about 225 acres;
- proximity to module delivery routes (thereby avoiding the need to construct new access roads);
- module haul distance (between 18 and 29 modules would be transported in each of four construction seasons, with each moving at less than 0.5 mile per hour; longer module haul distances would increase the risk that the deliveries could be made during the open construction season);
- distance from the PTTL (to minimize the length of the transmission pipeline from the PTU to the treatment site); and
- reasonable proximity to the PBU CGF (to allow for efficient management of by-products and availability of fuel gas).

Comparative data are shown in table 3.3.1-1 and the sites are shown on figure 3.3.1-1.

TABLE 3.3.1-1

Comparison of Alternative Sites for the GTP

Screening Criteria	Proposed Site (West of the PBU CGF Site)	North of Put-23 Mine Site	Southwest of Deadhorse Airport Site	North of PBU CGF Site	Northwest of PBU CGF Site
GTP pad size (acres)	228	228	239	251	228
NWI-mapped wetlands affected (acres)	228	228	239	251	228
Dredging (cubic yards)	0	0	0	4,500,000	0
Granular material required (cubic yards)	11,400,000	11,300,000	16,500,000	>11,000,000	11,400,000
Module delivery route length (miles)	5	6.7	20	0	4
Distance from PBU/CGF (miles)	1.0	1.3	12.5	3.8	5.0
PTTL pipeline length (miles)	62.5	62.0	62.4	66.0	66.7

NWI = National Wetland Inventory

Both the North of Put-23 Site and the Northwest of PBU CGF Site compare closely to the proposed site in most criteria. The North of Put-23 Site is 0.3 miles farther from the PBU CGF than the proposed site. Both alternative sites would affect the same acreage of wetlands as the proposed site.

The Southwest of Deadhorse Airport Site is not only the farthest from the PBU CGF and represents the longest module delivery haul distance of any of the alternatives examined, but it would also affect 11 more acres of wetland than the proposed site. The additional distance from the PBU CGF would have the added disadvantage of requiring more compression to move gas to the site, with associated air quality impacts.

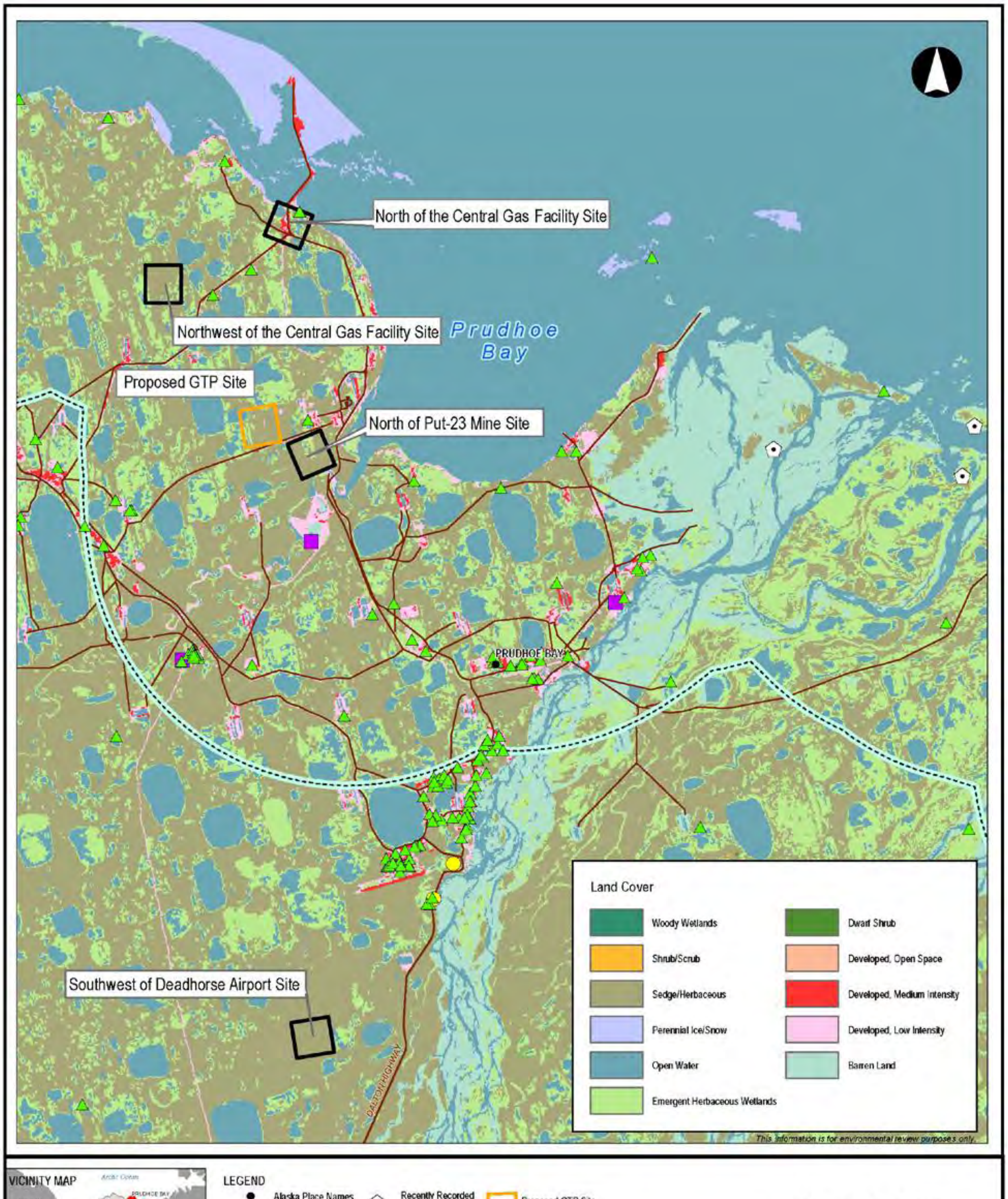


Figure 3.3.1-1
Alaska LNG Project
GTP Site Alternatives

The North of PBU CGF Site lies adjacent to the West Dock Causeway on the Prudhoe Bay shoreline. This site would avoid the need to transport modules over land, allowing them to be delivered directly by sea. In order to deliver the modules directly by sea, however, construction of a new dock would be required. This is in contrast to the other sites, which would all require upgrades to the existing West Dock Causeway. AGDC has estimated this would entail dredging about 4.5 million cubic yards of material. Moreover, wetland impacts would be increased by 23 acres with this alternative.

None of the four alternative sites evaluated would reduce impacts on wetlands. While the North of PBU CGF Site would eliminate overland transport of GTP modules, it would do so at the expense of significantly greater marine impacts associated with building a new dock. For these reasons, we do not find that the alternative sites provide a significant environmental advantage over the proposed site.

3.3.2 Alternative GTP Facility Configurations

During scoping, the EPA recommended that the EIS evaluate alternative GTP configurations. Accordingly, we examined the issue of alternative configurations for the GTP pad and operations center/camp pad, as well as GTP facility access roads and wastewater disposal.

3.3.2.1 GTP Pad and Operations Center / Camp Pad

We considered whether the GTP pad could be reconfigured to reduce effects on wetlands. Equipment configurations are subject to certain regulatory constraints and design considerations associated with safety concerns, such as minimum distances between flares and other equipment. AGDC selected the location of the components of the GTP based on the relevant regulations, codes, and guidelines. We did not find any alternative configurations that would meet all of these regulations, codes, and guidelines and at the same time avoid or reduce the impacts associated with the proposed GTP pad configuration. Accordingly, our review focused on whether reductions of the overall footprint of the operations center/camp pad could be made without compromising technical design considerations.

The proposed operations center / camp pad would accommodate the residential camp, offices, warehouses, and maintenance shop without any additional storage or staging space. We requested that AGDC evaluate collocating the operations center with the processing facilities on the GTP pad. AGDC responded that safety considerations associated with potential blast overpressures require the operations center and other buildings to be on a separate granular pad, and that nearby waterbodies, roads, pipeline corridors, and the PBU CGF further constrain the space available for locating the operations center facilities adjacent to the GTP pad. We concur and conclude that no alternative facility configurations are technically practical.

3.3.2.2 Access Roads

In response to EPA scoping comments, we evaluated alternatives to the proposed access roads for the Gas Treatment Facilities. Our evaluation assessed both seasonal use and the road routes. We considered the potential to minimize impacts on wetlands using seasonal ice roads instead of year-round granular roads to access the West Dock Causeway, emergency egress to the PBU CGF, and the mine site, and determined that it would not be practical to limit access roads to seasonal ice roads. Road access during the summer months would be needed to transport the modules for the Gas Treatment Facilities, which would be delivered to the West Dock Causeway during the summer open water period. Access to the mine site and reservoir during summer and winter months would also be needed to support construction. Additionally, the emergency egress access road to the PBU CGF would need to be available year-round for safety reasons. Seasonal ice roads would not meet AGDC's need for year-round access to each of these locations.

We also evaluated alternative access routes between the GTP and the gravel mine/water reservoir. AGDC proposes to construct a new road about 3.0 miles in length, which is the shortest access route possible. While existing roads are available to the east and the west of the proposed new road, their use would involve significantly longer haul distances. The western road would be about 11.1 miles long. The eastern road would be about 13.6 miles long. According to AGDC, either road would need to be widened and upgraded for Project use, and would also require 0.8 mile of new road construction. We determined that because the area bordering the existing roads is wetland, any incremental widening of these roads would also have wetland impacts and diminish, to some extent, the potential reduction of wetland impacts that might be achieved by using existing roads. For example, an additional 20 feet of widening along the entire length of the 11-mile-long existing road, plus an additional 0.8 mile of new road, would affect roughly 34 acres, or about 1 acre less than the proposed new access road. It is uncertain the extent of widening that would need to occur along existing roads; however, as demonstrated by the given example, any reduction in wetland impacts would likely be minor.

The longer haul distances for the existing road alternatives would increase air impacts. Use of the shorter of the two existing roads over a 2-year period would cause emission increases in all criteria air pollutants as well as greenhouse gases.[4]

Given the minor reduction in wetland impacts and the fact that longer haul distances for the existing road alternatives would increase air impacts, use of existing roads would not provide a significant environmental advantage over the proposed access road route.

The proposed module delivery access road would use a portion of the existing road from the West Dock Causeway to the K Pad Road, reducing the total volume of granular fill required for access roads. The new portion of the access road route avoids waterbodies and uses a direct path to the GTP main pad to minimize impacts on wetlands as well as on vehicular emissions. Because it is unlikely that any alternatives would offer a significant environmental advantage over the proposed route, alternatives to the proposed module delivery road route were not considered further.

3.3.2.3 Wastewater Disposal Alternatives

In response to EPA comments, we examined whether existing permitted UIC Class I injection wells could be used for disposal of liquid waste streams, as an alternative to the proposed two new injection wells at the GTP site. The nearest existing injection well is at the PBU's Pad 3, which lies about 5.4 miles south of the proposed GTP site. The EPA's database indicates this well is currently inactive. Three active injection wells are grouped about 7.7 miles east of the GTP site. The capacities of these wells to accommodate waste streams from the Project are not known. However, based on the assumption that at least two wells would be required, construction of a wastewater pipeline to the group of active existing injection wells would disturb a minimum of 93 acres in what is predominantly wetland (based on a 100-foot-wide construction right-of-way and a straight route between the GTP site and the wells). Capacities of these wells aside, we did not consider this alternative further because it would not provide a significant environmental advantage over the proposed new injection wells at the GTP site, which would not require transporting the waste stream off-site.

3.3.3 Module Delivery System Alternatives

[4] Estimated emission increases from use of the 11.1-mile existing road (in tpy) are: volatile organic compounds = 1.1, nitrogen oxides = 3.1, carbon monoxide = 1.3, particulate matter–aerodynamic diameter less than or equal to 10 microns (PM_{10}) = 48.5, particulate matter–aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) = 5.0, sulfur dioxide = 0.03, carbon dioxide equivalents = 3,984.3, based on data provided by AGDC in their December 17, 2019 response (Accession No. 20191217-5057) to FERC information request No. 9, dated November 22, 2019. The response is available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20191217-5057 in the "Numbers: Accession Number" field.

Based on comments from stakeholders, alternatives to AGDC's proposed module delivery system were evaluated. The facilities at the GTP would be constructed of pre-fabricated modules delivered by sealift during six open-water seasons. The modules would be about 90 feet wide by 300 feet long and weigh about 9,000 tons. Between 9 and 12 barges would dock each season, delivering as many as 57 modules during the ice-free period when ships can reach the North Slope docks.

Several alternatives were either not technically practical or did not reduce environmental impacts, and so were not considered further. Use of both larger (12,000-ton) and smaller (5,000-ton) modules was examined, and it was determined that neither would reduce environmental impacts. Transporting modules from the south via the Dalton Highway or via a combination of rail and highway transport, was examined. Both options would require major modifications to the Dalton Highway bridges and would exceed the highway's load limitations. The Dalton Highway is a two-lane, mostly unpaved road approximately 26 feet wide for most of its 416-mile length. AGDC estimates that most of the 416 miles would require doubling in width to mitigate the load and size limitations of the highway. Multiple bridges between Fairbanks and the North Slope have 110-ton weight restrictions; these bridges would require strengthening and/or widening as well. These improvements would allow smaller module components to be transported, but would not allow the module sizes that are proposed for delivery to the North Slope by barge.

Substantial environmental impacts would occur as a result of the necessary infrastructure upgrades. For example, the highway widening would permanently affect about 1,750 acres of wetlands according to National Wetland Inventory (NWI) data, with additional impacts from the bridge modifications. This compares to wetland impacts of approximately 35 acres for the new access road associated with the proposed module delivery system. Air emissions are also estimated to be greater if the Dalton Highway is used for all criteria pollutants except particulate matter–aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$).[5] Consequently, this alternative would not provide a significant environmental advantage.

Fabricating the modules on-site was evaluated; this could eliminate the need for major dock and road improvements with associated reductions in environmental impacts. Fabricating the modules on-site could eliminate the need for, or reduce the scope of, upgrades at the West Dock Causeway, access road, and staging pad. For this alternative, many of the smaller individual GTP components could be transported from the south over the Dalton Highway. However, components exceeding the maximum load allowance of 100 tons on the Dalton Highway would still need to be brought to the West Dock Causeway by barge and transported by truck over the same access road as the proposed Project.

AGDC indicates that on-site fabrication of the necessary GTP components would require more than 200 additional acres of workspace at the 228-acre site for storage and assembly of components, and would increase the construction duration by 2 to 3 years. Since almost all the area surrounding the GTP site consists of wetlands, the on-site fabrication would increase wetland impacts at the GTP site by at least 200 acres. This increase would be partially offset by a 136-acre reduction in wetland impacts associated with the proposed Project's module delivery system from the West Dock to the GTP site, which would not be necessary with the alternative; the on-site fabrication alternative would therefore result in a net increase in wetland impacts of at least 64 acres.

[5] Use of the Dalton Highway for module transport would result in an estimated additional 126.9 tpy of nitrogen oxides, 6.1 tpy of volatile organic compounds, 51.2 of tpy carbon monoxide, 4.1 tpy of $PM_{2.5}$, and 5.2 tpy of sulfur dioxide, and 17.6 tpy less of particulate matter–aerodynamic diameter less than or equal to 10 microns (PM_{10}), based on data provided by AGDC in their December 23, 2019 response (FERC Accession No. 20191223-5325) to FERC information request No. 10, dated November 22, 2019. The response is available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20191223-5325 in the "Numbers: Accession Number" field.

The on-site fabrication alternative would transport individual GTP components via the Dalton Highway. Transporting smaller components by road would not, unlike transporting larger modules, require upgrades to the highway infrastructure. However, air emissions associated with the longer Dalton Highway haul route and greater number of trucks would be higher than with the proposed delivery system. AGDC provided estimates confirming that over the duration of construction, use of the Dalton Highway would result in greater air emissions than the proposed delivery system for every criteria pollutant.[6]

Environmental advantages inherent in eliminating or reducing the West Dock Causeway, access road, and staging pad upgrades would be at least partially offset by increases in the GTP site construction footprint and increased traffic emissions during transport. Therefore, on-site fabrication would not provide a significant environmental advantage to the proposed means for delivering GTP equipment and material to the site.

3.3.4 North Slope Dock Alternatives

In response to comments from the EPA during scoping, we evaluated five alternative docking locations to the proposed West Dock Causeway modifications for delivery of gas treatment unit modules to the GTP site (see figure 3.3.4-1). Each of the alternative docking locations, like the proposed location, provides barge access from the Beaufort Sea. As indicated in table 3.3.4-1, the dock alternative sites require the construction and use of an expanded access road network.

In addition to the impacts associated with road construction, the extended travel time by construction equipment adds impacts on air quality caused by construction emissions. The additional transit time would also contribute to noise impacts. Finally, all of the alternative dock sites require more dredging than the proposed site, which would not involve any dredging. In light of all of these factors, none of the alternative dock sites would provide a significant environmental advantage.

TABLE 3.3.4-1

Comparison of Alternative Dock Sites for the GTP

Screening Criteria	Proposed Site (West Dock Causeway)	East Dock	Endicott Main Production Island and Satellite Drilling Island	Oliktok Dock	Badami Dock	Point Thomson Dock
Distance from GTP area (miles)[a]	<7	7	16	33	39	53
Distance of new roads or road upgrades needed (miles)	7	15	16	33	39	60
Water depth at dock (feet)	12–13	5	7–8 at Main Production Island and 14 at Satellite Drilling Island	7.5	6	7
Initial dredge volume needed (thousand cubic yards)[b]	0	2,088	593	771	452	780
Within polar bear “no disturbance zone”	No	No	Yes	No	Yes	Yes
Within musk ox calving area	No	No	No	No	No	No

a Straight-line distance.
b Dredging estimates provided by AGDC, based on bathymetry in NOAA Chart Nos. 16061, 16062, 16046, and 16045.

6 Use of the Dalton Highway for transporting components to the North Slope for on-site fabrication would result in an estimated additional 145.4 tpy of nitrogen oxides, 21.4 tpy of volatile organic compounds, 145.8 tpy of carbon monoxide, 1,673.0 tpy of PM_{10}, 176.4 tpy of $PM_{2.5}$, and 0.7 tpy of sulfur dioxide, based on data provided in AGDC’s December 23, 2019 response (see FERC Accession No. 20191223-5325) to FERC information request No. 10, dated November 22, 2019. The response is available on the FERC website at http://www.ferc.gov. Using the “eLibrary” link, select “Advanced Search” from the eLibrary menu and enter 20191223-5325 in the “Numbers: Accession Number” field.

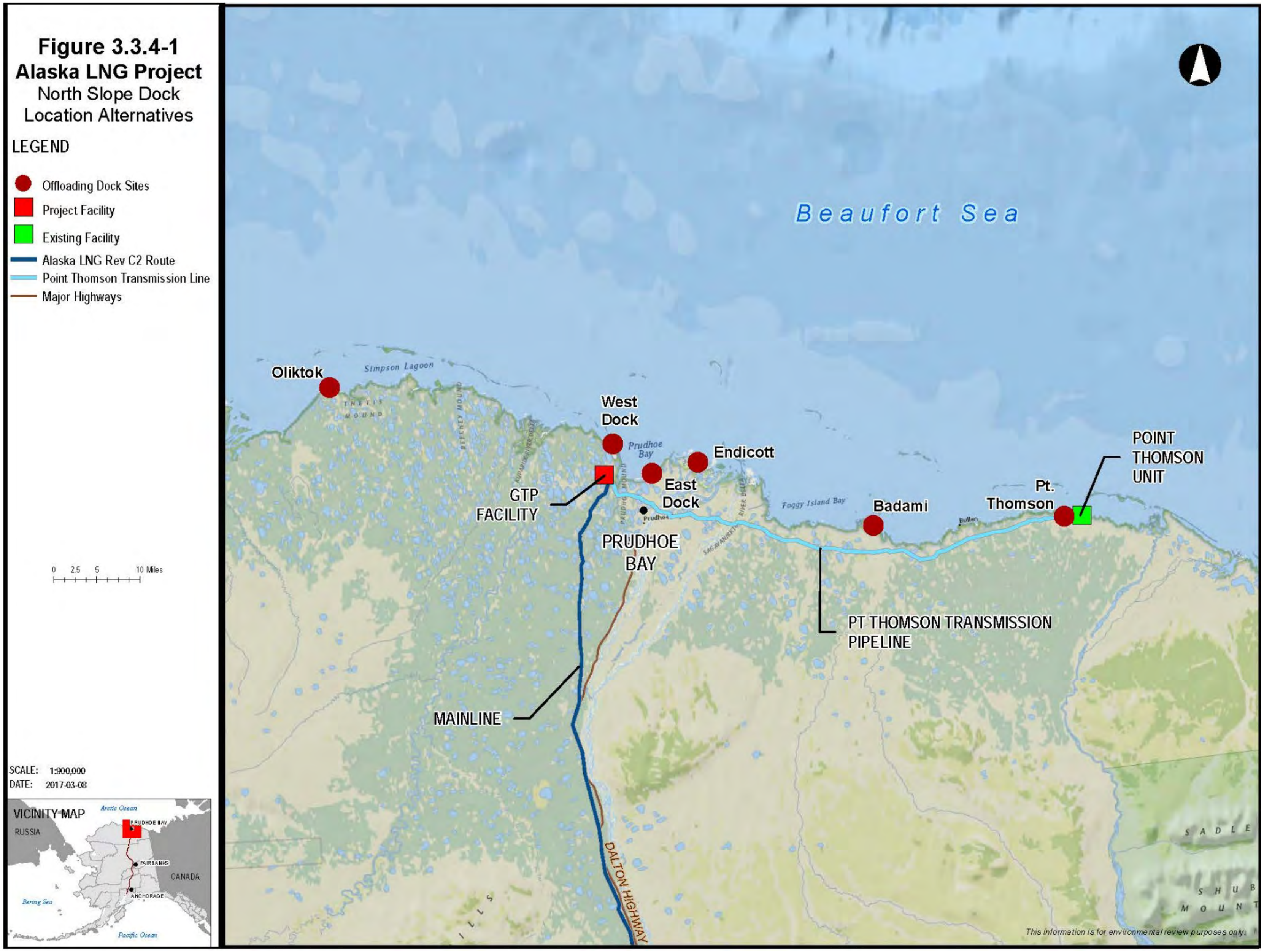


Figure 3.3.4-1
Alaska LNG Project
North Slope Dock
Location Alternatives

3.3.5 West Dock Causeway Alternatives

The proposed use of the existing West Dock Causeway infrastructure (identified herein as the Dock Head 4 – No Channel Option) would not require dredging to allow for module delivery, but it would require upgrades of the West Dock Causeway and construction of new berths. In response to comments from the EPA during scoping, we attempted to identify alternatives that would require less marine disturbance than the proposed use of, or upgrades to, the West Dock Causeway infrastructure (see figure 3.3.5-1). Table 3.3.5-1 provides comparative information for the proposed location and the alternatives.

Two alternatives (the Dock Head 4 – Saltwater Treatment Plant Alternative and the Dock Head 3 Alternative) would require significant amounts of dredging and would require causeway upgrades similar to the proposed site. Therefore, they would not provide any significant environmental advantage and were not considered further.

The Dock Head 2 Alternative, which is nearest the shore, would eliminate the need to upgrade the causeway to the proposed Dock Head 4. However, it would require the dredging of 4.5 million cubic yards of material to allow barges to reach the dock. Additionally, marine water studies conducted by AGDC indicate that there is a risk of sedimentation infill at Dock Head 2, which could require additional dredging in the summer prior to each sealift. Impacts on the marine environment from this volume of dredging would far exceed the marine impacts from upgrades to the existing causeway and related bridges. Consequently, we determined that the Dock Head 2 Alternative would also not provide any significant environmental advantage over the proposed Dock Head 4 location, and it was eliminated from further consideration.

3.3.6 Gravel Mine Site Alternatives

In response to scoping comments received from the North Slope Borough, AGDC was asked to identify and evaluate existing gravel mine sites to determine if an existing source could be used instead of the proposed new site. AGDC proposed a mine site location near the GTP, which minimizes haul distances and avoids open waterbodies. Use of the proposed new mine would affect about 175 acres of wetlands, of which approximately 140 acres would be from the mine site itself. Two existing mine sites, the Put-23 and the Pit-203 sites, lie farther from the GTP site than the proposed new mine site. AGDC indicated it may need to draw material from these sites until the new site is sufficiently developed to accommodate Project needs. Use of these existing mine sites exclusively would result in wetland impacts similar to the proposed new mine site, because 1) they would have to be expanded to a total acreage similar to that of the proposed new site (i.e., 140 acres); 2) almost all the area surrounding the two existing sites is wetland; and 3) AGDC indicates that even with the use of existing mine sites, construction of a new reservoir would be needed for water supply, resulting in an additional 35 acres of wetland impacts.

Use of the existing mine sites would also involve incrementally greater haul distances. For example, the distance from the GTP site to the nearest existing mine site, the Put-23 Mine, is 3.8 miles, compared with a 2.2-mile distance from the GTP site to the proposed new mine site. The Pit-103 Mine site is about 13.5 miles from the GTP site. Air emissions would be greater in proportion to the haul distances; for example, total particulate matter–aerodynamic diameter less than or equal to 10 microns (PM_{10}) emissions for the 2-year construction period are estimated at 11.7 tons per year (tpy) for the proposed new mine site versus 20.5 tpy for the Put-23 mine and 73.6 tpy for the Pit-103 mine.

For the reasons discussed above, sourcing granular fill from existing mines would not provide a significant environmental advantage over the proposed site.

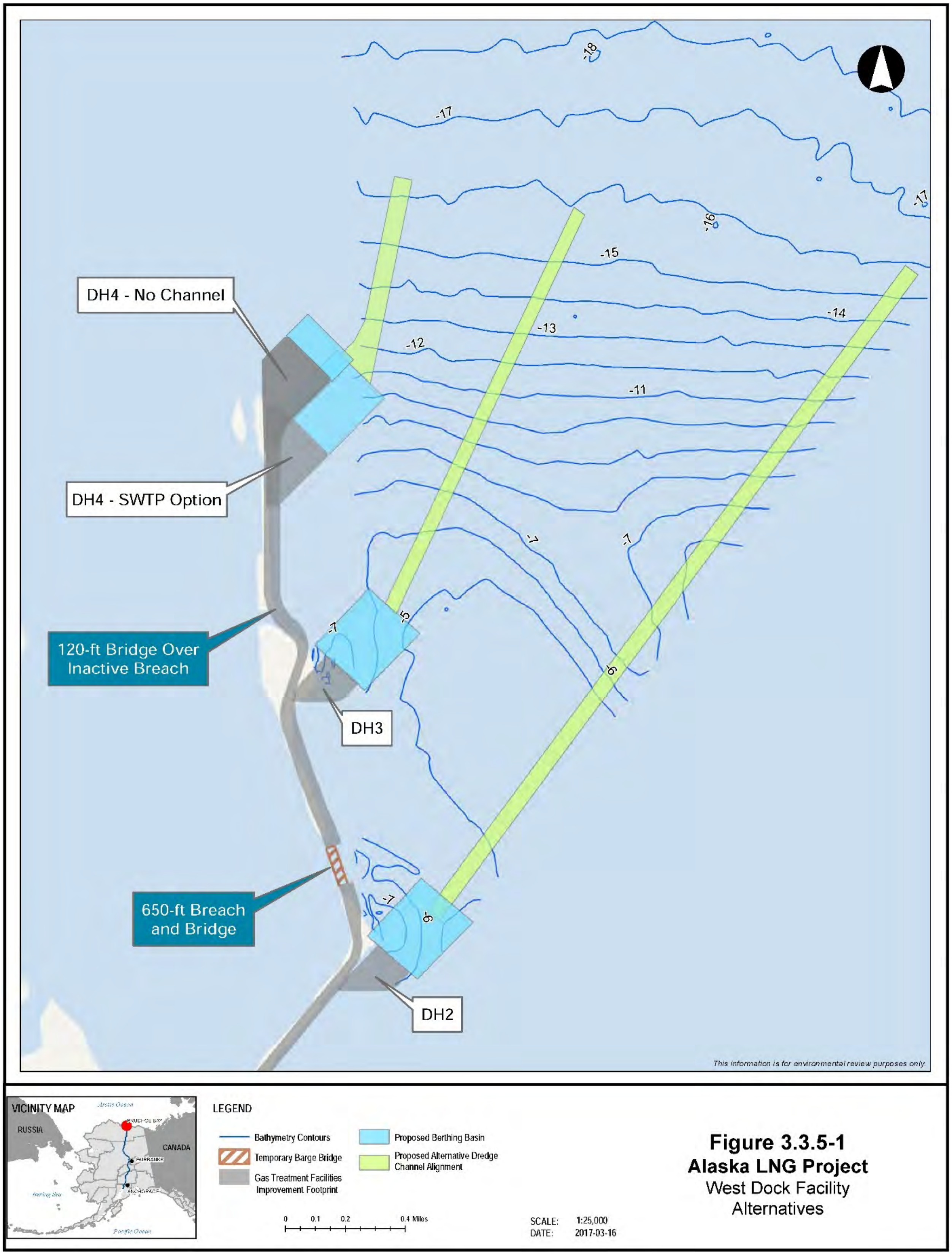


Figure 3.3.5-1
Alaska LNG Project
West Dock Facility Alternatives

TABLE 3.3.5-1 **Comparison of Alternatives for the West Dock Causeway Facility**				
Screening Criteria	Proposed Option (Dock Head 4 – No Channel)	Dock Head 4 – SWTP Option	Dock Head 3	Dock Head 2
Water depth (feet)	11 to 12	8 to 11	5 to 7	5 to 7
Navigational channel length (feet)	0	3,600	8,600	14,000
Dredge volume needed (million cubic yards)	0	0.8	3.3	4.5

SWTP = saltwater treatment plant

3.3.7 Water Supply System

AGDC proposes to construct a Project-specific reservoir to provide water for operation of the GTP (i.e., process water). This water could also be used to meet water needs for construction. The material excavated from the reservoir, along with that from the mine site discussed above, would provide granular fill for the GTP pad. In response to recommendations from the EPA that alternative water sources be evaluated, we examined use of existing municipal water sources and natural lakes. The alternative water sources are shown on figure 3.3.7-1.

We evaluated obtaining water from the North Slope Borough's water treatment facility via pipeline. The distance from the Deadhorse water treatment facility to the GTP site is about 8 miles. Construction of such a water pipeline would disturb about 100 acres (based on a 100-foot-wide construction right-of-way). Moreover, the current capacity of the water treatment plant is insufficient to meet the needs of existing customers. To supply the Project, the water treatment plant would need to be expanded, which would have associated environmental impacts. Therefore, this is not a technically practical alternative nor does it provide a significant environmental advantage over the proposed water supply system.

The saltwater treatment plant (SWTP) at the end of the West Dock Causeway treats seawater for use in enhanced oil recovery. This would not be a technically practical alternative to the proposed water source because the treatment process removes oxygen from the water, but does not desalinate it. The water would need additional treatment, requiring facilities be constructed either at the SWTP or the GTP, with associated increases in the footprint at one of those facilities. High turbidity during the spring also requires the SWTP to shut down its water treatment operation for about 4 to 6 weeks each year, which would require the Project to source water from a secondary location each year during this period. Consequently, use of the SWTP is not technically practical.

The use of existing lakes and mine sites, discussed below, would depend on trucks to haul process water to the GTP site on a more-or-less continuous basis. AGDC indicated that the reduced reliability of supplying water via truck, for example delays caused by weather, would pose an unacceptable risk to GTP operation. For this and the reasons stated below, such options are not technically practical alternatives to the construction and use of a Project-specific reservoir.

A number of natural lakes near the GTP would be potential water sources; however, none of these lakes would be capable of meeting the Project's annual water demands. Although they would have sufficient volume after existing water rights are accounted for, these shallow lakes would likely freeze to the bottom during the coldest time of the year and be unable to provide water year-round. Therefore, these lakes would not be technically practical alternatives to the construction of a Project-specific reservoir.

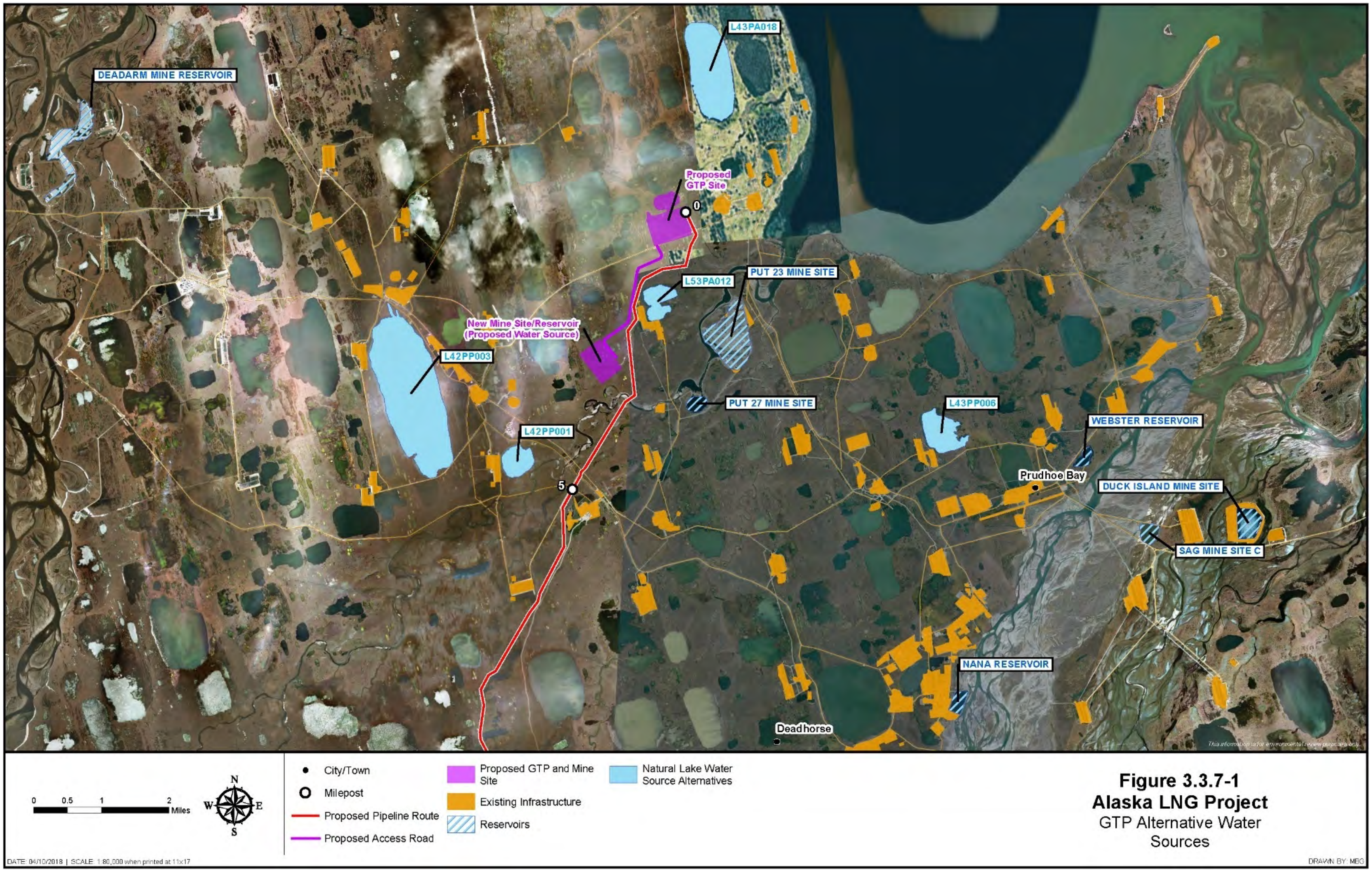


Figure 3.3.7-1
Alaska LNG Project
GTP Alternative Water Sources

We considered using existing flooded gravel mine sites near the GTP as potential water sources. These former gravel mine sites hold large volumes of water available for withdrawal year-round. However, according to AGDC, most of this water has been allocated to other users. Although the volumes that have not been committed to other uses could provide a supplemental water source to the GTP, the uncommitted volume of water is not sufficient to meet the Project needs. Therefore, these existing sources are not technically practical alternatives to construction of a Project-specific reservoir.

We also examined the potential for deepening natural lakes to provide water. Deepening these lakes would require excavation and disposal of large volumes of sediment. The removal of sediment would temporarily affect the water quality and aquatic resources of the lakes. The excavated lacustrine sediment would be too fine-grained for use as fill for the Project's pads and access roads, and so likely would require a non-utilitarian means of disposal, with potential effects on wetlands. For these reasons, deepening natural lakes would not provide a significant environmental advantage over the proposed construction of a Project-specific reservoir.

3.4 PTTL ALTERNATIVES

We did not identify any alternative gas transmission alternatives for the PTTL that could provide a significant environmental advantage to the proposed route. In addition, we received no stakeholder comments requesting the analysis of alternative routes. The EPA requested that we evaluate placement of the pipeline on existing VSMs supporting other pipelines. While other aboveground pipelines do lie within the same corridor as the PTTL route, none of the VSMs supporting these pipelines were designed to accommodate an additional large-diameter pipeline according to AGDC.

3.5 PBTL ALTERNATIVES

Because of its short (1-mile) length, limited resource impacts, and the lack of other options to avoid resources, our analysis of the PBTL did not identify any siting alternatives that could reduce impacts while still meeting the Project's stated objectives. Further, no comments were received from stakeholders requesting review of an alternative for the pipeline.

3.6 MAINLINE PIPELINE ROUTE ALTERNATIVES

We received comments requesting that we include an evaluation of a pipeline alignment following the existing TAPS pipeline right-of-way from Livengood, Alaska, to an LNG Plant site on Anderson Bay in Valdez, Alaska. This major route alternative is interdependent with the various Port Valdez LNG terminal alternatives, and so is discussed with those alternatives in section 3.8.1.

Prior to filing its application, AGDC evaluated and incorporated 134 route variations into the proposed route to avoid or reduce effects on environmental or other resources, resolve engineering or constructability issues, or address stakeholder concerns. We evaluated these 134 route variations during the pre-filing period and found them to be acceptable. These route variations are part of the proposed Mainline Pipeline route evaluated in section 4.0 of this EIS.

During scoping, the Knik Tribal Council identified a Mainline Pipeline route alternative in the vicinity of MPs 674.0 to 730.0 aimed at minimizing impacts on cultural resource sites and wetlands. Subsequently, AGDC made several adjustments to its proposed route, with the objective of addressing the Council's concerns about its proposed route. In May 2018, Tribal representatives indicated that AGDC's modifications to its proposed route adequately addressed their concerns. The route modifications are part of the proposed Mainline Pipeline route evaluated in section 4.0.

A group of Boulder Point neighbors expressed concerns with the segment of the proposed Mainline Pipeline route between MPs 793.0 and 798.0. According to the residents, this segment of the route crosses an area with abundant devilsclub (*Oplopanax horridus*), an important food source for black bear. The group of Boulder Point residents identified additional concerns with this portion of the Mainline Pipeline route, including its proximity to Suneva Lake Dam and the crossing of Suneva Canyon, impacts on residential drinking water, abundance of large boulders at Boulder Point, and its remoteness with respect to potential acts of terrorism. These stakeholders requested that we analyze a route alternative that would either follow existing cleared corridors from Beluga to Trading Bay, and/or make landfall in the industrial portion of Nikiski Bay.

In response to these concerns, we identified a potential alternative route that would follow existing rights-of-way from Beluga to Trading Bay and cross Cook Inlet from the West Foreland area. This route, while decreasing the length of the Cook Inlet crossing, would affect more devilsclub habitat and wetlands than the proposed route, and consequently was not evaluated further. Another potential route, the Cook Inlet West Alternative (West Alternative), would make landfall just south of Boulder Point, and would reduce impacts on this habitat type. This alternative route is analyzed in section 3.6.1.2.

3.6.1 Cook Inlet Alternatives

During scoping, we received numerous comments related to the proposed route across the Cook Inlet. Concerns included impacts on beluga whales, safety issues associated with shipping in the Cook Inlet, dredging impacts, impacts on family fishing operations, and impacts on salmon streams in the upland approaches to the inlet crossing. We evaluated two route alternatives to the proposed crossing location: the Cook Inlet East Alternative (East Alternative) and West Alternative. We received numerous comments on the West Alternative during the draft EIS comment period from various stakeholders, including landowners along the proposed route in the vicinity of Boulder Point. These are discussed in section 3.6.1.2.

3.6.1.1 Cook Inlet East Alternative

The East Alternative begins near MP 706.1 and proceeds about 36 miles southeast, crossing the Susitna and Little Susitna Rivers to a location near Point MacKenzie. There the East Alternative enters Cook Inlet and proceeds west, crossing north of Fire Island before turning south and exiting Cook Inlet near Miller Creek. From this point, the East Alternative proceeds southwest along the shoreline until it rejoins the proposed Mainline Pipeline route near Boulder Point, and follows the Mainline Pipeline route to the Liquefaction Facilities. Figure 3.6.1-1 depicts the proposed route and the East Alternative. An environmental comparison of the East Alternative to the corresponding segment of the proposed route is provided in table 3.6.1-1.

TABLE 3.6.1-1

Comparison of the Cook Inlet East Alternative to the Corresponding Segment of the Proposed Route

Environmental/ Engineering Factor	Proposed Route	Cook Inlet East Alternative
Length (miles)	101.0	114.0
Land disturbed during construction (acres)	1,340	1,567
Forested and scrub-shrub wetlands crossed (miles)	5.8	6.8
Waterbodies crossed (number)	37	23
Cook Inlet crossing length (miles)	27.3	27.8
Sand wave crossing length (miles)	1.5	14.1
Current velocity range (knots) (north shore/south shore)	5.9/3.7–6.4	1.2–4.0/2.5–5.7
Beluga whale critical habitat (type [miles])	Critical Habitat Area 2 (27.3)	Critical Habitat Area 1 (24.0) Critical Habitat Area 2 (3.8)
State fishery lease crossing (number [feet])	1 (1,109)	2 (1,689)

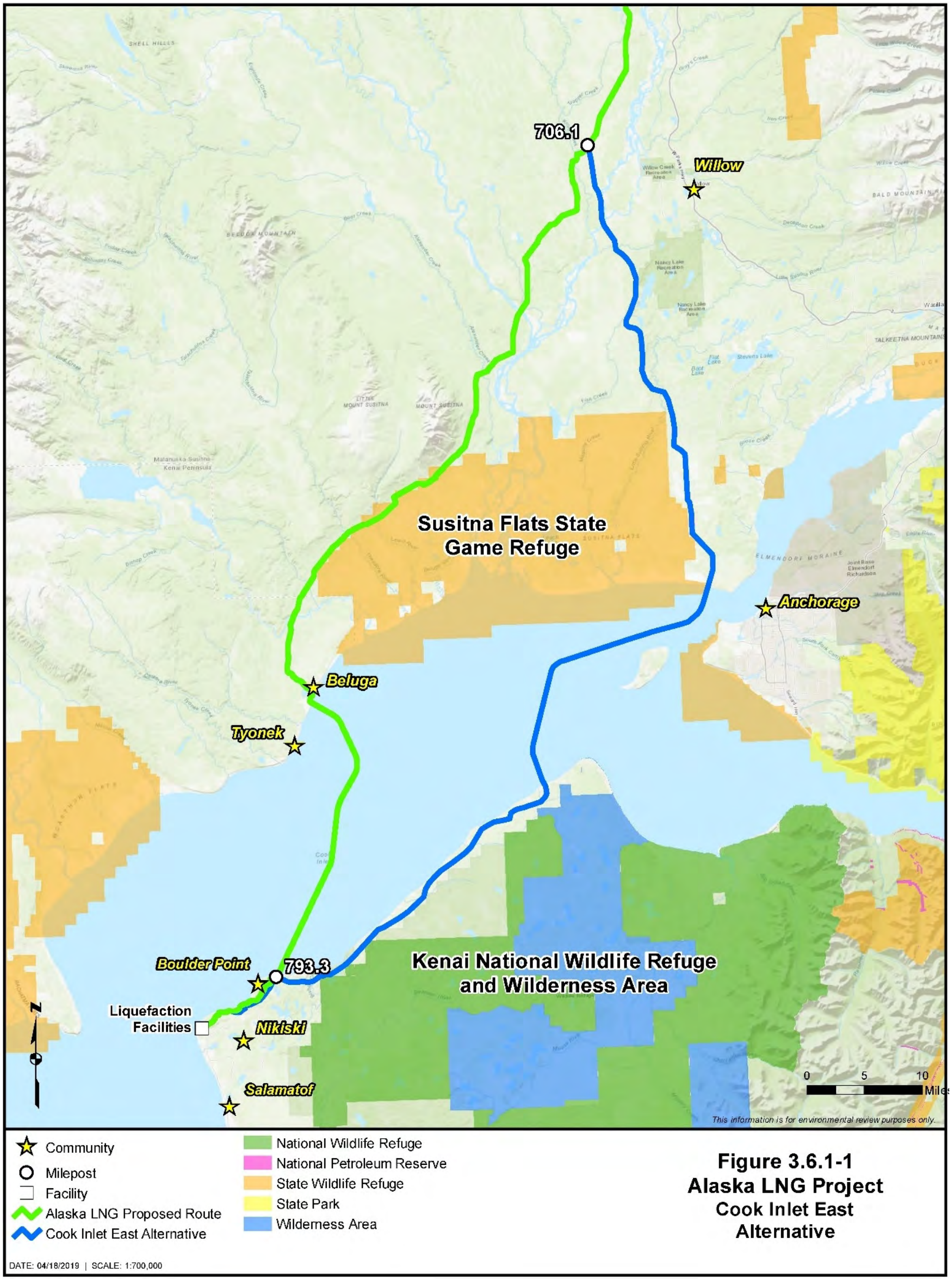


Figure 3.6.1-1
Alaska LNG Project
Cook Inlet East Alternative

The East Alternative's primary advantage over the proposed route is that it would cross 14 fewer waterbodies than the proposed route. However, it is about 13.0 miles longer than the proposed route, which would result in about 227 more acres of overall upland ground disturbance.

The East Alternative's crossing of Cook Inlet is 0.5 mile longer than the proposed route, so its overall disturbance to the marine environment would be greater. More importantly, the East Alternative would cross 24 miles of beluga whale Critical Habitat Area (CHA) 1. Beluga whale critical habitat is described in further detail in section 4.8.1. CHA 1 is considered the more sensitive of the two habitat types present in Cook Inlet, with the highest concentrations of beluga whales during spring through fall. CHA 1 also provides important areas for whale foraging, nursery, and predator avoidance. Activities that restrict or deter the beluga whales' use of CHA 1 could reduce calving success, impair the whales' ability to secure prey, and increase susceptibility to predation by orca whales. In contrast, the proposed route would cross only beluga CHA 2, which has less spring and summer beluga whale use. CHA 2 supports dispersed fall and winter feeding and transit areas in waters where beluga whales typically occur in smaller densities or deeper waters (NMFS, 2010).

The East Alternative additionally crosses 12.6 more miles of sand wave features on the floor of the Inlet. Sand waves are typically highly mobile seascape features that can uncover buried pipelines and erode support from beneath the pipe. The East Alternative's advantage in reducing the number of waterbody crossings is more than offset by its greater marine impacts, especially to the federally listed beluga whale. It would not provide a significant environmental advantage over the proposed route.

3.6.1.2 Cook Inlet West Alternative

The West Alternative begins on the western shore of Cook Inlet near Beluga Landing (MP 766.0) at the same point where the corresponding Mainline Pipeline route begins its crossing of the inlet. From this point, the West Alternative proceeds southeast across Cook Inlet along an alignment 2 to 4 miles west of the proposed route. The West Alternative makes landfall south of Boulder Point in Nikiski Bay and then follows the proposed route for about 9 miles to the Liquefaction Facilities. Figure 3.6.1-2 depicts the proposed route and the West Alternative. An environmental comparison of the West Alternative to the corresponding segment of the proposed route is provided in table 3.6.1-2.

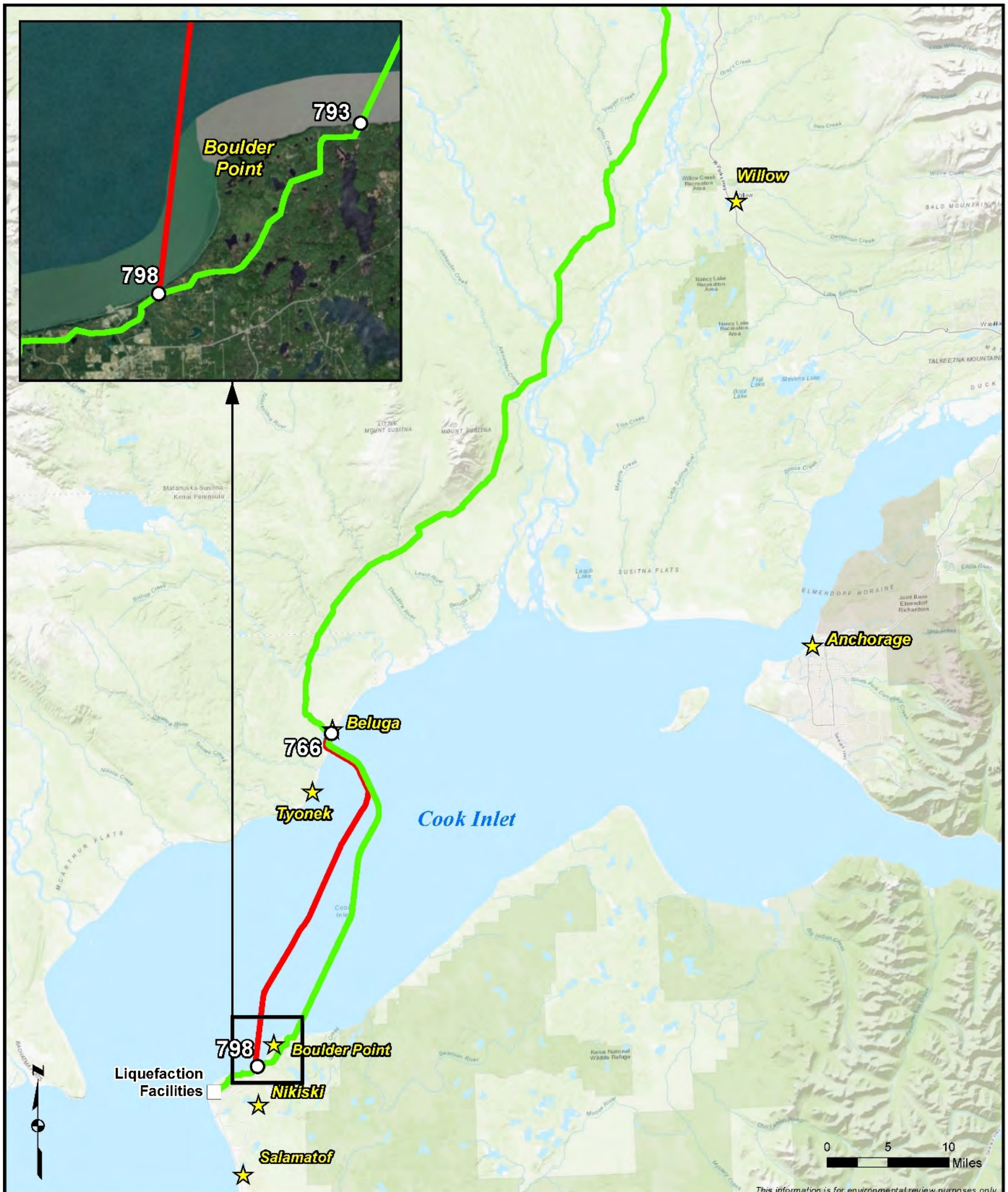
TABLE 3.6.1-2

Comparison of the Cook Inlet West Alternative to the Corresponding Segment of the Proposed Route

Environmental/Engineering Factor	Proposed Route	Cook Inlet West Alternative
Cook Inlet crossing length (miles)	27.3	29.9
Area of On-Shore Impact (acres) [a]	108.5	22.5
Area of Off-Shore Impact (acres) [b]	5,070.0	5,552.9
Total Area of Impact (acres)	5,178.5	5,575.4
Waterbodies crossed, not including Cook Inlet (number)	1	0
Terrestrial wetlands affected (acres)	1.6	0
Forested land affected (acres)	99.5	22.4
Residences within 150 feet (number)	0	0
Beluga whale critical habitat (type [miles])	CHA 2 (27.3)	CHA 2 (29.9)

[a] Based on a 150-foot-wide construction right-of-way.

[b] Based on an estimated disturbance area for pipelay and anchoring the offshore pipelay barge, including cable anchor drop, cable anchor drag, and cable anchor sweep (see section 2.1).



Community
Milepost
Facility
Alaska LNG Proposed Route
Cook Inlet West Alternative

DATE: 12/20/2019 | SCALE: 1:700,000

Figure 3.6.1-2
Alaska LNG Project
Cook Inlet West Alternative

The West Alternative crossing of Cook Inlet would be 2.6 miles longer than the proposed route, which would result in an additional 2.6 miles of impact on beluga whale CHA 2. The West Alternative would reduce the mileage of the route on land by 4.7 miles, thereby affecting about 86 fewer on-shore acres, much of it devilsclub habitat. The West Alternative would affect less forested land (77.1 fewer acres) and wetlands (1.6 fewer acres) than the proposed route.

Other pipelines that cross Cook Inlet make landfall just west of the West Alternative's location in Nikiski Bay, including a natural gas gathering pipeline. Several commenters said that the presence of these pipelines demonstrates that this area is suitable for routing the Mainline Pipeline. AGDC indicates that the proximity of the pipelines would not allow for safe anchoring of the pipeline lay barge during installation of the Mainline Pipeline. The landfall location for the Project route does not have such constraints.

AGDC states that the presence of boulders could significantly impair the success of a trenchless crossing method at the shoreline; an open-cut crossing would create greater shoreline disturbance, potentially requiring blasting and the construction of breakwaters or cofferdams. Several commenters pointed out, and AGDC acknowledged, that based on the visibility of boulders at low tide, the West Alternative does not appear to have a greater concentration of boulders than the proposed route. However, AGDC's seafloor soils mapping indicates that the West Alternative would cross an approximately 1-mile-wide area of boulders and gravel/bedrock offshore as the route approaches the exit point, and that, overall, the proposed route has less chance of encountering boulders.

During the draft EIS comment period, we received 12 letters opposing the proposed route at Boulder Point and in favor of the West Alternative. These letters, from residents in the vicinity of the proposed route, expressed concerns about the proposed route's location immediately downstream from Suneva Lake, impacts on a family fishing operation[7] at the proposed route's landfall, geotechnical issues associated with offshore boulder fields, land use compatibility, and impacts on forest and wildlife, including devilsclub habitat. Section 4.1.3.10 addresses issues associated with the potential for vertical scour along the proposed route in the area downstream from Suneva Lake, and the measures that would be implemented to mitigate risk to the pipeline.

While construction of the proposed route could disrupt fishing in the landfall area near Boulder Point, such impacts would be reduced through implementation of the DMT continuation methodology for installing the pipeline at the shoreline approach, if it is determined feasible.[8] This is a trenchless installation methodology that would involve tunneling the pipeline from the shore into the inlet. As discussed in section 4.3.3.3, AGDC has committed to incorporating the DMT continuation methodology into the shoreline crossing for the proposed route or filing a site-specific justification demonstrating that use of the methodology is not feasible. Should the DMT continuation methodology be successfully implemented, it would avoid direct impacts on all or most of the fishing area near the shoreline. However, even if the DMT methodology is not feasible, impacts on fishing would be addressed through AGDC's implementation of a Project Recreational and Commercial Fishing Construction and Mitigation Plan, as discussed in section 4.11.3.2.

With regard to land use, both routes are compatible with existing land uses. The on-shore portion of the proposed route lies in mostly forested land, and permanent impacts on forested land would result from regular maintenance of the Mainline Pipeline right-of-way. As noted above, the West Alternative would affect less forested land (77.1 fewer acres) and wetlands (1.6 fewer acres). However, the West Alternative would increase the crossing length of sensitive Cook Inlet beluga whale CHA 2 (2.6 additional miles). Off-shore impacts are much greater using the alternative (482.9 additional acres), as is the total

[7] The family fishing operation recently let its shore lease expire, although the family states it has been fishing in the area for 50 years.

[8] A preliminary feasibility assessment of the DMT continuation method concluded that the Beluga Landing approach has a 90-percent probability of success, while the Suneva Lake approach has a 75-percent probability of success.

footprint of construction (396.9 additional acres). No residences would lie within 150 feet of either route's construction right-of-way. Although the West Alternative would reduce impacts on devilsclub, this species is common in the Project area and possesses no legal status regarding its protection.

In summary, AGDC indicates that landfall alternatives in Nikiski Bay, such as the West Alternative, present problems associated with proximity to existing pipelines. Additionally, AGDC states that geotechnical considerations appear to make a successful trenchless crossing more likely for the proposed route. If a trenchless crossing can be successfully completed, direct impacts on the shoreline would be avoided and temporary impacts from trenching, such as disruption to fishing activities in this area, would be minimized. If a trenchless crossing is not successful, the proposed route would have a greater impact on fishing than the West Alternative, though these impacts would be temporary. The West Alternative would affect less forested land, devilsclub habitat, and wetlands than the proposed route, but would affect more offshore resources and have a greater total construction footprint. On balance, the overall differences in impacts on wildlife, forested lands, and wetlands would not be significant. Therefore, while we conclude that the West Alternative would provide certain advantages compared to the proposed route, overall it would not provide a significant environmental advantage over the proposed route.

3.6.2 Denali Alternatives

In section 3.6.2 of the draft EIS, we evaluated an alternative route through the DNPP (the Denali Alternative) and compared it to the then-proposed route for the Mainline Pipeline. This alternative route was also evaluated as part of the ASAP Project and identified as the LEDPA for that project by the COE. Our analysis concluded that either the Denali Alternative or the then-proposed Mainline Pipeline route would be acceptable for the Project without significant environmental advantages for either, and that the overall resource impacts resulting from the adoption of either route would not affect our significance determinations provided in section 4 of the draft EIS. Since the publication of the draft EIS, on August 16, 2019, AGDC adopted the Denali Alternative as the proposed Project route. Accordingly, we have revised our analysis to compare the currently proposed route—inclusive of the Denali Alternative—with suggested alternatives.

We received numerous comments regarding potential alternative routes in or near the DNPP. Various commenters suggested that there would be benefits to an alternative that remained within or adjacent to a transportation corridor in this area. One comment, for example, recommended a route adjacent to the west side of the Parks Highway; however, a route west of the highway would encroach on the designated Denali Wilderness Area, which extends to the west side of the highway right-of-way. Therefore, we did not consider a route west of the Parks Highway.

Based on scoping comments, we considered a route using the nearby highway bridge known as the Nenana River Bridge at Park Station to span the river. While use of the highway bridge would avoid temporary disruptions to pedestrian traffic that could occur during construction on the pedestrian bridge, as is proposed for the Mainline Pipeline, it would significantly disrupt vehicle traffic on the highway bridge, requiring a 69-mile-long detour for trucks during the construction period. While technically feasible, the resulting disruption of critical transportation service would render the alternative incapable of providing a significant environmental advantage. Therefore, we eliminated this alternative from further consideration.

In addition, we considered the route previously proposed by AGDC for the Mainline Pipeline, which we refer to as the Denali Avoidance Alternative. Relative to the proposed route, the Denali Avoidance Alternative passes east of the DNPP between about MPs 536.1 and 544.3 (see figure 3.6.2-1). An environmental comparison of this alternative with the corresponding segment of the proposed route is provided in table 3.6.2-1.

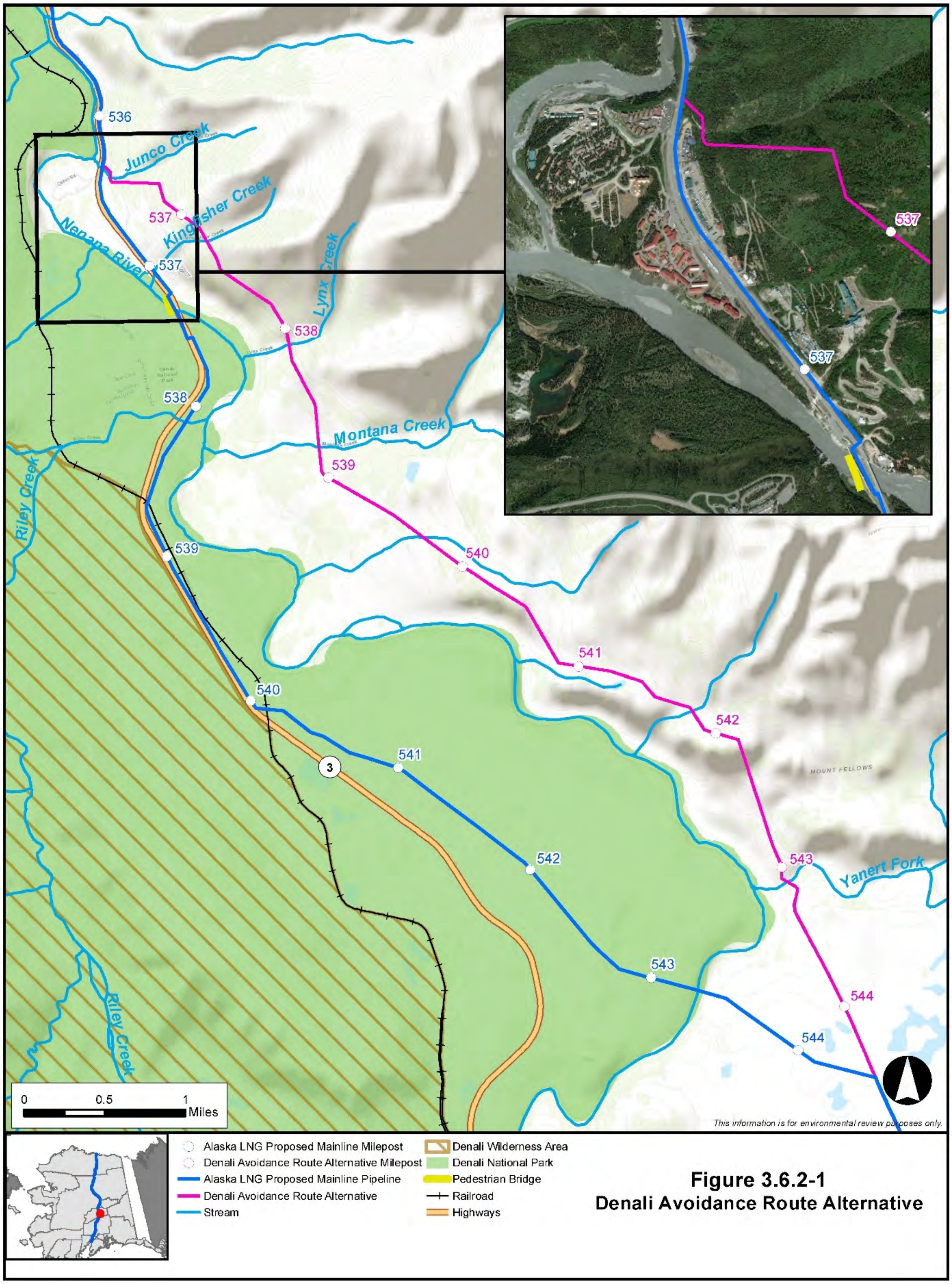


Figure 3.6.2-1
Denali Avoidance Route Alternative

TABLE 3.6.2-1

Comparison of the Denali Avoidance Alternative with the Corresponding Segment of the Proposed Route

Environmental/Engineering Factor	Proposed Route	Denali Avoidance Alternative
Length (miles)	8.5	8.1
Length adjacent to existing right-of-way (miles [percent])	3.9 (46)	0 (0)
New access roads (miles)	0.5	2.7
Land disturbed during construction (acres) [a]	137.7	119.7
Active fault crossings (number)	1	1
Potential slope stability hazards (miles)	0.3	3.0
DNPP crossing (miles)	6.1	0
Residential or commercial buildings within 150 feet of the centerline (number)	76	3 [b]
Forested land crossed (miles)	6.4	5.2
Wetlands crossed (miles)	0.4	2.2
Wetland impacts from pipeline construction (acres)	14.1	64.0
Waterbodies crossed (number)	6	7
Waterbody crossings >100 feet in width (number)	2	0
Cultural resource sites within construction right-of-way (number) [c]	0	3 [d]
Threatened and endangered species affected (number)	0	0
Important Bird Areas crossed (number)	1	1

[a] Includes construction right-of-way and access roads.
[b] Estimate based on aerial photography.
[c] Based on field surveys of route segments where access was granted.
[d] One of the three sites is recommended as eligible for listing on the NRHP. Does not include one NRHP-eligible site along an access road.

The Denali Avoidance Alternative is about 0.4 mile shorter than the proposed route. About 46 percent of the length of the proposed route is adjacent to existing infrastructure (e.g., the Parks Highway), whereas the Denali Avoidance Alternative is greenfield. The Denali Avoidance Alternative would require 2.2 more miles of new access road construction than the proposed route, which would increase the amount of disturbance and granular fill needed for construction.

The Denali Avoidance Alternative crosses the Nenana Canyon area, including about 3.0 miles of steep terrain with potential slope hazards, such as landslides, earth flows, rock falls, and debris flows. In contrast, the proposed route is mostly within the Nenana River valley, crossing only 0.3 mile of potentially unstable slopes. The remoteness of the route alternative and crossing of steep, rocky terrain would require specialized construction methods. The proposed route would largely avoid construction in these areas.

Both the Denali Avoidance Alternative and the proposed route would cross the seismically active Park Road Fault. The alternative route would cross the fault at Lynx Creek, and the proposed route would cross the fault adjacent to the Parks Highway within or near the Nenana River floodplain. Both fault crossings would use aboveground designs similar to those on TAPS.

The Denali Avoidance Alternative avoids the DNPP, unlike the proposed route, which crosses about 6.1 miles within the park. Under provisions of the Denali Park Improvement Act (Public Law 113-33 [as amended by Public Law 116-9]), the Secretary of the Interior may issue a right-of-way permit for a high-pressure natural gas transmission pipeline in non-wilderness areas within the DNPP boundary if the right-of-way is “the route through the Park with the least adverse environmental effects for the Park.”

AGDC's cultural resources investigations along the Denali Avoidance Alternative identified three sites within the pipeline construction right-of-way. Of these, one site is NRHP eligible and two sites are not eligible. AGDC also identified one NRHP eligible site that could be affected by new access roads associated with the Denali Avoidance Alternative. With respect to the corresponding segment of the proposed route, the SHPO indicated that the area around the entrance to the DNPP contains over 50 known prehistoric and historic cultural resources. However, AGDC conducted cultural resources surveys on NPS, State of Alaska, and Alaska Railroad lands along the proposed route in this area, and no sites were identified within the DNPP. Some segments of the proposed route on private or Denali Borough property (about 1.5 miles or 18 percent of the route) have not yet been surveyed for cultural resources (see section 4.13).

The Denali Avoidance Alternative would cross one more waterbody than the proposed route. The alternative route would avoid the Nenana River, but would cross seven incised tributary streams in the rugged topography above the Nenana River valley. The proposed route would cross the Nenana River in two locations, although only one of these crossings would affect the river during construction. The northernmost crossing of the Nenana River along the proposed route would span the river on an existing pedestrian bridge, encased in a box truss suspended between the bridge piers.

Based on field investigations,[9] the Denali Avoidance Alternative would cross 2.2 miles of wetlands and have permanent wetland impacts of 64.0 acres, including access roads. The proposed route crosses 0.4 mile of wetlands, and would affect a total of 14.1 acres of wetlands, including access roads. Both routes would traverse the Alaska Range Foothills State Important Bird Area (IBA), which contains large numbers of nesting golden eagles, gyrfalcons, and other nesting birds. No unique or special habitats or rare plant populations were identified along either route.

With respect to recreational uses, construction along the Denali Avoidance Alternative would have less impact than the proposed route due to the latter's temporary traffic disruptions and the increase in noise in an area with relatively high recreational use. Additionally, the area of the DNPP crossed by the proposed route has been proposed for recreational trail development since 1997. The Denali Avoidance Alternative would not create a corridor within the DNPP, so unlike the proposed route, it would not alter the range of options available to the NPS for planning recreational opportunities, including trails.

The Denali Avoidance Alternative passes east of the Parks Highway, and construction along this route would not directly affect traffic. In contrast, about 5 miles of the proposed route adjacent to the Parks Highway would be affected during construction by the need to use part of the road for workspace. AGDC estimates that traffic would be limited to one lane along this 5-mile-long stretch of highway during construction from September to May, with intermittent closures of several hours for specific construction activities such as blasting. This restriction would mostly avoid traffic constrictions during the peak of the tourist season, which generally extends from May 15 to September 15. The existing pedestrian bridge across the Nenana River would be closed to pedestrian traffic for about 2 months during pipeline construction.

The Denali Avoidance Alternative is located away from concentrations of residential and commercial establishments in the DNPP, and would have minimal temporary disruptions to commercial and residential activities and associated recreational experiences. The Denali Avoidance Alternative route centerline is within 150 feet of 3 residential or commercial buildings, whereas the proposed route lies within 150 feet of 76 residential and commercial buildings along the Parks Highway just north of the pedestrian bridge. Residents and visitors to the commercial establishments along this segment of the proposed route would experience noise, construction emissions, visual impacts, and traffic delays during the construction period. Although most construction activities would take place during the off-peak tourist season, any

[9] AGDC used the field target sampling method, the same method used for the rest of the Project, as described in section 4.4.1.2.

businesses that are open during this period would be affected by construction and could experience periods of restricted access.

Visual impacts would occur along both the Denali Avoidance Alternative and the proposed route. During construction, there would be noticeable contrast due to bare ground exposure, vegetation removal, the presence of construction workers and vehicles, and construction materials storage. Long-term visual impacts would result from vegetation maintenance within the permanent right-of-way as well as landform changes, including earthwork and rock formation alteration.

AGDC worked with the NPS to perform a visual resources inventory (VRI) and assess scenic qualities and values from key observation points (KOP) within the DNPP. AGDC then produced simulations of the views as they would appear with the pipeline along both the Denali Avoidance Alternative and proposed route. The analysis used a methodology that combined the NPS VRI for visual resources inside the DNPP and BLM's Visual Resources Management (VRM) methods for visual resources beyond the park. The analysis identified KOPs from which the pipeline right-of-way could be seen along either route. Utilizing either the NPS or BLM methodologies, views from these KOPs were rated according to their quality, importance, and scenic inventory value. Based on these ratings, and the visibility of the pipeline right-of-way from each KOP immediately after construction (i.e., before the right-of-way has revegetated) and post-reclamation, visual impact ratings were assigned. The visual assessment for the Denali Avoidance Alternative is provided in appendix E; the visual assessment for the proposed route is provided in appendix S.

Table 3.6.2-2 summarizes the conclusions of the comparative visual analysis. Two KOPs (Government Hill and Mt. Healy Overlook Trail Summit) are classified as having very high scenic inventory value and one (Triple Lakes Trail) is classified as having a high scenic inventory value. The Denali Avoidance Alternative would have greater visual impact than the proposed route from each of these KOPs. Two other KOPs (Railroad Above Horseshoe Lake and South of Parks Highway MP 236) are classified as having medium scenic inventory value. The Denali Avoidance Alternative would have less visual impact on the former and greater visual impact on the latter relative to the proposed route.

TABLE 3.6.2-2

Visual Impact Comparison of the Denali Avoidance Alternative with the Corresponding Segment of the Proposed Route

KOP	Scenic Quality [a]	View Importance [b]	Scenic Inventory Value	Proposed Route Visual Impacts: After Construction	Proposed Route Visual Impacts: After Reclamation	Denali Avoidance Alternative Visual Impacts: After Construction	Denali Avoidance Alternative Visual Impacts: After Reclamation
Denali Park Road	C	4	Low	Low	Low	Low	Low
Government Hill	A	3	Very High	Low	Low	High	Moderate
Railroad Above Horseshoe Lake	B	4	Medium	Low	Low	Moderate	Low
Mt. Healy Overlook Trail Summit	B	2	Very High	Moderate	Low	High	Moderate
Triple Lakes Trail	B	3	High	None	None	Low	Low
Nenana River Pedestrian Trail	C	4	Low	High	Moderate	Low	Low
South of Parks Highway, MP 236	B	4	Medium	Moderate	Moderate	Low	Low

[a] The NPS VRI system assigns a letter grade for overall Scenic Quality, based on ratings for individual scenery components. Scenic Quality ratings range from A (highest quality) to E (lowest quality).

[b] The NPS VRI system assigns a numerical ranking for overall View Importance, based on ratings for individual aspects of the view. View Importance ratings range from 1 (highest importance) to 5 (lowest importance).

In summary, the Denali Avoidance Alternative presents some advantages as well as disadvantages over the proposed route. It would avoid the proposed route's temporary disruptions and inconveniences on the recreation-oriented businesses along the Parks Highway and on recreational users and drivers on the Parks Highway during construction. Long-term impacts on recreational infrastructure development near the proposed route would not occur. The centerline of the alternative route would pass within 150 feet of only 3 residential or commercial buildings compared to 76 along the proposed route. The Denali Avoidance Alternative would also avoid an open-cut crossing of the Nenana River. The Denali Avoidance Alternative avoids the DNPP, but as noted above, the Denali National Park Improvement Act would allow for construction of a natural gas pipeline in the DNPP.

Among the Denali Avoidance Alternative's disadvantages are that it would not lie within or adjacent to any existing transportation corridors and would require 2.2 more miles of new access roads, cross 2.7 more miles of unstable slopes, and affect 49.9 more acres of wetlands than the proposed route. AGDC has stated that while the Denali Avoidance Alternative is technically feasible, the proposed route has engineering and constructability advantages over the Denali Avoidance Alternative, principally due to the latter route's rugged terrain and crossings of potentially unstable slopes. On balance, we conclude that the selection of either the proposed route or the Denali Avoidance Alternative would be acceptable, without significant environmental advantages from either. As the overall impacts are comparable, we conclude that the Denali Avoidance Alternative would not provide a significant environmental advantage over the proposed route.

3.6.3 Fairbanks Alternative

We received many comments during scoping recommending that the pipeline be routed nearer to Fairbanks, principally because this could increase the likelihood that natural gas would become available to its residents and businesses in the future. We received comments that a route alternative nearer Fairbanks would also avoid the extensive wetland complex in the Minto Flats SGR. As described in section 2.1.4, an interconnection is planned along the Mainline Pipeline to provide future natural gas deliveries to Fairbanks. We evaluated a route alternative that would locate the Mainline Pipeline closer to the City of Fairbanks, thereby shortening the length of any future interconnecting pipeline.

The Fairbanks Alternative begins at MP 401.7 near Livengood and proceeds southeast, generally following the Elliot Highway, to a point north of Fairbanks. From this location, the Fairbanks Alternative turns and proceeds southwest generally following the Parks Highway until it rejoins the proposed route at MP 471.3 north of Nenana (see figure 3.6.3-1). An environmental comparison of the Fairbanks Alternative to the corresponding segment of the proposed route is provided in table 3.6.3-1.

The Fairbanks Alternative would decrease the length of a future lateral to Fairbanks by about 25.7 miles, but it would increase the length of the larger diameter Mainline Pipeline by 37.5 miles, resulting in a greater overall environmental impact. For example, the total land disturbance of the Fairbanks Alternative, including the shorter lateral, would be about 370 acres greater than that of the proposed route and its required lateral.

Table 3.6.3-1 shows that the Fairbanks Alternative would affect a greater number of wetlands and waterbodies than the corresponding segment of the proposed route. While a future lateral off the Fairbanks Alternative would be significantly shorter and affect less wetland acreage than a lateral to Fairbanks off the proposed route, the overall wetland impacts (i.e., combining the mainline and future lateral impacts) would still be about 36 acres less using the proposed route.

The Fairbanks Alternative would avoid the Minto Flats SGR, which is crossed by the proposed route for 22.0 miles. Neither the Minto Flats SGR nor the Tanana Valley State Forest prohibits pipeline crossings, provided that they are compatible with their management plans. Also, AGDC has made numerous minor route changes to reduce impacts on wetlands through this area.

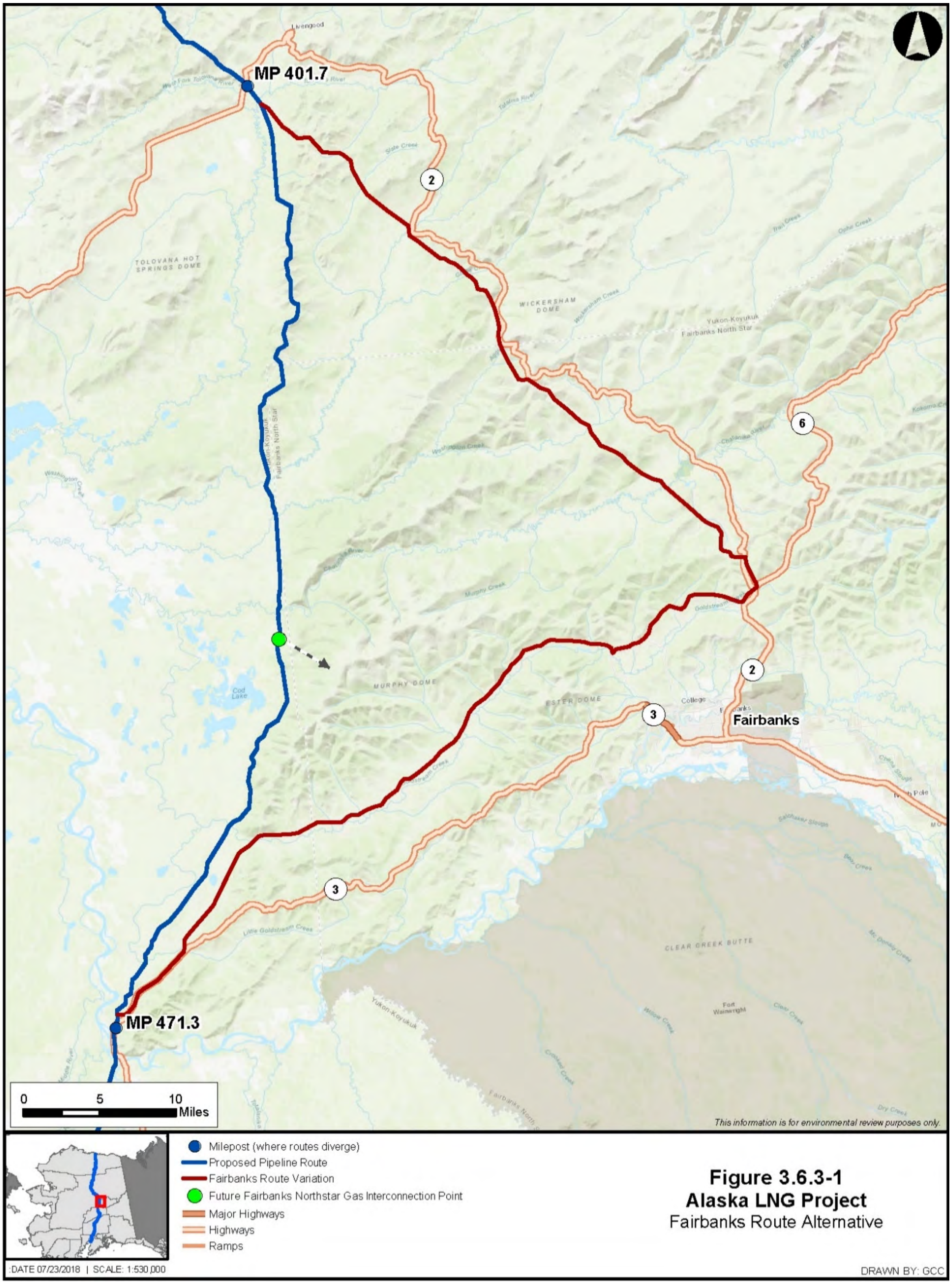


Figure 3.6.3-1
Alaska LNG Project
Fairbanks Route Alternative

TABLE 3.6.3-1

Comparison of the Fairbanks Alternative to the Corresponding Segment of the Proposed Route

Environmental/Engineering Factor	Proposed Route	Fairbanks Alternative
Length of Mainline Pipeline (miles)	69.6	107.1
Land disturbed for Mainline Pipeline construction [a] (acres)	1,265	1,947
Forested land crossed (miles)	58.1	64.2
Wetlands crossed (miles)	22.9	29.3
Wetlands disturbed (acreage) [a]	416.4	532.7
Minto Flats SGR crossed (miles)	22.0	0
Waterbodies crossed (number)	36	57
Approximate length of lateral to Fairbanks (miles)	30.0	4.3
Land disturbed for lateral construction [b] (acres)	364	52
Wetlands disturbed for lateral construction (acres)	86.6 [c]	6.0
Total wetland disturbance (Mainline and Lateral) (acres)	**503.0**	**538.7**
Total land disturbance (Mainline and Lateral) (acres)	**1,629**	**1,999**

[a] Based on a 150-foot-wide construction right-of-way.
[b] Based on a 100-foot-wide construction right-of-way.
[c] Based on the ASAP Project EIS's estimate of 6.9 miles of wetlands crossed by a lateral to Fairbanks, whose mainline tap is at the same location as the proposed Project's interconnect for a future lateral to Fairbanks.

In comments on the draft EIS, the USFWS said that the Fairbanks Alternative may affect less quality wildlife habitat than the proposed route. For example, the USFWS indicates that the proposed route would cross sensitive habitat for fish and wildlife through the Lower Tolovana Watershed, while the Fairbanks Alternative would not.

While the Fairbanks Alternative would avoid the Minto Flats SGR, this would be offset by the additional impacts on land, water, and other resources that would result from the longer Fairbanks Alternative. For these reasons, the Fairbanks Alternative does not provide a significant environmental advantage over the proposed route.

3.7 MAINLINE PIPELINE ABOVEGROUND FACILITY ALTERNATIVES

3.7.1 Aboveground Pipeline Alternative

Based on scoping comments from the USFWS, we evaluated the alternative of building the Mainline Pipeline aboveground on the Arctic Coastal Plain. The USFWS initially expressed concerns regarding the proposed pipeline installation method of trenching on the Arctic Coastal Plain (i.e., the first 60 miles of the route), including the risk of trench subsidence, ponding over the line, draining of adjacent wetlands, and bank thawing/erosion at river crossings. As the USFWS received more detailed Project information, they expressed concerns regarding trenching on thaw-sensitive permafrost along the entire length of the proposed pipeline, not just on the Arctic Coastal Plain. While the Aboveground Pipeline Alternative discussed below considers an aboveground Mainline Pipeline across the Arctic Coastal Plain, the general issues associated with an aboveground design (e.g., condensation of the gas stream) are applicable to other potential aboveground configurations as well.

For the first 60 miles, the Aboveground Pipeline Alternative would be placed on VSMs installed at about 50-foot intervals along the right-of-way, upon which the pipeline would be placed a minimum of

7 feet above the ground to allow for wildlife passage. The aboveground pipeline would also be wrapped in insulation.

The Aboveground Pipeline Alternative and the proposed buried pipeline would both require a standard construction right-of-way width of 145 feet. Both would be constructed during the winter season and employ ice pads, frost packing, and ice roads to avoid disturbing the tundra surface and the permafrost layer. Consequently, direct permafrost disturbance would be limited to the trenchline for the proposed installation method and to the VSM footings for the Aboveground Pipeline Alternative. The proposed winter construction for the buried pipeline would minimize ground disturbance to the 5-foot-wide trenchline and maintain existing surface water channels in their natural flow path.

Environmental benefits of the Aboveground Pipeline Alternative are principally associated with reducing disturbance to the permafrost during construction. The aboveground alternative would limit permafrost disturbance to the individual VSM sites, of which AGDC has estimated would number about 6,000. Each VSM would have a footprint of about 13 square feet, or 26 square feet if dual-base VSMs are utilized. AGDC estimates that 2 acres of permafrost would be permanently affected by the VSMs. The proposed route would have no permanent effects, but would impact about 36 acres of permafrost temporarily during construction.

The Aboveground Pipeline Alternative would require a slightly larger (0.5-acre or less) footprint at the Sagwon Compressor Station to accommodate tankage and equipment associated with collecting natural gas liquids that could form in the pipeline. The Aboveground Pipeline Alternative would have a greater visual impact than the proposed buried pipeline, although it would not traverse highly visually sensitive areas.

The Aboveground Pipeline Alternative and VSMs would also permanently disturb the viewshed for wildlife. Although design elements would lessen effects, it is not known if the Aboveground Pipeline Alternative would influence migration corridors. The migration corridors for some species, especially caribou, are critically important for subsistence users.

AGDC indicates that an aboveground pipeline is likely to experience operational difficulties during winter shutdowns or other operational upsets. The low ambient temperatures under such conditions would cause some of the heavier hydrocarbons in the gas to liquefy, which would settle in low spots in the line. The liquid would need to be moved down the line by carefully controlling the gas velocity and then removed by liquid handling equipment at the compressor stations. AGDC indicates that this procedure could result in shutdowns of days or weeks, creating disruptions at the Liquefaction Facilities.

With respect to safety and security, the Aboveground Pipeline Alternative would be more exposed to accidental and intentional damage than the proposed buried pipeline design. For example, during its lifespan, the aboveground TAPS pipeline has experienced bullet strikes and terrorism threats.

The Aboveground Pipeline Alternative, while technically feasible, is not technically practical due to the risk to normal commercial facility operations posed by condensation of the gas stream. Although the Aboveground Pipeline Alternative would reduce permafrost impacts, other considerations such as operational reliability lead us to conclude that the Aboveground Pipeline Alternative is not a technically practical alternative. Further, we conclude that the estimated additional 34 acres of permafrost avoided by the alternative is not a significant environmental advantage to the proposed construction method.

3.7.2 Compression Alternatives

To reduce noise levels and air emissions, we examined the feasibility of using electric-driven compressors as an alternative to gas-fired, turbine-driven compressors at the proposed Mainline Pipeline compressor stations. An advantage of electric-driven compressors is their potential to reduce emissions. Although the proposed gas turbine compressors would comply with ambient air quality standards, using electric-drive compressors at each station individually, and at all stations taken together, would eliminate air emissions from natural gas combustion. However, the overall air quality benefit of this would depend on how the electricity for the electric-driven compressors is generated. For the Project, the electricity would likely be generated by older coal- and oil-fired power plants in central Alaska. Because coal and oil combustion emits more pollutants than natural gas, the overall air quality benefits favor the proposed gas-fired turbine design. Even if the coal- and oil-fired power plants were eventually converted to burn natural gas, energy losses during electricity transmission from the power plant to the compressor stations would require more power to be generated relative to on-site gas-fired turbines, with associated air quality impacts. Finally, the environmental impacts of new electric transmission lines to reach up to eight compressor station sites, many of which are in remote locations, as well as expanded compressor station footprints to accommodate substations, would be incremental to the impacts of the proposed design.

In summary, electric-driven compressors would not provide a significant environmental advantage over the proposed gas-fired, turbine-driven compressors.

3.8 LIQUEFACTION FACILITIES ALTERNATIVES

In response to comments received during scoping, we evaluated several alternative sites for the liquefaction facilities, as well as alternative dredged material disposal locations for construction of the proposed Liquefaction Facility site at Nikiski. Certain alternative site concepts did not receive detailed consideration, as discussed below. We received numerous comments requesting that we evaluate an alternative mainline pipeline route that follows the existing TAPS pipeline right-of-way from Livengood, Alaska, to an LNG terminal site on Anderson Bay, Valdez, Alaska. Some commenters suggested that following the existing TAPS right-of-way would reduce overall impacts by avoiding the creation of new right-of-way through sensitive habitat and by using the existing TAPS access roads and construction camps. We have included an evaluation of an alternative mainline pipeline route following the TAPS right-of-way below, as part of the Anderson Bay LNG terminal site alternative discussion.

Other comments suggested placing the Liquefaction Facilities closer to the gas production areas on the North Slope. Concerns were also identified regarding safety of operating LNG carriers in Cook Inlet due to ice and tidal conditions.

Siting the LNG facility on the North Slope is not technically practical for the reasons described below.

- The annual ice-free window is only about 2 to 3 months, which would limit LNG shipping without specialized ice-breaking LNG carriers and require marine terminal facilities capable of withstanding Arctic ice conditions.

- The Beaufort Sea is shallow near the shoreline and does not reach the minimum water depth (60 feet) necessary to accommodate the draft of LNG carriers until about 20 miles offshore. As a result, either the loading facility or a dredged channel would need to be extended to reach the required water depth.

- Construction of the Liquefaction Facilities and GTP requires module delivery to both sites at the same time. With both sites on the North Slope, this would not be possible without construction of additional docking facilities.

Other potential LNG sites beyond the Cook Inlet-to-Prince William Sound area, such as in northwestern or western Alaska, were not considered reasonable alternatives to the proposed Liquefaction Facilities location, due to ice-cover restrictions as described above, or for the additional reasons described below.

- Infrastructure to support facility construction and operation (such as roads, railroads, or lodging) does not exist. Infrastructure would need to be constructed prior to mainline pipeline construction, which would lengthen the schedule and significantly increase environmental impacts.

- Routing a mainline pipeline to reach sites in northwestern or western Alaska shorelines would encounter numerous environmentally sensitive areas, such as wilderness areas, wildlife refuges, national parks, and national preserves. Significant support infrastructure (e.g., transportation facilities, work camps, borrow sites) would need to be built, and a new corridor would need to be established through relatively undeveloped areas.

3.8.1 Liquefaction Facilities Site Alternatives

During the initial siting process, AGDC focused on identifying an 800- to 1,200-acre location with waterfront access as well as the suitable terrain, geology, zoning, water depth, and supporting infrastructure to support an LNG export terminal. AGDC subsequently reduced the minimum site sizes for the alternative site locations to 400 acres, based on design work done for the proposed site at Nikiski.

After evaluating and eliminating the north and western shoreline of Alaska from further consideration, AGDC identified 24 possible LNG facility sites. Applying additional screening criteria, AGDC narrowed the list of potentially suitable locations to seven sites in south-central Alaska. This additional screening criteria included pipeline length to reach the site, availability of existing infrastructure, proximity to populated areas, site preparation characteristics, geologic hazards, potential for vessel conflicts, land-use conflicts, known environmental sensitivities, and permitting complexity. We concur that the screening criteria used by AGDC is reasonable, with the exception of its use of permitting complexity as a significant siting criterion.

We evaluated the seven site alternatives identified by AGDC. To meet the stated Project objectives, we applied screening criteria to identify which sites would be most reasonable and likely to provide some environmental advantage over the proposed Liquefaction Facilities site. The pipeline associated with each site alternative was also considered as part of the comparative evaluation. Our screening criteria are described below.

- Property Size and Availability – Based on the proposed design, the size of the waterfront site should be at least 400 acres to accommodate the liquefaction trains, storage tanks, and vessel loading facilities. It should be noted that unlike a pipeline under Section 7 of the NGA, an authorization granted under Section 3 of the NGA does not grant the applicant eminent domain. Therefore, the property must be available for purchase or lease.

- Waterfront Access – For facilities in Cook Inlet, as compared to other LNG terminals in the Lower 48, the naturally high current and extreme tidal ranges of Cook Inlet need to be considered when designing safety buffers (e.g., berth spacing and depth). In consultation with the Coast Guard and members of the Cook Inlet Harbor Safety Committee, the

Southwest Alaska Pilot's Association (2017) issued guidelines for transiting Cook Inlet, including a recommendation for an under-keel clearance of at least 10 feet. In consideration of these factors, AGDC determined that a minimum depth of 53.5 feet was required for safe transit and berthing in Cook Inlet.

Additional siting considerations included proximity to existing infrastructure, ice conditions, avoidance of geological hazards, and compatible existing land uses (i.e., industrial or commercial sites). The general locations of the seven alternatives along with the proposed site are shown on figure 3.8.1-1. A comparison of the alternatives to the proposed Project is presented in table 3.8.1-1.

3.8.1.1 Port Valdez Alternative Sites

Anderson Bay

The Anderson Bay site is adjacent to Prince William Sound within the Valdez city limits on a 464-acre greenfield parcel owned by the State of Alaska and managed by the ADNR (see figure 3.8.1-1). One advantage of the Anderson Bay Alternative is that the mainline pipeline required to reach the Anderson Bay site would lie within or adjacent to the TAPS corridor for all or most of its length from Livengood to the TAPS terminal at Valdez. In contrast, only about 190 miles (23 percent) of the proposed Mainline Pipeline would lie adjacent to transportation corridors or within BLM-designated utility corridors. This would allow for some reductions of impacts on previously undisturbed areas, although it should be noted that a new pipeline paralleling TAPS would not share the same right-of-way, and that many ancillary areas utilized during construction of TAPS have, 40 years later, been restored.[10]

A pipeline to the Anderson Bay site would be comparable in length to the proposed Mainline Pipeline, but would avoid crossing Cook Inlet. This would avoid the specialized construction techniques required to cross Cook Inlet and associated impacts on designated critical habitat for the Cook Inlet beluga whale, which is an advantage relative to the Project.

The Anderson Bay mainline pipeline, unlike the proposed Mainline Pipeline, would cross two federally designated WSRs. However, we note that minor deviations from the TAPS corridor would likely avoid the areas within the WSR designations, so this is not considered a disadvantage for the Anderson Bay Alternative.

One disadvantage of the Anderson Bay pipeline route alternative compared to the proposed Mainline Pipeline is that potential future laterals from interconnection points for in-state deliveries of natural gas would require constructing an additional 113 miles of pipeline to reach markets in Fairbanks and Anchorage relative to the Project.[11] Assuming a standard right-of-way width of 100 feet, the additional length of the laterals would affect about 1,370 more acres of land and associated resources such as forests and wetlands than the future laterals associated with the Project.

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[10] In comments on the draft EIS, the City of Valdez requested that the alternatives analysis also compare miles of new access roads, acres of new work camps, and other data for the mainline pipeline associated with each alternative. The City of Valdez suggested that the proposed facilities for constructing the Trans-Alaska Gas System (as described in a 1988 EIS) could be used to compare the Anderson Bay Alternative with related information for the proposed Project. We have reviewed the referenced EIS and find that the construction information contained therein would not provide a basis for a reasonable quantifiable comparison with the Project. An EIS prepared 32 years ago (which considered rehabilitation of facilities utilized 12 years prior to publication of the EIS) would not yield reliable information for a quantitative comparison. Sites and facilities that may have been reasonably rehabilitated in 1988 for the Trans-Alaska Gas System have experienced more than 4 decades of change through regeneration, re-use, deterioration, etc. Therefore, we have provided a qualitative observation regarding the potential advantages of utilizing the TAPS corridor in this regard.

[11] Our analysis for this alternative does not include the length of a future lateral pipeline to the Kenai Peninsula. Insufficient information is available to speculate on a potential route for this lateral.

Figure 3.8.1-1
Alaska LNG Project
Liquefaction Facility Alternatives

TABLE 3.8.1-1

Comparison of Alternative Sites for the Liquefaction Facilities

	Cook Inlet					Port of Valdez		Resurrection Bay
Environmental / Engineering Factor	Proposed Site	Port MacKenzie	Cape Starichkof	Kasilof South	North Foreland	Anderson Bay	Robe Lake	Seward
Mainline Pipeline length (miles)	807	747	880	835	773	810	802	877
Waters of the United States within the LNG plant site (acres)	14	0	330	88	275	60	64	112
NWI-mapped wetlands affected by the mainline pipeline, Livengood to liquefaction site (acres [a])	1,473.8	1,159.0	1,836	1,721	1,263	1,596	1,605	1,604
Number of major waterbodies (>100 feet wide) crossed by the mainline pipeline, Livengood to liquefaction site	22	16	25	25	23	16	17	21
Beluga whale CHA 2 crossed by the mainline pipeline (miles) [b]	27	0	27	27	0	0	0	0
Beluga whale CHA 1 traversed by vessel traffic (miles)	0	29	0	0	0	0	0	0
Beluga whale CHA 2 traversed by vessel traffic (miles)	138	175	90	120	160	0	0	0
Approximate assumed pipeline lateral length to Fairbanks (miles)	30	30	30	30	30	7	7	30
Approximate assumed pipeline lateral length to Anchorage (miles) [c]	0	0	0	0	0	136	136	0
Approximate dredging required (cubic yards)	800,000	640,000–990,000 [d]	2,000,000	3,400,000	1,900,000	3,800,000 [e]	1,500,000	750,000
Existing land use	Mixed	Industrial	Greenfield	Greenfield	Mixed	Greenfield	Developed	Industrial
Number of residences displaced	16	0	23	13	0	0	142	0
Number of displaced industrial/commercial facilities	10	0	4	0	0	0	2	15
Residences within 100 feet of the mainline pipeline [f]	1	1	125–175	25–75	0	1–5	1–5	150–200
Road relocation necessary	Yes	No	Yes	Yes	No	No	Yes	No

[a] Based on an assumed 100-foot construction right-of-way.

[b] No beluga whale CHA 1 would be affected by mainline pipeline construction for the proposed Project or any of the alternatives.

[c] The proposed in-state gas interconnection at MP 764 would allow connection with an existing ENSTAR pipeline, so gas could be delivered to Anchorage without a new lateral pipeline. We have assumed the mainline pipeline associated with the Port Mackenzie site would also intersect the ENSTAR system, about 10 miles north of the site.

[d] Values are based on AGDC's estimate of 290,000 cubic yards of dredging for MOF construction, plus between 350,000 and 700,000 cubic yards of dredging annually across Knik Shoal to accommodate passage of two vessels and lower the depth to 50 feet. MSB has conducted its own engineering analysis and concluded that Marine Terminal MOF dredging would require only about 91,500 cubic yards. Applying MSB's estimate would reduce the total estimated dredging to between 441,000 and 791,500 cubic yards.

[e] This number represents the estimated volume of overburden removed from the site that would require disposal, either as fill in the sound or off-site disposal.

[f] Estimate is based on aerial interpretation of individual residences.

In comments on the draft EIS, the City of Valdez said that impacts from future pipeline laterals should not be included in our analysis. Because in-state delivery of natural gas is an objective of the Project, we considered in our comparative evaluation of alternatives the distances for which new pipeline laterals would have to be built to deliver gas to in-state markets and associated environmental impacts. The City of Valdez also said that the analysis in the draft EIS aggregated impacts from future pipeline laterals with those of the mainline pipeline alternative to Anderson Bay. The data provided in table 3.8.1-1 comparing the Mainline Pipeline route to the proposed liquefaction site and Mainline Pipeline route to the alternative liquefaction site near Valdez does not aggregate data as the comment suggests. The comparisons in the table are for mainline routes only, except that the table separately provides approximate distances for future pipeline laterals to Fairbanks and Anchorage, should these facilities be built to provide in-state natural gas deliveries.

Another disadvantage for the Anderson Bay alternative is that its mainline pipeline route would cross an exceptionally rugged stretch of terrain for about 5 miles where it traverses Thompson Pass northeast of Valdez. AGDC evaluated the feasibility of collocating the pipeline with the Richardson Highway and the TAPS corridor, which is the only existing mountain gap to reach Valdez. AGDC concluded that this corridor does not have enough space to build the pipeline using conventional methods. Consequently, either a new route would need to be identified across the Chugach Mountains or an alternative method of crossing the pass, such as tunneling or terracing, would be required. This would likely add significantly to the construction complexity, lengthen the construction schedule, and increase environmental impacts.

With respect to the Anderson Bay site itself, liquefaction facilities at this location would require extensive civil design work and terracing, as well as construction of a new access road approximately 3.5 miles long to reach the site. From the shoreline, the topography rises steeply to an elevation of 2,500 feet. Site preparation would involve blasting, excavating, grading, and terracing the site to create level surfaces for the proposed facilities.

AGDC initially estimated that 39 million cubic yards of overburden and rock would need to be removed for preparation of the site. Based on comments from the City of Valdez on the draft EIS, we asked AGDC to re-examine this estimate. In response, AGDC revised its estimate to 9.7 million cubic yards of overburden and rock that would need to be excavated, of which about 3.9 million cubic yards would be in excess of what could be utilized at the site. This material would likely be disposed of in Anderson Bay.[12] If utilized as fill in the bay, for example to form the base for the Marine Terminal MOF, benthic habitat in the affected area would be permanently lost. There would also be temporary impacts on aquatic species, including increased turbidity during fill placement on the seabed. This contrasts with the proposed site, which would require dredging and disposal of 800,000 cubic yards of sediment for the Marine Terminal MOF. Thus, while the Anderson Bay Alternative would avoid impacts associated with construction of a pipeline across Cook Inlet, development of the Anderson Bay liquefaction site would result in greater marine impacts than development of the proposed site.

Development of the Anderson Bay site would increase the filling and loss of wetlands from 14 acres (at the proposed site) to 60 acres (at the Anderson Bay site), and require the filling or rerouting of an anadromous stream.

AGDC identified other constraints regarding the use of the Anderson Bay site. The entrance into the Port of Valdez would be through the Valdez Narrows, which is less than 1 mile wide. After being loaded with LNG, a safety zone would be established around LNG carriers, which would restrict other

[12] The topography at the Anderson Bay site makes it unlikely that this volume of material could be disposed of along the shoreline at the site, as has been suggested in the City of Valdez' comments.

vessel traffic through the Valdez Narrows or prevent the LNG carrier from exiting into Prince William Sound until vessel traffic cleared. The Hinchinbrook Entrance to Prince William Sound would have similar safety zones and constraints. AGDC indicated that unexpected delays or uncertainty in vessel transit would be greater than with the proposed site.

For the reasons described above, the Anderson Bay site would not provide a significant environmental advantage over the proposed site.

Robe Lake

The Robe Lake site is a 968-acre developed parcel south of Old Valdez, about 3 miles east of Port Valdez (see figure 3.8.1-1). The site is bordered to the north by Corbin Creek; to the east by forest and the Chugach Mountains; to the south by Robe Lake; and to the west by a residential development, Richardson Highway, and Port Valdez.

Except for the last 8 miles, the mainline pipeline route for the Robe Lake Alternative is the same as for the Anderson Bay Alternative. With respect to the pipeline, therefore, the impact comparisons with the proposed Project are similar to that discussed above for Anderson Bay.

Development of liquefaction facilities at the Robe Lake site would require relocation of the Richardson Highway and several residential developments. It would also require importation of about 4 million to 13 million cubic yards of fill to raise the site above potential tsunami wave heights. In addition, the PLF at the Robe Lake site would need to extend about 1 mile from the shoreline to reach a water depth of 60 feet. This would increase the amount of dredging required for the Project by 700,000 cubic yards. The site would face shipping constraints similar to those for the Anderson Bay site. Lastly, the Robe Lake site would require the displacement of substantially more residences (142) than would the proposed site (16).

For the reasons stated above, the Robe Lake site would not provide a significant environmental advantage to the proposed site.

3.8.1.2 Seward Alternative Site

The Seward site is a 559-acre industrial parcel on the east shore of Resurrection Bay near Seward, Alaska (see figure 3.8.1-1). The site is currently occupied by the Seward Industrial Marine Center (SIMC), which is owned by the City of Seward and used for the upland storage and maintenance of marine vessels. In addition to SIMC, 15 tenants currently occupy the site providing services ranging from marine vessel maintenance and repair, fabrication, and logistics services facilities and operations, to maritime vocational training programs. Alaska's Department of Corrections operates a 65-acre facility adjacent to the SIMC (SIMC, 2016).

The Seward site would require dredging 50,000 cubic yards less sediment than the proposed site. However, the Seward site development would also require filling 98 more acres of wetlands and waterbodies than the proposed site.

The length of mainline pipeline needed to transport gas to a site at the Seward location would be about 70 miles longer than for the proposed Project. Assuming a standard right-of-way width of 150 feet, this would result in about 1,270 acres of additional ground disturbance and require 49,012 hp of additional compression with associated air quality impacts. The pipeline route to the Seward site would also cross the Chugach National Forest.

Based on our comparison, the Seward Alternative site would not provide a significant environmental advantage to the proposed site.

3.8.1.3 Cook Inlet Alternative Sites

Port MacKenzie

The Matanuska-Susitna Borough (MSB) requested an evaluation of an alternative liquefaction facility site north of Anchorage near Port MacKenzie on the west bank of the Knik Arm in Cook Inlet (see figure 3.8.1-1). The configuration initially identified by AGDC would locate most of the liquefaction facilities about 2 miles from the shoreline. This location consists almost entirely of wetlands, based on NWI data. According to AGDC, the distance of the site from the shoreline would also present significant design, construction, and operational challenges; therefore, we did not analyze this site in detail.

A second configuration, which is the one analyzed in this section, would locate the liquefaction facilities near the shoreline in proximity to marine facilities. This location would reduce wetland impacts associated with the liquefaction facilities by 10 acres compared to the proposed site at Nikiski. Up to 4 additional acres could be avoided by shifting the site slightly northward or by configuring the facilities to avoid this wetland. The MSB indicated that shifting the site to the north about 0.1 mile would be optimal from an environmental standpoint, and so this adjustment to the location of the alternative site was adopted.

The MSB submitted comments on the draft EIS, many of which have been incorporated into our analysis in the final EIS. For example, the MSB indicated that the draft EIS underestimated the difference in wetland acreage impact estimates between the proposed Mainline Pipeline route to Nikiski and the alternative mainline pipeline route to the Port MacKenzie site. Based on our review of the additional information provided, we concur with this comment and have updated the wetland acreage estimates shown in table 3.8.1-1. Similarly, we have updated table 3.8.1-1 to show that no wetlands would be affected at the Port MacKenzie alternative liquefaction site alternative with the location adjustment recommended by the MBS, as discussed above. Other suggested changes to table 3.8.1-1 from the MSB appeared to be based on differences in the MSB's assumed route for the mainline pipeline to the alternative liquefaction site relative to the route used in our analysis. While these suggested changes were not adopted, they did not affect our overall conclusions regarding the alternative.

The Port MacKenzie Alternative would shorten the mainline pipeline route by almost 60 miles, which would reduce construction-related land disturbance by about 1,090 acres; eliminate one stand-alone heater station; avoid subsea pipeline construction within Cook Inlet; and avoid the need to relocate the Kenai Spur Highway (see section 4.19.2 for discussions regarding non-jurisdictional facilities).[13] Due to the shorter pipeline length, impacts on wetlands would be reduced by an estimated 315 acres and six fewer major waterbodies would be crossed.

The alternative mainline pipeline to the Port MacKenzie site would, like the proposed Project, connect to ENSTAR's distribution system, which serves the Municipality of Anchorage as well as the MSB and Kenai Peninsula Borough. Unlike the proposed Project, the Port MacKenzie Alternative would not allow for a future interconnect with an existing ENSTAR pipeline at the southern end of the system near MP 806 for gas delivery nearer to the Kenai Peninsula area. The Kenai Peninsula interconnect is one of three future delivery points that have been identified as an objective of the Project (see section 1.1).

In comments on the draft EIS, the MSB said that reversing flow in the ENSTAR pipeline system between Anchorage and the Kenai Peninsula would provide for service to the Kenai Peninsula area. We

[13] The Port MacKenzie Alternative would also eliminate the need to upgrade the City of Kenai's municipal water system; water supply infrastructure requirements, if any, for a liquefaction facility at Port MacKenzie have not been identified.

have no information regarding the feasibility or practicality of such an effort or of any system updates needed to do so. Additionally, we are unaware of any proposals by ENSTAR to reverse flow on its system. The MSB also said that an interconnection with the Kenai Peninsula should not be viewed as an objective of the Project. The three interconnects identified by AGDC address one of the Project objectives (see section 1.1), so the inability of the Port MacKenzie alternative to provide an interconnection on the Kenai Peninsula is a factor in our analysis.

In comments on the draft EIS, the MSB said that the Port MacKenzie Alternative would eliminate the need for an interconnect and future lateral to the Fairbanks area because LNG could be shipped from the alternative Port MacKenzie facility site to Fairbanks by rail or truck. We note that LNG is currently delivered to Fairbanks by truck; therefore, the MSB's suggestion would preserve the status quo with respect to gas service to Fairbanks. Our assumption for comparative purposes is that any of the alternative liquefaction facility sites and their associated pipelines would need to provide an interconnect that could service Fairbanks with a future pipeline lateral, so that LNG would no longer need to be shipped by truck (or by rail, should that become feasible in the future). The supplemental EIS for ASAP estimated future demand in Fairbanks at 30 MMscfd. Without a future pipeline lateral to Fairbanks, this demand would require an estimated 39 trucks per day on average.[14]

AGDC estimates that dredging to enlarge and maintain the ship channel across the Knik Shoal, which would be required to access the alternative liquefaction site, could range between 350,000 and 700,000 cubic yards annually. This volume of dredging is based on a widening of the shipping channel across Knik Arm shoal to accommodate the safe passing of two vessels and maintain the water depth at 50 feet MLLW. If channel widening is not performed (which could result in occasional delays for transiting LNG carriers), these volumes would be halved. The COE maintains the navigational channel across Knik Shoal. Historically, the COE has performed dredging when depths are less than 38 feet (COE, 2017a). Annual surveys indicate that channel depths have remained at or below 38 feet MLLW since dredging occurred in 2014. Consequently, annual maintenance dredging may not be necessary.

AGDC has indicated that the existing deepwater dock at Port MacKenzie could not accommodate LNG carrier vessels and would have to be demolished and rebuilt.[15] Demolition would involve undersea detonations at 60 piles. No dredging for vessel docking would be required, as the offshore area at the alternative terminal site is sufficiently deep. To allow for the existing barge dock to function as an MOF, AGDC estimates that expansions of that facility would require dredging of about 290,000 cubic yards and filling of approximately 268,000 cubic yards. Combined with AGDC's estimated dredging volumes across the Knik Shoal, total dredging would amount to between 640,000 and 990,000 cubic yards.

The MSB has conducted its own engineering analysis and estimates that dredging for a marine terminal MOF would require only about 91,500 cubic yards.[16] Combining MSB's estimate with estimated dredging volumes across the Knik Shoal would reduce the total estimated dredging to between 441,500 and 791,500 cubic yards. The MSB did not specify any fill requirements. Given the range of the dredging estimates, actual dredging associated with the Port MacKenzie Alternative could either be more or less than the estimated dredging volume (800,000 cubic yards) for the proposed Project. For this reason, and given that impacts from the dredging would be temporary, we have not weighed dredging volumes in our consideration of the Port MacKenzie Alternative.

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14 Based on a truck LNG capacity of 9,300 gallons.

15 AGDC indicates that reconstruction of the existing deepwater dock would still be necessary with the 0.1 mile northward shift of the liquefaction site, as recommended by the MSB. In comments on the draft EIS, the MSB said that "the existing 'deepwater dock' exceeds the MOF capabilities required by AGDC, so no reconstruction is necessary."

16 In comments on the draft EIS, the MSB revised its dredging estimate from 257,000 to 91,500 cubic yards.

The marine improvements required at the Port MacKenzie alternative site would occur within CHA 1 for the federally listed Cook Inlet beluga whale, while improvements at the proposed Liquefaction Facilities site would occur within CHA 2. Potential beluga whale impacts from construction of the Mainline Pipeline across Cook Inlet would be avoided with the Port MacKenzie Alternative.

In comments on the draft EIS, the MSB suggested that ice conditions, and associated ice practices, should be viewed as more or less equivalent at Nikiski and Port MacKenzie. Ice conditions are historically more severe in upper Cook Inlet, creating the potential for increased risk to vessels. With an abundance of freshwater draining into Upper Cook Inlet, ice floes can form rapidly around river drainages where freshwater begins to mix with saltwater. The ice floes are then carried out with the tide. Ice conditions are a regular occurrence in Upper Cook Inlet from about the end of November through April, triggering a set of standardized best practices for additional bridge manning, line handlers, assist tugs, and other precautions that mitigate the risk to vessels and the environment (Coast Guard, 2018). In contrast, the portion of Cook Inlet south of the Forelands in the Nikiski area experiences ice conditions for a much shorter time frame from January through February, and some years not at all (Cook Inlet Harbor Safety Committee, 2017). Ice conditions would be anticipated to increase the risk of delays in vessel transit relative to the proposed site, which could impact the ability of the Project to meet the proposed export volumes.

AGDC has said that, unlike the proposed site, ice mitigation structures would likely be required at the Port MacKenzie site. These would consist of four octagonal concrete structures about 95 feet across that are set on the seabed and anchored with fill or pilings or both. The MSB indicated that due to improving ice conditions in the Port MacKenzie vicinity, ice mitigation structures may not be necessary. For the purposes of this comparison, we have assumed that the current conditions would persist and that ice mitigation structures would be necessary for safe operation. Ice mitigation structures would increase the footprint of the facilities by about 0.7 acre, contributing to seafloor disturbance.

In comments on the draft EIS, the MSB reiterated that we should not assume that ice mitigation structures would be necessary, because, as far as MSB is aware, there is no documentation that such structures would be needed to meet minimum marine safety guidelines. Even assuming this is the case, the operator of the facility would be responsible for designing a facility that effectively manages risks to its operations, which according to AGDC, would likely include ice mitigation structures. In any case, the impact footprint of ice mitigation structures is not consequential. Ultimately, the fact that they may be necessary is simply an additional consideration for marine navigation during the winter months.

The Port MacKenzie location adds about 130 miles to the round-trip distance between the liquefaction facility site and any destination port. According to AGDC, the increased distance would result in 12 additional vessel transits annually to meet proposed export volumes compared with the proposed Nikiski site (i.e., because each transit would require more time, more vessels would be required to ship the same amount of LNG within the same time frame).

Offshore approaches to the Port MacKenzie site lie within CHA 1 for the beluga whale and ships would be required to reduce their speed upon a whale sighting. The summer density of Cook Inlet beluga whales in Knik Arm is more than 300 times greater than the density offshore of Nikiski (0.05 beluga per square kilometer [km^2] vs. 0.000158 beluga/km^2) (Goetz, 2012). The difference in beluga whale summer densities between the Nikiski area and the northern Cook Inlet/Knik Arm is illustrated on figures 7.4.2-1 and 7.4.2-2 in the Project BA, which is provided as appendix O. In considering the higher beluga whale densities in addition to the greater distances/vessel transit times within Cook Inlet for Port MacKenzie, we estimate that there would be about an 80-percent higher probability of a whale strike from LNG carriers transiting to and from Port MacKenzie during operation. Consequently, beluga whale vessel strikes and other disturbances are more likely for the Port MacKenzie site, particularly if additional transits are necessary.

We received a comment that vessel strikes on Cook Inlet beluga whales are unlikely to occur for either the Project or Port McKenzie Alternative. In the *Recovery Plan for the Cook Inlet Beluga Whale* (NMFS, 2016a), NMFS acknowledged that no vessel strikes on Cook Inlet beluga whales have been confirmed, but identified vessel strikes as a risk to the species based on observed trauma to individual whales in which injuries were consistent with a vessel strike. NMFS identified two instances, one in 2007 and one in 2012, "where death by ship strike was highly probable given the blunt trauma sustained by the whales" (NMFS, 2016a). NMFS noted other instances of injuries or scarring observed on Cook Inlet beluga whales consistent with propeller injuries.

Cook Inlet beluga whales tend to travel in shallow areas, which limits their ability to avoid noise impacts associated with shipping traffic (Braund, 2016). Noise is noted to be a key factor in the health and distribution of Cook Inlet beluga whales. As discussed in section 7.4 of the BA (provided as appendix O), noise from Project vessels, including transiting LNG carriers, could reach level B harassment of Cook Inlet beluga whales (see section 4.6.3.2). Relative to the Project, the potential for noise impacts on Cook Inlet beluga whales would be higher for the Port McKenzie Alternative due to the increased LNG carrier traffic and longer vessel transits through Cook Inlet beluga whale habitat.

In comments on the draft EIS, the MSB said that the proposed Mainline Pipeline would affect both beluga whale CHAs 1 and 2 as well as the Susitna Delta Exclusion Zone.[17] The proposed Project facilities and vessel routes would only affect CHA 2, while the Port MacKenzie Alternative facilities would affect CHAs 1 (facilities and vessel routes) and 2 (vessel routes). The Project facilities would have construction activities in the Susitna Delta Exclusion Zone, but no operational activities would occur within this zone. Vessel traffic for the Port Mackenzie Alternative would regularly transit through the Susitna Delta Exclusion Zone. In addition, the Port Mackenzie Alternative is located within Knik Arm, which historically has had the highest concentration of Cook Inlet beluga whales, particularly during the summer months. With regard to LNG carrier transits during Project operation, vessels would travel about 33 miles through CHA 2. For the alternative site at Port MacKenzie, LNG carriers would travel about 68 miles through CHA 2 and 30 miles through CHA 1, for a total of 98 miles through Cook Inlet beluga whale critical habitat.

In comments on the draft EIS, the MSB disagreed with our conclusion that CHA 1 for Cook Inlet beluga whales would not be affected by Mainline Pipeline construction for the Project based on the MSB's interpretation of where the "action area" for the Project lies with respect to the habitat.[18] The action area extends 6 miles seaward for marine facilities and 6 miles for vessel routes. The action area for the proposed Project's pipeline construction does not extend into CHA 1. The Mainline MOF action area extends 6 miles seaward (east-southeast), and the boundary of CHA 1 is north of the MOF facility (see figure 7.4.1-2 in the BA (appendix O of the EIS); therefore, the proposed Project's action area would not lie within CHA 1.

In comments on the draft EIS, the MSB provided its own calculations of construction impacts for various facility components on Cook Inlet beluga whale critical habitat for the Project and the Port MacKenzie Alternative. We have reviewed these calculations relative to the mapped boundaries of Cook Inlet beluga whale CHAs. We determined that the impact calculations we provided in the draft EIS for Cook Inlet beluga whale CHAs were accurate, and these calculations form the basis of our analysis in this final EIS.

The MSB commented that the draft EIS did not evaluate the risk of anchor line collisions to Cook Inlet beluga whales during construction of the proposed Mainline Pipeline across Cook Inlet, a risk that would not be present with the Port MacKenzie Alternative. The draft EIS acknowledged that while

[17] The Susitna Delta Exclusion Zone is an area of extreme importance to Cook Inlet beluga whales, primarily during summer salmon runs.

[18] An "action area" is defined by regulation as all areas that would be affected directly or indirectly by the federal action, not just the immediate area involved in the action (50 CFR 402.02).

entanglement is possible, whales would likely avoid the area of pipelay activities due to the increased disturbance caused by construction. Further, anchor handling would not occur in higher density beluga whale habitat nor would it occur in CHA 1.

The MSB also commented that the draft EIS did not include a comparison of impacts on other endangered species. Vessel traffic for both the proposed Project and the Port Mackenzie Alternative would encounter the same ESA-listed species. The proposed facilities would be within the molting and winter range for the Alaska-breeding Steller's eider, whereas the Port Mackenzie Alternative facilities would not. However, we conclude in the BA that the proposed Project may affect, but is not likely to adversely affect, the Alaska-breeding Steller's eider.

The additional distance to the Port MacKenzie site would result in increased air emissions from LNG vessels. The increase in annual air emissions stemming from the increased vessel transit time to and from the Port MacKenzie site are estimated at 247 tpy of nitrogen oxides, 226 tpy of carbon monoxide, and 28,481 tpy of CO_2. In comments on the draft EIS, the MSB said that converting LNG vessels from diesel to natural gas fuel would decrease these emissions. While this is true, our analysis addresses likely impacts; FERC does not have the authority to require LNG vessels to convert from diesel to natural gas and we have no basis to assume that they would.

The Knik Arm of Cook Inlet has the second highest tidal range in North America (up to 40.0 feet, compared to 30.2 feet at Nikiski). The high tidal range, in combination with the water's relatively high silt content, creates an abrasive environment for marine infrastructure. A site at Port MacKenzie would experience conditions similar to those at the Port of Alaska, which lies across Cook Inlet from Port MacKenzie. The Port of Alaska is seeking funding to rebuild dock facilities that have experienced significant deterioration since their construction. We acknowledge the MSB's comment on the draft EIS that recent engineering inspections at existing Port MacKenzie facilities identified no major issues, restrictions, or downgrades to marine facility capacity. However, any new marine facilities at a Port MacKenzie site would need to be engineered and constructed (or reconstructed) to withstand these conditions at greater construction and operating cost, or face a shorter life expectancy, relative to the proposed Nikiski site for this Project.

AGDC indicates that constructing the liquefaction facilities at Port MacKenzie is likely to extend construction by a year due to the greater vessel travel distance, increased risk of ice conditions from November to April, and the greater tidal range, which narrows the windows within which LO/LO vessels can unload material. The risk of construction delays could be mitigated to some extent by utilizing ice class module characters, if available. In comments on the draft EIS, the MSB said that concerns about ice conditions, tidal ranges, and the need for reconstruction of marine facilities for the Port MacKenzie Alternative are unfounded; therefore, the construction schedule could be accelerated rather than delayed. While we do not count the potential for construction delay as a significant factor in our analysis, we conclude that construction delays for the Port MacKenzie Alternative are more likely than the Project given the expected ice and tidal conditions and potential for infrastructure rebuilds or upgrades.

The Port MacKenzie site is near the City of Anchorage, where over 50 percent of the state population lives. In addition, LNG carriers would pass near the Port of Alaska, which, because it receives material and supplies for the Elmendorf Air Force Base, is classified as a strategic port by the Department of Defense. Whether the LNG vessel transits would be compatible with the operation of Elmendorf Air Force Base and with the dense commercial and population centers associated with Anchorage would need to be assessed during the determination of suitability of the waterway for LNG marine traffic by the Coast Guard. This review process would include consideration of the density and character of marine traffic in the waterway; locks, bridges, or other man-made obstructions in the waterway; water depths, tidal range, protection from high seas, natural hazards, underwater pipelines and cables, and distance of berthed vessel from the channel; and any other issues affecting the safety and security of the waterway.

As shown in table 3.8.1-1, the Port MacKenzie site offers certain environmental advantages. Some, but not all, of these include a shorter mainline pipeline length, avoidance of the Cook Inlet pipeline crossing, and elimination of the need to relocate the Kenai Spur Highway. Impacts on wetlands would be reduced by about 27 acres, and by avoiding a Cook Inlet pipeline crossing, temporary impacts on Cook Inlet beluga whales during construction would be reduced.

The proposed Project has other advantages over the Port MacKenzie Alternative. While both projects would affect beluga whales during construction of marine facilities, the probability of impacts such as vessel strikes during operation of the liquefaction facilities would be greater with the Port MacKenzie Alternative, particularly in the summer months. Operational air emissions would be greater for the Port MacKenzie Alternative owing to the increased shipping distances. Ice conditions in Upper Cook Inlet could hamper the ability to deliver the proposed export volumes required to meet the Project's principal commercial objective relative to the proposed site at Nikiski. Moreover, the Port MacKenzie Alternative would provide for only two of the three delivery points proposed by the Project. Overall, the alternative's environmental advantages are not sufficient to offset operational environmental impacts stemming from the increased vessel traffic in Upper Cook Inlet. Therefore, we conclude that the Port Mackenzie Alternative would not provide a significant environmental advantage over the proposed Nikiski site.

Cape Starichkof

The Cape Starichkof site is a 583-acre greenfield parcel adjacent to Cook Inlet on the south end of the Kenai Peninsula, about 60 miles south of the proposed site (see figure 3.8.1-1). The Cape Starichkof site is comparable to the proposed site with respect to the length of subsea pipeline. A major disadvantage of the Cape Starichkof site is that it would require constructing an additional 73 miles of mainline pipeline, which would disturb about 1,330 more acres of land and increase the impact of the proposed Mainline Pipeline, assuming a standard right-of-way width of 150 feet. Due to the increased pipeline length, AGDC estimates that an additional 39,562 hp of compression would also be required to transport the proposed volume of natural gas, with associated air quality impacts. In addition, the mainline pipeline would affect over 200 more acres of wetlands due to the increased pipeline length.

The Cape Starichkof site is bordered to the south by the Stariski State Recreation Site, which is a 60-acre campground with 13 individual campsites. Noise, traffic, and light from construction would affect campground users. Another disadvantage of the Cape Starichkof site is that it would require filling 330 acres of wetlands (compared to 14 acres for the proposed site) and filling or rerouting Stariski Creek, an anadromous fishery that supports coho, Chinook, and pink salmon. The water bordering the Cape Starichkof site is also shallower than at the proposed site and would require dredging about 1.2 million cubic yards more material than the proposed site. AGDC indicates that dredging would be required for a distance of about 2 miles to reach water depths suitable for barge and LNG carrier access.

For the reasons described above, the Cape Starichkof site would not provide a significant environmental advantage to the proposed site.

Kasilof South

The Kasilof South site is a 535-acre greenfield parcel adjacent to Cook Inlet about 25 miles south of the proposed site (see figure 3.8.1-1). The Kasilof South site is primarily forested and is bordered to the north by residences and Cohoe Loop, to the east by Cohoe Road, to the south by forest and wetlands, and to the west by Cohoe Loop and Cook Inlet.

The Kasilof South site is comparable to the proposed site with respect to the length of subsea pipeline, lengths of future laterals to Anchorage and Fairbanks, and compression. A disadvantage of the site is that it would require constructing an additional 28 miles of mainline pipeline, which would disturb about 510 more acres of land than the proposed Project. AGDC estimates that development of the Kasilof South site would affect 74 more acres of wetlands than the proposed site. Additionally, the nearshore area at the Kasilof South site is relatively shallow and does not reach a depth of 60 feet until 3.8 miles offshore. To achieve a depth similar to the proposed site, AGDC estimates that an additional 2.6 million cubic yards of sediment would need to be dredged at the Kasilof South site. Moreover, the shoreline between Cape Kasilof south to Happy Valley is designated as the Clam Gulch CHA, established in 1976 to ensure that the public has access to razor clam beds. Dredging and the development of the Kasilof South site would remove clams and destroy suitable habitat in the dredged area. Sedimentation as a result of dredging could smother clams adjacent to the dredged area. Locating the Marine Terminal at Kasilof South could also restrict public access along the shoreline to the beds.

For these reasons, the Kasilof South site would not provide a significant environmental advantage to the proposed site.

North Foreland

The North Foreland site is a 550-acre mixed use parcel adjacent to Beshta Bay on the western shore of Cook Inlet (see figure 3.8.1-1). The site is largely undeveloped, but contains several oil and gas wells and timber roads and is bordered to the southwest by forested land and the Trading Bay SGR, to the northeast by the Tyonek Village, and to the east by Cook Inlet.

The North Foreland site would use the same mainline pipeline route as the proposed Project, except that the pipeline would terminate on the western shore and would not cross Cook Inlet. Consequently, the pipeline would be about 34 miles shorter and avoid the marine impacts associated with the proposed pipeline crossing of Cook Inlet. Although pipeline construction impacts on beluga whale would be avoided, LNG vessels would need to traverse 22 miles more of beluga whale habitat than the proposed Project to reach the site.

Because of the shorter mainline pipeline length, the North Foreland alternative would affect about 355 fewer acres of wetlands than the proposed site, although the permanent loss of wetlands at the North Foreland liquefaction site itself would be about 261 acres greater than the proposed site. In addition, the water depth in Cook Inlet at the North Foreland site would require significantly more dredging (about 1.1 million cubic yards) than the proposed site.

Considering impacts on the human environment, the North Foreland site would not require the relocation of the Kenai Spur Highway. However, the North Foreland site is very close (about 1.6 miles) to the village of Tyonek, an Alaska Native village that relies on subsistence harvesting activities. Tyonek residents harvest wild food resources throughout the year, including fish, wildlife, and wild plant resources. The construction and operation of a terminal that close to Tyonek would certainly affect the community and its subsistence activities. The proposed terminal site would not directly affect terrestrial harvesting activities of local residents. However, temporary construction impacts would be possible where the mainline pipeline construction traverses areas that could be used for subsistence harvesting.

Based on our comparison, the North Foreland site would not provide a significant environmental advantage to the proposed site.

3.8.2 Dredged Material Placement Alternatives

During scoping, the EPA recommended that the EIS evaluate alternative dredging methods and disposal sites. Construction and maintenance dredging, along with dredged material disposal, would occur at the Marine Terminal MOF in western Cook Inlet. As discussed in Section 4.3.3.3, AGDC is proposing to dispose of dredged material at one of two open water disposal locations. One open-water disposal location would be about 4 miles west of Beluga. An alternative open water disposal location would be in deeper water. The proposal to use an open water disposal location has been submitted in the COE application and applicable ADNR Division of Mining, Land, and Water (DMLW) authorizations.

There is only one currently permitted dredge spoil disposal area in Cook Inlet. At present, this site is unavailable for private use and is only permitted for COE-dredged material. AGDC maintains that this site is too far from the dredging area for Project use.

AGDC searched for upland locations to dispose of dredge spoils but could not identify any known sites in the Project area that need, or are seeking, large volumes of fill. Sites farther from the Project area would likely have greater environmental impacts, including wetland and habitat loss, and impacts associated with dewatering the material prior to transport and placement.

Also considered, but eliminated from further consideration, were other potential dredge spoil disposal options, such as beach nourishment and/or coastal bluff erosion stabilization. Although the COE has used locally dredged spoils for beach nourishment and related marine improvements at locations 40 to 60 miles south of the Project area, no current or planned projects needing dredge spoil in such volumes have been identified; consequently, this is not a practical alternative to the proposed Project.

Based on such considerations, the potential dredged material placement alternatives are either technically impractical or are unlikely to offer a significant environmental advantage over the proposed disposal site.

3.9 ADDITIONAL WORK AREA ALTERNATIVES

We received a comment from the EPA requesting that we include an evaluation of alternative locations, configurations, and transportation methods for the proposed Mainline MOF. The Mainline MOF would be constructed as a permanent facility adjacent to the existing Beluga barge landing facility. AGDC indicated that material deliveries would need to be supported using RO/RO vessels,[19] LO/LO vessels, and pump-transferred fuels. Road transport was considered as an alternative to the proposed Mainline MOF, but this would require constructing an access road about 50 miles long to reach the Project area. Although no road alignment or design parameters have been identified, a road of this length could affect more than 240 acres of land (based on a 40-foot-wide roadway), including forested areas, wetlands, and waterbodies. In contrast, the permanent Mainline MOF would disturb just 6 acres of land. Therefore, the road transport alternative would not provide any significant environmental advantage over the proposed Project.

We also evaluated the use of two different existing berthing and docking facilities and the use of heavy-lift helicopters to transport materials to the Project area. These three alternatives are evaluated below.

The existing Beluga landing facility is immediately north of the west Cook Inlet shoreline crossing. The Beluga landing facility is a cut-bank beach landing with a graded gravel ramp capable of offloading RO/RO vessels during high tide. The landing area is about 80 feet wide and does not have a dock facility.

[19] RO/RO vessels are vessels designed to carry wheeled cargo such as trucks and trailers that are driven off the ship on their own wheels.

AGDC indicated that the site would require regrading after every tide to make the landing suitable for deliveries. The landing would be limited to RO/RO deliveries because a crane could not be safely located close enough to a landed barge to accommodate LO/LO deliveries. Moreover, using the existing facility would create scheduling conflicts with other users. AGDC indicated that the facility is used historically about 160 times in a given year and that the Project would require all the facility's capacity. To accommodate Project deliveries, AGDC indicated that the facility would also need to be upgraded to include:

- multiple berths to allow access for existing users and Project deliveries;
- construction of a dock to support LO/LO operations; and
- access road upgrades to stabilize the shoulders, reduce the grade, and reduce the turn radius.

Use of the Beluga landing facility by others would be limited during facility upgrades. For these reasons, the existing Beluga landing facility is not a practical alternative to the proposed Mainline MOF and would not provide a significant environmental advantage.

The existing Tyonek Dock, also referred to as the North Foreland Dock, is 5.8 miles south of the proposed Mainline MOF and about 1.6 miles south of the Native Village of Tyonek. The Tyonek Dock is 175 feet long and 50 feet wide and has been used to support ship loading of timber and aggregate as well as transportation for the oil and gas industry in the Cook Inlet Basin. The concrete causeway connecting the dock to shore is about 1,400 feet long and 50 feet wide. An existing 11-mile-long logging road would provide access from the dock to the Project area.

AGDC indicated that information on the historical use of the dock is not well documented and that in its current configuration, the Tyonek Dock would not support RO/RO deliveries. To meet the material transfer needs for the Project, AGDC indicated that the following upgrades would be required:

- widening of the dock by 40 feet to accommodate truck turning or constructing a second causeway on the western side of the dock;

- building a RO/RO ramp;

- upgrading the existing logging road or constructing a new road that would have fewer curves and lower grades to allow for long and heavy loads (e.g., camp modules, 80-foot-long pipe joints, or marine pipe); and

- upgrading the existing logging road bridge or building a new one over the Chuitna River.

These modifications would have environmental impacts similar to construction of the proposed Mainline MOF. In addition, the location of the Tyonek Dock would increase the travel distance to deliver materials to the Project area. Based on this comparison, use of the Tyonek Dock would not provide a significant environmental advantage to the proposed Mainline MOF.

We considered the use of heavy-lift helicopters to transfer materials from barges anchored in Cook Inlet. The helicopters would transport materials to a staging area for distribution to the Project area. AGDC would refuel and stage the helicopters from either Anchorage or a new helicopter landing pad near Beluga.

Use of heavy-lift helicopters would avoid the nearshore environmental impacts from the construction of a new landing facility. However, AGDC maintains that material transport by helicopters would be limited. For safety purposes, only a single 40-foot-long section of pipe could be transported at a time. Compared to the proposed Project's use of double-jointed 80-foot-long pipe sections, the use of helicopters would significantly lengthen the construction schedule, by doubling the number of welds to be made in the field. Based on these factors, the use of heavy-lift helicopters would not be a technically practical alternative to the proposed Mainline MOF.

3.10 CONCLUSION

We reviewed alternatives to the Project based on our independent analysis and comments received. Although many of the alternatives appear to be technically feasible, we identified no alternatives that would provide a significant environmental advantage over the Project. Based on these findings, we conclude that the proposed Project, as modified by our recommended mitigation measures, is the preferred alternative than can meet the Project objectives.

4.0 ENVIRONMENTAL ANALYSIS

This section of the EIS provides our[1] analysis of the general and site-specific impacts associated with Project construction and operation, as well as proposed measures to avoid, reduce, and mitigate impacts. This section describes the existing natural and human environment and discusses the potential environmental consequences of the Project. The discussion is organized by the following major resource topics: geology; soils; water resources; wetlands; vegetation; wildlife resources; aquatic resources; threatened, endangered, and other special status species; land use, recreation, and special interest areas; visual resources; socioeconomics; transportation; cultural resources; subsistence; air quality; noise; public health; reliability and safety; and cumulative impacts.

With the exception of wetland resources, applicable environmental resources (affected environment) are described and analyzed in the context of the ecoregions crossed by the Project using the Unified Ecoregions of Alaska classification system delineated by Nowacki et al. (2001c), as described by the ADF&G (2015a). This classification system is organized into three levels (Levels I, II, and III). Level I (referred to in this EIS as climate groups) divides the lower levels according to Polar, Temperate Continental, and Temperate Coastal climates. Level II (referred to in this EIS as ecoregions) is organized according to the dominant regional vegetation. Level III (referred to in this EIS as subregions) is further divided based on disturbance processes or topography that occur within each ecoregion. The climate groups, ecoregions, and subregions affected by the Project facilities are shown in table 4-1 and on figure 4-1. Freshwater, vegetation, and aquatic resources are further evaluated by watersheds, as defined by the USGS (see sections 4.3.2, 4.5, and 4.7). The wetland resources section uses watersheds along with a regional physical subdivision system delineated by Hall et al. (1994) to describe the wetland resources that are crossed by the Project (see section 4.4). Instead of the climate groups defined by Nowacki et al. (2001c), the air quality section uses climate divisions defined by the National Oceanic and Atmospheric Administration (NOAA) (2015), as described in more detail in section 4.15.

Four levels of impact duration are considered in our analysis: temporary, short-term, long-term, and permanent. Temporary impacts generally occur during the 8-year construction period, with the resource returning to pre-construction condition immediately after restoration or within a few months to a year following the installation of permanent erosion control measures. Short-term impacts could continue for up to 5 years following installation of permanent erosion control measures.[2] Long-term impacts would persist for more than 5 years and for up to 30 years after installation of permanent erosion control measures, with the affected resource eventually recovering to pre-construction conditions. A permanent impact would occur as a result of any activity that modifies a resource to the extent that it would not return to pre-construction conditions during the life of the Project, which AGDC defines as 30 years. Permanent impacts could also extend beyond the life of the Project. For example, we consider the clearing of mature forests a permanent impact because it would take several decades for these habitats to attain their pre-construction condition. The construction and operation of aboveground facilities would also cause permanent impacts.

When determining the significance of an impact, we consider the duration of the impact as well as the geographic, biological, and/or social context in which the effects would occur, and the intensity (e.g., severity) of the impact. The context and intensity vary by resource and impact and are therefore described throughout the analysis. "Intensity" refers to the severity of the impact, in whatever context(s) it occurs. To determine intensity, we consider the severity of the impact using both the quantity of the resource affected as well as the duration of the impacts. Unless otherwise noted for a specific resource, the

[1] The pronouns "we," "us," and "our" refer to the environmental and engineering staff of FERC's Office of Energy Projects.

[2] Permanent erosion control measures, such as trench breakers and permanent slope breakers, are generally installed after final grading, clean-up, and seeding has occurred. It is used here as a proxy for the start of restoration.

definitions above are used in the analysis. In the following sections, we address direct and indirect effects collectively by resource. Section 4.19 analyzes the Project's contribution to cumulative impacts.

TABLE 4-1

Ecoregions Associated with the Project [a]

Climate Group / Ecoregion [b]	Subregion	Facility	Total Miles [c,d]
Polar			
Arctic Tundra	Beaufort Coastal Plain	Gas Treatment Facilities	N/A
		Mainline Facilities MPs 0.0–62.0	61.6
		PTU Expansion Project [e]	N/A
		PBU MGS Project [e]	N/A
	Brooks Foothills	Mainline Facilities MPs 62.0–143.3	81.4
	Brooks Range	Mainline Facilities MPs 143.3–252.0	108.0
Subtotal			**251.0**
Total Polar			**251.0**
Temperate Continental			
Beringia Boreal	Kobuk Ridges and Valleys	Mainline Facilities MPs 252.0–257.1	5.2
	Ray Mountains	Mainline Facilities MPs 257.1–430.3	172.9
	Tanana-Kuskokwim Lowlands	Mainline Facilities MPs 430.3–516.5 [f]	73.2
	Yukon-Tanana Uplands	Mainline Facilities MPs 442.7–455.0 [f]	12.3
Subtotal			**263.6**
Coast Mountains Boreal			
	Alaska Range	Mainline Facilities MPs 516.5–616.5	100.3
	Cook Inlet Basin	Mainline Facilities MPs 616.5–806.6	191.9
		Liquefaction Facilities	N/A
		Kenai Spur Highway Relocation Project [e]	N/A
		Kenai Municipal Water System Upgrades [e]	N/A
Subtotal			**292.2**
Total Temperate Continental			**555.8**
Total Miles			**806.9**

N/A = Not applicable

a Ecoregions are based on the Unified Ecoregions of Alaska classification system delineated by Nowacki et al. (2001c), as described by the ADF&G (2015a).

b No Project facilities would be within the Temperate Coastal Climate Group.

c Total miles are based on the Mainline Pipeline centerline and may not exactly match estimated milepost numbers; the straight-line distance between consecutive mileposts may be greater than or less than 5,280 feet due to changes in elevation and adoption of route alternatives and variations. The mileposts should be considered reference points only.

d The sum of the addends may not equal the totals in all cases due to rounding.

e Non-jurisdictional facilities are addressed in the cumulative impacts section (see section 4.19).

f The Mainline Pipeline alternatively passes in and out of the Yukon-Tanana Upland and Tanana-Kuskokwim Lowlands Subregions between MPs 430.3 and 455.0.

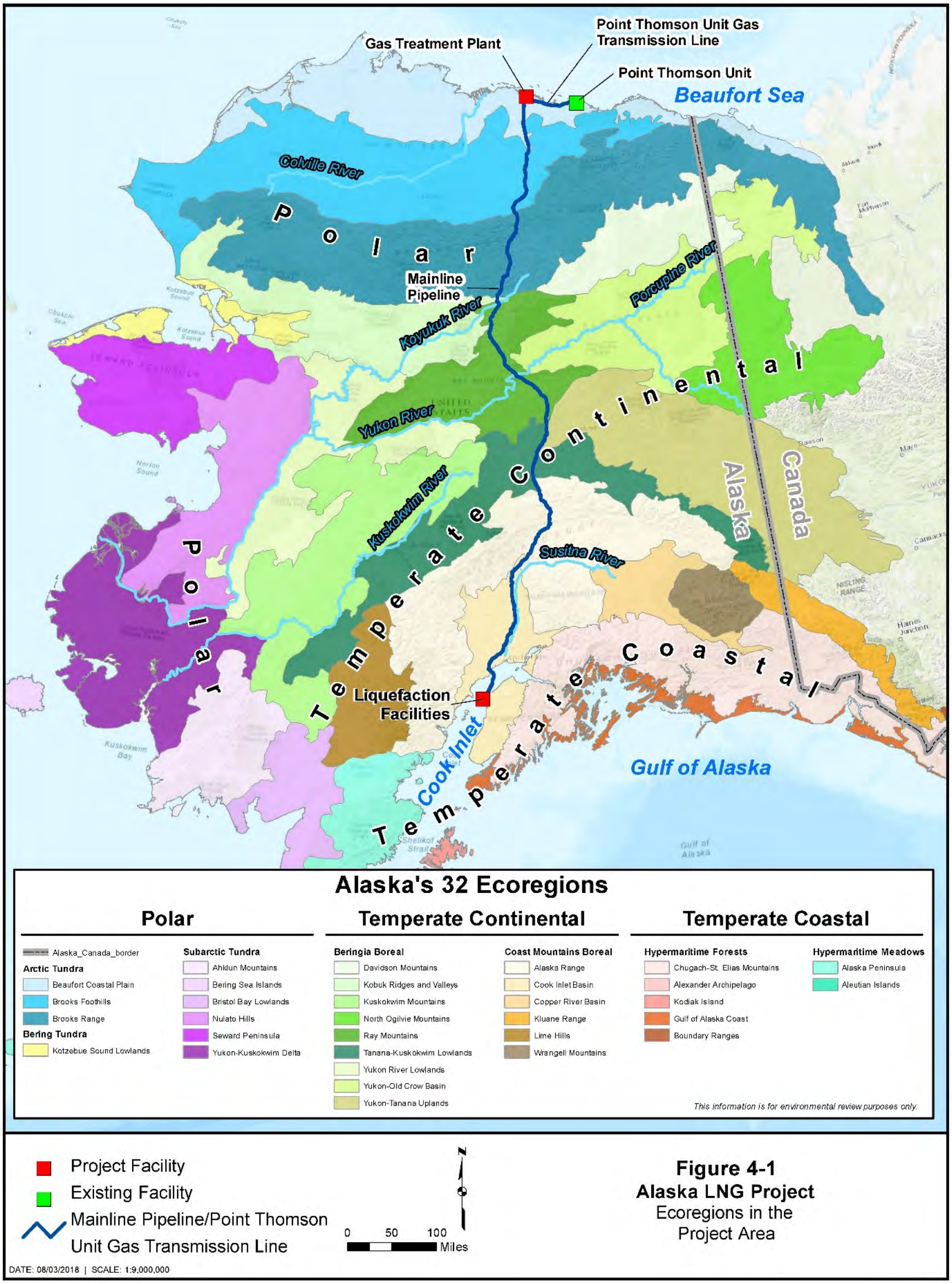

Figure 4-1
Alaska LNG Project
Ecoregions in the Project Area

The analysis is based on a review of the information provided by AGDC[3] and further developed from FERC information requests, site visits, scoping, literature research, alternatives analyses, public comments, and contacts with federal, state, and local agencies and other stakeholders. As discussed in more detail in section 1.4, traditional knowledge was also incorporated into the analysis where applicable.

AGDC, as part of its proposal, developed mitigation measures to reduce the impact of the Project. In some cases, we determined that additional mitigation measures could further reduce the Project's impacts. Our additional mitigation measures, or environmental recommendations, appear as bulleted, boldfaced paragraphs in the text of this section and are also included in section 5.2. AGDC agreed to or provided the required information needed to address many of our recommendations from section 5.2 of the draft EIS; this information has been incorporated into the applicable sections of the final EIS. We recommend to the Commission that the remaining measures and several new measures be included as specific conditions in any Order the Commission may issue authorizing the Project.

Throughout the resource sections that follow, we reference protective plans that AGDC would finalize prior to construction. For those that have sufficient detail in their current state, we recognize the protection provided. For those that have either not been drafted or exist in a preliminary or outline condition, we do not rely on that protection to draw conclusions of impact. However, we do note that the finalized plans would be subject to our review and approval prior to their implementation. Other agencies may also need to review and approve these plans prior to construction.

The conclusions in the EIS are based on our analysis of the environmental impacts. Any Commission order authorizing the Project would require that:

- the facilities be constructed and operated as described in section 2.0 or as modified by our recommendations;
- AGDC implement the mitigation measures included in their application and supplemental submittals to FERC; and
- AGDC comply with our recommended mitigation measures, listed in section 5.2.

In our experience, necessary modifications to a project, both spatial and procedural, are identified after it is authorized. These changes may include additional or different minor workspace configurations, changes to access roads, or even specific construction techniques (e.g., construction across waterbodies). These changes are often identified by the applicant once on-the-ground implementation work is initiated. Any Project modifications would be subject to review and approval from FERC's Director of the Office of Energy Projects (Director of the OEP) and any other permitting/authorizing agencies with federal or federally delegated jurisdiction.

Although not enforced by the Commission, we also consider that AGDC would be required to comply with all applicable laws and regulations and the stipulations/mitigation measures included in other agencies' permits and approvals.

[3] Actions taken by the original Project applicants (AGDC, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, ExxonMobil Alaska LNG LLC, and TransCanada Alaska Midstream LLP) are referred to as AGDC's actions for consistency in presentation throughout the document.

4.1 GEOLOGIC RESOURCES AND GEOLOGIC HAZARDS

The following section describes geologic resources and hazards present in the Project area, and their potential impacts related to various Project components, including the Gas Treatment, Mainline, and Liquefaction Facilities.

4.1.1 Physiographic and Geologic Setting

Alaska is a combination of tectonostratigraphic terranes that have accumulated over time on the North American craton,[4] consisting mainly of accreted fragments of igneous arcs, accretionary-wedges, and subduction-zone complexes. A tectonostratigraphic terrane, sometimes referred to as an accreted or exotic terrane, is a fault-bounded geologic entity with a distinctive stratigraphic sequence of rock that is differing from those of nearby, similarly aged materials. Terranes in the cordillera[5] of Alaska and Canada outboard of the North American craton are grouped into seven composite terranes, including the Arctic, Central, Yukon, Togiak-Koyukuk, Oceanic, Wrangellia, and Southern Margin composite terranes (Geological Society of America, 1994).

In the southeastern "panhandle" of Alaska, 10 tectonic assemblages are also recognized because of their distinct geologic record. Five of these are terranes (the Alexander, Chugach, Stikinia, Taku, and Wrangellia terranes), and five are lithic assemblages that consist of metamorphic rocks of unknown tectonic affinity or rocks in depositional or intrusive contact with terranes. These assemblages include Jurassic- and Cretaceous-age strata of the Gravinia belt along the west side of the Coast Mountain batholith;[6] metamorphic pendants of unknown tectonic affinity within the batholith;[7] plutonic rocks within the batholiths; Cretaceous-, Eocene-, Oligocene-, and Miocene-age plutons west of the batholith; and Tertiary- and Quaternary-age strata that are widespread throughout southeastern Alaska (Geological Society of America, 1994).

The southern border of Alaska is on the edge of the tectonic boundary between the Pacific Plate and the North American Plate. The Pacific Plate is being thrust beneath Alaska within a subduction zone. This convergent boundary contributes to Alaska's geologically active landscape, including the Aleutian chain of volcanoes and abundant earthquakes across the state. Portions of the state are part of the North American Cordillera. The great variety of structures produced by mountain-building activity and the differential movements of the recent geologic past have combined to give the state its extreme topographic diversity and active seismicity.

Alaska is comprised of four physiographic divisions that are primarily defined based on topography (see figure 4.1.1-1). From north to south, these divisions are the Interior Plains, Rocky Mountain System, Intermontane Plateaus, and Pacific Mountain System. Wahrhaftig (1965) subdivided the four divisions into physiographic provinces based on similar topographic characteristics and geologic processes, and each province into physiographic sections based on characteristic landforms and geomorphic history.

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[4] Craton: The stable interior portion of a continent, characteristically composed of ancient basement rock.

[5] Cordillera: An extensive series of parallel ranges of mountains, together with their associated valleys, having an overall trend in one general direction (American Geological Institute, 1984).

[6] Coast Mountain batholith: The continental volcanic arc that lies along the western margin of the North American Plate in the Pacific Northwest of western North America; also referred to as the Coast Plutonic Complex or Coast Range Arc.

[7] Batholiths are a type of igneous rock that form when magma rises into the earth's crust but does not erupt onto the surface. The magma cools forming a rock structure that extends a minimum of 40 miles across and to an unknown depth (USGS, 2015b).

Figure 4.1.1-1
Alaska LNG Project
Alaska Physiographic Regions

The following sections describe each Project facility within the context of the physiographic province and provide the typical range of topographic relief and surficial and bedrock geology in each region.

4.1.1.1 Physiographic Provinces

The Project would be built in portions of seven provinces (Wahrhaftig, 1965), each of which are described below. Table 4.1.1-1 and figure 4.1.1-1 provide the divisions, provinces, and sections for the Project by milepost range.

TABLE 4.1.1-1

Physiographic Divisions, Provinces, and Sections Associated with the Project

Physiographic Division	Physiographic Province	Milepost Range [a]	Physiographic Section
Interior Plains	Arctic Coastal Plain	0.0 – 63.9	Arctic Coastal Plain [b]
Rocky Mountain System	Arctic Foothills	63.9 – 145.4	Arctic Foothills
Rocky Mountain System	Arctic Mountains	145.4 – 243.4	Central and Eastern Brooks Range
Rocky Mountain System	Arctic Mountains	243.4 – 262.7	Ambler-Chandalar Ridge and Lowland
Intermontane Plateaus	Northern Plateaus	262.7 – 372.0	Kokrine-Hodzana Highlands
Intermontane Plateaus	Northern Plateaus	372.0 – 382.1	Rampart Trough
Intermontane Plateaus	Northern Plateaus	382.1 – 448.3	Yukon-Tanana Upland
Intermontane Plateaus	Western Alaska	448.3 – 501.9	Tanana-Kuskokwim Lowland
Pacific Mountain System	Alaska-Aleutian	501.9 – 530.7	Northern Foothills of Alaska Range
Pacific Mountain System	Alaska-Aleutian	530.7 – 564.8	Alaska Range (central and eastern part)
Pacific Mountain System	Coastal Trough	564.8 – 641.8	Broad Pass Depression and Talkeetna Mountains
Pacific Mountain System	Coastal Trough	641.8 – 806.6	Cook Inlet Susitna Lowland [c]

Sources: Wahrhaftig, 1965
[a] Mileposts associated with the Mainline Facilities.
[b] The Gas Treatment Facilities are in the Arctic Coastal Plain Section.
[c] The Liquefaction Facilities are in the Cook Inlet Susitna Lowland Section.

The GTP, PTTL, PBTL, and the first 63.9 miles of the Mainline Facilities would be within the Arctic Coastal Plain Province of the Interior Plains Division. Permafrost (i.e., ground that remains at or below 32°F for at least 2 consecutive years) is continuous in the area and ice rich. Permafrost is typically overlain by an active layer that seasonally thaws and, therefore, the active layer is not always perennially frozen and is not considered to be part of the permafrost. Soils are very poorly drained due to permafrost at depths of 6 inches to 4 feet below the ground surface (Wahrhaftig, 1965). The average elevation range in the Arctic Coastal Plain is about 200 to 600 feet above mean sea level (amsl). The coastal plain is flat to undulating with very low relief. Ice-cored pingos contribute to minor topographic highs between 20 and 230 feet above the plain, and polygonal ground[8] features provide small-scale topographic variations (Nowacki et al., 2001c; Wahrhaftig, 1965). The Arctic Coastal Plain is also marked by the presence of oriented oval- or rectangular-shaped thaw lakes, which can range from 2 to 20 feet deep and from a fraction of a mile up to 9.0 miles long. Permafrost features and continuity are discussed further in section 4.2.

The Mainline Facilities would be within the Arctic Foothills Province between about MPs 63.9 and 145.4. The Arctic Foothills consist of exposed east-trending linear ridges between narrow alluvial

[8] Polygonal, or patterned, ground is a general term for any ground surface exhibiting a discernibly ordered, more or less symmetrical, morphological pattern of ground and, where present, vegetation (van Everdingen, 2005).

valleys. The elevation ranges from 600 feet amsl in the north up to 3,500 feet amsl in the southern portion of the province (Wahrhaftig, 1965). As in the Arctic Coastal Plain, permafrost is continuous in this region. Frozen streambeds create extensive sheets of aufeis (i.e., anchor ice), that last into the summer (Nowacki et al., 2001c). Thaw lakes are also present in the Arctic Foothills Province in river valleys, and ice wedges,[9] polygonal ground, and other permafrost features are prevalent (Wahrhaftig, 1965).

The Arctic Mountains Province consists of mountains and hills carved chiefly from folded and overthrust Paleozoic- and Mesozoic-age sedimentary rocks. Continuous permafrost is prevalent in this region. The Mainline Facilities would cross the Central and Eastern Brooks Range and Ambler-Chandalar Ridge and Lowland Sections of this province between about MPs 145.4 and 262.7; of this length, about 100 miles of the Mainline Pipeline would be within the Middle Fork, Koyukuk, Dietrich, and Atigun River valleys. The Dietrich River valley in particular is very active in terms of mass wasting processes due to the prevalence of solifluction lobes[10] and flow slides. The rugged, glaciated mountains in the Central and Eastern Brooks Range Section rise to heights of about 8,000 feet amsl and form the continental divide. The average elevation range is about 600 to 4,700 feet amsl. The southern boundary of the section is marked by the Kobuk-Malamute fault (Nowacki et al., 2001c). The Ambler-Chandalar Ridge and Lowland Section consists of one or two east-trending lines of lowlands, with low passes 3 to 10 miles wide and 200 to 2,000 feet amsl immediately south of the Brooks Range.

The Mainline Facilities would cross the Kokrine-Hodzana Highlands, Rampart Trough, and Yukon-Tanana Upland Sections of the Northern Plateaus Province between about MPs 262.7 and 448.3. The Kokrine-Hodzana Highlands Section comprises isolated rugged mountains, including the Ray Mountains rising to 5,500 feet amsl, surrounded by lower-elevation rounded ridges up to 2,000 to 4,000 feet amsl. The Rampart Trough Section is a structurally controlled depression having gently rolling topography between 500 to 1,500 feet amsl, incised below highlands on either side. The Yukon-Tanana Upland Section consists of undulating, rounded ridges that rise up to 1,500 feet above alluvium valleys. All three sections are underlain by permafrost (continuous and discontinuous) and periglacial features including ice wedges, stone polygons, and cryoplanation terraces.[11] The ridges and valleys south of the Brooks Range were created by high-angle reverse faults, and later glaciations scoured the valleys to create large U-shaped troughs (Wahrhaftig, 1965; Nowacki et al., 2001c).

The Mainline Facilities would enter the Tanana-Kuskokwim Lowland Section of the Western Alaska Province at about MP 448.3, and would traverse the alluvial plains consisting of fluvial, glaciofluvial, colluvial, and eolian deposits, until about MP 501.9. This section of the Western Alaska Province is characterized as a broad northeast-trending depression and serves as the outwash plain for glacial streams originating from the Alaska Range to the south. Discontinuous permafrost can be found in this region. Thaw lakes are prevalent in the alluvial plain, and the entire area is underlain by discontinuous permafrost (Wahrhaftig, 1965).

After emerging from the Tanana-Kuskokwim Lowland Section, the Mainline Facilities would cross into the Northern Foothills of the Alaska Range and Alaska Range (central and eastern part) Sections of the Alaska-Aleutian Province between about MPs 501.9 and 564.8. The Northern Foothills of the Alaska Range Section consists of east-trending ridges and undulating lowlands incised by mostly parallel streams flowing north from the Alaska Range and draining to the Tanana River. Permafrost is prevalent, as are

[9] An ice wedge is a massive, generally wedge-shaped body with its apex pointing downward, composed of foliated or vertically banded, commonly white, ice (van Everdingen, 2005).

[10] A solifluction lobe is an isolated, tongue-shaped feature, up to 25 meters wide and 150 meters long or longer, formed by more rapid downslope flow of saturated unfrozen earth materials on certain sections of a slope showing variations in gradient, and commonly has a steep front and a relatively smooth upper surface (van Everdingen, 2005).

[11] Cryoplanation terraces are step-like or table-like bench cuts in bedrock in cold climate regions, which form under conditions of intense frost wedging associated with snowbanks (van Everdingen, 2005).

solifluction lobes and polygonal ground. The Alaska Range (central and eastern part) Section comprises rugged, glaciated mountains, including Denali, which rises to an elevation of 20,310 feet amsl. Similar to the Northern Foothills of the Alaska Range, continuous and discontinuous permafrost is prevalent throughout the range (Wahrhaftig, 1965).

From about MPs 564.8 to 641.8, the Mainline Facilities would follow the borders of and cross between the Broad Pass Depression and Talkeetna Mountains Section of the Coastal Trough Province. The Broad Pass Depression, between 1,000 to 2,000 feet amsl and about 5 miles wide, is a trough with a glaciated floor bound by mountain walls several thousand feet high. Long, narrow, drumlin-like[12] hills on the floor of the trough trend parallel to its axis. The Talkeetna Mountains are an ovular highland of diverse topography that interrupt the Coastal Trough Province, rising in some areas to 8,000 feet amsl. Continuous, discontinuous, and sporadic (10- to 50-percent coverage) permafrost can all be found in this range.

The Mainline Facilities from MP 641.8 to the Mainline Pipeline terminus at MP 806.6, as well as the Liquefaction Facilities, including the LNG Plant, Marine Terminal, and additional work areas, would be in the Cook Inlet-Susitna Lowland Section of the Coastal Trough Province. The Cook Inlet-Susitna Lowland Section records the most recent glacial movement in the form of glacial moraines,[13] eskers,[14] drumlins, and outwash plains.[15] The area is generally less than 500 feet amsl in elevation, although portions approaching the nearby Talkeetna Mountains to the east and Alaska Range to the north may rise up to 3,000 feet amsl (Wahrhaftig, 1965). This geologic section contains areas of isolated (0 to 10 percent) permafrost and areas with no permafrost present. The Mainline Pipeline would be installed across Cook Inlet between about MPs 766.0 and 793.3.

4.1.1.2 Surface and Bedrock Geology

The surficial and bedrock geology of the areas crossed by the Project were determined using information prepared by the USGS (2017a), ADNR Division of Geological and Geophysical Surveys (DGGS), Wahrhaftig (1965), and geotechnical and geophysical investigations completed for the Project. The following sections summarize the surficial and bedrock geology crossed by Project facilities.

The Gas Treatment Facilities are primarily underlain by surficial unconsolidated Quaternary Period marine sediments and Lower Tertiary Period sedimentary bedrock (Wahrhaftig, 1965). Gently north-dipping formations of sandstone, siltstone, and shale compose the bedrock in the area (Mull and Adams, 1989); these sedimentary deposits have been targets for petroleum exploration because they host valuable oil and gas reservoirs. Unconsolidated marine and terrestrial sediments caused by sea level changes in the Pleistocene Epoch overlie sedimentary bedrock and extend about 50 miles offshore near Prudhoe Bay (Nowacki et al., 2001c).

Similar to the Gas Treatment Facilities, the portion of the Mainline Facilities within the Arctic Coastal Plain would be underlain by unconsolidated Quaternary Period marine sediments. Farther south in the Arctic Foothills Province, the linear ridges are composed of tightly folded Cretaceous Period sedimentary bedrock, whereas in the southern part of the province, Cretaceous Period and Devonian Period sedimentary rocks are tightly folded along with igneous (mafic) intrusions, and buttes and mesas are present. Pleistocene Epoch alluvial, colluvial, glacial, and eolian deposits overlie sedimentary bedrock, and braided streams and rivers, including the Sagavanirktok River, incise these deposits to expose bedrock

[12] A drumlin is "an elongated ridge of glacial sediment sculpted by ice moving over the bed of a glacier" (Molina, 2004).

[13] Moraine is a general term for unstratified and unsorted deposits of sediments that form through the direct action of, or contact with, glacier ice (Molina, 2004).

[14] An esker is a meandering, water-deposited, generally steep-sided sediment ridge that forms within a subglacial or englacial stream channel (Molina, 2004).

[15] An outwash plain is "a broad, low-slope angle alluvial plain composed of glacially eroded sorted sediment that has been transported by meltwater" (Molina, 2004).

(Wahrhaftig, 1965; Nowacki et al., 2001c). On shallow slopes, subsidence and thermal erosion[16] may occur, while mass wasting and subsidence are more likely to occur on steeper slopes (Natural Resource Conservation Service [NRCS], 2004). Subsidence hazards are discussed in section 4.1.3.6.

Surficial geology of the Brooks Range in the Arctic Mountain Province consists of colluvial and eolian deposits. Bedrock in the Brooks Range is comprised of limestone, shale, quartzite, slate, and schist sequences that have been folded and faulted north of the Sagavanirktok River (Wahrhaftig, 1965) and were uplifted in the Late Jurassic or Early Cretaceous Periods (Fuis et al., 2008). The southern part of the Brooks Range features primarily metamorphic assemblages that are about the same age as the northern Paleozoic Era bedrock. Granitic intrusions in the sedimentary deposits along the southern portion of the Brooks Range are known to host metallic ore deposits such as gold, silver, antimony, and arsenic. In addition, placer gold deposits[17] are in and along the southern flank of the Brooks Range (Wahrhaftig, 1965; Alaska Resource Data File [ARDF], 2016). Mineral resources are described in section 4.1.2.

The northern portion of the Northern Plateaus Province contains Paleozoic Era limestone formations and volcanic rocks that have been highly deformed, while the remaining bedrock of the province is primarily schist and gneiss with irregular granitic intrusions. Gold and other deposits have been found within the alluvial plain (Wahrhaftig, 1965). Bedrock in the Ray Mountains is composed of sedimentary rocks in the northern portion (including greywacke, siltstone, shale, and conglomerate) and volcanic sequences interbedded with chert in the southern portion (Foster and Keith, 1994).

Farther south, the Mainline Facilities would be underlain by unconsolidated Quaternary Period fluvial, glaciofluvial, eolian, and colluvial sediments in the Tanana-Kuskokwim Lowland Section of the Western Alaska Province. Bedrock consists of the Wickersham unit (i.e., metasedimentary conglomerate, arenite, chert, and quartzite) and Fossil Creek volcanic rocks (Wilson et al., 2015). In the southern part of the lowlands, the Tertiary Period Usibelli Group comprises sedimentary sequences of conglomerate, mudstone, sandstone, claystone, and lignite beds. In the eastern part of the Western Alaska Province, metavolcanic and metavolcaniclastic rock outcrops have been mapped in addition to coal-bearing sedimentary rocks.

The Northern Foothills and Alaska Range Sections of the Alaska-Aleutian Province were formed during several episodes of accretion, which resulted in a diverse series of rocks that extend in a generally southwest–northeast trend where the Mainline Pipeline would cross the province (Wilson et al., 2015). The majority of the Alaska Range formed about 6 million years ago, but less significant mountain building events occurred starting about 25 million years ago (Fitzgerald et al., 2014). The igneous rocks that compose portions of the Alaska Range, including Denali, formed below the earth's crust as part of a batholith. Glacial erratics (i.e., rocks that differ from the types of rocks found where they were deposited by a glacier) are also prevalent in the Alaska Range (NPS, 2015). The Alaska Range consists of Paleozoic and Precambrian Era rocks on the outer flanks of the mountains with a core of Cretaceous Period rocks (Wahrhaftig, 1965). Tertiary Period deposits associated with the Usibelli Group include seams of subbituminous coal along the northern side of the mountain range. Bedrock in the southern portion of the Alaska Range near the Denali Fault zone consists of the Cretaceous Period Cantwell formation with limestone blocks and mélange[18] (Wilson et al., 2015).

Finally, where the Mainline Facilities would be in the Cook Inlet-Susitna Section of the Coastal Trough Province, the Mainline Pipeline would cross oil- and gas-bearing Tertiary Period sedimentary

16 Thermal erosion is the erosion of ice-bearing permafrost by the combined thermal and mechanical action of moving water (van Everdingen, 2005).

17 Gold placer deposits result from the weathering and release of gold from lode deposits, transportation of the gold, and concentration of the gold dominantly in stream gravels (Yeend and Shawe, 1989).

18 A body of rock characterized by a lack of internal continuity of contacts or strata and by the inclusion of fragments and blocks of all sizes, both exotic and native, embedded in a fragmented matric of finer-grained material (USGS, 2018d).

deposits that host coal seams (Wilson et al., 2012). Pleistocene-age glacial moraines or glacial outwash or lake deposits are also common throughout the area (Wahrhaftig, 1965).

The surficial geology underlying the Liquefaction Facilities in the Cook Inlet Basin consists of Tertiary Period fill and overlying Quaternary Period deposits sourced from the Alaska and Chugach Ranges. The alluvial and glacial deposits comprise the West Foreland Formation, Hemlock conglomerate, Tyonek Formation, Beluga Formation, and Sterling Formation, and include massive sandstones, conglomeratic sandstones, and interbedded claystones (Hartman et al., 1972, 1974; Calderwood and Fackler, 1972). Near-surface Quaternary Period deposits consist of Pleistocene-age glacial till overlain by Holocene Epoch eolian, lacustrine, and fluvial deposits. In the area of the LNG Plant, these Quaternary Period deposits range from 200 to 800 feet in thickness based on deep seismic reflection data collected in 2015 by Fugro Consultants, Inc. on behalf of AGDC (Fugro, 2015b).

The surficial geology of the Liquefaction Facilities site was confirmed between 2014 and 2016 when AGDC, in completing geotechnical investigations, installed 195 geotechnical onshore and offshore borings, 26 monitoring wells, and 14 test pits. These investigations confirmed that dense sands and gravels would be directly beneath the Liquefaction Facilities.

4.1.2 Mineral Resources

Mineral resources within 0.5 mile of the Project were identified by reviewing aerial photographs and publicly available information from the USGS, ADNR, ARDF, Alaska State Geo-spatial Data Clearinghouse, and BLM Mineral Assessments. Identified mineral resources are described below; aerial map sets depicting active mining claims and oil and gas wells within 0.5 mile of the Project were provided by AGDC.[19]

4.1.2.1 Mining Operations

Ore Deposits and Industrial Materials

The Project would cross several regions that contain or could potentially contain viable ore deposits. According to the ADNR (2015e), the Project area overlies or is adjacent to several areas of known mineral resources, including antimony, chalcopyrite, gold, manganese, molybdenite, silver, chromite, tin, rare earth elements, sulfides, and titanium. In addition to mineral resources, the Project would cross or would be adjacent to potential industrial material sales sites, including deposits of sand, gravel, riprap, slate, sand, limestone, and peat.

Although the Project would cross Alaska's northern, eastern interior, and south-central primary mining regions (Athey and Werdon, 2017), there are minimal active production sites near the proposed facilities. The Kinross Fort Knox gold mine is about 38 miles east of the Mainline Pipeline at MP 437.7; placer mining operations on BLM lands within the Koyukuk District are discussed below. Table 4.1.2-1 summarizes the ADNR mining claims and USGS mineral resources (occurrences, prospects, and material sales sites) within 0.5 mile of the Project. Figure 4.1.2-1 shows the locations of existing USGS mineral resources and ADNR mining claims relative to Project facilities. There are about 162 state and federal mining claims within 0.5 mile of Project facilities, of which about 60 state and 4 federal mining claims are within the Project footprint. Mining claims grant exclusive rights to locatable minerals at a particular site. ADNR mining claims include those purchased by individuals or mining companies. Federal mining claims are unpatented.

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[19] The aerial map sets were included as responses to FERC information requests for Resource Report 6 (Accession Nos. 20171002-5306 and 20171201-5163). They can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20171002-5306 and 20171201-5163 in the "Numbers: Accession Number" field.

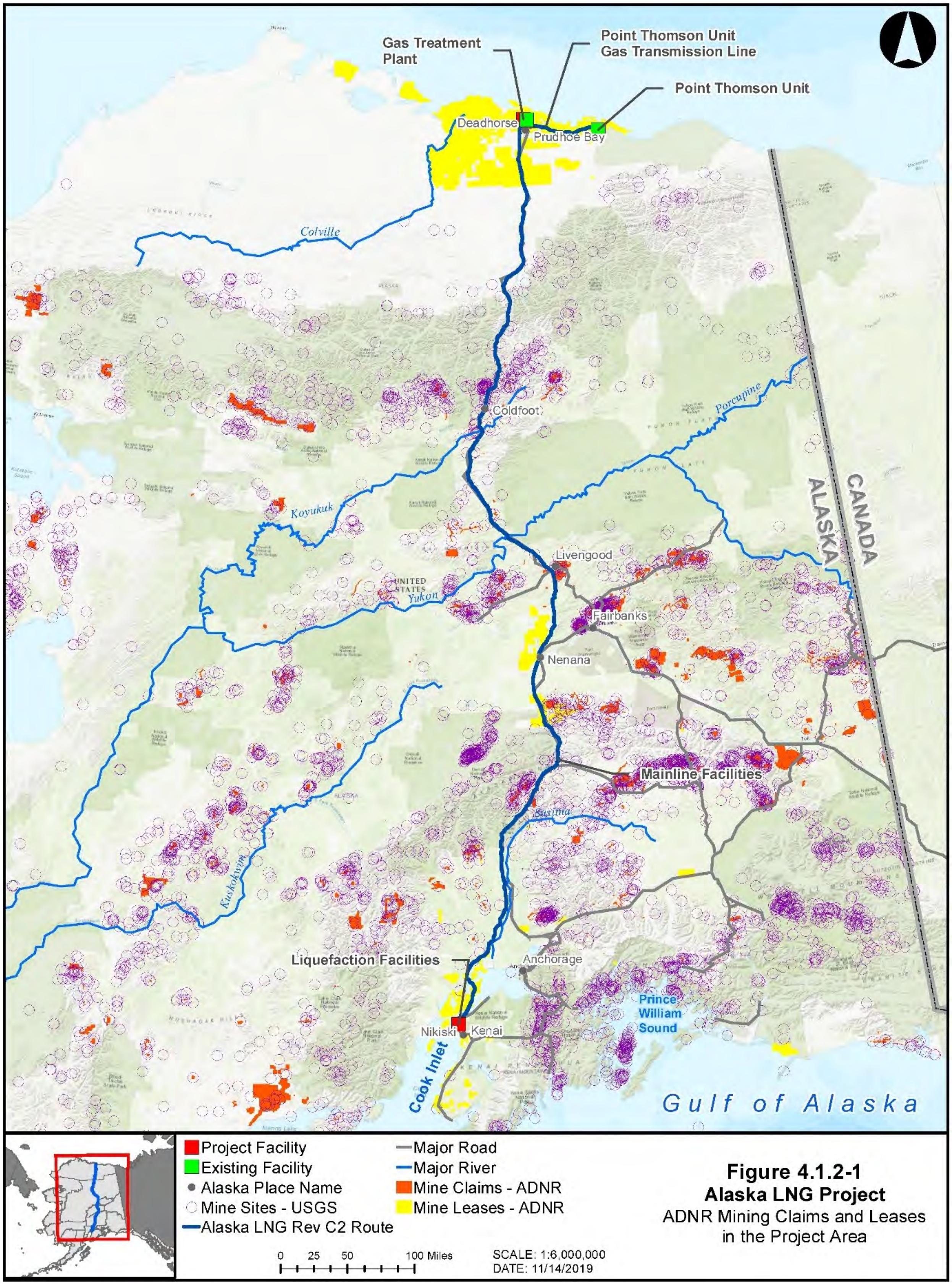

Figure 4.1.2-1
Alaska LNG Project
ADNR Mining Claims and Leases in the Project Area

TABLE 4.1.2-1 **Mineral and Industrial Material Resources Within 0.5 Mile of the Project**			
Facilities	Number of ADNR Mining Claims	Number of USGS Mineral Resources	Number of Industrial Material Sales Sites
Gas Treatment Facilities			
GTP	0	0	0
PBTL	0	0	0
PTTL	0	0	3
Subtotal	**0**	**0**	**3**
Mainline Facilities			
Mainline Facilities	**157**	**13**	**134**
Liquefaction Facilities			
LNG Plant	4	0	15
Marine Terminal	1	0	1
Subtotal	**5**	**0**	**16**
Total	**162**	**13**	**153**

Sources: ADNR, 2015e; ARDF, 2016; BLM, 2016b

The Gas Treatment Facilities would be within Alaska's northern mining region. With the exception of three industrial material sale sites, there are no identified ADNR mineral claims or USGS mineral resources within 0.5 mile of these proposed facilities.

The Mainline Facilities would be on or would cross Alaska's northern, eastern interior, and south-central mining regions as defined by Athey and Werdon (2017). AGDC identified 162 ADNR mining claims (including federal claims), 13 USGS mineral occurrences, and 153 material sales sites within 0.5 mile of the Mainline Facilities (see table 4.1.2-1). The mineral resources described below were identified as high potential and high certainty according to the USGS classification (Karl et al., 2016).

- Placer gold is likely to be found in non-continuous segments between about MPs 208.9 and 265.2, MPs 280.3 and 283.5, and MPs 528.3 and 602.9 (about 90.3 miles total). Two compressor station sites (Coldfoot and Honolulu) are also in areas of high potential and high certainty for placer gold. Permanent and temporary access roads for the Mainline Pipeline would cross a total of 4.0 and 22.0 miles, respectively, of areas in non-continuous high potential and high certainty for placer gold within these ranges. The permanent access roads would be at about MPs 240.2, 442.9, 561.8, and 598.2.

- Copper associated with shallow-water carbonate rocks is likely to be found in non-continuous segments between about MPs 144.9 and 151.0, MPs 199.4 and 208.9, and MPs 399.9 and 409.9 (about 24.3 miles total).

- High value platinum group elements, including nickel, are likely to be found along about 89.9 miles of the Mainline Pipeline in non-continuous segments between about MPs 222.3 and 265.2, MPs 280.3 and 315.3, and MPs 528.3 and 602.9. Two compressor station sites (Coldfoot and Honolulu) are also in an area of high potential and high certainty for high value platinum group deposits. No access roads would cross high potential areas for platinum group elements.

- Rare earth elements are likely to be found in non-continuous segments between about MPs 257.5 and 315.3, MPs 345.5 and 354.3, and MPs 589.5 and 602.9 (including about 38.5 miles of the Mainline Pipeline and about 10.8 miles of construction access roads within the same high-potential rare earth element area). The Honolulu Creek Compressor Station site would also be within an area of rare earth element and tin potential.
- Tin associated with granitic intrusions is likely to be found in non-continuous segments between about MPs 280.3 and 315.3, MPs 345.5 and 354.3, and MPs 559.7 and 602.9 (43.7 miles total). Temporary gravel access roads for the Mainline Pipeline would cross areas of high tin potential for a combined length of 13.4 miles within the milepost ranges listed above, and three permanent access roads would cross high potential areas for tin deposits at MPs 442.9, 562.0, and 598.5, for a total of 3.6 miles.

Federal and State of Alaska placer gold mining claims are within 1.0 mile of the Mainline Facilities at about MP 213 and between about MPs 218 and 265, MPs 395 and 409, and MPs 560 and 760, including placer State of Alaska gold mining claims adjacent to and partially overlapping the Mainline Pipeline near Livengood between about MPs 401 and 409.

The Liquefaction Facilities would be within Alaska's south-central mining region, as defined by Athey and Werdon (2017). No active surface or underground mines were identified within 0.5 mile of the Liquefaction Facilities, but five ADNR mining claims are within 0.5 mile of the site. In addition, 16 material sales sites were identified within 0.5 mile of the Liquefaction Facilities (see table 4.1.2-1).

Project impacts on mineral resources would include blocking or restricting access to these resources beneath Mainline Facilities. There are currently no copper or platinum group element mining claims or active mines; no active rare earth element or tin mines; and no known lead or zinc deposits within the Project area.

Borrow Sites and Mineral Material Sites

AGDC has identified locations where granular material (sand, gravel, and stone) deposits could be suitable for use as granular fill sources for the Project. Gravel deposits are typically associated with current or historic river systems where centimeter-sized or larger sediment was carried by fast-flowing rivers from weathering bedrock and deposited along river banks. Due to the deposition history, gravel resources are typically found in linear deposits, outwash plains, and glacial deposits. Near the Project area, gravel resources generally parallel the Sagavanirktok River, Oksrukuyik Creek, Toolik River, Atigun River, and other riparian settings, but gravel resources are also found in non-riparian areas. Table 4.1.2-2 identifies potential borrow source sites for Project construction identified by AGDC within 35 miles of the Mainline Pipeline centerline.

TABLE 4.1.2-2

Potential Granular Fill Material Sites Within 35 Miles of the Mainline Pipeline Centerline

Physiographic Provinces	Start Milepost	End Milepost	Number of Material Sites	Acres of Material Sites
Arctic Coastal Plain	0.0	63.9	8	224
Arctic Foothills	63.9	145.4	15	690
Arctic Mountains	145.4	262.7	17	912
Northern Plateaus	262.7	448.3	33	1788
Western Alaska	448.3	501.9	15	627
Alaska-Aleutian	501.9	564.8	20	497
Coastal Trough	564.8	806.6	45	1117
Total			**153**	**5,855**

AGDC provided a Project Gravel Sourcing Plan and Reclamation Measures that describes the Project's expected granular fill needs, provides existing and potential new locations of granular fill borrow sites and excess disposal locations, and outlines procedures for extracting and transporting granular fill. AGDC estimates that Project construction would require a total volume of about 31.3 million cubic yards of granular fill, as described below for each Project facility.

- The GTP would require about 6.9 million cubic yards for the GTP pad, Dock Head 4 construction, and West Dock Causeway upgrades.
- The Mainline Facilities would require the granular fill volumes identified below for construction.
    - The Mainline Pipeline would require about 8.8 million cubic yards for the right-of-way granular fill work pads, about 1.9 million cubic yards for padding the pipeline, and about 0.6 million cubic yard for slope stabilization and weight bags.
    - Mainline aboveground facilities, including compressor and heating stations, would require about 1.2 million cubic yards of granular fill.
    - Access roads and rail spur roads would require about 3.8 million cubic yards of granular fill.
    - Construction camps would require about 1.9 million cubic yards of granular fill.
    - Pipe storage yards would require about 1.5 million cubic yards of granular fill.
- The Liquefaction Facilities would require about 4.7 million cubic yards for use as fill material and for ready mixed concrete.

According to the Project Gravel Sourcing Plan and Reclamation Measures, AGDC anticipates that a sufficient volume of granular material would be available at the Liquefaction Facilities to supply the volume needed for fill. If needed, existing local quarries would be identified prior to construction that could provide supplemental material.

Coal Resources

The DGGS defines coal fields as areas with a high resource potential due to the presence of one or more known mineable coal beds. The DGGS defines coal basins as containing one or more coal fields and coal units as individual beds whether or not they are recoverable (Merritt and Hawley, 1986). Coal resources in Alaska are generally in three areas of the state:

- the North Slope in northern Alaska;
- the Nenana Valley in central Alaska; and
- Cook Inlet in southern Alaska.

Despite the extensive coal deposits in Alaska, estimated to total over 5.5 billion tons (5 billion metric tons) (McDowell Group, 2015b), the Usibelli coal mines are the only active mines in the state. These mines are in the Hoseanna and Marguerite Creek Valley east of Healy, about 6 miles northeast of the Mainline Pipeline at about MP 532.5 (ADNR, 2019c).

There are no identified active coal mines or potential coal units and/or fields within 0.5 mile of the GTP, PTTL, PBTL, or associated workspaces. There are also no identified active coal mines within

0.5 mile of the Mainline Facilities, but the Mainline Pipeline crosses several coal fields within larger coal basins with the potential to become future development opportunities. Table 4.1.2-3 summarizes the coal resources crossed by the Mainline Pipeline. Although no active coal mines were identified within 0.5 mile of the Liquefaction Facilities, the facilities are within the Kenai coal field of the Cook Inlet coal basin.

TABLE 4.1.2-3

Coal Resources Crossed by the Mainline Pipeline

Physiographic Province	From Milepost	To Milepost	Coal Resource Type
Arctic Coastal Plain	26.6	34.1	Lignite coal
Arctic Coastal Plain/Arctic Foothills	34.1	70.2	Lignite coal underlain by subbituminous coal
Arctic Foothills	70.2	75.3	Subbituminous coal of mineable thickness
Arctic Mountains	251.0	252.9	Northern coal district
Arctic Mountains	252.9	256.8	Tramway Bar coal field
Arctic Mountains/Northern Plateaus	261.9	268.7	Bituminous coal unit
Northern Plateaus	268.7	274.5	Upper Koyukuk
Northern Plateaus	367.6	373.7	Rampart coal field
Northern Plateaus	437.0	442.5	Middle Tanana coal basin
Western Alaska	461.3	500.0	Middle Tanana coal basin
Western Alaska/Alaska-Aleutian	500.0	534.7	Nenana coal basin
Coastal Trough	574.7	595.9	Broad Pass coal field
Coastal Trough	611.7	622.4	Broad Pass coal field
Coastal Trough	633.5	731.7	Susitna coal basin
Coastal Trough	731.7	806.6	Cook Inlet coal basin

Sources: Merritt and Hawley, 1986

4.1.2.2 Oil and Natural Gas Well Production

The Project would cross sedimentary sequences within the Beaufort Sea, North Slope, North Slope foothills, and Cook Inlet where oil and gas sales areas are designated by the ADNR. These areas account for important oil and natural gas well development due to the moderate to high potential for energy resources (ADNR, 2015e). Oil and gas resources are extracted through production wells. Table 4.1.2-4 provides a list of known production wells within 0.25 mile of the Project, based on information from the ADNR.

The ADNR regulates leasing of designated tracts of land that may be developed for oil and gas production. The total acreage of ADNR-designated sales tracts and the acreage of tracts that are actively leased and crossed by the Project are provided in table 4.1.2-4. Area-wide oil and gas lease sale areas are shown relative to Project facilities on figure 4.1.2-2.

The GTP and PBTL would be entirely within active leases associated with the Beaufort Sea and North Slope tracts. The GTP would be within 0.25 mile of 201 oil and gas production wells, 99 of which are active. AGDC did not identify any active oil and gas wells within 0.25 mile of the PBTL. The PTTL would be within the Beaufort Sea and North Slope designated tracts, but only partially within active lease areas. There are 48 identified oil and gas wells within 0.25 mile of the PTTL, 25 of which are active. The Gas Treatment Facilities would overlap about 3,009 acres of state designated sale tracts of which 2,893 acres are being actively leased.

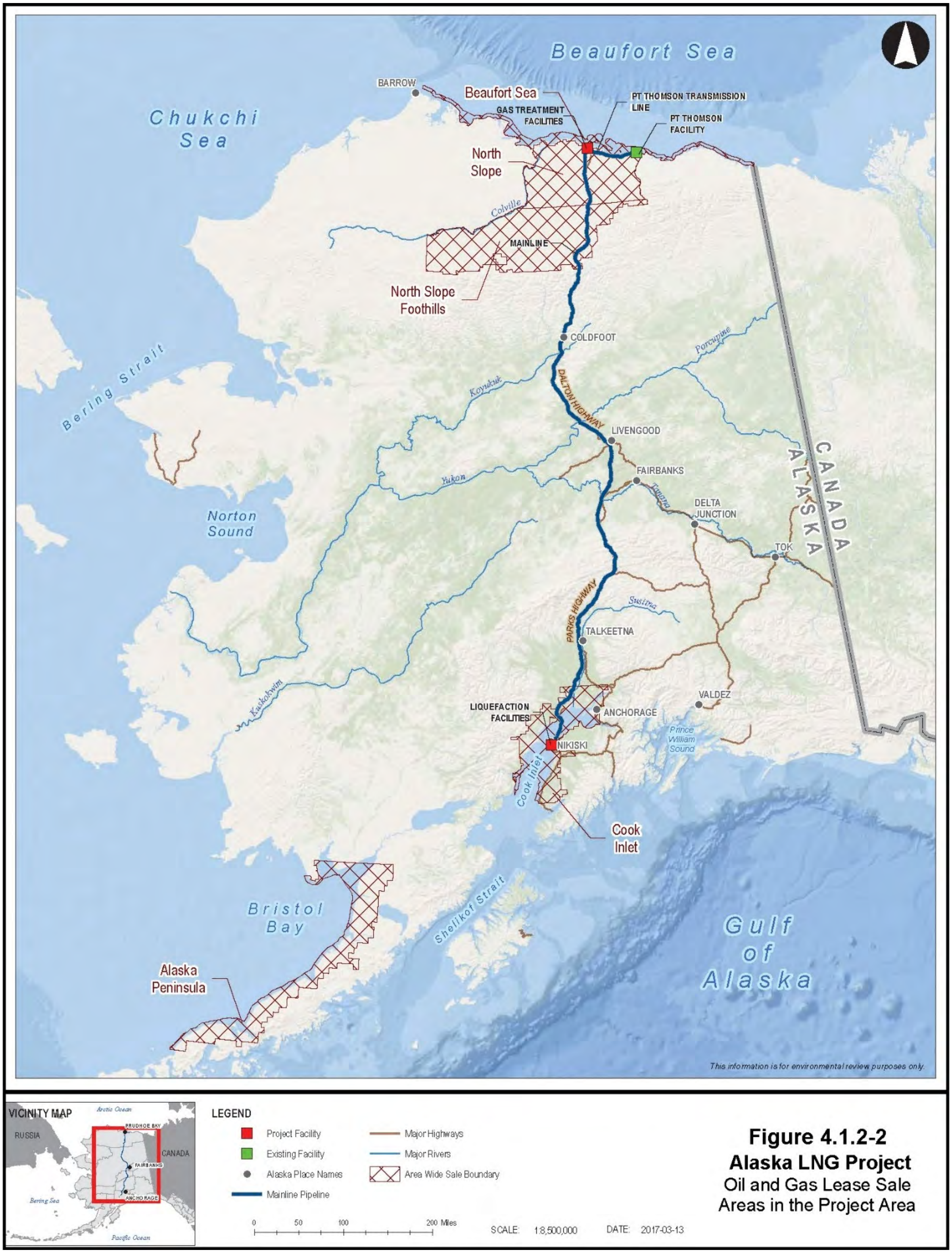

Figure 4.1.2-2
Alaska LNG Project
Oil and Gas Lease Sale Areas in the Project Area

TABLE 4.1.2-4 Oil and Gas Resources Within 0.25 Mile of the Project				
Facilities	Number of Oil and Gas Production Wells	Number of Active Oil and Gas Production Wells	State Designated Sale Tracts Crossed (acres)	Active State Designated Leases Crossed (acres)
Gas Treatment Facilities				
GTP	201	99	926	926
PBTL	0	0	7	7
PTTL	48	25	2,076	1,960
Subtotal	**249**	**124**	**3,009**	**2,893**
Mainline Facilities				
Mainline Facilities	76	40	46,162	34,309
Subtotal	**76**	**40**	**46,162**	**34,309**
Liquefaction Facilities				
LNG Plant	0	0	902	0
Marine Terminal	0	0	181	0
Subtotal	**0**	**0**	**1,083**	**0**
Total	**325**	**164**	**50,254**	**37,202**

Sources: ADNR, 2015e; Alaska Oil and Gas Conservation Commission, 2016

The Mainline Facilities would span the Beaufort Sea, North Slope, North Slope foothills, and Cook Inlet designated tracts and would overlap about 46,162 acres of state designated sale tracts, of which 34,309 acres are actively being leased. There are 76 oil and gas wells identified within 0.25 mile of the Mainline Facilities, 40 of which are active.

No known oil and gas wells or actively leased areas were identified within 0.25 mile of the Liquefaction Facilities. The Liquefaction Facilities would overlap about 1,083 acres of state designated sale tracts in Cook Inlet, but none of these areas are actively leased.

4.1.2.3 Impacts and Mitigation

Activities associated with Project construction and operation could affect mining operations and/or oil and gas extraction near the Project area. Construction activities include blasting and granular fill extraction, temporary land disturbance within construction workspaces, and/or temporary restrictions on development or access to mining claims or leases near the right-of-way.

Mining and Oil and Gas Operations

As described in section 4.1.2.1, rare earth elements, tin, and base metal deposits are along sections of the Mainline Pipeline. AGDC has stated that surface and/or subsurface mining would not be allowed within the footprint of the permanent Project facilities and access roads; access to resources in these areas would be permanently blocked to prevent damage to the Project. Blasting and drilling activities to access mineral resources proximal to the Project would be restricted and evaluated for safety on a case-by-case basis.

In their comments on the draft EIS, the State of Alaska said that any limitations on mining must be consistent with state laws and regulations as determined by the agencies that authorize the activity through the permitting process. AS 38.34.050(c) requires acquisition of a right-of-way permit for a gas pipeline transmission corridor, which is granted by the ADNR Commissioner. State land may be closed to multiple purpose use where the ADNR commissioner makes a finding that multiple purpose use would be incompatible with significant surface uses on the state land, or when classification is necessary for the development of utility or transportation corridors (AS 38.05.185 to 38.05.275 and 38.05.300). If the state declines permitting authorization for portions of the alignment authorized by the Commission, then AGDC would need to file a revised route for review and approval by FERC and other federal agencies with jurisdiction.

Existing mining claims include a prior existing right to mine, and AGDC would need to work with claim holders and land management agencies to identify areas to be withdrawn from mineral entry near the Project. Existing claims may be abandoned or voluntarily relinquished with or without compensation. Mineral Order No. 1162 was enacted to prevent adverse impacts of mining operations on ASAP pipeline construction and operation, and to accommodate future related facilities that could be added to the ASAP Right-of-Way Lease; a similar order could be implemented for the Project on State and State selected lands. All new federal and state mining claimants would be subject to permitting requirements, including blasting, drilling, and off-road transport. As part of the claimants permit process, AGDC would be given the opportunity to comment on the proposed mining activity if the activity has the potential to affect Project construction or operation. Additionally, if they can prove that they have standing in the case, AGDC could appeal a land management agency's decision to issue an authorization to mine with the BLM State Director or the Interior Board of Land Appeals.

Potential hazards associated with current or historic mining claims include tailings or chemical wastes, mud pits, contaminated water and/or soils, explosives, and subsidence of the ground surface. In particular, placer gold mining activities historically utilized elemental mercury to facilitate the separation of gold dust from excavated material. Settling ponds are used to clarify water in modern placer gold mining, and reclamation of disturbed areas is required. Historic placer gold mine tailings may contain elemental mercury residue and/or mercury-affected soils and sediment that could be encountered during construction if the Project intersects a historic mining area. For more information on potential contamination associated with current or historic mining claims see section 4.9.6.

There are six federal gold placer mining claims upstream of the Mainline Pipeline at distances ranging from 880 feet to greater than 0.5 mile between about MPs 218 and 282, and one additional claim upstream of the Mainline Pipeline at about MP 402 that may have historically discharged sluice water or solids in the Project area. Of these mining claims, only the Clara Creek mine near MP 239.3 remains active. While there are no known hard rock mine tailing ponds within drainages that could affect the Project, runoff, seepage, and sediments from historic mines could be transported distances greater than 1.0 mile through surface runoff, groundwater movement, or wind dispersion. This potential infiltration could lead to large volumes of metals leaching into stream and river ecosystems, resulting in acid mine drainage (see section 4.1.3.7). In the event that Project construction encounters contaminants from these historic and active mine sites, AGDC would follow the mitigation and response measures outlined in the Project Unanticipated Contamination Discovery Plan discussed in sections 4.2.6 and 4.9.6.

Although there are no active coal mines within 0.5 mile of the Project, the proposed Mainline Pipeline route would cross a combined total of about 1 mile of Cook Inlet Region, Inc. (CIRI) land within the Beluga coal field on discontinuous tracts between MPs 750 and 770. In comments on the draft EIS, CIRI said that AGDC should accommodate CIRI's access to its lands and resources, including its coal resources, via the Mainline Pipeline right-of-way or access roads. AGDC would negotiate easement agreements with private landowners and Alaska Native corporations, including CIRI. The ability of CIRI to access its lands and resources via the Project right-of-way or access roads could be addressed in easement negotiations.

In comments on the draft EIS, CIRI asked about potential limitations on blasting in the Beluga coal field after construction of the Mainline Pipeline. AGDC's Blasting Analysis Report evaluates potential effects of blasting on the Mainline Pipeline as well as the TAPS and associated fuel gas line and suggests standard setbacks for blasting from the Mainline Pipeline.[20] Based on pipe stress and peak particle velocity evaluations, blasting could theoretically be performed with as little as 75 feet of separation from the Mainline Pipeline, depending on the explosive charge used. Higher explosive loading would require greater setback distances and would need to be evaluated on a case-by-case basis. Lesser separation distances (30 feet minimum) may be acceptable for some blast plans, but additional evaluations and safety measures would be required.

Granular Fill Sourcing for Construction

Impacts from granular fill borrow (material) site development include stripping topsoil and overburden, potential contamination due to surface spills from construction equipment, compaction and increased runoff due to land clearing, and dewatering. Topsoil would be placed in areas that have already been mined to reclaim the area or would be stockpiled for use in future reclamation. As stated in the Project Gravel Sourcing Plan and Reclamation Measures, overburden could be placed onto previously mined areas as it is removed, which reduces handling costs and maintains useful soil properties.

We received scoping comments regarding the potential impact of granular fill extraction on water resources and availability of granular fill resources for highway and other projects. With the preparation and implementation of the site-specific mining and reclamation plans to be developed in coordination with the appropriate land management agency (i.e., the ADNR, BLM, and ADOT&PF) as part of the permitting processes, potential impacts on water resources and other environmental concerns would be avoided or minimized.

Granular fill for construction of the Project would be sourced from 153 potential off-right-of-way sources with a combined area of 5,855 acres (see table C-8 in appendix C). Of the 153 potential material sites, only sites that are available for the Project and have not been assigned for highway or other projects would be developed in accordance with the Project Gravel Sourcing Plan and Reclamation Measures. Because specific material sites and volumes have not been finalized, prior to construction, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, an updated Gravel Sourcing Plan and Reclamation Measures, finalized in coordination with appropriate state and federal agencies, including the BLM, that identifies the material volumes to be acquired from each material site. This plan would include measures for testing material sites for potential acid rock drainage (ARD) and presence of contaminants, such as mercury, arsenic, antimony, etc., that may not be suitable fill material for construction of granular fill pads and access roads. Additional recommendations and commitments regarding granular fill use and selection are provided in section 4.2.4.

New side hill-cut material sites are being considered for development in the upper Dietrich River and the hillslopes near Livengood, Alaska, along the right-of-way. A mining and reclamation plan would be prepared in coordination with the appropriate land management agency (i.e., the ADNR, BLM, and ADOT&PF) for each material site. The site-specific plan would outline the permits necessary to mine at the site, in addition to an environmental review that may include a review of cultural resources, wildlife and fisheries considerations, potential contamination, wetland impacts, and visual impacts. The plan would include logistical details such as access road locations, spill cleanup procedures, vibration reduction procedures, and signage and security, in addition to extraction and operational protocols.

A new material site (the Gas Treatment Facilities gravel mine) would be developed southwest of the GTP, north of the Putuligayuk River, to source granular fill for the GTP and associated infrastructure. This site would be developed at the same time as the ongoing excavation required for GTP water reservoir

[20] AGDC's *Blasting Analysis Report* was provided as appendix P to Resource Report 11 (Accession No. 20170417-5346), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5346 in the "Numbers: Accession Number" field.

excavation. Overburden would be removed from the gravel mine by blasting. Following blasting and excavation, granular fill would be hauled away for use during construction. Overburden would be stockpiled along the perimeter of the gravel mine in berms to be used during site reclamation. For additional information on construction of the gravel mine, see section 2.1.3. Additional granular fill would be sourced from existing mines.

No new or expansion of existing material sites would be required for construction of the Liquefaction Facilities. Material from construction of the heavy haul road and the LNG Plant footprint would be processed and used for granular fill. AGDC has indicated that if an adequate amount of material is not available on site, it would purchase material from local commercial quarries in the vicinity of the Liquefaction Facilities.

AGDC has identified 59 mineral material source sites within 250 feet of the construction workspace for the Mainline Pipeline, including 9 existing sites within the proposed construction right-of-way. Existing material sites selected for use for Project construction would be operated in accordance with landowner requirements. State-owned sites would be subject to operating conditions under ADNR's Material Sales Contract and federally owned sites would be subject to BLM's Purchase of Mineral Material Sales Contract. AGDC would address measures for site access control and operating safety in a plan of operations.

Potential impacts on existing material sites within close proximity to the Mainline Pipeline that the Project does not intend to utilize for construction would be evaluated on a site-by-site basis with the material site landowner. Sites that adjoin the Project's operational right-of-way on state or federal lands may be subject to access or buffer restrictions imposed by State of Alaska right-of-way lease and BLM right-of-way grant conditions. Mitigation measures to ensure access to existing material sites would be consistent with AGDC's Traffic Mitigation Plan. Project contractors would coordinate with ADOT&PF and local entities for the use of public roads and with landowners for the use of approved access roads.

4.1.3 Geologic Hazards

Geologic hazards are natural, physical conditions that can damage land and structures or injure people. Such hazards typically include seismicity (e.g., earthquakes, surface faults, tsunamis and seiches, and soil liquefaction), mass wasting, volcanic eruptions, subsidence, permafrost, acid rock drainage, naturally occurring asbestos (NOA), and hydrologic processes and flooding. Permafrost is discussed in more detail in section 4.2.

In its application, AGDC provided the results of a series of geohazard analyses conducted to determine areas where geologic hazards would be crossed by the Project and where these hazards would need to be mitigated. The geohazard analyses included:

- an *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018);
- a *Probabilistic Seismic Hazard Analysis* (Golder Associates Inc., 2016);
- a *Seismic Liquefaction and Fault Displacement Hazard Assessment* (WorleyParsons, 2016c); and
- a *Slope Stability and Mass Movement Assessment Update* (WorleyParsons, 2016d).

4.1.3.1 Seismicity

Earthquakes generally occur when the two sides of a fault suddenly slip past each other. The movement creates ground motion, which can cause property and structure damage if the motion is sufficiently intense. The geologic activity occurring in south-central Alaska, including volcanism and seismicity, is a consequence of the Pacific plate subduction in a north–northwest-trending direction beneath the North American plate in the Aleutian subduction zone. To the east of the Pacific plate subduction, the Yakutat microplate is converging with the North American plate, which has the effect of rotating a block of southern Alaska in a counterclockwise direction (Haeussler, 2008; Bemis et al., 2015). The rotation of the block manifests in slippage along the Denali fault zone and the Northern Foothills fold and thrust belt north of the Alaska Range (Bemis et al., 2015). In addition, the Minto Flats seismic zone and the active Castle Mountain and Lake Clark faults in central Alaska would be crossed by the Project (see figure 4.1.3-1).

Generally, earthquake depth at the plate boundary in southern Alaska corresponds to the distance from the seafloor trench of the subduction zone: the deepest earthquakes (greater than 90.0 miles) occur farther from the convergent boundary and reflect the depth of the subducting plate, and shallower earthquakes (0 to 20.0 miles) occur closer to the plate boundary. This is true for earthquakes that specifically occur on the plate interface of the subduction zone but may not describe the general behavior or upper crustal, intra-slab, and outer rise earthquakes. The southern portion of the Project area, including the Liquefaction Facilities and the Mainline Facilities between about MPs 518.0 and 806.6, would be within an active seismic area due to earthquakes associated with the active tectonic plate boundary and earthquakes associated with structural folds mapped within Cook Inlet (WorleyParsons, 2016c).

Ground surface displacement (i.e., fault surface rupture) occurs when movement along a deep fault breaks through to the surface (USGS, 2019e). After the initial fault rupture, seismic waves cause shaking of the ground surface. Fault displacement could occur where the Mainline Pipeline intersects known or previously unknown faults. Earthquakes along nearby or distant crustal faults and subduction zone earthquakes have the potential to produce significant ground shaking in the Project area. Potentially active faults (a fault that has been observed or has evidence of seismic activity during the last 10,000 years) were a design engineering consideration as described in more detail in sections 4.18.6 and 4.18.10.

On November 30, 2018, a magnitude 7.0 earthquake occurred north of Anchorage as a result of a fault within the subducting Pacific slab in the Alaska-Aleutian subduction zone. The earthquake was not due to movement of a fault near the Earth’s surface. The epicenter was about 24 miles southeast of Mainline Pipeline MP 734.4 and about 70 miles northeast of the Liquefaction Facilities. The earthquake induced a peak ground acceleration of 0.843 gravity at the epicenter. Nearby seismic monitoring stations in the Anchorage area, less than 16 miles from the earthquake epicenter, recorded peak ground accelerations ranging between 0.123 and 0.470 gravity. On the Kenai Peninsula, a monitoring station, about 10 miles northeast of the Liquefaction Facilities, recorded a peak ground acceleration of 0.378 gravity. The earthquake caused power outages; damage to roads and buildings; closures of schools, businesses, and government offices; and soil liquefaction in the Anchorage area. As of December 2019, more than 11,000 aftershocks had occurred. Aftershocks are expected to continue at least through June 2021, with a forecast of more than 80 aftershocks during that time (Morrison, 2019). Of those aftershocks, the majority are expected to be at least a magnitude 3.0, with a 48-percent chance of up to three magnitude 5.0 quakes or higher and a 6-percent chance of up to two magnitude 6.0 quakes or higher.

The USGS published intensity contours derived from data collected during the November 2018 earthquake. Portions of the proposed Mainline Pipeline route experienced shaking intensity ratings of VII or greater from the earthquake. Shaking of this intensity can cause slight to moderate damage in well-built structures and considerable damage in poorly built or badly designed structures (USGS, 2017b; Alaska Earthquake Center [AEC], 2018). The site of the Liquefaction Facilities experienced shaking intensity ratings up to VI, which can cause slight damage in well-built structures.

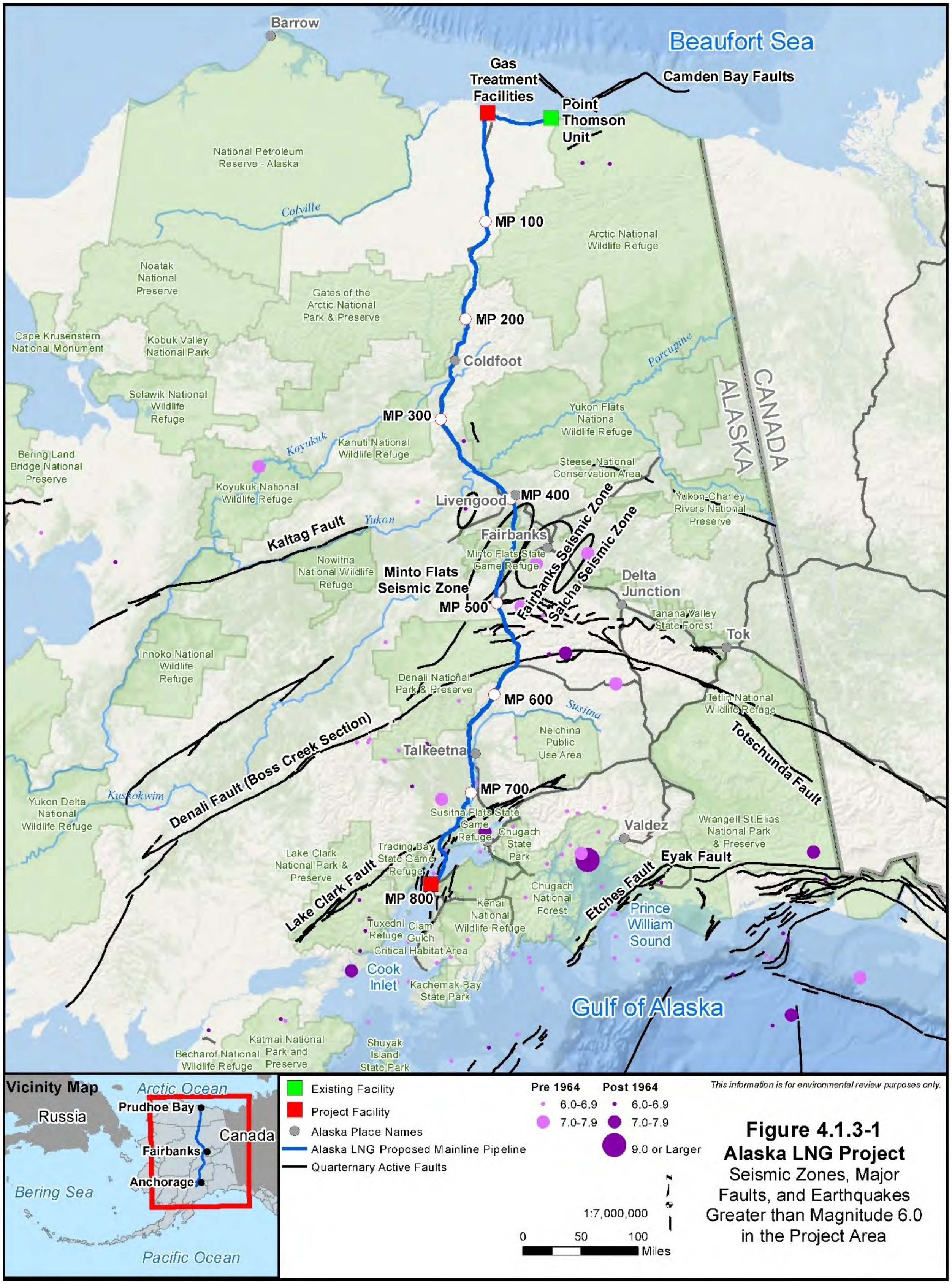

Figure 4.1.3-1
Alaska LNG Project
Seismic Zones, Major Faults, and Earthquakes Greater than Magnitude 6.0 in the Project Area

In January 2016, a magnitude 7.1 earthquake (the Iniskin Earthquake) occurred southwest of Anchorage as a result of intermediate-depth strike-slip faulting. Intermediate-depth earthquakes typically cause less damage on the ground surface than similar magnitude shallow-focus earthquakes, but large intermediate-depth earthquakes may be felt at greater distances from their epicenters.

If a previously unknown fault directly under the Project resulted in a magnitude 7.0 earthquake scenario, a typical shaking intensity of VIII at the epicenter could cause considerable damage in ordinary substantial buildings with partial collapse. Slight damage could occur in specially designed structures, and factory stacks, columns, and walls could fall (USGS, 2017b). O'Rourke and Palmer (1996) performed a review of the seismic performance of existing gas transmission lines in southern California and concluded that nearly all pipeline damages requiring repairs occurred in areas with shaking intensity greater than or equal to VIII and that damage occurred primarily in the form of ruptures at oxy-acetylene girth welds. O'Rourke and Palmer (1996) also concluded that modern electric arc-welded gas pipelines perform well in seismically active areas of the United States. The study included 11 earthquakes with a magnitude of 5.8 or greater and shaking intensity ratings of VI and higher.

Oxy-acetylene girth welds are typically not used in modern pipeline construction. The proposed Project would be constructed using a combination of mechanized electric arc-welding and manual metal arc welding or stick welding. While the Iniskin Earthquake was of a shaking intensity where damage did occur as reported in the O'Rourke and Palmer (1996) study, given the modern construction techniques that AGDC would use to construct the Project, impacts from an earthquake with a similar intensity would not be anticipated. Additionally, as discussed in sections 4.18.6 and 4.18.10, the Mainline and Liquefaction Facilities would be designed to meet all applicable seismic safety requirements.

While megathrust earthquakes do not originate within the Project area, they can generate strong ground motions for hundreds of miles in all directions. The most significant instrumentally recorded earthquake to have affected the Project area was the 1964 Great Alaskan Earthquake. The magnitude 9.2 megathrust earthquake remains the most powerful earthquake recorded in North American history. Significant damage occurred throughout southern Alaska, including soil liquefaction, ground displacement, landslides, and tsunamis. Other significant historical earthquakes have occurred along the megathrust, including earthquakes with a magnitudes of 7.5 or greater in 1979, 1987, 1988, and 2002 (AEC, 2018).

Earthquakes are much less frequent in northern Alaska, and seismicity is considered low in the northern Project area (Koehler et al., 2012). Within 50.0 miles of the Project area in the northernmost physiographic provinces (i.e., the Arctic Coastal Plain, Arctic Foothills, and Arctic Mountain Physiographic Provinces), there have been 13 earthquakes in the last 50 years with magnitudes greater than 5.0 (AEC, 2018; USGS, 2019d).

The Quaternary fault and fold database (Koehler, 2013) identified the locations and characteristics of faults and folds near the Project facilities. The locations of faults and seismic zones crossed by the Project are shown on figure 4.1.3-1. The number of faults and folds within 100.0 miles of the Project area, as well as the number of historic earthquakes, are summarized in table 4.1.3-1.

Gas Treatment Facilities

In contrast to the seismically active southern portion of Alaska associated with active subduction along the Aleutian arc and crustal faults described above, the northern portion of Alaska has been in a state of inactivity or dormancy. There are no mapped faults or folds within 0.25 mile of the proposed Gas Treatment Facilities (USGS, 2018g). On August 12, 2018, a 6.4 magnitude earthquake was recorded about 52 miles southwest of Kaktovik in the Sadlerochit Mountains about 25 miles south of the Beaufort Sea. This is the largest recorded earthquake on the North Slope. The epicenter was about 40 miles southeast of the eastern end of the PTTL. While information is still being gathered on this recent event, it is considered a naturally caused earthquake from the stick-slip[21] tectonics in the region. The behavior of the fault or faults responsible for the earthquake is currently unknown (Dickson, 2018).

TABLE 4.1.3-1

Summary of Quaternary Faults, Folds, and Historic Earthquakes Within 100 Miles of the Project

Facilities	Number of Mapped Faults and Folds	Number of Historic Earthquakes with Recorded Maximum Intensity of IV or Greater [a]	Number of Historic Earthquakes with a Body Wave Magnitude of 6 or Greater [b]
Gas Treatment Facilities			
GTP	1	16	1
PTTL	14	79	2
PBTL	1	16	1
Mainline Facilities			
Mainline Facilities	515	147	52
Liquefaction Facilities			
LNG Plant	4	38	26
Marine Terminal	3	38	26

Sources: Koehler, 2013; USGS, 2019d

[a] Values are based on the Modified Mercalli Intensity, which measures the strength of shaking produced by the earthquake at a certain location. An intensity rating of IV could cause rattling noises and noticeable shaking of indoor items (USGS, 2017b).

[b] Magnitude measures the energy released at the source of the earthquake (USGS, 2017b).

Although the location and magnitude were atypical, stick-slip events are common in the Brooks Range, producing a few magnitude 4 to 5 earthquakes per year (AEC, 2018). The Alaska State Seismologist stated that the August 12, 2018 earthquake followed “tectonic patterns of previous, smaller earthquakes that have historically occurred in the area,” indicating the earthquake is not related to factors such as permafrost thawing from climate change or oil field activity (DeMarban, 2018).

No damage was reported to any North Slope oil-production facilities or networks, including the TAPS System (DeMarban, 2018) and Prudhoe Bay oil field facilities (Mackintosh, 2018). The AEC found little to no potential for tsunamis, landslides, or liquefaction in the area (USGS, 2018e). See section 4.18.6 for additional discussion on seismic risk and the Gas Treatment Facilities.

Mainline Facilities

The Mainline Facilities would cross several seismically active and potentially active regions. These major faults and seismic zones have documentation of surface displacement dating to the Holocene Epoch. The potential exists that additional unmapped faults could be active near or within Mainline Pipeline workspaces. Appendix F provides fault and seismic zone mapping within 5.0 miles of the compressor stations and heater station associated with the Mainline Facilities.

As part of the ASAP Project, the DGGS conducted an investigation of potentially active tectonic faults along the pipeline route (Koehler et al., 2015). The following summarizes the findings from that report for the faults that would also be crossed by the Mainline Facilities. Additional information on

[21] Stick-slip refers to the fast movement that occurs between two sides of a fault when the two sides become unstuck. Rock becomes distorted, or bent, but holds its position until the earthquake occurs. Stick-slip displacement on a fault radiates energy in the form of seismic waves (USGS, 2018c).

Mainline Pipeline fault crossings, including design and the potential for seismic effects on the pipeline can be found in section 4.18.10.

The Minto Flats seismic zone would be crossed by the Mainline Pipeline between about MPs 411.0 and 488.0. The Minto Flats seismic zone is an active, strike-slip seismic zone that extends north of the Northern Foothills Fold and Thrust Belt. The Minto Flats seismic zone has been the source of multiple earthquakes felt in the Fairbanks area. The largest of these earthquakes was the magnitude 6.0 Minto Flats Earthquake of 1995. A magnitude 5.1 earthquake occurred August 30, 2014, in the northern part of the zone and generated an aftershock sequence of more than 1,500 events (AEC, 2018).

The Northern Foothills Fold and Thrust Belt is a system of thrust faults that extends along the northern side of the Alaska Range. The Mainline Pipeline extends across the western part of the system where diffuse seismicity is associated with several faults, including the Park Road, Healy, Healy Creek, Stampede–Little Panguingue Creek, and Northern Foothills faults. The main fault of the system, the Northern Foothills thrust fault, would be crossed between MPs 500.0 and 500.6 along the north and south traces of the fault. This fault is thought to be the source of a 1947 magnitude 7.2 earthquake. Although surface rupture was not documented, this earthquake underscores the possibility of future magnitude 6 to 7 earthquakes in the thrust belt (Koehler et al., 2015).

The Stampede-Little Panguingue Creek thrust fault would be crossed by the Mainline Pipeline between MPs 520.0 and 521.0. The potentially active Stampede–Little Panguingue Creek fault extends about 28 miles from the East Fork Toklat River to the vicinity of the Parks Highway. Uplift of the hanging wall of the fault indicates that the fault has been active in the post Plio–Pleistocene time. Koehler et al. (2015) concluded that the Stampede–Little Panguingue Creek fault has not displaced late Pleistocene or Holocene deposits near the Project. Although the fault could become more active to the west, no evidence of Holocene activity in the area was found.

The Healy Creek reverse fault is a potentially active fault that would be crossed by the Mainline Pipeline between MPs 522.4 and 522.5 (Koehler et al., 2015). The fault is a major element of the Northern Foothills fold-thrust belt. The only detailed information on the activity of the Healy Creek fault comes from topographic analyses and trenching performed in 2010 by Bemis (Bemis, 2010). Topographic profiles constructed by Bemis determined that the surfaces were not deformed, and it was inferred that the fault has not generated a surface rupture for at least 7,000 years (Bemis, 2010).

The Healy reverse fault is a Holocene-active fault that would be crossed by the Mainline Pipeline at about MP 526.9 to 527.0. The trace of the fault is mapped several miles north of the town of Healy, where it extends about 0.5 mile westward from the Nenana River. Based on exposed stratigraphy, Bemis (2010) concluded at least three earthquakes have occurred along this fault that postdate deposition of the Riley Creek-age glaciation deposits and deduced that the most recent earthquake occurred between 1,200 and 1,600 years ago. Koehler et al. (2015) suggested the possibility that complicated stratigraphy and cryoturbation processes could have limited the interpretation of multiple surface-rupturing earthquakes along the fault.

The active Park Road fault, the southernmost fault of the Northern Foothills fold-thrust belt, is a reverse fault that would be crossed by the Mainline Pipeline near MPs 537.7 to 537.8. The fault extends from the Sanctuary River in the DNPP east to the upper Moody Creek Drainage. Uplift and folding in the hanging wall of the fault are responsible for the development of the Mount Healy anticline. Koehler et al. (2015) determined that the fault length results in an estimated maximum earthquake of moment magnitude of 6.7.

The Holocene-active Denali strike-slip fault would be crossed by the Mainline Pipeline from MPs 560.3 to 561.5. The fault extends for hundreds of miles along the southern margin of the Alaska Range in south-central Alaska and was determined to pose a fault rupture hazard for the ASAP Project. Active tectonic geomorphology is evident along the Denali fault's entire length. The eastern part of the central Denali fault section was the source of the 2002 magnitude 7.9 Denali fault earthquake. The rupture crossed TAPS near the Richardson Highway, where seismic design engineering at the crossing prevented damage to the pipeline. There is no evidence of historic ruptures of the Denali fault west of the 2002 rupture (Koehler et al., 2015).

The Castle Mountain strike-slip fault would be crossed at about MPs 743.2 to 743.4. The fault traces southward into Cook Inlet where many south–southwest trending folds have been mapped, including the Beluga River and north Cook Inlet (SRS) anticlines. Evidence for active deformation includes a well-defined topographic scarp that is easily identified by a distinct vegetation line in the Susitna lowland. Two moderate historic earthquakes have occurred along this fault, a magnitude 5.7 earthquake in 1984 and a magnitude 4.6 earthquake in 1996. Koehler et al. (2015) determined that the fault length results in an estimated maximum earthquake of moment magnitude of 7.2.

The tectonic structure of the Cook Inlet Basin consists of a northeast-trending forearc[22] basin with the subducting Pacific plate about 150 to 200 feet beneath the center of the basin. The majority of the deformation in the basin is Pliocene to recent, resulting in folds that are doubly plunging, discontinuous, and asymmetric (Haeussler and Saltus, 2011). Two anticlines would be crossed by the offshore portion of the Mainline Pipeline: the Beluga River anticline and the North Cook Inlet-SRS anticline. The Beluga River anticline, which is a thrust fault cored anticline, would be crossed by the Mainline Pipeline between about MPs 766 and 768. The North Cook Inlet-SRS anticline is a fault-cored fold anticline in the middle of Cook Inlet. The offshore Mainline Pipeline would run generally parallel with the alignment of the mapped North Cook Inlet-SRS anticline with multiple crossings between about MPs 776 and 787.

No data is available to characterize the potential deformation of the two subsea anticlines at the pipeline crossing locations, but AGDC conducted aerial reconnaissance of portions of the Beluga River anticline extending on land on the west side of Cook Inlet. While there was evidence of morphologic changes, there was no clear evidence of deformed strata in exposures along the Beluga River cut bank, which would have indicated sustained, long-term deformation. Based on this aerial reconnaissance, the anticline was noted of having no compelling evidence of substantial late Quaternary deformation, and the probability of discrete surface rupture is low (WorleyParsons, 2016b). No aerial reconnaissance of the Cook Inlet-SRS anticline was completed as it is completely within Cook Inlet. Additional information on Mainline Pipeline fault crossings, including design and the potential for seismic effects, can be found in section 4.18.10.

Liquefaction Facilities

The Liquefaction Facilities would be in an area of elevated seismic risk due to the prevalence of earthquakes associated with subduction and Cook Inlet folds. Geologic field mapping, assessment of available geologic maps, topographic surveying in 2015, and geomorphic analysis of Light Detection and Ranging (LiDAR) data from 2008 and 2012 did not identify any surface faults within a 5.0-mile radius of the facilities. In addition, published literature corroborates the absence of active surface faults within 5.0 miles of the facilities (Koehler et al., 2012). The *Alaska LNG Facilities Geologic Hazard Report* (Geologic Hazard Report [Fugro, 2015a]) identified 13 lineaments within 5.0 miles that were determined to have a non-tectonic origin and were primarily caused by glacial processes or meltwater streams from receding glaciers. A previous investigation by Kent and Sullivan Inc. (1997) identified two surface

[22] The forearc is the region between a subduction zone and volcanic chain (USGS, 2019c).

lineaments, referred to as the Salamatok Road faults, north of the Liquefaction Facilities that were also determined to have a non-tectonic origin.

AGDC's Geologic Hazard Report indicated that the glacial deposits underlying the onshore facilities do not show evidence of surface fault displacement based on field mapping of stratigraphic marker elevations along the coastal bluff and a shallow geophysical survey that evaluated the uppermost 200 feet of glacial sediments. Deep seismic reflection data indicate that the faults nearest the Liquefaction Facilities in Cook Inlet are within Tertiary and Mesozoic Era strata and do not reach the surface. Finally, an analysis of the seafloor bathymetry and seismic reflection data near the Liquefaction Facilities did not identify surface faulting in Tertiary Era strata beneath the site (Fugro, 2015a). See section 4.18.6 for additional discussion of seismic risk and the Liquefaction Facilities.

4.1.3.2 Soil Liquefaction

Soil liquefaction is a process whereby earthquake shaking or other rapid loading reduces the strength and stiffness of a saturated non-cohesive soil. The result is a transformation of soil to a liquid state. Typically, a combination of the following three factors is necessary for liquefaction to occur.

- Loose, granular soil materials – The presence of non-cohesive sands and silts with very low or no clay content, naturally deposited (beach or river deposits, windblown deposits), or man-made land (hydraulic fill, backfill).
- Saturation of the soil materials by groundwater – In saturated ground, the space between individual particles is completely filled with water. The water pressure on the particles increases during ground shaking and can overcome the overburden pressure and result in liquefaction. Deposits with a high susceptibility to liquefaction are most commonly found near bodies of water such as rivers, lakes, bays, oceans, and wetlands.
- Severe shaking – The potential for liquefaction depends on the amplitude and duration of shaking at the site. Higher magnitude earthquakes produce longer duration shaking and higher ground motion amplitudes, which result in a higher liquefaction potential (WorleyParsons, 2016c).

Gas Treatment Facilities

Soil liquefaction was not considered a hazard for the GTP, Dock Head 4, PTTL, or PBTL by AGDC because the facilities are in an area of historically low seismic risk and soil liquefaction does not occur where soils are frozen. A discussion of potential soil liquefaction due to climate change is presented in section 4.1.3.10. As discussed above, after the August 12, 2018, magnitude 6.4 earthquake, it was determined that little to no soil liquefaction occurred (USGS, 2018e). See section 4.18.6 for additional discussion of the geotechnical evaluation of the Gas Treatment Facilities.

Mainline Facilities

AGDC provided a report, *Seismic Liquefaction and Fault Displacement Hazard Assessment* (WorleyParsons, 2016c), that analyzed the Mainline Pipeline route to locate areas where soils have the potential to laterally spread and/or become more buoyant due to liquefaction. The report focused on seismically active areas and calculated lateral spread displacement and buoyancy. The analysis determined that about 38.1 miles of the Mainline Pipeline had the potential for lateral spread, 9.6 miles of which were considered to have a high hazard, and the remaining 28.5 miles to have a moderate hazard. The longest

Mainline Pipeline section characterized as having a high hazard would be within the Cook Inlet-Susitna Section of the Coastal Trough Province, about 46 miles southwest of Anchorage.

The *Seismic Liquefaction and Fault Displacement Hazard Assessment* determined that 56.5 miles of the Mainline Pipeline would be in areas of potentially buoyant soils, which are defined as saturated, granular, and cohesionless soils dating to less than 500 years old or the Late Holocene Epoch that were uncemented following deposition. Buoyant soils that are triggered by liquefaction could lead to buoyancy rise where a buried pipeline floats up to the surface and could become exposed and/or rupture. Of the total miles crossed, 22.9 miles were classified as having a high potential for buoyancy and the remaining 33.6 miles as having a moderate buoyancy potential. The area of the Mainline Pipeline where buoyancy hazards are the highest is between about MPs 448.3 and 501.9 in the Tanana-Kuskokwim Section of the Western Alaska Province. Overall, the Project area south of about MP 338.0 was determined to have sufficient seismic potential to generate buoyant rise potential (WorleyParsons, 2018).

Liquefaction Facilities

AGDC collected onshore borings from the Liquefaction Facilities to assess the potential for soil liquefaction at the site. The evaluation determined that continuous liquefiable layers are not present at the site, but certain horizons classified as sandy silt and lean clay were recognized as having the potential to liquefy. These lenses were found to be thin and intermittent, and it was determined that any liquefaction of the horizons would be localized with an estimated displacement of less than 0.5 inch (Fugro, 2015b).

Nearshore borings were evaluated to determine the likelihood that liquefaction could occur on the Marine Terminal footings. While the analysis found that potential liquefiable horizons are within the uppermost 10 feet, the estimated settlement of the horizons in the construction area was less than 0.5 inch, and the lenses were thin and discontinuous, similar to the onshore potentially liquefiable horizons. Thus, any liquefaction that could occur would be localized (Fugro, 2015b). See section 4.18.6 for additional discussion of the geotechnical evaluation of the Liquefaction Facilities.

4.1.3.3 Mass Wasting

Mass wasting encompasses geologic hazards that involve down-slope movement of several types of materials, including rock, soil, sediment, snow, or ice, at timescales ranging from slow and creeping to fast and catastrophic. Although gravity is generally the force that causes mass wasting events, slope instability can be triggered by heavy precipitation, freeze-thaw cycles and melting of permafrost, earthquake vibrations, or human activities. Depending on the type of movement, mass wasting events are classified into falls, slides, and flows (Hunger et al., 2014).

Mass wasting hazards in the Project area where permafrost features are present, including the Arctic Coastal Plain, Arctic Foothills, Arctic Mountains, and Alaska Range, could take the form of frozen debris lobes, rock glaciers, or movement caused by solifluction or thaw layer detachment (McRoberts, 1978; van Everdingen, 2005; Wahrhaftig and Cox, 1959). Frozen debris lobes consist of frozen soil, sediment, and rock that advance on a timescale of inches to feet per year.

In areas where permafrost is discontinuous or nonexistent, slope instability may occur in the form of deep or shallow landslides, slope creep, debris flows, rock falls, or snow or rock avalanches. Deep landslides are distinguished from shallow landslides by a characteristic rotational or translational slide, but both types of landslides generally occur along a rupture surface. Slope creep is a slow flow that commonly occurs where fine-grained soils or certain types of weathered bedrock compose the slope surface (Highland and Botrowsky, 2008). In contrast, debris flows are typically triggered by heavy precipitation and form when water mixes with soil, rock, and/or organic material in a flow that travels quickly downslope

(Highland and Botrowsky, 2008). Avalanches and rock falls are similarly rapid and can be triggered by freeze-thaw cycles, seismic activity, or human-generated vibrations. AGDC provided a *Slope Stability and Mass Movement Assessment Update* (WorleyParsons, 2016d) report, which includes discussion of active mass wasting processes and potential hazards near Project facilities. This study was conducted using information from 2015 and 2016 field programs, geologic maps, LiDAR data, Helicopter Electromagnetic Survey data, an updated geological model and borehole database, and previous slope stability analyses.

Gas Treatment Facilities

The topographic relief and slopes in the area of the GTP are low, with an average gradient of about 4 feet per mile (Harrison and Osterkamp, 1976); thus, the risk of mass wasting is considered low. In addition, no mass wasting hazards were identified along the PTTL or PBTL routes. Potential hazards associated with permafrost processes are discussed in section 4.2.2. See section 4.18.6 for additional discussion of mass wasting and the Gas Treatment Facilities.

Mainline Facilities

AGDC reviewed aerial photographs and LiDAR data to identify several active mass wasting processes along the Mainline Pipeline, including existing landslide, rock fall, rock glacier, solifluction, slumping, thaw flow, debris flow, and rock slide hazards, as well as potential static and dynamic slope instability (WorleyParsons, 2018). The geohazard assessment showed that the Mainline Pipeline would be within 1 mile of 152 mapped potential deep landslides, 271 mapped potential shallow landslides, 124 mapped potential slope creep features, 54 mapped potential rock fall features, 99 mapped potential rock avalanche features, 105 mapped potential debris flows, 16 mapped potential snow avalanche features, 24 mapped potential solifluction features, and 156 mapped potential thaw layer detachment features. The lengths of the Mainline Pipeline where mass wasting processes would be crossed by the Mainline Pipeline are summarized in table 4.1.3-2.

According to the *Slope Stability and Mass Movement Assessment Update* (WorleyParsons, 2016d) and *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018), mapped natural landslides occur across the Mainline Facilities between MPs 50 and 800. AGDC identified unstable mass wasting areas where the Mainline Facilities could be affected by mass wasting hazards. These areas, which could require mitigation, would primarily be where the pipeline crosses the Brooks Range Section of the Arctic Mountains Province Alaska Range and within the Aleutian Province near the Alaska Range.

Frozen debris lobes are typically found in the Brooks Range. Specifically, the portion of the Mainline Pipeline within the Dietrich River Valley is currently in the path of an advancing frozen debris lobe (Daanen et al., 2012). In the summer and fall of 2018, ADOT&PF realigned the portion of the Dalton Highway near the advancing frozen debris lobe. The rerouted highway is within the Mainline Pipeline right-of-way between about MPs 196.0 and 197.0 and crosses the right-of-way at MP 196.5; therefore, AGDC and ADOT&PF have coordinated and would continue to coordinate the two projects. Following the relocation of the highway, AGDC would monitor the frozen debris lobe movement. Recent research predicts that the debris lobe is expected to move at an average rate of 31.6 feet per year (Darrow, 2018). At this rate, it is anticipated that the lobe would travel 419 feet to reach the area of the Mainline Pipeline and new highway in about 12 years (about 2032). The rate of movement is known to be variable, however, and may increase or decrease within that timeframe.

TABLE 4.1.3-2

Potential for Mass Wasting Hazards Along the Mainline Facilities by Physiographic Province

	Arctic Coastal Plain		Arctic Foothills		Arctic Mountains		Northern Plateaus		Western Alaska		Alaska-Aleutian		Coastal Trough		**Total [a]**	
Potential Mass Wasting Type	Miles	No.	Miles	No.	Miles	No.	Miles	No.	Miles	No.	Miles	No.	Miles	No.	**Miles**	**No.**
Deep landslide	0.0	0	0.3	1	0.0	0	1.0	2	0.0	0	0.2	4	0.3	2	**1.8**	**9**
Shallow landslide	0.0	0	0.0	0	0.4	5	0.3	4	0.0	0	0.5	5	0.9	17	**2.1**	**31**
Slope creep	0.0	0	1.0	2	0.2	3	1.3	5	0.5	2	0.7	4	2.4	10	**6.1**	**26**
Rock fall	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.8	3	0.2	1	**1.0**	**4**
Rock avalanche	0.0	0	0.2	3	0.0	0	0.6	2	0.0	0	0.4	2	0.0	0	**1.2**	**7**
Debris flow	0.0	0	6.6	23	2.6	9	0.3	2	0.0	0	1.0	2	0.6	2	**11.0**	**38**
Snow avalanche	0.0	0	0.3	2	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	**0.3**	**2**
Solifluction	0.0	0	<0.1	2	1.4	6	0.0	0	0.0	0	0.0	0	0.0	0	**1.5**	**8**
Thaw layer detachment	0.0	0	2.6	12	2.2	9	1.2	7	0.0	0	0.0	0	0.0	0	**6.0**	**28**
Total [a]	**0.0**	**0**	**10.9**	**45**	**6.8**	**32**	**4.7**	**22**	**0.5**	**2**	**3.6**	**20**	**4.3**	**32**	**31.4**	**153**
Pipeline Affected (percent) [b]	**0.0**		**13.1**		**5.8**		**2.5**		**0.9**		**5.7**		**1.8**		**3.8**	

Sources: WorleyParsons, 2015

[a] The totals shown in this table may not equal the sum due to rounding

[b] Percent of pipeline affected is calculated for each physiographic province. The total percent of pipeline affected is not the sum of addends, but the percent of the Mainline Pipeline affected.

Liquefaction Facilities

The primary mass wasting processes occurring near the Liquefaction Facilities are landslides and slumps from the top and face of the coastal bluff combined with wave erosion at the base of the bluff. The estimated rate of bluff face erosion near the LNG Plant and Marine Terminal is 1 to 3 feet per year, with a maximum erosion rate of 5 feet per year (Kenai Peninsula Borough, 2014), but strong storms have been documented to cause up to 50 feet of bluff face retreat in one event (COE, 2011). As discussed further in section 4.18.6, the Marine Terminal would be sited about 300 feet from the bluff. The bluff slopes range from 35 to 50 degrees from horizontal and are covered with thin grass and shrubs or are bare, according to 2014 and 2015 field mapping (Fugro, 2015a). LiDAR surveys in 2015 and 2016 noted the presence of debris flows and rotational slumps with shallow slide planes up to 6 feet in height associated with higher groundwater seepage rates in a few locations along the bluff at the contact between the Killey and Moosehorn deposits. These features indicate that groundwater flow contributes to bluff face destabilization, but no evidence of large mass wasting occurrences was observed during field mapping or LiDAR surveys. See sections 4.2.5 and 4.18.6 for additional information on bluff erosion impacts, mitigation measures, and facility design factors.

4.1.3.4 Tsunamis and Seiches

Tsunamis are large waves generated by seafloor vertical fault displacement that propagate through water, while seiches are oscillating waves in partially or entirely enclosed waterbodies that can be generated by submarine landslides, submarine and subaerial mass movements, earthquakes, storms, and strong winds. Both types of waves are hazardous in shallow water and have the potential to inundate coastal areas. The southern portion of Alaska has a higher probability of being affected by tsunamis and seiches due to the frequency and magnitude of seismic events and proximity to expansive coastlines.

Gas Treatment Facilities

Based on review of publicly available information, including NOAA's *Tsunamis Affecting Alaska* report (NOAA, 1996) and recent tsunami data (NOAA, 2018e), there have been no reported instances of tsunamis on the North Slope near the Gas Treatment Facilities. As previously mentioned in section 4.1.3.1, a magnitude 6.4 earthquake recently occurred on the North Slope, but no tsunami alert was generated from this quake (Rosen, 2018) and little to no evidence of a tsunami was reported by USGS (2018e). See section 4.18.6 for additional discussion of tsunamis and seiches at the Gas Treatment Facilities.

Mainline Facilities

AGDC conducted an assessment of potential tsunami activity near the Mainline Facilities and documented the results in the *Probabilistic Tsunami Hazard Assessment* (Fugro, 2017). A probabilistic hazard assessment uses historical data to extrapolate the likelihood that a scenario would occur in the future. Based on this assessment, local submarine landslides triggered by earthquake-induced ground motions were determined to be the source of the highest tsunami risk to the Mainline Facilities. Volcanic eruptions and an earthquake with a magnitude similar to the 1964 Great Alaskan Earthquake were also considered potential tsunami sources, but the maximum wave heights caused by a volcanic flank collapse at Redoubt Volcano or a large-scale earthquake were found to be about 3 feet above ambient tide level, which would not be expected to affect the Mainline Facilities (Fugro, 2017).

The probability of a seiche occurring in the southern portion of the Mainline Facilities was not included in the hazard assessment because the shallow depth of the northern portion of Cook Inlet is less favorable to the generation of seiches. As a result, seiche waves have not been documented north of Kalgin

Island, which is about 20 miles south of the Liquefaction Facilities and MP 806.6 of the Mainline Pipeline (Fugro, 2017).

Liquefaction Facilities

Due to its location in southern Alaska adjacent to a coastline and in an area where many earthquakes have been recorded, AGDC conducted a probabilistic tsunami hazard assessment for the Liquefaction Facilities. The *Probabilistic Tsunami Hazard Assessment* (Fugro, 2017) modeled wave propagation based on the bathymetry of Cook Inlet and worst-case tsunamigenic sources, including a submarine landslide in Cook Inlet, earthquake similar to the 1964 Great Alaskan Earthquake, and collapse and debris flow from Augustine Volcano. See section 4.18.6 for additional discussion of tsunamis and seiches at the Liquefaction Facilities.

4.1.3.5 Volcanic Eruptions

Due to the convergent plate boundary that accounts for the orientation of the Aleutian Arc and geologic processes in southern Alaska, several active volcanoes exist near the southern portion of the Project on the west side of Cook Inlet (Alaska Volcano Observatory [AVO], 2016). These volcanoes include Mount Spurr, Crater Peak, Redoubt, Iliamna, Augustine, Double Glacier, and Hayes Volcanoes. The volcano locations and historical tephra thicknesses associated with the 2009 Redoubt eruption are shown on figure 4.1.3-2.

The hazards associated with volcanoes include volcanic ash clouds, volcanic ballistics and ash fallout, lahars[23] and floods, pyroclastic flows, lava flows, debris blasts and avalanches, volcanic tsunamis, and volcanic gases. Of these, the proximal hazards include direct blasts and volcanic gases, which may be encountered within about 4 miles of an eruption, and lahars, pyroclastic flows, and debris avalanches which may travel up to several miles from an erupting volcano. For example, the estimated runout distance for an advancing lahar or pyroclastic flow from a 9,843- to 13,123-foot-tall (3,000- to 4,000-meter-tall) peak would be about 7 miles (Hayashi and Self, 1992). Flat expanses between the volcanoes and Cook Inlet would decrease the probability that a lahar or pyroclastic flow would become channelized in a ravine or river valley and travel closer to the Project. Due to the separation provided by Cook Inlet, it is unlikely that lahars, pyroclastic flows, or lava flows would reach the Project area. As described in section 4.1.3.4, a tsunami generated by a flank collapse is unlikely to affect the Project as the maximum modeled wave height due to a flank collapse would be 3 feet above ambient tide level (WorleyParsons, 2018; Fugro, 2017).

Gas Treatment Facilities

There are no active volcanoes near the GTP, PTTL, and PBTL. The majority of volcanoes in Alaska are in Cook Inlet or along the Aleutian Islands. The nearest volcano to the Gas Treatment Facilities is Buzzard Creek, an unmonitored volcano about 440 miles south of the facilities. Therefore, the potential impact on the GTP, PTTL, and PBTL from a volcanic eruption is considered very low. See section 4.18.6 for additional discussion of volcanic risk at the Gas Treatment Facilities.

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[23] A lahar is a hot or cold mixture of water and rock fragments that flows down the slopes of a volcano and typically enters a river valley (USGS, 2018i).

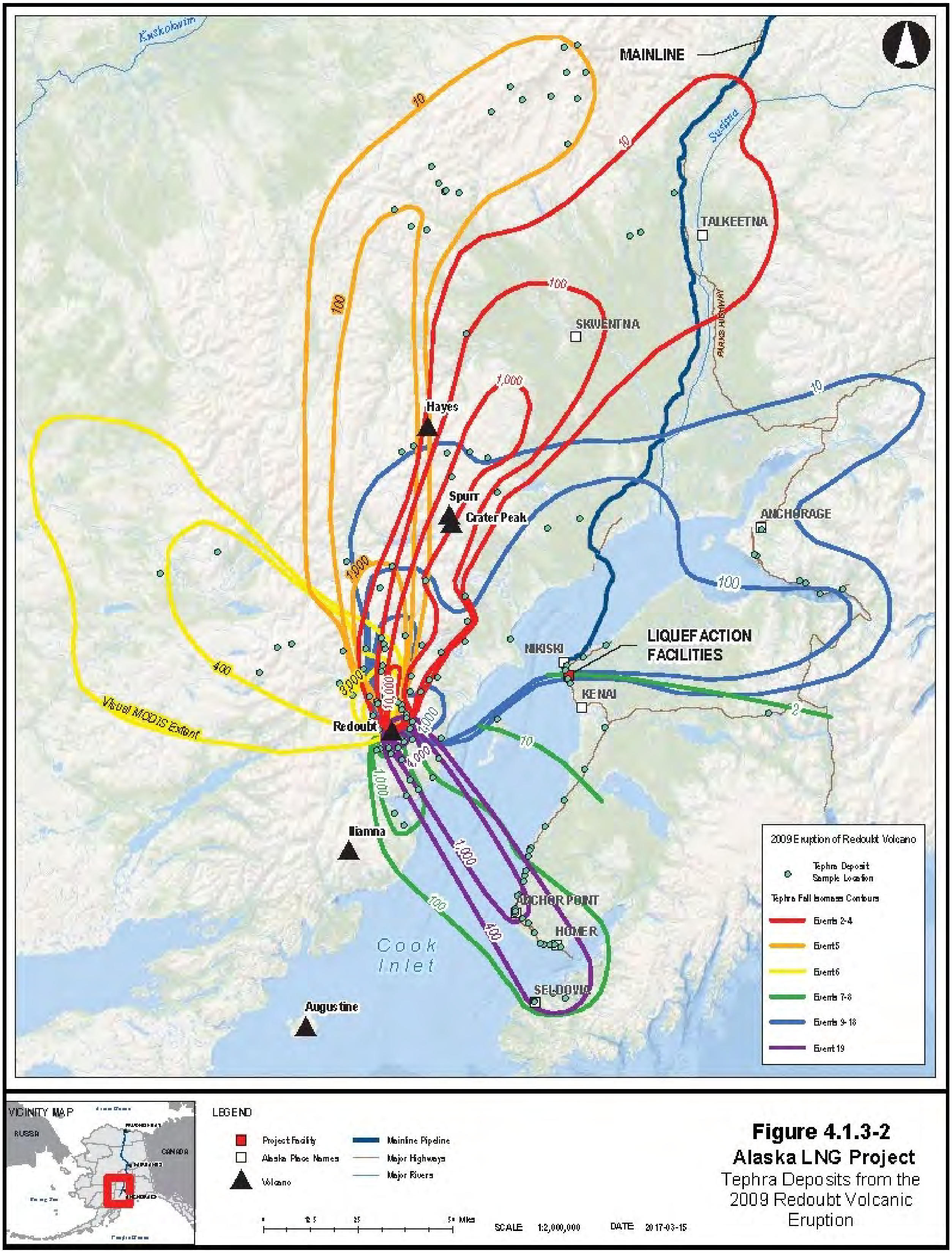


Figure 4.1.3-2
Alaska LNG Project
Tephra Deposits from the 2009 Redoubt Volcanic Eruption

Mainline Facilities

Ashfall is a possible volcanic hazard for the Mainline Facilities near the active volcanoes due to the historical range of tephra deposits associated with the 2009 Redoubt Volcano eruption (see figure 4.1.3-2). In addition, depending on the wind direction and scale of eruption, volcanic gases may temporarily affect air quality within about 6 miles of an erupting volcano based on emission rates after the 1990 eruption of Redoubt Volcano (Casadevall et al., 1994; Waythomas et al., 1997). As the Mainline aboveground facilities would be farther than about 6 miles from the closest active volcano, the potential that volcanic gases would temporarily affect working conditions during construction or operation is considered very low.

Liquefaction Facilities

Cook Inlet provides separation between the Liquefaction Facilities and the active volcanoes to the west. The potential volcanic hazards in the area of the Liquefaction Facilities are similar to the hazards for the southern portion of the Mainline Facilities, as described above.

Ashfall would pose a risk to the Liquefaction Facilities from active volcanoes about 50 miles west of the site, including Redoubt, Spurr, and Augustine Volcanos. Ash particles may be dispersed hundreds of miles from the erupting volcano and can disrupt or impede telecommunications, damage mechanical equipment with air intake systems, and cause roadways to become impassable due to low visibility and slippery conditions. Finally, airborne ash would exacerbate health issues for individuals with cardiac or respiratory concerns.

Volcanic gasses would disperse prior to reaching the Liquefaction Facilities (Casadevall et al., 1994; Waythomas et al., 1997). The potential that gases would affect the Project is considered very low. See section 4.18.6 for additional discussion of volcanic risk at the Liquefaction Facilities.

4.1.3.6 Subsidence

Subsidence can be caused by naturally occurring or human-triggered activities and generally involves the downward displacement of the ground surface due to settlement or collapse. The *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018) includes a discussion of subsidence due to karst terrain and underground mines. Karst terrain, which is formed by the dissolution of carbonate bedrock, is generally associated with subsidence caused by the collapse of underground caves or voids. Traditional knowledge obtained from the Seldovia and Port Graham community workshops indicates that significant land subsidence was associated with the 1964 Great Alaskan Earthquake (Braund, 2016). The USGS's Professional Paper entitled *Effects of the Earthquake of March 27, 1964, on Various Communities* supports this, stating that virtually all the damage to Seldovia and Port Graham was caused by tectonic subsidence of about 3.5 and 3.0 feet, respectively (Plafker et al., 1969). The Nikiski tide gauge near the Liquefaction Facilities recorded about 0.9 foot of subsidence associated with this earthquake (Foster and Karlstrom, 1967). Subsidence hazards, and specifically the potential for thaw settlement, are discussed in greater detail in section 4.2.

Gas Treatment Facilities

Subsidence hazards would not be anticipated in the GTP, PTTL, and PBTL areas because no karst features were identified within 30 feet of the surface and there are no known underground mines in the area. The GTP would be constructed on granular pads and a cooling system would prevent thaw migration beneath the warehouse slab. The foundation system would be constructed using adfreeze piles, which consist of closed-end pipe piles that are inserted into a drilled hole and backfilled with a sand and water mixture. The slurry would freeze to maintain the pile foundation position within the hole. See section 4.18.6 for additional discussion of subsidence at the Gas Treatment Facilities.

Mainline Facilities

AGDC investigated mining-induced subsidence by identifying existing and possible future mining activity near the Mainline Pipeline. For underground mining, the potential for subsidence reduces with distance from an active mining area. AGDC conducted a screening level analysis to estimate the vulnerability of an active mining area to subsidence based on the anticipated minimum depth of an underground mine opening and its proximity to the Mainline Pipeline right-of-way. AGDC made two minor route adjustments to the Mainline Pipeline route to avoid active mines with the potential for subsidence. Based on their distance from the right-of-way, none of the remaining mines are areas with the potential for ground subsidence.

Two known karst features are near the Mainline Pipeline between MPs 145.0 and 146.7. They are offset from the pipeline route by 4,750 and 2,435 feet, respectively. Although the Mainline Pipeline would cross areas of potential karst terrain, geologic field mapping has not found evidence of shallow karst features that could collapse beneath the pipeline. Similar to the GTP, the foundation construction method for the compressor stations would be based on the soil condition (e.g., cold ice-rich, warm ice-rich, or no permafrost) and could include the use of:

- adfreeze piles for the Sagwon and Galbraith Lake Compressor Stations;
- thermopiles for the Coldfoot, Ray River, and Healy Compressor Stations;
- anchored rock sockets for the Minto Compressor Station; and
- typical driven piles for the Honolulu and Rabideux Creek Compressor Stations and the Theodore River Heater Station.

For additional information on thaw settlement occurring during Mainline Facilities operation, see section 4.2.5.

Liquefaction Facilities

Hazards due to subsidence at the Liquefaction Facilities would not be anticipated due to the absence of karst topography within 30 feet of the surface and of underground mines near the area. As discussed in section 4.1.1.2, geotechnical and geophysical investigations at the Liquefaction Facilities confirmed the presence of dense sand and gravel; these materials are unlikely to subside and pose a hazard to the Liquefaction Facilities. See section 4.18.6 for additional discussion of subsidence at the Liquefaction Facilities.

4.1.3.7 Acid Rock Drainage

Acid rock drainage and metal leaching (ARD/ML) processes result from exposure of sulfide minerals (e.g., pyrite and pyrrhotite) and coal to oxygen and water, which oxidizes metals and releases chemical constituents that lower the pH of the drainage. The weathering process that results in ARD/ML may be naturally occurring or triggered by increased exposure of bedrock through trenching or the development of quarries. Several bedrock units crossed by the Project that may host sulfide minerals include sedimentary rocks such as mudstone, claystone, coal, and shale; metamorphic rocks such as slate and schist; and mafic igneous rocks such as basalt and gabbro. Where carbonate minerals (e.g., calcite and dolomite) or reactive aluminosilicate minerals (e.g., anorthite) are in close proximity to sulfide-rich minerals, the acidity of the drainage can be neutralized in situ. If the pH of the solution is neutral to slightly alkaline, however, several toxic metals (e.g., mercury, arsenic, and antimony) could reach elevated concentrations and damage the environment. In areas where glacial sediments are thick and bedrock is unlikely to be encountered during excavation, the potential for ARD/ML is low to absent.

AGDC assessed the potential to encounter ARD/ML during Project construction. A preliminary desktop analysis was conducted to identify and rank the Mainline Facilities according to potential for ARD/ML and to strategically select sites for field investigation in areas with a higher potential for ARD/ML. Two field investigations conducted in 2014 and 2015 collected and analyzed 42 samples for ARD/ML characteristics. The laboratory results were evaluated along with a mineralogical analysis of geologic units, depth to bedrock maps, and existing geochemical data from the USGS, DGGS, and other sources (WorleyParsons, 2015). Additionally, AGDC used the ARDF, which contains point locations and field descriptions for mines, prospects, and mineral occurrences in the state and is filterable by sulfide materials likely to result in ARD/ML. The results of the ARD/ML characterization are included in the *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018).

Based on the studies, GTP, PTTL, and PBTL construction would be unlikely to encounter ARD/ML due to the bedrock type and/or depth in the area. Construction of the Liquefaction Facilities would also be unlikely to encounter hazards associated with ARD/ML due to the depth to bedrock.

WorleyParsons (2018) categorized portions of the onshore Mainline Facilities as having a high, moderate, low, or no ARD/ML potential based on the results of the desktop assessment, 2014 and 2015 field investigations, and 2016 geotechnical analyses. Area of high potential include rock units with known or elevated potential for ARD/ML, or known coal-bearing formations. Sulfide-bearing rock units with acid buffering capacity were classified as moderate potential, and rock units with good acid buffering capacity such as limestone were classified as low potential. About 5.4 miles were identified as having a high potential for ARD/ML and 19.2 miles as having a moderate potential. The remaining areas of the Project had low to no ARD/ML potential. Table 4.1.3-3 summarizes the lengths and rankings of potential ARD/ML hazards along the Mainline Facilities.

TABLE 4.1.3-3

Potential for Acid Rock Drainage/Metal Leaching Hazards Along the Mainline Facilities

Physiographic Province [a]	Start Milepost	End Milepost	Length of "Moderate" Potential ARD/ML Crossed (miles)	Length of "High" Potential ARD/ML Crossed (miles)
Arctic Mountains	145.4	262.7	1.1	0.0
Northern Plateaus	262.7	448.3	18.0	0.0
Alaska-Aleutian	501.9	564.8	0.1	5.3
Coastal Trough	564.8	806.6	0.0	0.1
Total			**19.2**	**5.4**

Sources: WorleyParsons, 2015

[a] ARD/ML is not likely to be encountered in the Arctic Coastal Plain, Arctic Foothills, and Western Alaska Provinces.

As indicated in table 4.1.3-3, the largest proportion of the Mainline Facilities that cross areas of ARD/ML potential is within the Northern Plateaus Province. Specifically, the *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018) indicates that the areas of ARD/ML potential in the Northern Plateaus Province are between about MPs 350.0 and 450.0 in the Ray Mountains area.

The three bedrock types hosting sulfide minerals exposed in the Ray Mountains include:

- Triassic Period intrusive and extrusive mafic and ultramafic rocks;
- Silurian Period to Late Proterozoic Eon siliceous dolomite, chert, and basaltic greenstone with minor limestone, shale, and siltstone; and
- Cambrian Period serpentinite and greenstone intruded by gabbro and diorite.

In contrast, the majority of bedrock types hosting sulfide minerals with a ARD/ML potential in the Alaska-Aleutian and Coastal Trough Provinces are sedimentary and include a coal-bearing group; conglomerate and sandstone interbedded with claystone and lignite (coal) beds; volcanic rocks; mélange; and Quaternary moraine deposits.

4.1.3.8 Naturally Occurring Asbestos

NOA is a variety of fibrous silicate minerals that can be hosted in several different metamorphosed rocks where magnesium is a primary component. Asbestos is the cause of asbestosis, a lung disease resulting from inhaling asbestos particles. The ADOT&PF contracted with DGGS to evaluate Alaska's bedrock geology for NOA potential. The DGGS mapped known occurrences of NOA and assigned rankings to bedrock units based on known geologic settings where asbestos is most likely to be present. Map units were assigned a rating based on the characteristics described below.

- High to Known – Unit consists either entirely or more than 50 percent of rock types known to host NOA somewhere in the world. Serpentinite and ultramafic rocks (i.e., an igneous rock composed entirely of mafic minerals) are the most common hosts of NOA.
- Medium – Unit is either a compound unit consisting of multiple rock types that include at least one NOA-favorable rock type, or a unit with rock types that could host NOA in portions of the unit. Units with this rating have the possibility to contain NOA in localized portions of the unit.
- Zero to Low – Unit contains 0 to less than 1 percent of highly favorable NOA rock types, minor to major amounts of low-NOA-favorable rock types (e.g., basalt and marble), and NOA-unfavorable rock types. In general, units with this ranking are not likely to contain NOA; however, they cannot be assumed to have no potential.

Review of DGGS mapping of these rankings shows that there are no known NOA that the Project would cross. The majority of the Project would cross areas with zero-to-low or medium rankings identified by the DGGS. The Mainline Pipeline would cross a few areas with a high-to-known rating (Solie and Athey, 2015). Table 4.1.3-4 summarizes the lengths and rankings of potential NOA along the Mainline Facilities. In comments on the draft EIS, the DOI commented that a fibrous mineral was encountered near the Dalton Highway at highway MP 222 (approximately 0.1 mile east of the Mainline Pipeline route at pipeline MP 194.3) (Hudson Institute of Mineralogy, 2019).

Construction activities in areas identified as having a moderate- or high-to-known potential to encounter NOA would include excavation, blasting, and backfilling. AGDC would implement measures from the Project Fugitive Dust Control Plan and Blasting Plan to reduce the likelihood of NOA becoming airborne. The State of Alaska has regulatory authority regarding naturally occurring asbestos.

TABLE 4.1.3-4

Potential for Naturally Occurring Asbestos Along the Mainline Facilities

Physiographic Province [a]	Start Milepost	End Milepost	Length of Moderate Potential NOA Crossed (miles)	Length of High to Known Potential NOA Crossed (miles)
Northern Plateaus	262.7	448.3	22.2	1.1
Alaska-Aleutian	501.9	564.8	1.6	1.5
Total			**23.8**	**2.6**

Sources: WorleyParsons, 2015

[a] NOA is not likely to be encountered in the Arctic Coastal Plain, Arctic Foothills, Arctic Mountains, Western Alaska, and Coastal Trough Provinces.

4.1.3.9 Hydrologic Processes and Flooding

Flash floods result from rapid increases in water volume and flow rate within waterbodies and onto adjacent floodplains. A flash flood follows heavy or excessive rain in a short period, generally less than 6 hours. Heavy precipitation events can fill dry stream and river beds quickly, sending large volumes of water downstream. Vertical scour is defined as the reduction of soil over the pipeline within an existing waterbody channel, which may accompany a flash flooding event. Generally, pipelines are buried with adequate depth of cover to avoid or minimize impacts from erosion processes, but flash flooding at waterbody crossings could cause considerable erosion that may expose the pipeline and/or cause damage by impact from gravel and cobbles or other debris due to loss of cover.

Flooding caused by storm surges (defined as higher water levels than the daily tidal fluctuation during a storm event) is not anticipated to be a concern for the portion of the Mainline Facilities near Cook Inlet or the Liquefaction Facilities. Based on measured water levels at the Nikiski tide gage over a timeframe of 29 years (NOAA, 2017b), the 100-year-return period storm surge was calculated to be 3.8 feet above ambient tide level, and the 100-year extreme water level was determined to be 5.8 feet above mean higher high water (MHHW).

Rapid lake drainage (glacial outburst) occurs when there is a breach in the bank of a lake or large pond resulting in the sudden release of large quantities of water that can flood downstream waterbodies. In Alaska, this type of break could be caused by water running over, under, or through glaciers due to rain or glacial melt, which can sometimes get dammed by glacial ice. The volume of water stored behind the ice-dammed lake increases until it breaches. It can also occur due to thawing permafrost and excessive settlement in the bank of a waterbody. The water from such a breach could cause soil erosion resulting in scour holes in the right-of-way and near the pipeline.

Thaw lakes are scattered across the Arctic Coastal Plain varying in size and depth. These lakes include floating ice lakes (i.e., where lake depth exceeds maximum ice growth, the formation of a talik beneath lake occurs, and an ice pan with liquid water forms between the ice and talik); bedfast lakes (i.e., where ice growth exceeds lake depth, ice pan is anchored to the lake bed, and permafrost beneath the lake remains intact); and transitional ice lakes where some years have bedfast ice and some floating ice. The ice-rich permafrost found on the Arctic Coastal Plain is susceptible to the expansion of thaw lakes through melting of ground ice associated with water impoundment. Floating ice lakes on the outer Arctic Coastal Plain were found to have a mean expansion rate of about 2.6 feet per year, while bedfast ice lakes expand at about 1.1 feet per year (Bondurant et al., 2016). AGDC sited or routed Project facilities to directly avoid thaw lakes, but the Mainline Pipeline would be near thaw lakes between MPs 0 and 60 and immediately adjacent to five thaw lakes between MPs 0 and 25. Due to the potential expansion of thaw lakes near Project facilities, AGDC would conduct routine aerial and ground surveys to monitor the Project for visual evidence of effects related to permafrost alteration. This monitoring is discussed in more detail in section 4.2.5.

Gas Treatment Facilities

Because Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRM) are unavailable for the Gas Treatment Facilities, AGDC provided an analysis of historic peak flood elevations for the Putuligayuk River (USGS, 2015e, 2003a) and NOAA tidal data (NOAA, 2011). Although extreme sea level estimates may not be reliable due to the limited data, the analysis of the available data indicates that the GTP and PBTL would not be in an area inundated during a flood event. The West Dock Causeway and PTTL, however, could be affected by a 100-year coastal flooding event.

The peak historic flood elevation for the Putuligayuk River was estimated based on a stream gage 3.7 miles from the GTP site. Flood frequency analysis for this gage, based on the available period of record (25 years), indicates that the highest recorded peak flow would have a return interval of between 10 and 25 years. The GTP would be located within the Kuparuk River sub-basin and near the Putuligayuk River catchment area. No glaciers are within this sub-basin; therefore, there is no potential for flooding at the GTP due to glacier melt (RGI Consortium, 2017). The GTP would not be in an area that would be inundated during a flood of the Putuligayuk River, and the PBTL is also unlikely to be inundated during most flood events.

As described in Section 4.18.6, storm surge data on the North Slope is not extensively available (there are no published FEMA FIRM; FEMA Flood Insurance Studies; or NOAA Sea, Lake, and Overland Surges from Hurricanes maps for the North Slope of Alaska); however, the DOI recorded storm surges as high as 10 feet (3 meters) through 1978. Additionally, according to the current relative sea level trends published by NOAA, Prudhoe Bay would likely experience up to 0.4 foot of sea level rise.

Available NOAA tidal data were reviewed to estimate areas of potential coastal flood risk near the GTP. Analysis of a 16-year sea level dataset indicates that the highest observed water level represents an approximate 25-year return interval extreme sea level event, which includes storm surge, astronomic tide, and seasonal cycle (NOAA, 2011). Although extreme sea level estimates may not be reliable beyond the 25-year return period due to the limited data, it is estimated that the 50-year and 100-year return interval events would be 5.1 feet and 5.3 feet, respectively (Sultan et al., 2010).

Because the GTP final site grade is +30 feet amsl, the threat of flooding including from storm surge and sea level rise is considered insignificant. The 100-year coastal flooding elevation (5.3 feet amsl) was also used to estimate the potential flood extent for the PTTL and West Dock Causeway. This analysis indicated that West Dock Causeway and some sections of the PTTL could be inundated during a 100-year coastal flooding event, but the PBTL is unlikely to be inundated. To address potential impacts, we are recommending in section 4.18.9 that, prior to construction of the final design, AGDC should file a monitoring and maintenance plan that ensures the grade of the GTP site would be maintained to prevent flooding throughout the life of the facility, considering settlement, subsidence, thermocycling, and sea level rise.

Peer-reviewed scientific research identifies the Arctic as having one of the most rapid rates of coastal erosion in the world (Jones et al., 2009). AGDC did not provide any data or analysis concerning the potential for erosion to affect the PTTL. The PTTL would be routed along the Beaufort Sea coastline, which is subject to coastal erosion that can exceed 6.6 feet (2.0 meters) per year (USGS, 2019a). During 2007, a particular spot along the Beaufort Sea coastline experienced 82.0 feet (25.0 meters) of erosion absent a storm event (Jones et al., 2009). In most locations, the PTTL would be offset from the coastline by 0.5 to 1 mile or more, with the exception of the Point Thomson Meter Station, which would be about 0.25 mile from the Beaufort Sea coast. To address potential impacts, we are recommending in section 4.18.9 that, prior to construction of the final design, AGDC should file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan.

One waterbody crossing on the PTTL, the Sagavanirktok West Channel, was assessed to have high potential for scour, but at this location the crossing would be aerial, so no mitigation measures for vertical scour were proposed. As the PTTL would be elevated above the floodplain, potential impacts due to flooding and scour would be avoided.

The PBTL would be installed above the floodplain and it is unlikely that flooding would inundate the pipeline or cause scouring along its route.

Mainline Facilities

The *Onshore Geohazard Assessment Methodology and Results Summary* (WorleyParsons, 2018) includes a qualitative analysis of waterbodies crossed by the Project to identify areas that are susceptible to flooding and scour based on potential water volumes, streambed sediment size, and waterbody profile. Potential flood zones were identified using terrain types along the Mainline Pipeline within alluvial floodplains and fans. A total of 108 watercourses adjacent to or crossed by the Mainline Pipeline were identified as susceptible to vertical scour.

AGDC identified areas potentially susceptible to rapid lake drainage in their *Onshore Geohazard Assessment Methodology and Results Summary*. Rapid lake drainage is a rare phenomenon where there is a breach in the bank of a lake or large pond and a sudden outflow of a large volume of water. In the Project area, such a breach could be due to thawing permafrost, excessive settlement in the bank, or glacial meltwater impounded by ice that suddenly releases. Potential impacts on the Mainline Pipeline could occur if the water should reach the right-of-way and cause significant erosion, resulting in scour holes and damage to the pipeline from debris or ice. Six lakes were identified as possible rapid lake drainage hazard sites. Of these, only one was concluded to have a potential to affect the pipeline. This site, Beluga Lake, is at MP 757.5 where the Mainline Pipeline crosses the Beluga River.

In addition to flooding and rapid lake drainage hazards, the *Onshore Geohazard Assessment Methodology and Results Summary* analyzed the potential for channel migration, avulsion (rapid abandonment of an existing river channel), horizontal and vertical scour, and pipeline buoyancy along the Mainline Pipeline route. AGDC's susceptibility analysis evaluated factors such as:

- stream gradient, where higher potential is associated with higher gradients (i.e., mountain streams);
- extent of stream incision, where incised streams are associated with higher scour potential;
- depth to bedrock, with lower potential where bedrock is shallow; and
- vertical scour potential, where less than 3 feet was considered low and more than 10 feet was considered high (WorleyParsons, 2018).

The number of waterbodies crossed by the Mainline Pipeline assessed to be susceptible to vertical scour are listed in table 4.1.3-5 and included in appendix I.

TABLE 4.1.3-5 **Waterbodies Susceptible to Vertical Scour Along the Mainline Pipeline**			
Physiographic Province	Start Milepost	End Milepost	Number of Waterbodies
Arctic Coastal Plain	0.0	63.9	4
Arctic Foothills	63.9	145.4	13
Arctic Mountains	145.4	262.7	22
Northern Plateaus	262.7	448.3	20
Western Alaska	448.3	501.9	5
Alaska-Aleutian	501.9	564.8	6
Coastal Trough	564.8	806.6	38
Total			**108**

Sources: WorleyParsons, 2018

Liquefaction Facilities

Flooding and scour due to strong currents, tidal fluctuations, and sediment loads are more likely to become hazards along the seafloor in Cook Inlet, whereas onshore hazards at the LNG Plant could be caused by heavy precipitation, soil characteristics, and proximity to waterbodies (Thurston and Choromanski, 1995). There were no waterbodies identified in the LNG Plant area that would cause scour or flooding. See section 4.18.6 for additional discussion of flooding at the Liquefaction Facilities.

4.1.3.10 Impacts and Mitigation

Geohazards in the Project area range from tectonic to hydrologic and have the potential to adversely affect pipeline infrastructure, safety of construction personnel, and the surrounding environment. The following are summaries of proposed mitigation measures to minimize or avoid the primary geohazards, both natural and anthropogenic, that could be encountered during Project construction or operation. Final mitigation measures would be selected based on site-specific conditions for one or more of the following functions:

- control the geohazard by reducing the chance that a hazard would influence additional geohazard development;
- modify facility geometry to minimize exposure of facilities to the geohazard or reduce external force on the facilities;
- confirm geotechnical conditions to better understand the potential vulnerability of the facilities and recurrence of geohazards;
- monitor and manage pipeline integrity to evaluate shifts in geohazard conditions; and
- protect the pipeline by reducing forces imposed on the pipeline.

In addition to data collected, AGDC would use information obtained prior to and during construction to confirm and enhance geohazard assessment mitigation measures and monitoring activities. During Project operation, various monitoring methods could be utilized, including airborne or ground surveillance, remote sensing, in-line inspection, and/or use of select instrumentation. AGDC has provided a Project Pipeline Operation and Maintenance Plan that describes operational monitoring methods that would be used on the Mainline Pipeline to determine if altering conditions created an unacceptable risk to this facility. For more information on this plan, see section 4.2.5.

Seismicity

Hazards associated with seismicity, including fault movement, co-seismic subsidence, and soil liquefaction, would exist in specific areas of the Mainline Facilities and at the Liquefaction Facilities. For the Mainline Pipeline, primary mitigation measures in areas of known seismic hazards and active faults would involve avoiding fault crossings to the extent practicable and modifying the pipeline geometry to minimize pipeline exposure to movement along the fault (as described in section 4.18.10). Additional mitigation for areas prone to liquefaction include buoyancy control measures, use of interceptor ditches and deep vertical drains, and modified burial depths and geometries at waterbody crossings.

Based on the results of the *Probabilistic Seismic Hazard Analysis* (Golder Associates Inc., 2016), the Mainline Pipeline would be installed aboveground over the Denali, Northern Foothills Thrust, Castle Mountain, and Park Road faults, using designs similar to those on TAPS, with saddles on beams supporting the pipeline, all on top of a granular fill pad. These crossing designs enabled the TAPS pipeline to withstand the magnitude 7.9 earthquake on the Denali fault in 2002, where the ground shifted about 2.5 feet vertically and 14 feet horizontally in what is considered to be among the 20 strongest earthquakes in the last 100 years.

The potential fault crossing designs for the Denali, Northern Foothills Thrust, and Castle Mountain faults would include the conceptual "Zee" or "Trapezonidal" designs for strike-slip faults, or the conceptual "Zee" design for reverse or thrust faults. The Park Road fault would be crossed using a conventional aboveground crossing design where the pipeline would be placed aboveground on "sleeper" supports. AGDC's *Seismic Liquefaction and Fault Displacement Hazard Assessment* (WorleyParsons, 2016c) and *Alaska LNG Integrated Seismic Design Report* (WorleyParsons, 2016a) provide typical fault crossing concepts for the pipeline. The fault crossing methods were selected at each fault location to accommodate the maximum estimated horizontal and vertical displacement. Each fault crossing would be accessed using a permanent gravel road in the event that post-earthquake repairs are needed. The Park Road fault would be reached via an access road connecting the Parks Highway to the permanent right-of-way less than 0.2 mile north of the fault crossing.

We received several scoping comments related to the potential seismic hazard in the Minto Flats seismic zone. The *Probabilistic Seismic Hazard Analysis* modeled two faults based on mapped left-lateral strike-slip fault traces and an estimated slip rate of 0 to 2 millimeters per year (0 to 0.08 inch per year) as determined by Tape et al. (2015). A fault investigation conducted for the proposed ASAP Project found no evidence of surface ruptures where the fault parallels the proposed ASAP route (Tape et al., 2015; Koehler et al., 2015), which would be less than 0.3 mile from the Mainline Pipeline between about MPs 460.0 and 464.0 in the Minto Flats seismic zone.

As described in section 4.1.3.1, the Liquefaction Facilities would be in an area of elevated seismic risk. As such, the components (such as structural and mechanical) of the LNG Plant would be constructed in accordance with NFPA 59A-2001, except LNG tanks and safety systems, which would be constructed in accordance with the seismic requirements of NFPA 59A-2006, as required by the current version of 49 CFR 193. The NFPA 59A-2006 standard defines two levels of earthquake motion:

- the Operating Basis Earthquake, which has a 10-percent probability of exceedance within a 50-year period (475-year-return period); and

- the Safe Shutdown Earthquake ground motion, which is defined as a 2-percent probability of exceedance within a 50-year period (2,475-year-return period).

These earthquake motion levels are used to classify components as critical safety-related systems (included in Seismic Category I), systems or structures that are not critical for safety but are required for safe plant operation (Seismic Category II), and systems or structures that are not classified as Seismic Category I or II (Seismic Category III).

Seismic Category I structures and components, including the LNG containers and systems that would isolate and maintain the containers in safe shutdown mode, would be designed to withstand Operating Basis Earthquake and Safe Shutdown Earthquake ground motion levels. Seismic Category II structures and components would be considered essential facilities, and designed such that damage due to a Design Earthquake ground motion (defined by American Society of Civil Engineers [ASCE] standard 7-05) would not preclude continued function of the facility. Seismic Category III structures and components would be designed to meet seismic goals defined by ASCE 7-05 for non-essential facilities (WorleyParsons, 2016a).

The AEC seismic monitoring network that is situated throughout Alaska would be monitored during construction and operation of the Mainline Facilities and Liquefaction Facilities to detect earthquakes and ground motions. Real-time seismic information would be used to initiate inspections or repairs as needed. Additional analysis of the seismicity relative to the Liquefaction Facilities is provided in section 4.18.6.

Soil Liquefaction

As described in section 4.1.3.2, 38.1 miles of the Mainline Pipeline were identified as having the potential for lateral spread (9.6 miles of high hazard and 28.5 miles of moderate hazard) and 56.5 miles were identified as having buoyancy potential (22.9 miles of high potential and 33.6 miles of moderate potential). Potential mitigation measures provided by AGDC include the use of heavy walled pipe and pressure relief wells and ground improvements. Mitigation measures would be selected during the design phase of the Project on a site-by-site basis (WorleyParsons, 2018).

AGDC's analysis of potential liquefaction hazards took into consideration the effect of long-term permafrost degradation due to pipeline construction and operation, but it did not consider the effects of climate change. As discussed in section 4.2.5, as warming continues during the life of the Project, melting permafrost and changes to groundwater conditions could result in mechanically weaker soils and affect pipeline integrity. Permafrost, including the formation, preservation, and/or degradation of permafrost and ground-ice features, is discussed in section 4.2.2.

It can be challenging to estimate the liquefaction potential of degraded permafrost as soil strength can vary substantially based on physical soil properties and the ability for excess water to drain from thawing permafrost. Whether the liquid state persists long enough to have adverse mechanical effects is influenced by the extent of ground-ice in the surrounding landscape (USGS, 1970b). AGDC would implement measures outlined in the Project Pipeline Operation and Maintenance Plan to monitor, mitigate, and manage potential permafrost degradation and resulting impacts, including soil liquefaction and other forms of mass wasting. AGDC intends to implement similar monitoring and mitigation techniques as those used on the TAPS pipeline to estimate the potential for liquefaction in thawing permafrost soils. The TAPS pipeline uses monitoring equipment to record air, surface, and subsurface temperatures and/or moisture values and investigate any anomalies that are detected. If required, mitigation measures would be implemented to protect the pipeline integrity. We additionally note that, prior to construction of the Mainline Facilities, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, a modified Pipeline Operation and Maintenance Plan that specifies the applicable Project facilities and locations, and provides details of the equipment, monitoring parameters, and frequency of data collection that it would implement to minimize potential impacts from permafrost degradation on the Mainline Facilities.

Mass Wasting

As described in section 4.1.3.3, mass wasting and landslide hazards with the potential to affect the Mainline Facilities would be most likely to occur along about 33.4 miles of the Mainline Pipeline route in the Brooks Range and near the Alaska Range where conditions for mass wasting are prevalent. According to the *Slope Stability and Mass Movement Assessment Update* (WorleyParsons, 2016d), about 2.8 miles of the Mainline Pipeline would require mitigation during construction and operation. Mitigation measures would be selected based on the type and speed of the mass wasting events (such as deep or shallow landslides, debris flows, rock avalanches, thaw layer detachments, and solifluction) and the orientation of the anticipated mass wasting and distance relative to the Mainline Pipeline.

Geohazard control mitigation measures could include, but would not be limited to, drainage and surface water control, heavy wall or high strain capacity pipe, deep burial, slope stabilization measures and/or grading, and revegetation. Deep burial would be implemented for areas where shallow landslides or slope creep could occur to protect the pipeline, and could be accompanied by protective ditch cover in areas of potential rock falls or rock avalanches. In areas of active or anticipated debris flows, aerial crossing would be considered as a mitigation measure during the design phase if the flow is oriented perpendicular to the pipeline. Ongoing monitoring of slope movements and pipeline integrity would supplement any geohazard controls and pipeline protection measures.

To mitigate potential impacts from advancing frozen debris lobes, AGDC would monitor those near the Mainline Pipeline to anticipate future rates of movement and periodically monitor pipeline strain using inline inspection tools in the event that a frozen debris lobe should intersect the pipeline. Proactive mitigation measures would include installing a buttress, removing drainage pathways, and/or removing mass from the frozen debris lobe, depending on the characteristics of an individual lobe. If a frozen debris lobe intersects the Mainline Pipeline and inline inspection records an unacceptable level of pipe strain, potential options could include excavating and repositioning the pipeline or installing a bypass using trenchless techniques. Impacts and mitigation for thaw layer detachment, solifluction, and soil creep are discussed in section 4.2.

At the Liquefaction Facilities, the primary mass wasting hazard is related to erosion of the coastal bluff. Coastal erosion in the Nikiski area was measured at 0.8 foot (0.2 meter) per year on average, with hot spots of 4.0 to 5.7 feet (Kenai Peninsula Borough, 2014). To avoid potential impacts of erosion, LNG Plant structures and foundations for the Marine Terminal would be set back at least 300 feet inland. Mitigation measures to minimize coastal bluff erosion during construction would include installing a stormwater collection system and positioning sand or gravel-filled bags at the toe of the bluff near the temporary Marine Terminal MOF. Long-term mitigation would involve monitoring the bluff slope and shoreline to evaluate if additional mitigation measures are warranted.

Based on the proposed geohazard control mitigation measures, it is unlikely that Project facilities would be adversely affected by mass wasting processes.

Volcanic Hazards

To mitigate any potential impacts from ashfall on the Liquefaction and Mainline Facilities, AGDC would design and build the structures to withstand the historic thickness of ashfall and implement monitoring procedures for eruptions during operation to minimize damage to equipment and secure the safety of on-site personnel. The AVO has publicly available models that would be monitored to predict and plan for measurable (millimeter or greater) ashfall accumulation at the Liquefaction and Mainline Facilities, and the AVO's Volcano Notification System would be used for planning and assessing the potential impacts of ashfall on these facilities. Based on the proposed mitigation measures and volcanic network systems that would be monitored, it is unlikely that Project facilities would be adversely affected by volcanic processes.

Acid Rock Drainage and Metal Leaching

The EPA commented regarding the need to identify ARD/ML occurrences in the Project area and develop an Acid Rock Drainage and Metal Leaching Disposal and Management Plan (ARD/ML Management Plan). Based on the results on the ARD/ML analysis discussed in section 4.1.3.7, AGDC has identified certain areas that would require site-specific evaluations to be completed prior to construction as part of the Project's detailed design and permitting stage. In these areas, AGDC would implement a Geotechnical Verification Program prior to construction to confirm current conditions along the Project area, inform construction planning, and verify mitigation requirements.

The site-specific evaluations would include:

- collection and testing of additional samples from the Mainline Pipeline alignment to ensure a complete assessment to meet regulatory requirements;
- collection and testing of additional samples of high and moderate ARD/ML potential areas not previously surveyed; and
- in-depth evaluation of areas where large rock excavation/cut is anticipated within high and moderate ARD/ML potential areas.

AGDC would prepare a Project-wide ARD/ML management plan with prevention and mitigation options based on the results of the site-specific evaluations. AGDC has proposed example mitigation measures that would be implemented on a site-specific basis depending on where potential ARD/ML rock is exposed. Mitigation measures include:

- amending soil in the pipeline ditch with lime and/or limestone;
- covering the right-of-way with low permeability soil, clay, or artificial material;
- covering exposed cut slopes with shotcrete (i.e., sprayed concrete conveyed through a hose) or other artificial sealant;
- surface water control; and
- permanently storing excavated and blasted rock in designated ARD/ML rock disposal areas.

In addition to these mitigation measures, standard procedures to protect the pipeline would include normal pipe coating and cathodic protection to prevent corrosion. During operation of the Mainline Facilities, monitoring for potential ARD/ML seepage would allow AGDC to evaluate the success of the mitigation measures.

While AGDC has provided FERC staff with example mitigation measures, we have not seen the results from previous sampling events to verify the risk of encountering ARD/ML during Project construction. In addition, AGDC has not stated which mitigation measures it would apply under the range of conditions that could be encountered. Some of the mitigation measures (e.g., covering the right-of-way with low permeability soil, clay, or artificial material) would affect the existing environment or revegetation. To address these issues, prior to construction of the Mainline Facilities, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, the results of all site-specific evaluations for ARD/ML with a map set depicting sampling locations along the Mainline Pipeline; and the Project-wide ARD/ML Management Plan, to include mitigation measures specific to blasting, trenching, and granular fill pads/roads, and details for surface and groundwater monitoring in areas of known high ARD/ML potential.

In comments on the draft EIS, the EPA said that monitoring in areas of moderate ARD/ML potential in addition to areas of high potential should be conducted if ARD/ML is encountered during construction due to the risk for impacts on surface water and groundwater quality. As discussed in section 4.1.3.7, although areas classified as having moderate ARD/ML potential possess some acid buffering capacity, metal leaching can still occur in neutral to alkaline solutions, resulting in increased concentrations of toxic metals such as mercury, arsenic, and antimony. Therefore, **we recommend that**:

- **<u>Prior to construction of the Mainline Facilities</u>, AGDC should file with the Secretary, for the review and written approval of the Director of the OEP, a Project-wide ARD/ML Management Plan that includes details for surface and groundwater monitoring in areas of moderate ARD/ML potential.**

Hydrologic Processes: Vertical Scour

Where the Mainline Pipeline would cross the 108 waterbodies assessed as having high susceptibility to vertical scour, mitigation would include one or more of the following measures to be determined on a site-specific basis during the design phase of the Project:

- bury the pipeline to a depth of 5 feet or greater compared to the required 4 feet of cover for navigable river and stream crossings (i.e., deep burial);
- install heavy-walled pipeline and/or continuous concrete coating in areas of increased potential for damage; and
- apply bed armor across specific waterbodies instead of deep burial, especially across waterbodies in Atigun Pass (from about MPs 167.1 to 169.0) where the Mainline Pipeline would be close to TAPS.

Based on the proposed mitigation measures and systems that would be monitored during Mainline Pipeline operation, it is unlikely that Project facilities would be adversely affected by vertical scour.

As identified in section 4.1.3.9, Beluga Lake is the one lake identified as having the potential for rapid lake drainage. If a breach were to occur, water from Beluga Lake would flow east toward the right-of-way, and any resulting erosion could expose the Mainline Pipeline. AGDC has proposed potential mitigation measures to reduce impacts from rapid lake drainage, including deep burial, channel protection, use of heavy wall pipe, and right-of-way maintenance, if required.

We received comments from the residents in the Boulder Point area expressing concern about the Mainline Pipeline's proximity to Suneva Lake and Suneva Lake Dam. The comments indicated that in 1972, the outflow weir of the dam was breached due to disturbance from beaver dams within the lake, releasing lake water and creating a washout channel and small canyon. According to these residents, the earthen dam was rebuilt in 1982 with unclassified fill material and the dam requires maintenance from residents to manually clear debris and keep the overflow pipe clean. If a breach should occur, residents expressed concern that scour from water within the lake could erode the soils of the canyon floor and potentially expose the Mainline Pipeline.

AGDC provided a scour analysis of the crossing of the Suneva Lake area to analyze the potential hydrologic hazards to the Mainline Pipeline. The analysis was completed using the COE Hydrologic Engineering Center River Analysis System model based on a worst-case flood scenario from a complete failure of the existing Suneva Lake dam structure.

The ADNR's *Draft Guidelines for Cooperation with the Alaska Dam Safety Program* suggest that ice loading on dams and appurtenances, including snow and ice buildup in spillways, can affect dams during routine operations (ADNR, 2017g). AGDC states that based on the past 34 years of performance of the current Suneva Lake dam structure, a significant winter/spring flood event with ice flow is unlikely and that flow at the dam would not be affected as it is driven by gravity rather than surficial ice pressure. Ice flow and buildup in the channel could either decrease or increase potential scour. For example, ice buildup could block water flow through the channel, decreasing water velocity, and in turn, reducing scour potential in certain areas. In other areas, ice buildup could create preferential flow channels and increase scour potential. During winter and early spring breakup periods, however, the frozen conditions of the earthen dam and surrounding ground would provide additional structural support.

Based on the potential scour from a worst-case scenario at the pipeline crossing location, AGDC proposes to use deeper burial and protective ditch measures at the Suneva Creek canyon crossing location to minimize the risk of damage to the pipeline. Specific crossing engineering details would be developed during detailed design. If additional investigation determines the presence of bedrock within the predicted scour zone beneath the streambed, the scour analysis would be revisited.

4.1.4 Blasting

AGDC anticipates that rock removal using blasting methods would be required during Project construction where bedrock is shallow or exposed, or in areas where boulders, cobbles, or other granular materials are frozen in permafrost. In addition, potential granular fill material sites could require blasting to access frozen or densely packed granular materials. The anticipated trenching depth would be between 6 and 8 feet below ground surface depending on the substrate and resources being crossed. Conventional excavation techniques, including hydraulic hammering, ripping and cutting, or non-explosive demolition methods, would be attempted before blasting activities proceed.

4.1.4.1 Gas Treatment Facilities

No blasting is anticipated for the majority of Gas Treatment Facilities construction due to the depth to bedrock in the area. As a result of the prevalence of continuous permafrost in the Arctic Coastal Plain Province, however, blasting through permafrost and frozen tundra for granular fill material sites would likely be required.

4.1.4.2 Mainline Facilities

Blasting would be required for sections of the Mainline Pipeline where bedrock is exposed or within 8 feet of the ground surface along the right-of-way. Alternative trenching techniques, such as hoe-hammering, ripping and cutting, or non-explosive demolition agents, would be used before initiating blasting procedures. Based on review of bedrock depths, about 254.7 miles of the Mainline Pipeline would require blasting due to shallow or exposed bedrock, and an additional 203.1 miles are considered potential areas of blast-assisted trenching where boulders or other granular material are likely present within permafrost. Another 44.2 miles of blasting could be needed to grade and prepare the right-of-way prior to trenching activities. Potential blasting locations along the Mainline Pipeline are summarized in table 4.1.4-1. Based on the results of geotechnical studies, blasting is not anticipated for construction of aboveground facilities (i.e., compressor stations and the heater station).

4.1.4.3 Liquefaction Facilities

Blasting would not be required for Liquefaction Facilities construction due to the anticipated depth to bedrock being greater than 8 feet below ground surface and the absence of permafrost.

TABLE 4.1.4-1

Potential Blasting Associated with the Mainline Facilities [a]

Physiographic Province	Start Milepost	End Milepost	Blasted Ditch Length (miles) [b]	Blasted Ditch Length (percent)	Blast-Assisted Trenching Length (miles)	Blast-Assisted Trenching (percent)	Right-of-Way Prep Blasting Length (miles)	Right-of-Way Prep Blasting Length (percent)
Arctic Coastal Plain	0.0	63.9	0.0	0.0	0.0	0.0	0.0	0.0
Arctic Foothills	63.9	145.4	61.1	75.0	0.0	0.0	0.3	0.4
Arctic Mountains	145.4	262.7	80.3	68.5	0.5	0.4	4.8	4.1
Northern Plateaus	262.7	448.3	92.2	49.7	6.2	3.3	29.5	15.9
Western Alaska	448.3	501.9	0.4	0.7	13.3	24.8	0.1	0.2
Alaska-Aleutian	501.9	564.8	13.4	21.3	26.7	42.4	4.7	7.4
Coastal Trough	564.8	806.6	6.1	2.5	158.0	65.3	3.4	1.4
Total			**253.5**	**31.4** [c]	**204.7**	**25.4** [c]	**42.8**	**5.3** [c]

Sources: WorleyParsons, 2015

[a] Summary table is based on preliminary geotechnical analysis and available route data and may be updated or revised as needed prior to Project construction.

[b] The total length of blasting includes about 44.2 miles of right-of-way that could need to be blasted for grading preparation before trenching excavations would commence.

[c] Percentage of pipeline affected is calculated for each physiographic province. The total percentage of pipeline affected is not the sum of addends, but the percentage of the total Mainline Pipeline affected.

4.1.4.4 Impacts and Mitigation

Blasting activities could potentially affect water wells, springs, nearby aboveground facilities, wildlife, and adjacent pipelines and utility lines. Table 4.1.4-1 summarizes the distances of potential blasting per physiographic province. Blasting typically involves a small scale, controlled, rolling detonation procedure resulting in limited ground upheaval. These blasts do not typically result in large, aboveground explosions. Any required blasting would be conducted in accordance with federal, state, and local regulations. Additionally, AGDC prepared a Project Blasting Plan that would be implemented during Project construction and would follow the ADF&G Alaska Blasting Standard for the Proper Protection of Fish (Blasting Standard) (Timothy, 2013). As described in the Project Blasting Plan, AGDC would:

- require the blasting contractor to submit a Contractor Blasting Plan and Site-Specific Blasting Plan for AGDC and FERC approval for each individual blasting area, which would be determined prior to construction;

- offer water quality and yield monitoring to landowners with water supply wells within 1,000 feet of Mainline Pipeline trench and material site blasting activities before and after blasting;

- obtain information about water quality and yield for springs up to 300 feet from Mainline Pipeline trench blasting activities;

- contact adjacent property owners, municipalities, and other parties as required by FERC, permits, and regulations at least 48 hours prior to blasting;

- identify and inspect aboveground and underground structures, utilities, and water wells and assess wetlands within a minimum of 150 feet of blasting activities before blasting;

- monitor ground vibrations and air blast overpressures at adjacent and nearby structures to ensure the thresholds recommended by the U.S. Bureau of Mines are not exceeded (the limit for air blast overpressures would be 133 decibels [peak impulse] or 0.013 pound per square inch for all blasting areas; the maximum allowable peak particle velocity would consider local slope stability and minimize impacts on waterbodies, wetlands, wildlife, habitat, wells, springs, and aboveground structures);

- use blasting mats or padding, where necessary, to prevent the scattering of loose rock and other debris and damage to nearby structures or environmentally sensitive areas;

- implement dust control, noise, and fume mitigation measures as required by applicable regulations;

- design the site-specific blast drilling pattern to produce rock material suitable for backfill (i.e., less than 1 foot in diameter);

- comply with applicable ADF&G regulations and blasting standards where blasting activities would be within or near waterbodies; and

- mitigate blasting impacts on wildlife during sensitive life stages, including avoiding nesting or denning periods, minimizing vibrations, and monitoring nests and dens before, during, and after blasting.

To determine the potential impact of vibrations from blasting on nearby water wells, the potential peak particle velocity was calculated using the *American Lifelines Alliance Guidelines for the Design of Buried Steel Pipe* (ASCE, 2005). Based on the distances between the proposed blasting areas and ADNR water wells within 1,000 feet, along with a typical explosive design and soil density in the Project area, the potential peak particle velocity produced by Project blasting did not exceed the safe level of 5 inches per second (125 millimeters per second) for wells as recommended by the U.S. Bureau of Mines (Siskind et al., 1994). The recommended peak particle velocity for nearby structures based on information from the U.S. Bureau of Mines is 0.5 inch per second (12.7 millimeters per second) for frequencies less than 40 hertz and 2 inches per second (50.8 millimeters per second) for frequencies greater than 40 hertz to prevent damage to plaster (Siskind et al., 1989). A description of the Blasting Standard and impacts on fisheries is provided in section 4.7.1.

Impacts on geologic resources and nearby residences and facilities would be avoided or adequately minimized by following the Project-specific Blasting Plan; completing site-specific blasting plans prior to construction; and adhering to applicable federal, state, and local regulations.

4.1.5 Trenchless Crossings Geotechnical and Feasibility Assessment

AGDC reviewed geotechnical data for the five trenchless crossing locations along the Mainline Pipeline to assess the viability of two potential installation technologies: the horizontal directional drill (HDD) and DMT. Several factors were considered in assessing the technical feasibility of each method at the five crossings, including length of alignment, pipeline diameter, and subsurface materials. Subsurface conditions that can affect the feasibility of an installation include excessive rock strength and abrasivity, poor rock quality, solution cavities, and artesian conditions. While both crossing methods were determined to be feasible, DMT was selected for all crossings for a variety of reasons, including:

- the pipeline can be installed in one pass while excavating the borehole versus multiple passes for an HDD;
- DMT allows for a shallower approach angle resulting in shallower required burial depth;
- drill hole collapse is rare in comparison to HDD crossings;
- the annulus around the advancing pipe is a smaller size than that needed for an HDD, thereby reducing the risk of hydraulic fracture and fluid loss;
- smaller amounts of drilling fluid are required;
- the pipeline remains in compression, versus tension, during installation;
- continuous borehole support makes it possible to drill through collapsible soils, coarse grained materials, and weathered bedrock, which could allow for a shorter crossing length; and
- the method does not require temporary casings, while HDD does.

The DMT method involves a steerable cutterhead at the tunnel face, also known as a microtunneling boring machine. Soil or rock is removed using slurry pumped to the cutterhead while the pipe is pushed into the ground. Cuttings are mixed with the slurry and then pumped out through the pipeline. Cuttings are then separated from the drilling slurry and disposed of offsite, while the drilling slurry is reused. Similar to HDD installation, the product pipe to be installed is welded and pressure tested before installation, requiring temporary extra workspaces similar to the HDD installation method.

Hydraulic fracturing, which can lead to inadvertent releases of drilling fluid at the ground surface, could occur when the downhole annular pressure exceeds the overburden effective stress and shear/tensile strength of the soil or bedrock along the drill path. Hydraulic fracturing typically occurs in weak cohesive or loose granular soils. Therefore, determining the maximum allowable annular pressure is a tool to control the risk for hydraulic fracturing. When maintaining pressures below this threshold, the risk of hydraulic fracturing is reduced but not eliminated. For all DMT crossing locations, a factor of safety was estimated by dividing the formation limit pressure by the estimated minimum pressure required for the crossing with a recommended minimum factor of safety between 1.5 and 2.

For DMT installations, the calculation for the formation limit pressure does not change as the casing follows the cutterhead. Also, during the DMT process, drilling fluid annular pressures are typically much lower than those needed for HDD because of how drilling slurry is transported back to the surface. In the DMT process, drilling fluid consisting primarily of fresh water and non-toxic additives, including bentonite, is used to provide a pressure balance at the cutting face. During drilling, the water-bentonite mixture combines with cuttings at the cutting face, creating a slurry that is transported back to the surface via slurry lines running on the inside of the pipe. Drilling fluid is typically applied to the small annular space outside of the pipe to act as a lubricant and reduce friction forces during pipe advancement. Unlike the DMT process, HDD drilling fluids are transported back to the surface within an open annulus outside of the drill bit and drill string. In HDD installations, the drilled or bored hole is filled with drilling fluids under pressure. The annular pressure required to maintain the open annulus and transport slurry for an HDD installation may be up to 50-percent more than that required for DMT, depending on actual drill fluid properties. AGDC states that to reduce the risk of drilling fluid release to the surface, drilling contractors would use a combination of annular pressure monitoring tools to control annular pressure during drilling and compare it with overburden pressure along the alignment.

AGDC provided a qualitative risk assessment for each river crossing that looked at the following potential risks associated with DMTs:

- downhole equipment failure;
- product pipe becoming lodged in the hole;
- out of tolerance trajectory;
- loss of fluid circulation;
- hole collapse;
- unexpected changes in geology; and
- presence of permafrost.

AGDC's DMT Plans include Trenchless Feasibility Crossing Studies, which describe subsurface conditions identified by geotechnical investigations that could increase the risk of drill complications and the measures that would be implemented to minimize risks to a successful crossing (instructions for accessing the DMT Plans are provided in table 2.2-1). In general, coarse-grained gravel, coarse-grained sand, cobbles, and boulders present challenges to trenchless advancement, as these are unstable layers with propensity to crumble. A microtunneling boring machine can handle gravel and cobbles up to about one-third of its outside diameter. The contractor would select the proper cutterhead for the types of soil to be encountered along the entire drill path and keep the bore path above or below the identified bedrock surface.

The risk of encountering permafrost exists at DMT entry and exit locations. Properly managing the drilling rate along with drilling fluid temperature and fluid design mitigates the risk to advancing the DMT bore through permafrost. Permafrost thaw at entry and exit areas would be managed by placing concrete, gravel, or a combination of insulation and gravel to reduce the effects of ground thawing. A benefit to the DMT installation is the limited number of passes, reducing the effect of radial thaw on borehole stability.

AGDC has determined the potential for closed taliks under the Yukon, Middle Fork Koyukuk, and Tanana Rivers. Closed taliks are unfrozen zones that do not fully penetrate permafrost, while open taliks do fully penetrate permafrost, thereby connecting suprapermafrost and subpermafrost groundwater (Jorgenson et al., 2008). Conducting a DMT crossing through permafrost into or from taliks or thawed soils would form a localized thaw bulb around the pipeline during construction. Thaw settlement or ground instability could occur in these areas, which AGDC proposed to mitigate with slope protection and/or ground improvements at the entry and exit locations. During operation, the potentially thawed areas would not be anticipated to refreeze as chilled gas would be flowing through the pipeline. As described above, the DMT annulus space around the pipeline would be just slightly larger than the pipe diameter, which would minimize the amount of seasonal water flux and the potential for permafrost degradation at the crossings.

As discussed in sections 4.1.5.1 through 4.1.5.5, we have determined, based on available information, that the DMT method is an appropriate technique for installing the pipeline at each crossing and that each DMT crossing could be completed successfully. The details of each crossing would be further reviewed during the detailed engineering stage of the Project. The final installation design and drilling plans would include bedrock characterization for fracture spacing/jointing, weathering, strength, and abrasiveness. AGDC would also conduct jacking force and stress analysis during the detailed engineering stage as the drill paths are further refined. To finalize the DMT crossing design, AGDC would utilize geophysical methods, such as electrical resistivity tomography and ground-penetrating radar supported by traditional geotechnical borehole data.

Prior to construction of the Mainline Facilities, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, final installation design and drilling plans for each DMT crossing. The plans would further characterize subsurface and permafrost conditions (updated to reflect new site-specific geotechnical information, where available) along with proposed mitigation measures, if required. Additionally, AGDC would provide the results of jacking force and stress analyses for each DMT crossing.

As discussed in section 2.2.2, AGDC's DMT Plans identify measures to be implemented in the event of an inadvertent return of drilling fluids. Loss of drilling fluids would not prevent completion of a drilled alignment, nor would it necessarily result in an inadvertent release of drilling fluids at the ground surface. Inadvertent releases are more likely to occur in less permeable soils or via fractures or fissures in bedrock. Chances for an inadvertent release to occur are greatest near the drill entry and exit points where the drill path has the least amount of ground cover. AGDC's plans include preventative measures such as the installation of containment structures and staging of response equipment at the entrance and exit points of the drill. The DMT Plans incorporate applicable elements of the latest FERC guidance on the information required for a complete plan. Implementation of these plans would effectively minimize impacts on freshwater resources. Site-specific plans for each DMT crossing are included in appendix G.

4.1.5.1 Middle Fork Koyukuk River

The Middle Fork Koyukuk River is a high energy, multi-channel, braided river. The crossing is within the southern portion of the Central and Eastern Brooks Range Section and between 1,300 and 1,600 feet of the Dalton Highway river bridges. Sediments in the river valley were deposited during successive glacial and post-glacial events. The entry site would be on the southeast side of the river near MP 211.5 at an elevation of 1,400 feet, and the exit location would be on the northwest side of the river near MP 211.0 at an elevation of about 1,400 feet. The setbacks from the top of bank would be about 250 feet on the southeast and about 280 feet on the northwest side of the river. The exit would be adjacent to the Dalton Highway right-of-way. The total length of the drill path would be 2,625 feet (see appendix G).

AGDC did not conduct a Project-specific evaluation of the geotechnical conditions of the proposed DMT alignment at the Middle Fork Koyukuk River. Instead, AGDC relied on information collected for ASAP, the Dalton Highway, and TAPS. This data included more than 20 geotechnical borings near the proposed river crossing, 3 of which were close to the Mainline Pipeline centerline (within about 800 feet or less) and used for the analysis below. These three borings were collected from April to November between the years 1972 and 1983 to a depth range of 51 to 52 feet below ground surface. The pipeline would have a maximum burial depth of 72 feet for the crossing, with 50 feet of cover on the northwest bank and 40 feet on the southeast bank. No permafrost was present in the three borings reviewed for this analysis, but AGDC inferred its presence at the entry and exit locations of the bore path from review of nearby boring data, terrain type, and geologic mapping from previous pipeline projects.

The entry point would be in glacial till deposits consisting of dense gravels and sands with the potential for frequent cobbles and possible boulders. Soils in this unit were inferred to contain permafrost. The drill path would descend through the glacial till and head north under the river crossing to an interface with glaciofluvial deposits. These deposits consist of sand with varying amounts of silt and small amounts of coarse-grained material with no cobbles or boulders indicated during the geotechnical investigations. The drill would continue through these deposits as it ascends on the northwest side of the river into braided floodplain riverbed deposits consisting of sand and gravel with the potential for cobbles and small boulders. This deposit is assumed to be frozen on the northwest bank of the river, but not within the active river channel. Permafrost is expected in upland areas outside of the active channel to a maximum depth of 30 feet, with an active layer of seasonal thaw at the entry and exit points. Surface soils in the area may have seasonally perched surface water during spring breakup through the summer.

AGDC would, prior to construction of the Mainline Facilities, file with the Secretary, for the review and written approval of the Director of the OEP, a revised Feasibility Crossing Study that provides updated site-specific geotechnical information for the Middle Fork Koyukuk River with borings conducted at the proposed crossing location at least as deep as the proposed crossing depth.

The most prevalent risks associated with the Middle Fork Koyukuk River crossing are the potential for changes in subsurface geology and permafrost. The coarse-grained gravel identified and the potential for cobbles and boulders could present challenges to the DMT advancement through floodplain deposits. The drill is likely to encounter permafrost at both the entry and exit locations. To mitigate the construction risk to advancing the DMT bore, the drilling rate of penetration and drilling fluid temperature and fluid design would be continuously managed. Thawing permafrost would be managed by placing granular fill or a combination of granular fill and insulation at the surface to reduce the potential thaw of frozen soils. The entry pit and jacking frame installation would use piles to support the jacking frame and implement design measures to control thaw instability of side slopes, if needed.

Based on our recommendations, our assessment of the geologic conditions at the proposed crossing, and the risk factors and proposed mitigation measures, we conclude that the DMT method is an appropriate technique for installing the pipeline beneath the Middle Fork Koyukuk River.

4.1.5.2 Yukon River

The Yukon River is the widest Mainline Pipeline river crossing at about 1,900 feet. The crossing is about 0.5 mile west of the existing TAPS/Dalton Highway crossing and close to the existing Yukon River camp. The north bank of the river is a large floodplain with easy access from the Dalton Highway. The south side of the river is steep with about a 30-percent grade for 350 feet from the river before leveling to an approximately 7-percent grade. The entry site would be on the south side of the river near MP 356.8 at an elevation of about 350 feet, and the exit location would be on the north side of the river near MP 356.2 at an elevation of about 300 feet. The setbacks from the top of bank would be about 145 feet on the north and 220 feet on the south sides of the river. The total length of the drill path would be 2,668 feet (see appendix G).

AGDC did not conduct a Project-specific evaluation of the geotechnical conditions of the proposed DMT alignment of the Yukon River. Instead, AGDC relied on information collected for ASAP that used hollow-stem auger drilling and techniques, including standard penetration tests in 13 geotechnical borings within 150 feet of the proposed right-of-way. These 13 borings were collected between 2011 and 2013, with depths ranging from 51 to 126 feet below ground surface. The pipeline would have a maximum burial depth of 100 feet for the crossing, with 26 feet of cover on the north and south sides of the crossing. Permafrost was encountered in two boreholes about 100 to 150 feet from the entry point and in two boreholes about 100 to 150 feet from the exit point with both visible and non-visible ice bonding and up to 20-percent visible ice content. Based on this data, permafrost was inferred at the actual bore entry and exit sites and in the banks of the river basin. No permafrost was indicated in the boreholes within the active river channel. Permafrost was inferred to be absent along the path of the crossing beneath the river.

As shown in appendix G, the entry point for the DMT crossing is in frozen upland loess deposits comprised of wind-blown silt covering bedrock hills. The drill would then descend through the upland loess and make contact with floodplain deposits consisting of well- to poorly-graded gravels and sands with varying silt content. The path would then continue to descend and would encounter residual bedrock soils consisting of silty sands and gravel-sized material which comprise the majority of the drill path beneath the riverbed. The path would continue north and ascend through the floodplain deposits and into abandoned floodplain deposits on the north side of the river. These abandoned floodplain deposits consist of sandy silts and silty sands. It is anticipated that the ice-bonded permafrost is discontinuous in this unit depending on the soil gradation, surface conditions, and proximity to the river, with an active layer of seasonal thaw at the entry and exit points. Surface soils may also have a seasonally perched surface water during spring breakup through the summer.

The most prevalent risks associated with the Yukon River crossing are the potential for changes in subsurface geology and permafrost. The coarse-grained gravel identified and the potential for cobbles and boulders could present challenges to the DMT advancement through floodplain deposits. The bore path would be above the bedrock surface within residual bedrock soil and permafrost logged in the borings. Permafrost could be encountered by the drill path at both the entry and exit locations. To mitigate the construction risk to advancing the DMT bore, the drilling rate of penetration and drilling fluid temperature and fluid design would be continuously managed. Thawing permafrost would be managed by placing granular fill or a combination of granular fill and insulation to reduce the potential thaw of frozen soils. The entry pit and jacking frame installation would use piles to support the jacking frame and implement design measures to control thaw instability of side slopes.

In comments on the draft EIS, the State of Alaska said that there are known northeast-trending faults in the area of the Yukon River crossing. In the summer of 2016, the DGGS conducted a field program in a study region that coincided with the Yukon River crossing area. The study region extended from about 8 miles north to about 31 miles south of the proposed Mainline Pipeline crossing of the Yukon River. During consultations with AGDC, the DGGS indicated that the preliminary conclusions of this field program are that faults and lineaments investigated in the study region do not show tectonic geomorphic evidence of Quaternary deformation (age of the most recent movement within the last 2.8 million years). The two closest identified Quaternary faults to the Mainline Pipeline crossing of the Yukon River are: 1) the west-dipping Dall Mountain fault about 24 miles to the north, and 2) the east-west-striking Preacher fault about 101 miles to the east. Based on AGDC's Probabilistic Seismic Hazard Analysis (Golder Associates Inc., 2016), AGDC said that the level of moderate seismic hazard associated with these faults was addressed in the current Project design for the area of the Yukon River crossing.

Based on our assessment of the geologic conditions at the proposed crossing and the risk and proposed mitigation measures, we conclude that the DMT method is an appropriate technique for installing the pipeline beneath the Yukon River and that the DMT crossing could be completed successfully.

4.1.5.3 Tanana River and Parks Highway

The Tanana River is a meandering high-volume river with many islands and sand bars. The proposed river crossing is southeast of the town of Nenana and to the west of the Parks Highway bridge over the Tanana River. The area is characterized by outwash and floodplains deposited by rivers and streams originating in the Alaska Range. The entry site would be on the north side of the river near MP 472.7 at an elevation of about 350 feet, and the exit location would be on the south side of the river near MP 473.3 at an elevation of about 350 feet. The setbacks from the top of bank would be about 270 feet on the south side and 370 feet on the north side of the river. The entry point would also be set back from the Parks Highway by about 290 feet. The total length of the drill path would be 3,124 feet (see appendix G).

AGDC did not conduct a Project-specific evaluation of the geotechnical conditions of the proposed DMT alignment of the Tanana River. Instead, AGDC relied on information collected for ASAP, which included 16 geotechnical borings, 5 of which are within the proposed Project drill path and were used for the analysis below. The 16 borings were drilled between 2011 and 2015 using hollow-stem auger drilling and sampling techniques, including standard penetration tests through unconsolidated material and rotary drilling and coring through bedrock. The depth of the five borings within the proposed Project drill path ranged from 52 to 135 feet below ground surface. The pipeline would have a maximum burial depth of 66 feet for the crossing, with 60 feet of cover on the north bank and 40 feet on the south bank. While none of the borings at the current proposed crossing location identified permafrost, sporadic permafrost was observed in similar floodplain riverbed deposits at a former crossing location about 4 miles from the proposed crossing site.

As shown in appendix G, the DMT would begin on the north side of the river in embankment fill consisting of poorly-graded fine sand with gravel and occasional cobbles that was used for construction of the Parks Highway. The north side was selected for the entry side given more favorable workspaces for pipe fabrication and laydown areas. Boreholes on the north side of the river encountered fill to a depth of between 5 and 17 feet below ground surface, where the drill path would then descend into floodplain and riverbed deposits consisting of sand and gravel. The drill path would continue south through the floodplain and riverbed deposits, then make contact with the weathered bedrock unit, Birch Creek Schist. Geologic logs through bedrock show very poor rock quality, with rock quality designations in many cases less than 20 percent, as well as intervals of void spaces with losses of drilling fluid circulation noted in the drilling logs. Under the Tanana River, the drill path would transition out of weathered schist bedrock and into meandering floodplain deposits of the river valley consisting mostly of sand and gravel. While no boulders were encountered in borings, they have the potential to occur in this unit. As the drill path starts to ascend to the exit location, it would transition into floodplain riverbed deposits similar to those on the north side of the river with sand and gravel present. The drill path would exit through meandering floodplain cover deposits consisting of sediment and organic deposits, including surficial organic mat, soil, sand, and peat.

The most prevalent risk associated with the Tanana River crossing is the potential for changes in subsurface geology and geotechnical parameters. The coarse-grained gravel and cobbles identified and the potential for encountering boulders could present challenges to the DMT advancement through floodplain deposits, while weathered bedrock could pose challenges with mixed-face conditions or remnant boulders within the bedrock unit on the north side of the river crossing. The boulder risk would require mitigation planning to determine the best course of action during construction.

Based on our assessment of the geologic conditions at the crossing and the risks and proposed mitigation measures, we conclude that the DMT method is an appropriate technique for installing the pipeline beneath the Tanana River and that the DMT crossing could be completed successfully.

4.1.5.4 Chulitna River

The Chulitna River is a highly-braided and high energy river with a large number of sand bars. The proposed river crossing is in lowlands between the Talkeetna Mountains to the east and the Alaska Range to the west. The lowlands are characterized by complex deposits from successive glacial and post-glacial erosion and deposition events. The entry site would be on the west side of the river near MP 642.2 at an elevation of about 660 feet, and the exit location on the east side of the river near MP 641.7 at an elevation of about 550 feet. The setbacks from the top of bank would be about 610 feet on the west side and 190 feet on the east side of the river. The total length of the drill path (based on the site-specific plan provided in appendix G) would be 2,625 feet.

The analysis presented by AGDC in the text of the *2018 Trenchless Feasibility Crossing Study* describes the entry location as being on the east side of the river and the exit on the west side of the river, but the site-specific crossing plans show the entry on the west side of the river and the exit on the east side. Our analysis below is consistent with the site-specific crossings plans, but given the discrepancy, and the potential for the location of the DMT entry to affect the planned location of pipe laydown work areas, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, a revised Feasibility Crossing Study for the Chulitna River prior to construction of the Mainline Facilities, that consistently identifies the proposed DMT entry and exit locations throughout the document, including all figures, appendices, and drill path descriptions.

AGDC conducted a Project-specific evaluation of the geotechnical conditions of the proposed DMT alignment of the Chulitna River. The exploration consisted of three geotechnical boreholes near the river crossing using rotary drilling and sampling techniques, split spoon sampling, standard penetration tests through unconsolidated materials, and bedrock coring in bedrock. AGDC also used information collected for ASAP, which included five geotechnical borings. Of these eight total borings, two were on the east bank of the river, and one on the west bank of the river. The remaining five borings were drilled within the limits of the Chulitna River. Additionally, a helicopter electromagnetic (HEM) survey was conducted in 2015 along the proposed alignment to investigate the continuity of subsurface conditions to support the borehole analysis. Neither the borehole data nor the HEM survey results indicate the presence of permafrost along the DMT path.

AGDC proposes to install the DMT using a drill path primarily within glacial till and glacial lacustrine deposits consisting of clays, silts, silty gravel, dense gravel, and scattered cobbles. The pipeline would have a maximum burial depth of 83 feet for the crossing, with 27 feet of cover on the west bank and 31 feet on the east bank. Boreholes on the entry side of the river encountered glacial till deposits of silty sand gravel overlaying bedrock, with interfaces ranging between 43 and 92 feet. AGDC has stated that the current planned depth of cover indicates that the drill path would be above bedrock with a high potential for interference with bedrock as the drill descends and traverses east below the river. As shown in appendix G, the path is currently projected to pass through bedrock (siltstone and igneous rock types) as it descends below the river. Based on the HEM data, the top of the bedrock deepens to the east; therefore, the alignment proposed in appendix G may not reflect the actual path conditions.

The drill path would continue out of bedrock and travel east through glacial till deposits consisting of very dense gravel with silt and sand, and well-graded sand with gravel, under the Chulitna River. As the path continues east, it would ascend from the glacial till deposits under the Chulitna River through a contact with glaciolacustrine deposits composed of clays and silts. Continuing east, the drill path would ascend towards the exit point within abandoned floodplain deposits consisting of well- to poorly-graded sands and silt.

The most prevalent risk associated with the Chulitna River crossing is the potential for changes in subsurface geology and geotechnical parameters. The coarse-grained gravel and cobbles identified and the potential for boulders could present challenges to the DMT advancement. While none of the Project-specific borings identified boulders, one bore log for ASAP about 150 feet from the proposed crossing did identify small boulders. The boulder risk would require mitigation planning to determine the best course of action during construction.

Based on our recommendation, our assessment of the geotechnical conditions at the proposed crossing, and the identified risks and proposed mitigation measures, we conclude that the DMT method is an appropriate technique for installing the pipeline beneath the Chulitna River and that the DMT crossing could be completed successfully.

4.1.5.5 Deshka River

The Deshka River is a meandering single-channel river with sidebars near the proposed crossing site. The riverbed consists primarily of cobbles. The crossing is within the Susitna Lowland about 7 miles upstream from the confluence of the Susitna and Deshka Rivers. Sediments in the river valley were deposited during successive glacial and post-glacial events. The entry site would be on the south side of the river near MP 705.0 at an elevation of about 110 feet, and the exit location would be on the north side of the river near MP 704.7 at an elevation of about 125 feet. The setbacks from the top of bank would be about 470 feet on the south and 600 feet on the north sides of the river. The exit would be adjacent to the Dalton Highway right-of-way. The total length of the drill path would be 1,299 feet (see appendix G).

AGDC conducted a Project-specific evaluation of the geotechnical conditions of the proposed DMT alignment of the Deshka River. The exploration consisted of two geotechnical boreholes collected in 2016 near the river crossing using hollow-stem auger drilling and sampling techniques, including split spoon sampling and standard penetration tests through unconsolidated materials. The depth of these borings ranged from 55 to 70 feet below ground surface. The pipeline would have a burial depth of 33 feet below the river bottom for the crossing, with about 40 feet of cover on the north and south banks. Additionally, Electrical Resistivity Tomography was conducted on both sides of the river to further investigate subsurface conditions along the alignment. Neither the borehole data nor the Electrical Resistivity Tomography survey results indicate the presence of permafrost along the DMT path.

As shown in appendix G, the entry point would be in meandering floodplain cover deposits comprised of unconsolidated sediments and organic deposits including peat, organic soil, sand, and the surficial organic mat. The path would descend to a contact with meandering floodplain deposits consisting of silty sand and poorly graded gravel with silt and sand with the presence of cobbles and boulders. Continuing north below the Deshka River, the path would encounter a contact with glacial till deposits of medium to very dense, silty gravel, and poorly graded gravel with sand and silt. This formation also contains cobblers and boulders. The path would continue through this formation under the Deshka River and then ascend upwards to the exit point until reaching the meandering floodplain deposits. The path would continue to ascend and would reach the meandering floodplain cover deposits on the north side of the river. The subsurface profile for the Deshka River crossing is projected based on two soil borings, with one located over 150 feet from the proposed crossing location. Therefore, **we recommend that:**

- **<u>Prior to construction of the Mainline Facilities</u>, AGDC should file with the Secretary a revised Feasibility Crossing Study that provides updated site-specific geotechnical information for the Deshka River with additional borings conducted at the proposed crossing location. If the results of the study indicate that a modification to the crossing location or method is necessary, AGDC shall file, for the review and written approval of the Director of the OEP, a revised crossing plan for the Deshka River.**

The most prevalent risks associated with the Deshka River crossing are the potential for changes in subsurface geology and geotechnical parameters. The coarse-grained gravel, cobbles, and boulders identified could present challenges to the DMT advancement through floodplain deposits. The boulder risk would require mitigation planning to determine the best course of action during construction.

Based on our assessment of the geotechnical conditions at the proposed crossing and the identified risks and proposed mitigation measures, we conclude that the DMT method is an appropriate technique for installing the pipeline beneath the Deshka River and that the DMT crossing could be completed successfully.

4.1.6 Paleontological Resources

Paleontological resources are vertebrate and invertebrate fossils, molds, traces, imprints, or frozen remains that are sometimes discovered at locations under excavation or in areas exposed by erosion or ice melting. Direct effects on paleontological resources could occur during Project construction by activities such as grading or trenching as well as material site development. Indirect effects on fossil beds could result from erosion caused by slope regrading, vegetation clearing, and/or unauthorized collection. Disturbance of paleontological resources could result in exposure to wind, water, and freeze–thaw cycles.

Fossils that could be encountered during Project construction include both large and small terrestrial vertebrate species. These could include large dinosaur fossils dating to the Mesozoic Era; Pleistocene-age vertebrate mammals, including mammoth, horse, and bison remains; and marine invertebrate fossils, including brachiopods, crinoids, corals, and mollusk shell fragments. Traditional knowledge regarding paleontological resources that could be present on the North Slope was obtained from residents of the Nuiqsut community, which primarily related to the unanticipated findings of Pleistocene-age mammal fossils along the Colville River (Braund, 2016).

Potential paleontological resource impacts are determined at the geologic unit level. Fossils are typically encased in bedrock, sediments, or permafrost, so field surveys that employ surface inspections or shallow subsurface testing in unconsolidated sediments have limited utility in determining the presence or absence of paleontological resources in the Project footprint. The BLM's Potential Fossil Yield Classification (PFYC) sensitivity modeling system ranks geologic units by their potential for containing significant paleontological resources and is the primary means for assessing potential Project impacts on paleontological resources in this EIS.

The entire Project route was reviewed for existing paleontological resources using aerial photographs, BLM planning documents and maps, USGS geologic maps, DGGS maps and publications, soil survey maps, and other accessible information. Areas were selected for field survey based on the locations of identified geologic units with known or high-potential paleontological resources. In 2015, AGDC conducted field assessments within the targeted areas to identify paleontological resources. In total, 33 discontinuous areas, comprising 558 acres, were surveyed. During the field surveys, seven new sites with marine invertebrate fossils and five sites with significant vertebrate fossils were identified.

4.1.6.1 Gas Treatment Facilities

The GTP, PTTL, and PBTL would overlie potential fossil-bearing bedrock in the Arctic Coastal Plain Province, including marine sandstone, siltstone, shale, and limestone, the oldest of which date to the Devonian Period (Lindsey, 1986). Specifically, significant vertebrate fossils could be encountered where Project facilities overlie Cretaceous-age sandstone, marine invertebrate fossils where Devonian sedimentary bedrock is present, or terrestrial plant fossils where Middle Jurassic to Cretaceous Period rocks occur. In addition, dinosaur fossils representing 12 species dating to the Late Cretaceous Period (between 65 million and 100 million years ago) were recovered about 50 miles west of Prudhoe Bay in 1961 (BLM, 2016a). The PFYC sensitivity modeling designated the GTP as having a low probability for significant paleontological resources (AECOM, 2015).

4.1.6.2 Mainline Facilities

Similar to the Gas Treatment Facilities, Mainline Facilities construction in the Arctic Coastal Plain Province could encounter vertebrate fossils in Cretaceous-age sandstone, marine invertebrate fossils in Devonian sedimentary bedrock, or terrestrial plant fossils in middle Jurassic to Cretaceous rocks.

Based on the paleontological field surveys conducted in 2015, the Mainline Pipeline could encounter fossil-bearing unconsolidated colluvial, alluvial, lacustrine, glacial, or eolian deposits where it traverses the Brooks Range (AECOM, 2015). In addition, marine sedimentary rocks crossed by the Project could contain marine invertebrates, gastropods, bivalves, and coral (Reifenstuhl, 1991). The Project footprint on the North Slope and Brooks Range has varying PFYC recommendations, ranging from moderate or unknown to very high in areas of significant vertebrate remains.

Within the Northern Plateaus Province, primarily between MPs 260.9 and 429.9, the Mainline Pipeline would cross bedrock that contains Early Cambrian Period trace fossils and marine invertebrates dating from the Ordovician through the Mississippian Periods. Cretaceous Period plant fossils could be encountered (Lindsey, 1986).

The area where the Mainline Facilities would cross the Tanana-Kuskokwim Lowland and Yukon-Tanana Upland Sections has been documented to contain freshwater invertebrate and vertebrate fossils. Large Pleistocene-age vertebrates including mammoth, mastodon, saiga antelope, bison, horse, musk oxen, and birds have also been found in this area. Most of the Project footprint in the interior is recommended as very low to low, with some areas recommended as moderate or unknown.

As discussed in section 4.1.1, bedrock in the Alaska Range is diverse due to the accretion of various terranes associated with the Pacific plate and Yakutat microplate subduction. As such, several strata have Mesozoic Era invertebrate fossils and microfossils such as radiolarians. Rocks of the Chulitna Terrane are known to contain abundant fossil specimens including Paleozoic-age radiolarian, crinoids, and bivalves along with Triassic-age gastropods, bivalves, and ammonites. The West Fort Terrane contains Upper Jurassic radiolarians, bivalves, and belemnite fossils (Blodgett and Clautice, 2000). Quaternary-age deposits including those in the Maclaren terrane have recorded fossils, including brachiopods and pelecypods (Nokleberg et al., 1996). The PFYC evaluation indicates varying PFYC recommendations, ranging from very low to very high in potential areas of significant vertebrate remains.

The lower Cantwell Formation, where vertebrate paleontological sites have been reported about 10 to 20 miles east of the Mainline Facilities within the DNPP (Fiorillo and Adams, 2012; Fiorillo and Tykoski, 2016; Fiorillo et al. 2014a; Fiorillo et al., 2014b; Fiorillo et al., 2007), is crossed by the Project between about MPs 538.6 and 557.4. The Cantwell Formation consists of successions of conglomerate, sandstone, mudstone, coal seams, and altered tuffs. The Cantwell formation is about the same age as dinosaur-bearing strata on the North Slope and in southwestern Alaska (Csejtey et al., 1992; Ridgway et al., 2002; AECOM, 2015).

The Mainline Pipeline would enter the Cook Inlet-Susitna Lowland Section, which is underlain by the Tertiary-age Kenai Group sedimentary deposits at about MP 576.4. Bedrock of equivalent age and lithology on the western side of Cook Inlet contains plant fossils. The PFYC evaluation indicates that south-central Alaska and the Kenai Peninsula have low probability for containing paleontological resources. Recommended PFYC values for the entire corridor in this region are low.

In summary, portions of the Mainline Facilities and associated areas adjacent to the right-of-way would cross areas with a high probability of encountering vertebrate fossils, including dinosaur and Pleistocene-age mammal remains.

4.1.6.3 Liquefaction Facilities

The Liquefaction Facilities are underlain by sandstone, siltstone, conglomerate, claystone, and coal deposits of the Kenai Group that date to the Upper Tertiary Period. Although bedrock outcrops are not present in the Liquefaction Facilities area, the same strata of Upper Tertiary-age sedimentary deposits exposed on the western side of Cook Inlet are known to contain Tertiary-age plant fossils (Wolfe et al., 1966). In addition to Tertiary-age fossiliferous sedimentary rocks, the Cook Inlet–Susitna Section may also contain Mesozoic Era marine invertebrate fossils. Based on the types of documented fossils in the area, Project construction would be unlikely to encounter vertebrate fossils at the Liquefaction Facilities. The PFYC evaluation indicates that south-central Alaska and the Kenai Peninsula, including the Liquefaction Facilities, have a low probability for containing paleontological resources. Recommended PFYC values for the entire corridor in this region are low.

4.1.6.4 Impacts and Mitigation

Paleontological resources could be directly affected by ground-disturbing activities, causing damage, fragmentation, or stratigraphic displacement; or indirectly affected due to increased potential for erosion or vandalism. AGDC would implement the Project Paleontological Resources Management Plan (PRMP) to minimize potential impacts on paleontological resources. As portions of the Project are within BLM-managed and NPS-managed lands, and the Project requires FERC authorization, AGDC developed the PRMP in accordance with NEPA, FLPMA, Paleontological Resources Preservation Act of 2009, and FERC guidelines.

The PRMP addresses known paleontological resources that were identified and classified during surveys in 2015, and includes specific mitigation measures to avoid or reduce adverse disturbance where there is high potential to encounter paleontological resources. These mitigation measures include conducting a full assessment and inventory before excavating in areas of paleontological resources, monitoring of ground-disturbing activities in areas likely to contain paleontological resources, excavating and recovering finds, and training for Project personnel. In addition, during construction of Project facilities, AGDC would implement the Project Paleontological Resources Unanticipated Discoveries Plan (PRUDP) in the event that undocumented paleontological resources are discovered.

The PRUDP and PRMP include the following preventive measures and procedures:

- A qualified paleontologist would conduct paleontology sensitivity training for site inspectors, contractors, supervisors, heavy equipment operators, and other personnel.
- If a discovery is identified during construction, construction activities would be stopped, a 100-foot barrier would be installed around the discovery, and an area of at least 30 feet around the discovery would be flagged or staked to prevent any traffic through the area immediately surrounding the discovery.
- The EI would notify a qualified paleontologist who would evaluate the discovery.
- If the discovery is evaluated as a significant paleontological resource, Project personnel, FERC, and the landowner or appropriate land management agency would be notified.
- The fossil would be photographed or salvaged as considered appropriate by a qualified paleontologist (if on BLM-managed lands, the paleontologist must have obtained a Paleontological Resource Use Permit to collect or disturb fossils).
- The finding would be included in a Discovery Report.

- Any collected materials would be curated, as appropriate, into an established, accredited museum repository with permanent retrievable paleontological storage.

Paleontological resources could be adversely affected by ongoing maintenance activities during Project operation where additional ground disturbance is required outside former construction workspaces. The probability that Project operation would disturb paleontological resources, however, is considered to be low. Therefore, with the implementation of the PRUDP and PRMP to minimize and mitigate construction and operational impacts, the Project would not have significant adverse effects on paleontological resources

4.1.7 Conclusion

The Project would traverse a range of geologic conditions and resources. As discussed, AGDC conducted studies to characterize geologic conditions and developed Project-specific plans that would minimize impacts on or near geologic resources during construction and operation. AGDC has agreed to implement six of our recommendations from section 4.1 of the draft EIS (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS). Based on the above discussion, we conclude that impacts on geologic conditions and resources would be less than significant with implementation of the mitigation measures described above, AGDC's commitments, and our recommendations, as well as compliance with applicable regulatory approvals and requirements.

4.2 SOILS AND SEDIMENTS

4.2.1 Existing Soil Resources

Given the expansive nature and lack of accessibility in Alaska and the Project area, the U.S. Department of Agriculture (USDA) NRCS has less detailed Soil Survey Geographic Database (SSURGO) information available than is typical in other states. To analyze the soil properties affected by construction and operation of the Project, the Exploratory Soil Survey of Alaska (Soil Conservation Service, 1979), Digital General Soil Map of the United States (STATSGO2) (NRCS, 2017d), and SSURGO, where available, were reviewed (NRCS, 2017b). In addition, data were used from the Project-specific geotechnical engineering studies conducted by AGDC, including terrain mapping and a digital elevation model data analysis. The terrain mapping was used to identify potentially thaw-stable or thaw-sensitive soils, as defined in section 4.2.4.

The Mainline Pipeline would closely follow segments of other existing, proposed, or previously considered pipeline projects. These include the TAPS, Alaska Natural Gas Transportation System, Alaska Pipeline Project, ASAP, Alaska Gas Pipeline Producers Team, and the Denali Pipeline Project. Varying levels of soil and geotechnical studies were performed for these projects. As applicable, the results of these studies were incorporated into our analysis of the Project.

4.2.1.1 Soil Types

The Project would cross a wide variety of soil types. The majority of the soils within the Project area are Gelisols, Entisols, Inceptisols, and Spodosols. Gelisols, which are further discussed in section 4.2.2.1, are soils with permafrost, evidence of cryoturbation, and/or ice segregation near the soil surface. Gelisols make up about 9 percent of the world's ice-free land surface and, for U.S. land, are unique to Alaska (NRCS, 2017c). These soils typically have minimal profile development; the majority of soil-forming processes occur near the surface, which can cause a significant accumulation of organic matter. Many Gelisols are waterlogged, which inhibits internal drainage during the summer thaw. They can become boggy wetlands in the summer, providing food and habitat for a variety of wildlife, including caribou, muskox, and migratory birds.

Entisols are soils that show little-to-no evidence of pedogenic (i.e., soil forming) horizon development. They occur in areas where erosion or deposition rates exceed the rate of soil development (e.g., dunes, steep slopes, and floodplains). In addition, they can be found in environmental conditions where biological pedogenic processes are slowed or absent (e.g., subaqueous soils, extreme cold, or heat). Entisols are the transition between the other soil taxonomic orders and non-soil materials such as bare rock, deep water, or ice at the surface of the earth. They make up about 16 percent of the world's ice-free land surface (NRCS, 2017c).

Inceptisols are soils that exhibit moderate pedogenic horizon development. Inceptisols have a wide range of characteristics and can occur in many climates and landforms. Many soil formation processes may be expressed or active in an Inceptisol, but none are predominating and/or qualify for another soil order. Inceptisols are the most widely spread soil in the world, covering about 17 percent of the world's ice-free land surface (NRCS, 2017c).

Spodosols are formed due to weathering processes that strip organic matter and aluminum, and sometimes iron, from the surface layer and deposit them deeper in the subsoil. A well-formed Spodosol has distinct morphology in which a dark surface is underlain by an ashy, gray eluvial horizon with reddish brown or black subsoil. These soils tend to be acidic and infertile, and often form in areas having coarse-textured parent materials under humid coniferous forests. Complex interactions between rainfall and acidic vegetative litter form organic acids that dissolve and transport the organic matter, aluminum, and iron during water infiltration. Spodosols make up about 4 percent of the world's ice-free land surface (NRCS, 2017c).

4.2.1.2 Major Land Resource Areas

Soil interpretations at the broadest scale in the United States are based on Major Land Resource Areas (MLRA). The Project facilities would be within 10 MLRAs recognized by the NRCS (see table 4.2.1-1 and figure 4.2.1-1). Descriptions of each MLRA and the Project facilities within that MLRA are provided in the following sections.

TABLE 4.2.1-1

Major Land Resource Areas Crossed by the Project

Major Land Resource Area	Project Facilities [a]
Arctic Coastal Plain	Gas Treatment Facilities and MPs 0.0 to 61.7
Arctic Foothills	MPs 61.7 to 143.0
Northern Brooks Range	MPs 143.0 to 169.9
Interior Brooks Range	MPs 169.9 to 251.5
Upper Kobuk and Koyukuk Hills and Valleys	MPs 251.5 to 256.7
Interior Alaska Highlands	MPs 256.7 to 442.9
Interior Alaska Lowlands	MPs 442.9 to 516.2
Interior Alaska Mountains	MPs 516.2 to 580.0
Cook Inlet Mountains	MPs 580.0 to 616.8
Cook Inlet Lowlands	MPs 616.8 to 806.6 and Liquefaction Facilities

Sources: USDA, 2006; van Everdingen, 2005
[a] Mileposts are on the Mainline Facilities.

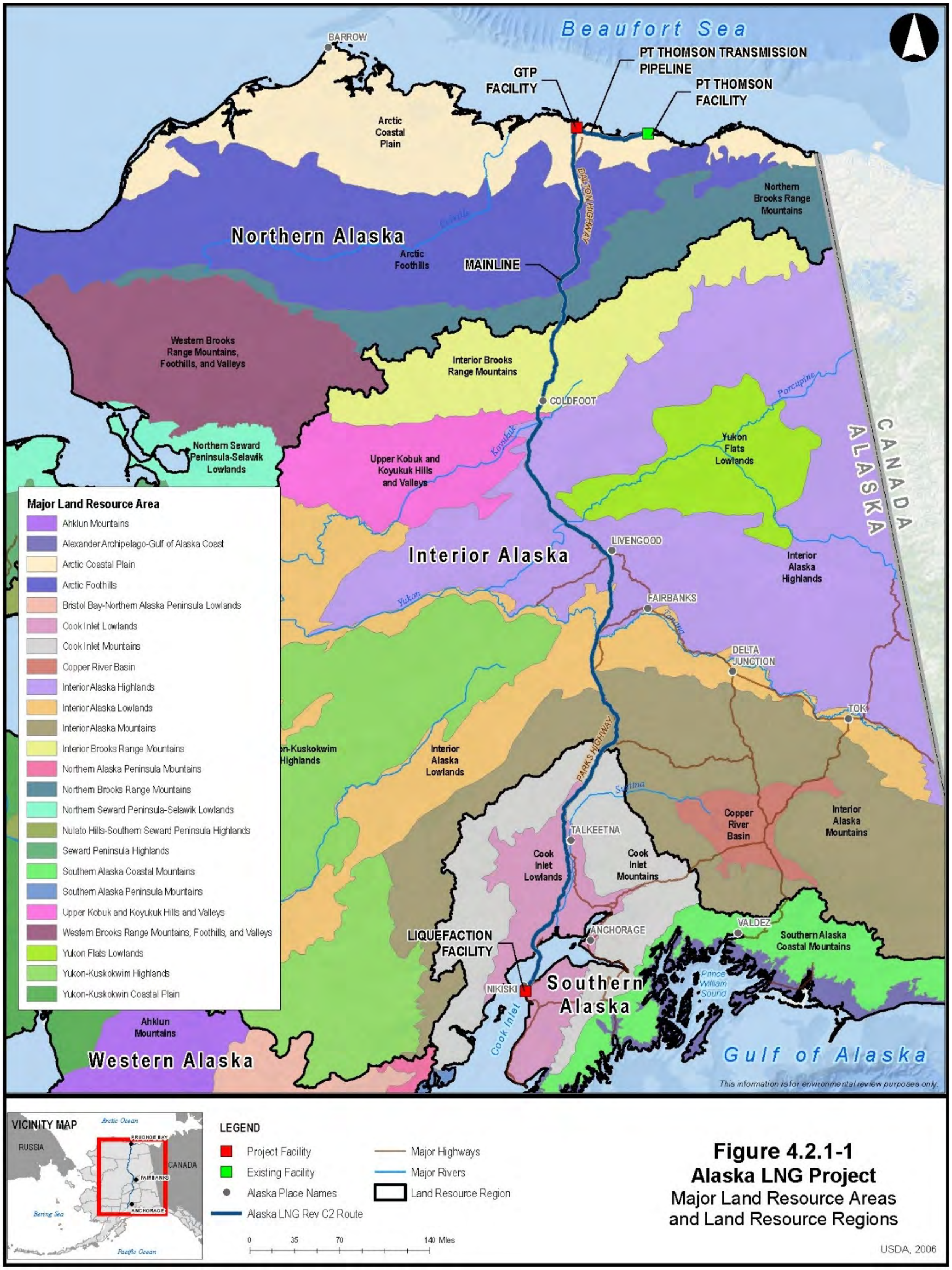


Figure 4.2.1-1
Alaska LNG Project
Major Land Resource Areas
and Land Resource Regions

Arctic Coastal Plain, MLRA 246

The Gas Treatment Facilities and about 61.7 miles of the Mainline Facilities would be within the Arctic Coastal Plain MLRA. This MLRA's physiography is characterized by level to gently rolling plains rising from the Arctic Ocean to the Arctic Foothills. The soils in this MLRA contain permafrost. The dominant soil order in the Arctic Coastal Plain is Gelisols, which have a pergelic soil-temperature regime, indicating that they have a mean soil temperature of less than 32°F at 20 inches below the surface. Soils within the Arctic Coastal Plain MLRA are typically poorly and very poorly drained, loamy stratified materials with thaw-sensitive ground ice below 10 inches. Soil groups found within the Gelisols order in the Arctic Coastal Plain MLRA include Aquiturbels, Histoturbels, Haploturbels, Psammoturbels, and Fibristels. Non-soil areas make up about 20 percent of this MLRA, consisting primarily of beaches, ice, waterbodies, and riverwash.

The major soil resource concern identified by the USDA within the Arctic Coastal Plain MLRA is the disturbance of permafrost soils. Disturbing the surficial organic material or vegetative cover, which provides an insulating layer, could cause permanent impacts on the soil (i.e., thawing of permafrost). This thawing could result in ponding, soil subsidence, erosion, and surface drainage disruption (USDA, 2006; van Everdingen, 2005). The same major soil resource concerns have been identified for the Arctic Foothills, Northern Brooks Range, Interior Brooks Range, and Upper Kobuk and Koyukuk Hills and Valleys MLRAs.

Arctic Foothills, MLRA 245

About 81.3 miles of the Mainline Facilities would be within the Arctic Foothills MLRA. This MLRA's physiography is characterized by broad, rounded ridges and mesa-like uplands in the north, and irregular buttes, mesas, and linear ridges with dominant rolling plains and plateaus to the south. The Arctic Foothills MLRA contains continuous permafrost in thick layers in fine and coarse textured deposits. The dominant soil order is Gelisols, with minor extents of Entisols and Inceptisols. The majority of soils have a pergelic soil-temperature regime, an aquic (i.e., saturated with water long enough to cause oxygen depletion) soil moisture regime, and mixed mineralogy. Soils are also typically shallow or moderately deep to permafrost, poorly or very poorly drained, and loamy and gravelly. Soil groups found within these orders include Histoturbels, Aquiturbels, Molliturbels, Gelepts, Gelorthents, and Fibristels. Non-soil areas make up about 4 percent of this MLRA consisting primarily of rock outcrops, ice, and talus (USDA, 2006).

Northern Brooks Range, MLRA 244

About 26.9 miles of the Mainline Facilities would be within the Northern Brooks Range MLRA. This MLRA's physiography is characterized by steep, rugged, high mountains and narrow valleys associated with the Brooks Range. The Northern Brooks Range MLRA is within a zone of continuous permafrost. About 75 percent of the MLRA consists of non-soil areas (i.e., rubble land, chutes, rock outcrops, and small glaciers). The dominant soil order is Gelisols, which typically have a pergelic soil-temperature regime, an aquic or udic (i.e., common to the soils of humid and subhumid climates) soil moisture regime, and mixed mineralogy. Soil groups present in the Northern Brooks Range include Aquiturbels, Histoturbels, Molliturbels, Haploturbels, and Fibristels. Throughout this MLRA, the Mainline Pipeline corridor follows river valleys where thin soils over bedrock and soils with thin surface peat covering colluvium and alluvium are dominant on steep lower slopes. Colluvium consists of loose, unconsolidated sediments deposited at the base of slopes, while alluvium consists of sediments deposited by running water (USDA, 2006).

Interior Brooks Range, MLRA 234

About 81.6 miles of the Mainline Facilities would be within the Interior Brooks Range MLRA. This MLRA's physiography is characterized by steep, rugged, high mountains and narrow valleys. The Interior Brooks Range MLRA is within a zone of discontinuous permafrost. Permafrost is typically found near the surface in areas of finer textured sediments on stream terraces and swales found on hills and footslopes.[24] The dominant soil orders are Gelisols, Entisols, and Inceptisols. Soils generally have a subgelic (i.e., cold summer temperatures with mean annual soil temperatures greater than 24.8°F but less than 32°F) or cryic (i.e., cold summer temperatures with mean annual soil temperatures greater than 32°F but less than 46.4°F) soil-temperature regime, an udic or aquic soil moisture regime, and mixed mineralogy. Soil groups in the Interior Brooks Range include Histoturbels, Aquiturbels, Turbels, Gelepts, Gelolls, Fibristels, Hemistels, Cryothents, Eutrocrypts, and Dystrocryepts. About 63 percent of the MLRA consists of non-soil areas (i.e., rubble land, rock outcrops, glaciers, and river wash).

Gelisols in the Interior Brooks Range MLRA are shallow to moderately deep to permafrost, and are somewhat poorly drained to very poorly drained. Wildfires are common in this MLRA and can disturb the insulating surface organic layer and lower the permafrost layer, thereby changing the soil classification. Depending on the frequency of fires, particle size, and geomorphology, soils may not revert back to Gelisols. Entisols and Inceptisols in this MLRA are generally excessively to poorly drained (USDA, 2006).

Upper Kobuk and Koyukuk Hills and Valleys, MLRA 233

About 5.2 miles of the Mainline Facilities cross the Upper Kobuk and Koyukuk Hills and Valleys MLRA. This MLRA's physiography is characterized by broad, nearly level river valleys, shallow basins, rolling uplands, isolated hills, and low mountains. Permafrost is typically close to the surface, and isolated masses of ground ice may occur on terraces and lower side slopes. Permafrost usually does not occur on steep, south-facing slopes or in floodplains. The dominant soil orders in this MLRA are Gelisols, Inceptisols, and Entisols. These soils typically have a subgelic or cryic soil-temperature regime, aquic or udic soil moisture regime, and mixed mineralogy. Soil groups present in the Upper Kobuk and Koyukuk Hills and Valleys MLRA include Aquiturbels, Haploturbels, Hemistels, Fibristels, Eutrocryepts, Dystrocryepts, and Cryorthents. Non-soil areas make up about 8 percent of this MLRA, primarily consisting of waterbodies and rock outcrops (USDA, 2006).

Interior Alaska Highlands, MLRA 231

About 186.2 miles of the Mainline Facilities would be within the Interior Alaska Highlands MLRA. This MLRA's physiography is characterized by moderately steep to steep, high-relief hills and mountains and narrow to broad flat-bottomed valleys. The Interior Alaska Highlands MLRA is in the zone of discontinuous permafrost. Permafrost is typically found close to the surface, and isolated masses of ground ice may occur on thick deposits of loess on terraces and side slopes. Permafrost usually does not occur on floodplains or south-facing slopes on steeper mountains. Dominant soil orders in the Interior Alaska Highlands MLRA are Gelisols, Inceptisols, Entisols, and Spodosols. In general, these soils have a subgelic or cryic soil-temperature regime, aquic or udic soil moisture regime, and mixed mineralogy. Soil groups present in the Interior Alaska Highlands MLRA include Historubels, Aquiturbels, Haploturbels, Fibristels, Hemistels, Dystrocryepts, Eutrocryepts, Haplocryods, Cryofluvents, and Cryorthents.

All Gelisols within the Interior Alaska Highlands are shallow or moderately deep to permafrost, poorly to very poorly drained and, similar to the Gelisols described above for the Interior Brooks Range

24 A footslope is the hillslope profile position that forms the concave surface at the base of a hillslope. It is a transition zone between upslope sites of erosion and transport and downslope sites of deposition (USDA, 2008)

MLRA, can be subject to changing soil classification due to wildfires. Inceptisols and Spodosols do not contain permafrost within their soil profile and are usually moderately deep to deep and well drained. Non-soil areas make up about 2 percent of this MLRA and consist of rock outcrops and rubble land.

The major soils resource concerns in this MLRA identified by the USDA are erosion of shallow soils in upland areas and permafrost soils disturbance. The permafrost layer in boreal soils within this MLRA is thinner than arctic permafrost soils, and therefore more susceptible to degradation. Project clearing would remove protective vegetative cover and expose soils to the effects of permafrost degradation, wind, and rain, which would increase the potential for soil erosion and sedimentation of sensitive areas. Disturbing the surface organic material or vegetative cover, which provides an insulating layer, can result in thawing the upper soil layers, which could cause permanent impacts on the soil. This thawing could result in ponding, soil subsidence, erosion, and surface drainage disruption (USDA, 2006).

Interior Alaska Lowlands, MLRA 229

About 73.3 miles of the Mainline Facilities would be within the Interior Alaska Lowlands MLRA. This MLRA's physiography is characterized by broad, nearly level, meandering, and braided floodplains, outwash plains, and stream terraces. The Interior Alaska Lowlands MLRA is within a zone of discontinuous permafrost (USDA, 2006). Permafrost typically does not occur on floodplains or in areas near lakes or other bodies of water, though thermokarst can lead to ponding. Dominant soil orders in the Interior Alaska Lowlands MLRA are Gelisols, Inceptisols, Entisols, and Spodosols. In general, these soils have a subgelic soil-temperature class or a cryic soil-temperature regime, an aquic or udic soil moisture regime, and mixed mineralogy. Soil groups present in the Interior Alaska Lowlands MLRA include Aquiturbels, Histoturbels, Hemistels, Fibristels, Eutrocryepts, Dystrocryepts, Cryaquepts, Haplocryods, Cryorthents, Cryofluvents, and Cryofibrists.

All of the Gelisols within this MLRA are poorly to very poorly drained, and between shallow and moderately deep to permafrost. Similar to the Gelisols described for the Interior Brooks Range MLRA, the Gelisols in this MLRA can be subject to changing soil classification due to wildfires. Entisols within this MLRA range from moderately well drained to excessively drained. Non-soil areas (i.e., river wash and waterbodies) make up about 19 percent of this MLRA.

The major soil resource concerns within this MLRA identified by the USDA are wind and water erosion, especially in areas where native vegetation has been removed (USDA, 2006). Project soil resource concerns would also include impacts on areas of discontinuous permafrost where thermal regime and hydrology could be permanently affected by permafrost disturbance.

Interior Alaska Mountains, MLRA 228

About 63.8 miles of the Mainline Facilities would be within the Interior Alaska Mountains MLRA. This MLRA's physiography is characterized by rugged high mountains and low rounded hills. This MLRA is within a zone of discontinuous permafrost. Permafrost is generally close to the surface and found on stream terraces, swales on hills, and footslopes. In more mountainous regions, permafrost usually appears on gently sloping areas of rounded ridges, footslopes, and swales, but it can also be found on south-facing angle-of-repose talus slopes. Floodplains are generally free of permafrost. About 58 percent of the Interior Alaska Mountains MLRA consists of non-soil areas (i.e., rock outcrops, rubble land, and glaciers). In the remaining areas, the dominant soil orders in this MLRA are Gelisols, Inceptisols, Spodosols, and Entisols. These soils generally have a subgelic or cryic soil-temperature regime, an aquic or udic soil moisture regime, and mixed mineralogy. Soil groups found within the Interior Alaska Mountains MLRA include Histoturbels, Aquiturbels, Gelepts, Cryepts, Haplocryods, Cryorthents, and Cryofluvents.

No major soil resource concerns have been identified within the Interior Alaska Mountains MLRA by the USDA (USDA, 2006). Project soil resource concerns would include impacts on areas of discontinuous permafrost where thermal regime and hydrology could be permanently affected by permafrost disturbance. Additionally, the NPS has identified concerns with disturbance of permafrost soils related to impacts from infrastructure, including damage to buildings, roads, trails, and utilities.

Cook Inlet Mountains, MLRA 223

About 36.8 miles of the Mainline Facilities would cross the Cook Inlet Mountains MLRA. The physiography of this MLRA is characterized by rugged, moderate to high mountains, large valley glaciers and ice fields, and narrow to broad valleys with braided high-gradient floodplains. Permafrost is discontinuous and sporadic in the Cook Inlet MLRA. Thermokarst lakes and ice-rich permafrost can occur in lower elevations, but permafrost is typically not found on south-facing slopes. Non-soil areas in the Cook Inlet Mountains (rock outcrops, glaciers, and rubble land) make up about 70 percent of the Cook Inlet Mountain MLRA. Of the remaining 30 percent, the dominant soil orders are Spodosols, Inceptisols, Gelisols, and Entisols. In general, these soils have a cryic or subgelic soil-temperature regime, an udic or aquic soils moisture regime, and amorphic (i.e., without clearly defined shape or form) or mixed mineralogy. Soil groups present within the Cook Inlet Mountains MLRA include Eutrocryepts, Dystrocryepts, Histoturbels, Aquiturbels, Haplocryods, Humicryods, Cryaquods, Cryofluvents, Cryorthents, and Cryaquents.

No major soils resource concerns have been identified within the Cook Inlet Mountains MLRA by the USDA (USDA, 2006). Project soil resource concerns would include impacts on areas of discontinuous permafrost where thermal regime and hydrology could be permanently affected by permafrost disturbance.

Cook Inlet Lowlands, MLRA 224

About 190.1 miles of the Mainline Pipeline and the Liquefaction Facilities would be within the Cook Inlet Lowlands MLRA. This MLRA's physiography is characterized by broad expanses of gently sloping to rolling plains and low to moderate hills adjacent to the low slopes of neighboring mountains. The dominant soil orders within this MLRA are Spodosols, Histosols, Entisols, and Inceptisols. These soils typically have a cryic soil-temperature regime, udic or aquic soil moisture regime, and mixed mineralogy. Soil groups in the Cook Inlet Lowlands MLRA include Haplocryods, Humicryods, Eutrocryepts, Dystrocryepts, Cryaquepts, Cryofibrists, Cryohemists, Cryofluvents, and Cryaquents. Soils range from very poorly drained to well drained. Non-soil areas (i.e., beaches, river wash, and waterbodies) make up about 15 percent of this MLRA. The major soil resource concerns identified by the USDA within this MLRA are water erosion and off-road vehicle use that can result in soil compaction and erosion (USDA, 2006).

4.2.2 Permafrost and Soil Properties

Soils within the Project footprint were evaluated to identify permafrost and major soil characteristics that could affect construction or increase the potential for construction-related impacts on soils. The soil characteristics evaluated were permafrost, erosion potential, prime farmland and soils of local importance, hydric and compaction-prone soils, soils with poor revegetation, potential shallow bedrock, and rocky soils. Individual soil characteristics and contaminated soils and sediments are discussed in the sections below.

4.2.2.1 Permafrost

Permafrost is defined as ground (soil or rock, including ice and organic material) that remains at or below 32°F for at least 2 consecutive years and does not include the active layer that may thaw seasonally. Permafrost can only exist if the amount of yearly heat flowing into the soil is less than or equal to the amount of cooling. Permafrost and ice content are not synonymous; permafrost may be ice free when the water it contains is saline or when it contains no water. While permafrost is defined on the basis of temperature, it is not necessarily perennially frozen. Permafrost should not be thought of as permanent because natural and anthropogenic (human-caused) changes in terrain and climate can cause ground temperatures to rise above 32°F. Permafrost includes perennial ground ice, but not glacier ice or icings, or bodies of surface water with temperatures perennially below 32°F. It does include anthropogenic perennially frozen ground, such as around or below chilled pipelines (van Everdingen, 2005).

Ground ice is a general term referencing all types of ice contained in freezing and frozen ground. Common forms of ground ice include:

- pore ice (coatings on soil particles or crystals within the empty space of soil, rock, or unconsolidated deposits);
- segregated ice (discrete layers, lenses, and veins of ice often in alternative layers of ice and soil); and
- massive ice (large bodies of ice such as wedges and pingos).

Ground ice bodies can result from the burial and preservation of surficial ice, such as snow banks, river ice, or glaciers (Brown et al., 1997). Generally, the amount of ground ice is related to the porosity and moisture content of the material before it freezes, though moisture migration during freezing can create massive ice formations. Fine-textured soils tend to have higher ice content than coarse-textured soils, which in turn generally have higher ice content than fractured bedrock.

Permafrost occurrence is influenced by a number of biotic and abiotic factors, including past and present climate, geology, hydrology, vegetation, and soil type. The relationship between these factors leads to the formation, preservation, and/or degradation of permafrost and ground-ice features (Brown and Kreig, 1983). The regional extent of permafrost can be classified as:

- continuous (covering from 90 to 100 percent of a geographic region);
- discontinuous (50- to 90-percent coverage);
- sporadic (10- to 50-percent coverage); or
- isolated patches (up to 10-percent coverage).

Permafrost underlies about 81 percent of Alaska, of which about 32 percent is continuous, 31 percent is discontinuous, 8 percent is sporadic, and 10 percent is isolated patches (Jorgenson et al., 2008). Figure 4.2.2-1 shows the general extent and range of permafrost within the state as mapped by Jorgenson et al. (2008). As shown in this figure, the entire Arctic Coastal Plain is underlain with continuous permafrost. Discontinuous permafrost occurs between the Brooks Range and the Alaska Range, while more southern portions of the Project area are either absent of permafrost or have sporadic or isolated permafrost.

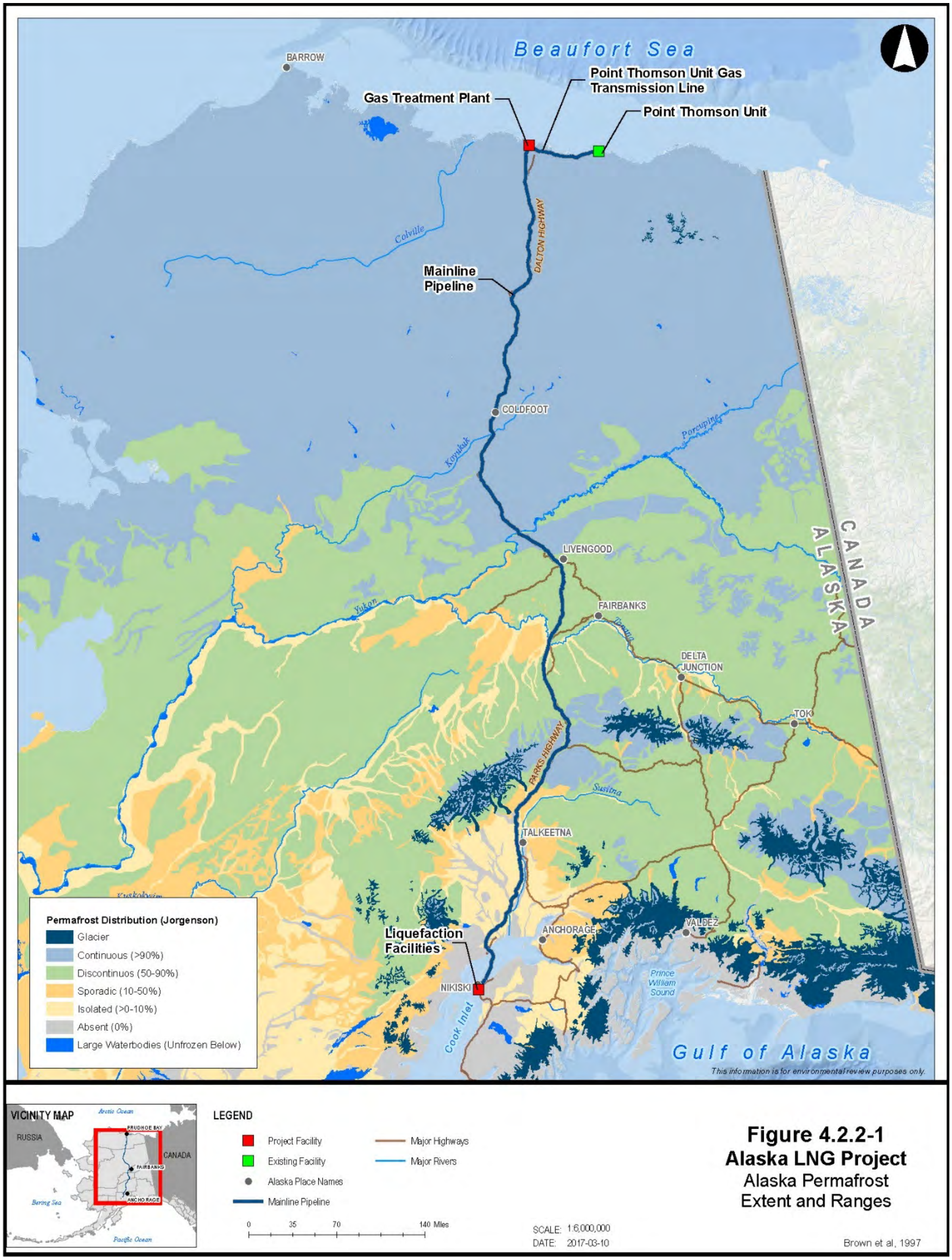


Figure 4.2.2-1
Alaska LNG Project
Alaska Permafrost
Extent and Ranges

As discussed above, permafrost is not necessarily perennially frozen. It is often covered by an active layer that is subject to seasonal thaw. Based on previously mapped and recorded permafrost data, active layer thickness in the Project area is estimated to range from 0.9 to 4.2 feet, with an average of about 1.5 feet (Jorgenson et al., 2008). The thickness of the active layer is determined by multiple variables, including mean annual air temperature, soil texture, water-holding capacity, and vegetation cover. Generally, the active layer is thin in the high Arctic and becomes thicker farther south, but specific thickness can vary from year to year (van Everdingen, 2005). Areas with the deepest active layers are usually adjacent to waterbodies. Permafrost with a thick organic cover tends to have a shallower active layer than other areas due to the insulation provided by the organic material (Kade et al., 2006).

A talik is a layer of unfrozen ground occurring in a permafrost area due to a local anomaly in thermal, hydrological, hydrogeological, or hydrogeochemical conditions, such as areas near rivers and lakes. Taliks may occur in areas of continuous permafrost (Brown et al., 1997; van Everdingen, 2005). Taliks can form beneath surface waterbodies during winter ice-covered conditions from the high heat capacity of water and reduced heat transfers. The tendency for open talik development (i.e., a talik that penetrates permafrost completely, connecting suprapermafrost and subpermafrost water) to occur increases when surface waterbodies do not freeze to their beds in the winter. Taliks can also form in response to land disturbance, including wildfires and infrastructure development (Walvoord and Kurylyk, 2016). In areas of discontinuous, sporadic, or isolated permafrost, the heat balance generally favors permafrost development or preservation in certain areas, such as sheltered valleys, north facing slopes, or heavily vegetated areas where the protective vegetative cover can maintain cooler temperatures.

A distinct morphologic feature that often develops in permafrost landscapes is patterned ground. While patterned ground is not limited only to permafrost areas (it also can occur in peatlands and string fens,[25] for example), it is best developed in regions of intensive frost action (van Everdingen, 2005). Permafrost creates an impermeable layer that inhibits drainage and causes surface saturation on much of the landscape (Everett, 1975). Polygonal ground patterns may develop when winter contraction forms fractures in the surface soils, which fill with water in summer and freeze in the winter. Subsurface ice wedges, mud or frost boils, and turf hummocks grow as a result of seasonal soil surface distortion (Lachenbruch, 1962; Washburn, 1980; van Everdingen, 2005).

The Arctic Coastal Plain, within which the Gas Treatment Facilities and portions of the Mainline Facilities would be located, is characterized as having continuous permafrost with the exception of major active river systems and taliks beneath waterbodies. This continuous permafrost ranges from less than 650 feet to more than 1,950 feet in depth, with active layers typically ranging in thickness from less than 1 foot to 2 feet on the North Slope. Active layer depths can reach as deep as 80 inches on the North Slope in well-drained inland gravel sites (National Research Council, 2003). Active layer thickness generally increases from the Arctic Coast to the Brooks Range and is directly related to air temperatures and thawing index (Streletsky et al., 2014; Zhang et al., 1997).

During the summer, key influencers in permafrost temperatures include the length of thaw season and thawing index. During the winter, interactions of seasonal snow cover, vegetation, wind, and microrelief are key factors affecting ground surface and permafrost temperatures (Zhang et al., 1997). The thickness and temperatures of permafrost have changed since the 1980s, reflecting variations in air temperature and snow depth, as well as extended periods of ice-free conditions. Data collected since the 1980s show that permafrost temperatures are changing along a north–south bioclimatic gradient, with

[25] A string fen is a peatland with roughly parallel narrow ridges of peat dominated by fenland vegetation interspersed with slight depressions, many of which contain shallow pools (van Everdingen, 2005).

temperatures ranging from 15.8 to 21.2°F at Arctic Coastal Plain sites and 21.2 to 24.8°F at Arctic Foothills sites (Streletsky et al., 2014).

Gelisols

Gelisols consist of soils that are permanently frozen or contain evidence of permafrost within 6.6 feet (2.0 meters) of the soil surface. These soils are found in high-latitude polar regions; within the United States, they are only found in Alaska. Gelisols show little morphological development, and due to the low soil temperatures, soil-forming processes such as organic matter decomposition proceed at much slower rates than other soils. As a result, Gelisols typically store large quantities of organic carbon. Given the frozen condition in which Gelisols are found, they are more sensitive to human activities than other soil orders. Gelisols are divided into three suborders: Turbels, Orthels, and Histels (NRCS, 2017a; Brady and Weil, 2002).

Turbels have one or more horizons that show evidence of cryoturbation in the form of broken, irregular, or distorted horizon boundaries, involutions, organic matter accumulated above permafrost, ice or sand wedges, and oriented rock fragments. Cryoturbation occurs in soils with sufficient moisture levels. Cryoturbated horizons that occur in soils that are dry for the majority of the year were likely moist soils that have dried out. Turbels are the dominant soil order and make up the majority of Gelisols in Alaska. Vegetation consists mostly of mosses, sedges, shrubs, and black spruce. Turbels and the various great groups within Turbels represent the largest class of thaw-sensitive permafrost due to the high ground ice content.

Orthels show little to no evidence of cryoturbation and occur primarily within a zone of widespread permafrost or in areas of coarse-textured materials in a continuous zone of permafrost. Orthels are typically drier than Turbels and Histels. Orthels are the second most common Gelisols in Alaska with vegetation similar to Turbels consisting mostly of mosses, sedges, shrubs, and black spruce.

Histels contain large amounts of organic carbon that typically accumulate under anaerobic conditions, or contain organic matter that at least partially fills voids in fragmental, cindery, or pumiceous materials. Cold temperatures also contribute to organic matter accumulation. Within Alaska, Histels are the least common suborder of Gelisols. Vegetation consists primarily of mosses, sedges, and shrubs.

Effects of Permafrost Alteration

Permafrost can be disrupted by natural events, such as climate variation or forest fires, or artificially by anthropogenic impacts, such as through the disturbance of vegetative cover for agriculture or construction of roads and pipelines (van Everdingen, 2005; U.S. Arctic Research Commission [USARC], 2003). Permafrost degradation occurs as a result of near-surface permafrost thawing and increasing of active layer thickness. Permafrost aggradation is the result of cooling soil temperatures and permafrost propagation. Altering the depth of the active layer can have immediate effects, including changes in the rate of CO_2 and methane (CH_4) release due to microbial respiration of either freezing or thawing organic matter, and the freezing and thawing of moisture present in the ground (USARC, 2003).

The release of CO_2 and CH_4, which are greenhouse gases (GHG), can act as a positive feedback mechanism by increasing the concentration of these radiative gases in the atmosphere. In turn, these gases can trap more heat leading to increased permafrost degradation and gas release. While permafrost does not necessarily respond directly to air temperature increases, thermal interaction with ecosystem characteristics that are directly affected by air temperature, such as vegetation and snow cover, can influence the rate of permafrost degradation (Hong et al., 2013; USARC, 2003).

Where permafrost is present, it plays a primary role in the control of water flow paths and distribution. Permafrost typically acts as an impermeable layer that inhibits infiltration and causes surface runoff; however, unsaturated permafrost areas can allow for water flow. When unsaturated permafrost comes into contact with water, it can quickly become saturated and non-permeable. Permafrost has a low hydraulic conductivity, which heavily impacts the movement, storage, and exchange of surface and subsurface water. Subsurface flows can influence the distribution of permafrost by enhancing the transfer of thermal energy through the transfer of heat by the flow of a fluid. When permafrost distribution is modified, hydrologic conditions are also affected, including changes to soil moisture, streamflow seasonality, connectivity of inland waters, and the division of water stored aboveground and belowground (Walvoord and Kurylyk, 2016).

The presence or absence of permafrost provides variations in physical soil foundations and determines surface micro-topography. As discussed above, permafrost is also a factor in hydrological functions of the soil, which is a key factor in the vegetation community and distribution (Christensen et al., 2004). Vegetation relies on the surface water table created by permafrost; when permafrost is altered, it also changes the vegetation found in that area.

The conversion of ice to water can, under certain conditions, cause downward displacement of the ground surface, also known as thaw settlement. As further defined in section 4.2.4, permafrost can either be thaw-stable or thaw-sensitive. Similar to karst terrain (formed by the chemical dissolution of limestone or other soluble bedrock), the irregular surface created by the thawing of ice-rich, thaw-sensitive permafrost is called thermokarst terrain. Thermokarst terrain can occur in localized areas, such as individual depressions, or occupy many square miles and lead to features such as thermokarst lakes (USARC, 2003). Thermokarst is amplified where flowing water produces thermal erosion, a dynamic process that involves the thawing of ground ice, and by mechanical erosion (i.e., hydraulic transport of soils). Thermal erosion can be significant along river banks or coastal bluffs (van Everdingen, 2005). AGDC estimates that there may be as many as 100 thaw lakes near the Project in the Arctic Coastal Plain. These features can be as large as 117 acres in the proposed Project area, but the majority are about 3 acres or less in size. LiDAR analysis estimates that the larger thaw lakes may be about 20 feet deep. As discussed in section 4.1.3, AGDC sited or routed Project facilities to directly avoid thaw lakes.

Frost heaving in fine-grained soils can happen when long-term freezing of previously unfrozen soil occurs. Frost heaving triggers soil expansion due to the formation of ice within pore spaces. The formation of ice causes a change in volume, which in turn results in the upward movement of the ground surface. Pingos, perennial frost mounds containing a core of massive ice and covered with soil and vegetation, may form when frost heaving occurs on a large scale. Pingos can occur in discontinuous and continuous permafrost areas, and commonly occur on Alaska's North Slope. There are two types of pingos: closed system and open system. Closed system pingos, also known as hydrostatic pingos, are formed when the permafrost level rises beneath a drained waterbody, during which free pore water is expelled upward. The pressure from the expelled water forces the ground to dome upward as ice is formed in its place. Open system pingos, also known as hydraulic pingos, form primarily in zones of discontinuous permafrost. These pingos are formed when groundwater enters the permafrost from an outside source (e.g., natural aquifer), which then freezes and pushes the ground upward. Both types of pingos continue to grow as water is supplied and freezes, but the growth is slow (less than 1 inch per year). The Project was routed and facility locations selected to avoid all known pingos, as identified by van Everdingen, 2005.

4.2.2.2 Erosion by Wind and Water

Erosion is a continuing natural process that can be accelerated by human disturbance. Factors such as soil texture, structure, slope, vegetative cover, rainfall intensity, wind intensity, soil depth, and thermal regime can influence the degree of erosion. Soils most susceptible to water erosion are typified by bare or sparse vegetative cover, non-cohesive soil particles with low infiltration rates, and moderate to steep slopes. Soils typically more resistant to erosion by water include those that occupy low relief areas, are well vegetated, and have high infiltration capacity and internal permeability. Wind erosion processes are less affected by slope angles than water processes. Wind-induced erosion often occurs on dry soil where vegetative cover is sparse and strong winds are prevalent.

The water erosion potential for Project soils was evaluated based on the soil erosion factor (Kw) values in the STATSGO2 database. The Kw factor represents a relative quantitative index of susceptibility of bare soil to particle detachment and transport by water, which is also modified by the presence of rock fragments. Kw factors are primarily based on soil texture, although organic matter content, structure size, and permeability are also pertinent factors. The higher the Kw factor value, the more susceptible the soil is to water erosion. The following categories were used for potential water erosion classification for the Project:

- severe water erosion potential – greater than 0.4 Kw;
- moderate water erosion potential – 0.25 to 0.4 Kw; and
- low water erosion potential – 0.02 to 0.25 Kw.

Wind erosion susceptibility was based on the wind erodibility group (WEG) designation, where available. WEG is a grouping of soils that have similar surface-soil properties affecting their resistance to soil blowing, including texture, organic matter content, and aggregate stability. WEGs may range from 1 to 8, with 1 being the highest potential for wind erosion and 8 the lowest (NRCS, 2013). The following categories were used for wind erosion evaluation for the Project:

- severe wind erosion potential – WEG values 1 to 2;
- moderate wind erosion potential – WEG values 3 to 6; and
- low wind erosion potential – WEG values 7 to 8.

4.2.2.3 Prime Farmland and Soils of Local Importance

The USDA defines prime farmland as “land that is best suited to food, feed, fiber, and oilseed crops” (Soil Science Division Staff, 2017). This designation includes cultivated land, pasture, woodland, or other lands that are either used for food or fiber crops or are available for these uses. The fact that a particular soil is considered prime farmland does not mean that it is in agricultural use; prime farmland soils may be in forested, open, or residential areas. Urbanized land and open water are excluded from prime farmland designation. Prime farmland typically contains few or no rocks, is permeable to water and air, is not excessively erodible or saturated with water for long periods, and is not subject to frequent, prolonged flooding during the growing season. Alaska does not have designated prime farmlands because the soil temperatures do not meet the threshold.

Soils of local importance, which are designated by local agencies (i.e., soil and water conservation districts or boroughs), consist of soils that have specific properties favorable to regional agriculture and crops. These properties vary from region to region. Within Alaska, soils of local importance have been designated in the Kenai Peninsula, Matanuska-Susitna Valley, and Greater Fairbanks areas. The soils were identified by querying the SSURGO data available for Alaska. Data is only available for about 172 miles of Mainline Facilities and is not available for any of the other Project facilities (Soil Survey Staff, 2017). The STATSGO2 data does not include information on soils of local importance.

4.2.2.4 Compaction Potential

Soil compaction modifies the soil structure and reduces its porosity and moisture-holding capacity. Construction equipment traveling over wet soils could disrupt the soil structure, reduce pore space, increase runoff potential, or cause rutting. The degree of compaction depends on moisture content and soil texture. Fine-textured soils with poor internal drainage that are moist or saturated during construction are most susceptible to compaction and rutting.

Some soils within the Project area have likely been compacted due to past development, including TAPS construction. AGDC evaluated the degree of compaction potential based on the drainage class and surface texture of the soils by querying the STATSGO2 database for soils that have a surface texture of sandy clay loam or finer, and/or a drainage class of somewhat poorly drained through very poorly drained. Soils with a high potential for compaction and structural damage in the Project area are typically very poorly drained soils in wetlands with an organic soil component. Coarse-textured, well-drained, and non-permafrost soils or permafrost soils that remain frozen are typically not considered compaction-prone.

4.2.2.5 Revegetation Potential

The drainage class, slope class, and erosion potential of each soil type within the Project area were evaluated to determine revegetation potential. Considerations included whether or not the mapped soils were natural, human-transported material (anthropogenic soils), or disturbed.

Droughty soils that have coarse-textured surface layers and are moderately to excessively well drained could be difficult to revegetate. Drier, coarser-textured soils have a lower water-holding capacity, which can hinder germination and produce moisture deficiencies in the root zone, creating unfavorable growing conditions. Droughty soils in the Project area were identified by querying the STATSGO2 database for soils that have a surface texture of sandy loam or coarser and are moderately well to excessively drained. In addition, steep slopes along the Project could make vegetation reestablishment difficult. Soils that occur on slopes greater than 8 percent are considered areas with a revegetation concern. Additional discussion on revegetation can be found in sections 4.5.2 and 4.5.3.

4.2.2.6 Shallow Bedrock and Rocky Soils

Bedrock and permafrost could be encountered when the depth of trench excavation exceeds the soil cover. Introducing stones and other rock fragments to surface soil layers could reduce soil moisture-holding capacity, resulting in a reduction of soil productivity. Additionally, agricultural equipment could be damaged by contact with large rocks and stones. Rock fragments at the surface and in the surface layer could be encountered during grading, trenching, and backfilling. Construction through soils with shallow bedrock could result in the incorporation of bedrock fragments into surface soils. In permafrost areas where drill and shoot (blasting) would occur, the blasted natural soils would be frozen and would come out of the trench in large irregular pieces with organic material attached. These pieces would be excavated from the trench with backhoes and set aside in the spoil area to be used as backfill. Backfilling of the trench with these blocks of permafrost soils would cause disruption to soil structure and permafrost properties.

A large portion of the soils that would be affected by the Project is considered rocky. Alaska has extensive areas of gravelly, stony, and/or cobbly soils due to the presence of colluvial, alluvial, and glacial parent materials. The potential to introduce stone and rock into surface soils in those areas could be significant, but many of these soils already contain surface layers with significant quantities of rock.

The potential for introducing rock into the surface layer was evaluated based on the depth to the restrictive layer and the presence of a rocky soil profile. STATSGO2 data was used to identify soils containing frequent cobbles and boulders for the Mainline Facilities. Geotechnical and geophysical site investigations were used to determine the presence of rocky soil for the remaining Project facilities. STATSGO2 data was used to identify soil map units where a restrictive layer is generally anticipated to be less than 5 feet from the soil surface. Blasting could be required in areas where bedrock, boulders, and/or permafrost cannot be excavated by conventional mechanical equipment. Geotechnical, geological, and geophysical datasets have been analyzed to identify areas where blasting could be required for right-of-way preparation and pipeline ditch excavation. Areas potentially requiring blasting are discussed in section 4.1.4.

4.2.2.7 Contaminated Soils

AGDC conducted a database search using the ADEC Contaminated Sites Database, ADEC Leaking Underground Storage Tank (LUST) Program Database, ADEC Solid Waste Information Management System, and the EPA RCRA database to identify facilities with potential and/or actual sources of contamination that could affect soils near Project facilities. The search identified contaminated sites and landfills within 0.25 mile of the Project footprint within all databases except the EPA National Priorities List, where no sites were identified. A summary of these findings is provided in section 4.9.6. The Alaska Contaminated Sites Program manages the cleanup of contaminated soil in Alaska. Previously identified and reported past and present contaminated sites, underground storage tanks, and LUST sites are tracked and listed through this program.

4.2.3 Sediments

Sediments occur throughout the Project area both on and offshore. The discussion below focuses on sediments offshore at the Gas Treatment Facilities, the offshore portion of the Mainline Pipeline and Mainline MOF, and the Liquefaction Facilities.

4.2.3.1 Beaufort Sea and Prudhoe Bay

The sediment in the nearshore of the Beaufort Sea is primarily the result of riverine input of suspended material and coastal erosion of tundra cliffs and beaches. Riverine sediments and coastal peat contribute large amounts of organic carbon and trace metals to these coastal sediments. A large contributor to the sediment cycle in the Beaufort Sea is the annual deposition of Sagavanirktok River sediments during the spring breakup flood (Weingartner et al., 2009). This sediment is adhered to bottom ice that begins to melt and separate from the riverbed, at which point sediments are re-suspended and transported when ice fully melts during open-water storms due to wind-generated waves and longshore currents. Additionally, when landfast ice forms, it contains large amounts of sediment that are transported with the ice or returned to the local area as the ice melts in place the following summer (Hodel, 1986).

Sediment grain size distribution in the Beaufort Sea varies greatly. Based on existing borehole data collected for past infrastructure projects near West Dock, substrates in the West Dock and Prudhoe area vary widely from muddy sand and sandy mud to more coarse sand and gravel (AGDC, 2014). AGDC conducted field investigations to supplement studies completed in the summer of 2011 as part of the Alaska Pipeline Project. AGDC collected and analyzed sediment samples in 2014, 2015, and 2016 from several locations in Prudhoe Bay near the West Dock Causeway where construction activities would take place (e.g., improvements to the causeway or screeding, which involves pushing sediments around to provide a flat surface, allowing a barge to sit evenly on the seafloor) (AGDC, 2014).[26,27] Figure 4.2.3-1 depicts the

[26] AGDC's *Results of Test Trench Field Study to Support Winter Navigation Channel Construction* was provided as appendix R to Resource Report 2 (Accession No. 20170417-5357), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

[27] AGDC's *2016 Data Report – West Dock Summer 2016 Field Program* was provided as appendix R to Resource Report 2 (Accession No. 20170417-5357). The report can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

sediment sampling locations near the West Dock Causeway from the 2014 sampling period, with the mean sediment grain size data for two of the sampling sites (#3A and #3B) provided in table 4.2.3-1. At these outer-most sampling locations (#3A and #3B), the majority of the sediment is silt and fine sand. This supports the statement by Niedoroda et al. (1980) that, although the sediment composition is not necessarily uniform throughout Prudhoe Bay, it is primarily silt with a thin layer of sand (Niedoroda et al., 1980).

TABLE 4.2.3-1

Mean Sediment Grain Size for Sampling Sites #3A and #3B in Prudhoe Bay

Soil Grain Size Classification	Trench Site #3A (percent)	Trench Site #3B (percent)
Gravel	<1	0
Sand		
Coarse sand	<1	<1
Medium sand	<1	<1
Fine sand	4	41
Very fine	21	23
Fines		
Silt	65	27
Clay	9	8

Figure 4.2.3-2 provides the 2015 and 2016 sediment sampling locations. The differentiation in color in the figure delineates between the five general sample locations (Test Trench #2.5, Test Trench #1, the control site, the Dock Head 4 site, and the west side of the causeway). Four samples were obtained at each test trench site. Three of the samples were within the trench, and one was on the ambient seabed adjacent to the site. The samples provide some relative differences between the infilled material properties and those nearby the trench.

In the winter of 2015, a Hach TSS portable nephelometer was used to measure turbidity within the excavated trench and beneath the floating ice near test trench #2.5. Before test trench excavation, the natural background turbidity was measured at several sites. The turbidity of the undisturbed arctic water beneath the ice surface was noted as 0.3 to 0.5 nephelometric turbidity units (NTU). In the summer of 2016, an FE Advantech Optical Backscatter Sensor was used to measure turbidity in formazin turbidity units; the results at test trench #2.5 ranged from 250 to 750 formazin turbidity units. The most turbid conditions occurred during the latter part of the summer, beginning around August 22. Regarding sediment type, from the sediment sieve analysis conducted on the 2016 sampling of surficial sediment with a Petite Ponar grab sampler, the majority of the samples were comprised of fine sand and silt/clay at about 52- to 97-percent weight per sample.

To put the 2015 and 2016 sediment sampling results into context, a turbidity reading below 25 NTU appears clear, a reading of 50 formazin nephelometric units or 100 NTU will start to look cloudy, and a reading over 500 formazin nephelometric units and 500 NTU will appear completely opaque.

Figure 4.2.3-1
Alaska LNG Project
Sediment Sample Locations in Prudhoe Bay near West Dock

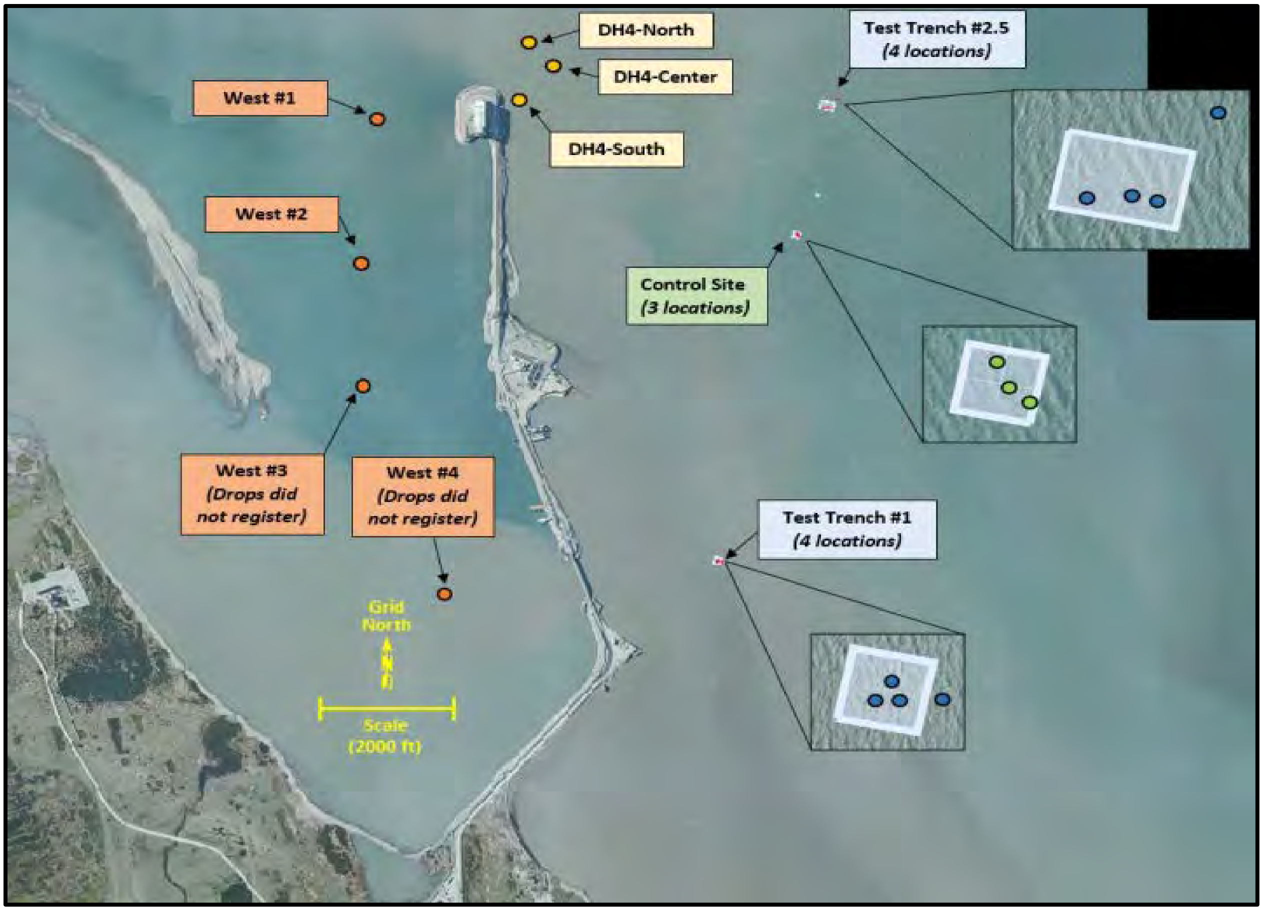


Figure 4.2.3-2 Sediment Data Collection Sites from 2015 and 2016

From the sediment samples, metal concentrations were documented to be below both the COE Seattle District Dredged Material Management Program (DMMP) (COE, 2015b) screening levels (used by the EPA and COE to evaluate dredged material in Alaska in lieu of an Alaska-specific program) and the ADEC-recommended permissible exposure limits. The metal concentrations additionally were within the range of background sediments for the Beaufort Sea coastal area (ADEC, 2012b). In several of the samples, arsenic, copper, and nickel concentrations exceeded their marine threshold effects levels (TEL), but not their probable effects levels.[28] Beaufort Sea sediments are naturally high in these three metals, however, and the observed concentrations were well within the established range for background levels (Exponent, 2010; Neff, 2010).

No evidence of petroleum contamination was observed in the samples collected, and concentrations of diesel-range organics and residual-range organics in the samples were found to be below ADEC-recommended soil cleanup levels for the Arctic region (AGDC, 2014). Polycyclic aromatic hydrocarbons (PAH) concentrations were found to be well below the DMMP screening levels, TELs, and permissible exposure limits. Concentrations were well below DMMP guidance and sediment quality guideline levels and showed no evidence of anthropogenic inputs or contamination.

While very low levels of pesticides were detected in many samples, there was generally no indication of any contamination from chlorinated pesticides or polychlorinated biphenyls of the test trench

[28] TELs are concentrations below which adverse biological effects can be rarely expected. Probable effects levels are concentrations above which adverse effects are expected to occur frequently.

sediments. The data support other recent findings that the West Dock Causeway area of Prudhoe Bay is generally free of contamination from metals or hydrocarbons (AGDC, 2014). For instance, the May 2002 geotechnical and environmental testing activities east of the West Dock Causeway also found that none of the samples exceeded cleanup or screening levels for organic or inorganic analytes, except arsenic. Arsenic occurs naturally in concentrations ranging from 2.5 to 8.0 milligrams (mg) per kilogram in the West Dock Causeway area (OASIS, 2002; AGDC, 2014). Additionally, as part of this study, sampling in the area indicated that petroleum hydrocarbon levels, particularly residual-range organics, are naturally occurring from the Prudhoe Bay Oil Field and not present due to contamination (AGDC, 2014). ADEC's review of the oil and hazardous substance spill reporting indicates that, while spills of varying sizes have occurred in western Prudhoe Bay in the past 15 years, the majority were contained or recovered, with only a total of about 15 gallons lost (ADEC, 2018c; AGDC, 2014).

4.2.3.2 Cook Inlet

The Kenai lowlands of the Cook Inlet Basin are made up of two geologic formations that include several thousand feet of layered sand, silt, clay, conglomerate, coal seams, and volcanic ash. Cook Inlet has extreme tidal ranges that play a significant role in the reworking and redistribution of sediments along the inlet floor. Sediment input also has a seasonal element, with large quantities of glacially derived sediment added to the upper reaches of the inlet during summer and minimal sediment input during winter. Inlet floor and subsurface soil conditions vary greatly, ranging from gravely clay loam to gravely sand mantled with silty material and bands of volcanic ash (LaRoche and Kenai Borough, 2007). Existing information on sediments in the Marine Terminal area has been summarized in the *Soil Stratigraphy Report* (CH2M Hill, 2015b), which includes data from a 1967 exploration by McClelland Engineers, a 1975 report prepared by Fugro Gulf, Inc. for the Western LNG Project, and onshore borings conducted by Fugro for the Project in 2014. The *Soil Stratigraphy Report* indicates that within the limits of the Marine Terminal MOF, the sediments consist of medium dense sandy silt and sand overlying hard sandy clay. Cobbles and boulders of varying sizes up to 10 or 15 feet in diameter are also present throughout the site.

AGDC conducted surveys along Revision B[29] of the Mainline Pipeline route (Shorty Creek to Boulder Point) between September 2014 and November 2017 using sub-bottom profilers collecting surficial grab samples. These samples indicate that the surficial soils consist primarily of gravels and cobbles with smaller patches of sandy/clayey soils. Nine samples were taken, seven of which contained high amounts of well-rounded rock fragments and coarse sand, corresponding to the high energy environment of Cook Inlet. Two samples taken from the shallows east of Shorty Creek landing consisted of very fine silt and mud. These two sample locations are part of the Beluga/Susitna River delta (Fugro, 2015c). No Project-specific offshore geotechnical soil borings have been collected along the Mainline Pipeline alignment (Beluga Landing South to Suneva Lake) at either side of Cook Inlet or at the Mainline MOF.

We received a comment from the EPA regarding the potential of the bottom sediments along the offshore pipeline route to support the weight of the pipeline and/or the need for dredging or placement of non-native fill on the seabed to support the pipeline. Sections 2.2.2.2 and 4.3.3.3 describe AGDC's design of the offshore pipeline and the status of PHMSA's review of this design relative to the cover requirements of 49 CFR 192.327(f)(2).

The USGS National Water-Quality Assessment program has conducted streambed sediment analysis in the Cook Inlet Basin (USGS, 2002). While none of the samples were taken in the exact location of the Cook Inlet crossing, data for the basin in general indicate that concentrations of arsenic, chromium, copper, mercury, and nickel were higher than those in samples collected for studies in the Lower 48 states

[29] Throughout development of the Project, AGDC analyzed different route revisions and made adjustments as needed for engineering and environmental purposes. Revision B is not the current proposed route.

(Lower 48). These concentrations were elevated near more urban areas, the Denali area, and locations downstream of an ore body in Lake Clark National Park and Preserve (USGS, 2002).

A sediment particle size distribution analysis was conducted on samples collected in the Marine Terminal MOF construction area in September 2015 with the resulting sediment grain size distribution shown in table 4.2.3-2 (CH2M Hill, 2016c; ADF&G, 1986c). Over 75 percent of the sediment was represented by three sediment size classes (fine sand, very fine sand, and clay).

TABLE 4.2.3-2

Sediment Grain Size Distribution in Samples from the Marine Facilities MOF Construction Area

	Grain Size (micrometers)	Settling Speed (centimeters/second)[a]	Total Percentage (%)
Fine sand	180	1.3	40
Very fine sand	100	0.5	20
Clay particle (75 micrometers)	75	0.3	25
Fine fraction (<74 micrometers)	32	0.05	15

Source: CH2M Hill, 2016c

[a] Settling speed computed from median particle diameter and viscosity of saltwater using Cheng (1997).

Grab samples of surficial seafloor sediments were collected in the Marine Terminal area (see figure 4.2.3-3) in 2015 and analyzed for physical and chemical parameters. The sediments were generally found to contain metal concentrations at or near regional background concentrations (CH2M Hill, 2016c). Dredging would disturb more than just surficial sediments, and it should be noted that deeper sediments could have higher concentrations of contaminants than those identified in the grab samples. The metal concentrations for all samples were well below screening level guidelines established by the COE Seattle District's DMMP (COE, 2015b). Most were also below ADEC's recommended sediment quality guidelines consisting of marine TELs developed by MacDonald et al. (2000) and NOAA Screening Quick Reference Tables (SQuiRT). Several metals (nickel, copper, chromium, and arsenic) exceeded TELs but were below permissible exposure limits and within the range of background concentrations. Total petroleum hydrocarbons concentrations were low in the samples, indicating no evidence of anthropogenic petroleum contamination.

AGDC conducted field investigations in November 2015 to study the properties of the dredged material and the behavior of sedimentation at the Marine Terminal portion of the Liquefaction Facilities. Four sediment borings were collected within the test pit, ranging in actual total depths from about 18 to 21 feet. These borings were broken into 10 samples for laboratory testing. One beach nourishment site reference grab sample was also collected in October 2015 to determine if the dredged sediment would be suitable for reuse as beach nourishment. Conventional testing (total solids, total volatile solids, grain size, total organic carbon, total sulfides, and ammonia) was conducted on the samples.

Field observations and laboratory testing of the sediment cores showed that the sediment has limited heterogeneity, dominated by dark gray sand with sporadic silty material near the top of the borings, transitioning to lean clay near 10 to 13 feet below the mud line. Laboratory results indicate that the amount of fines in these samples varies greatly, ranging from less than 5- to 88-percent silt and clay fines. The beach nourishment sample consisted of coarse-grained soil dominated by sand and gravel with minimal (2.4 percent) fines (CH2M Hill, 2016c).

Figure 4.2.3-3
Alaska LNG Project
Cook Inlet
Sediment Sampling Locations

Chemical testing for volatile organic compounds (VOCs), semi-VOCs, PAHs, pesticides, polychlorinated biphenyl, trace metals, total petroleum hydrocarbons-gasoline range organics, and total petroleum hydrocarbons diesel range organics and residual range organics was conducted for all 10 lab samples discussed above in the sediment characterization section. The beach nourishment sample was analyzed for cadmium, copper, lead, nickel, and zinc. The marine sediment samples were additionally analyzed for antimony, arsenic, barium, beryllium, chromium, mercury, selenium, silver, thallium, vanadium, and hexavalent chromium.

Laboratory chemical concentrations were compared with the COE's *Dredged Material Evaluation and Disposal Procedures User Manual* (Dredged Material User Manual) chemical guideline values (COE, 2015b). AGDC would use the Dredged Material User Manual, and if test results do not meet these standards, then no in-water placement would occur and dredged material would be beneficially reused or placed in approved upland disposal sites. Per the Project Plan, disposal of materials for beneficial reuse must not result in adverse environmental impact and would be subject to compliance with landowner or land management agency approval and permit requirements. No potential contaminants were detected at concentrations above the associated screening levels identified in the Dredged Material User Manual. For trace metals, the NOAA SQuiRT chemical guideline values were used for comparison against laboratory chemical concentrations of the sediment samples. Trace metals include copper, nickel, silver, arsenic, chromium, and selenium. Copper, nickel, and silver were detected at concentrations exceeding the NOAA SQuiRT TEL values. Arsenic, chromium, nickel, and selenium were detected at concentrations exceeding the ADEC Method 2 Cleanup Levels for migration to groundwater (CH2M Hill, 2016c).

4.2.4 General Impacts and Mitigation

As discussed in section 2.3, the Project would be constructed over the course of about 8 years, which would amplify soil impacts typical to pipeline and aboveground facility construction. Project construction and operational impact values for soils are presented in tables 4.2.4-1 through 4.2.4-3. Table 4.2.4-1 provides acres of soil characteristics; table 4.2.4-2 provides acres of permafrost thaw sensitivity, including acres of permanent impact; and table 4.2.4-3 provides acres of permafrost extent. In the discussions below, individual soil impacts for the Project are presented by facility. Potential construction and operational mitigation measures that AGDC would employ for specific Project facilities are discussed in the following sections.

Construction activities would affect soil resources. More specifically, clearing removes protective vegetative cover and exposes the soil to wind and rain, which increases the potential for soil erosion and sedimentation of sensitive areas and can expose the soil to thermal permafrost degradation. Grading, spoil storage, and equipment traffic could also affect permafrost along with compacting soil, reducing porosity, and increasing runoff potential. Excess rock or fill material brought to the surface during trenching operations or applied for stabilization could hinder right-of-way restoration.

AGDC would monitor construction, implement industry BMPs, and implement Project-specific mitigation plans to prevent or mitigate adverse effects on soils wherever possible. These plans include, but are not limited to, the Project Plan, Winter and Permafrost Construction Plan, SWPPP, SPCC Plan, Revegetation Plan, Blasting Plan, and Geological Hazards Assessments (WorleyParsons, 2018). These plans are designed to accommodate varying field conditions while maintaining standards for protecting soil resources.

TABLE 4.2.4-1

Acres of Soil Characteristics Associated with Project Construction and Operation [a, b]

	Farmland of Local Importance [c]		Compaction Prone [d]		Highly Erodible				Revegetation Concerns [g]		Rocky [h]		Shallow to Restrictive Layer [i]	
					Water [e]		Wind [f]							
Facilities	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper
Gas Treatment Facilities														
GTP	0	0	0	0	0	0	0	0	284	284	0	0	0	0
West Dock Causeway	0	0	0	0	0	0	0	0	103	0	0	0	0	0
Gravel mine	0	0	0	0	0	0	0	0	141	141	0	0	0	0
Water reservoir	0	0	0	0	0	0	0	0	35	35	0	0	0	0
PBTL Pipeline	0	0	0	0	0	0	0	0	7	7	0	0	0	0
PTTL Pipeline	0	0	0	0	0	0	0	0	1,696	609	0	0	0	0
Additional work areas [j]	0	0	0	0	0	0	0	0	615	262	0	0	0	0
Gas Treatment Facilities Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2,881**	**1,338**	**0**	**0**	**0**	**0**
Mainline Facilities														
Onshore Pipeline right-of-way	807	344	207	72	9,153	3,683	5,216	2,123	11,827	4,404	10,888	4,407	7,048	2,858
Aboveground facilities	32	32	1	1	236	236	97	97	270	264	270	264	157	157
Additional work areas [k]	909	123	284	1	8,312	490	4,872	307	11,259	636	10,498	636	6,858	284
Mainline Facilities Subtotal	**1,748**	**499**	**492**	**74**	**17,701**	**4,409**	**10,185**	**2,527**	**23,356**	**5,304**	**21,656**	**5,307**	**14,063**	**3,299**

TABLE 4.2.4-1 (cont'd)

Acres of Soil Characteristics Associated with Project Construction and Operation [a, b]

	Farmland of Local Importance [c]		Compaction Prone [d]		Highly Erodible				Revegetation Concerns [g]		Rocky [h]		Shallow to Restrictive Layer [i]	
					Water [e]		Wind [f]							
Facilities	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper
Liquefaction Facilities														
LNG Plant	0	0	0	0	896	896	888	888	888	888	888	888	0	0
Marine Terminal	0	0	0	0	1	1	1	1	1	1	1	1	0	0
Construction camp	0	0	0	0	81	0	81	0	81	0	81	0	0	0
Liquefaction Facilities Subtotal	**0**	**0**	**0**	**0**	**978**	**897**	**970**	**889**	**970**	**889**	**970**	**889**	**0**	**0**
Total	**1,748**	**499**	**492**	**74**	**18,679**	**5,306**	**11,155**	**3,416**	**27,207**	**7,531**	**22,626**	**6,196**	**14,063**	**3,299**

Sources: NRCS, 2017d; Soil Survey Staff, 2017

Const = Construction; Oper = Operation

[a] The data in the table do not include areas of open water.

[b] The numbers in this table have been rounded for presentation purposes. As a result, the totals may not reflect the sum of the addends. The values in each row do not add up to the total acreage for each facility because the soils may occur in more than one characteristic class or may not occur in any class listed in the table.

[c] As designated by the NRCS.

[d] Soils in somewhat poor to very poor drainage classes with surface textures of sandy clay loam and finer.

[e] Soils with severe water erosion potential, soil erosion factor (Kw) greater than 0.4.

[f] Soils with a Wind Erodibility Group (WEG) classification of 1 or 2.

[g] Soils with 30-percent or greater rock fragment content.

[h] Soils with one or more horizons that have a cobbley, stony, bouldery, channery, flaggy, very gravelly, or extremely gravelly modifier to the textural class and/or contain greater than 5 percent by weight rocks larger than 3 inches.

[i] Soils identified as containing bedrock within 60 inches of the soil surface.

[j] Includes access roads, ATWS, associated transfer pipelines, construction camps, a helipad, MLV, and pipe storage yard.

[k] Includes ATWS, construction camps, pipe storage yards, disposal sites, double joining yards, material sites, railroad spurs, railroad work pads, helipads, and selected access roads that would be retained during operation.

TABLE 4.2.4-2

Acres of Permafrost Thaw Sensitivity Associated with Project Construction and Operation [a, b]

	Thaw-Stable Permafrost			Thaw-Sensitive Permafrost			Seasonal Frost		
Facilities	Const	Oper	Perm	Const	Oper	Perm	Const	Oper	Perm
Gas Treatment Facilities									
GTP	0	0	0	284	284	284	0	0	0
West Dock Causeway	0	0	0	120	0	120	0	0	0
Gravel mine	0	0	0	141	141	141	0	0	0
Water reservoir	0	0	0	35	35	35	0	0	0
PBTL Pipeline	<1	<1	<1	7	7	0	0	0	0
PTTL Pipeline	4	0	0	1,692	609	<1	0	0	0
Additional work areas [c]	5	<1	<1	669	262	323	0	0	0
Gas Treatment Facilities Subtotal	**9**	**<1**	**<1**	**2,948**	**1,338**	**903**	**0**	**0**	**0**
Mainline Facilities									
Onshore Pipeline right-of-way	3,182	1,315	398	7,059	2,795	2,143	2,174	882	89
Aboveground facilities	64	64	64	148	148	148	58	52	58
Additional work areas [d]	3,996	41	3,037	4,030	72	3,024	1,862	282	1,277
Mainline Facilities Subtotal	**7,242**	**1,420**	**3,499**	**11,237**	**3,015**	**5,315**	**4,094**	**1,216**	**1,424**
Liquefaction Facilities									
LNG Plant	0	0	0	0	0	0	900	900	0
Marine Terminal	0	0	0	0	0	0	6	1	0
Construction camp	0	0	0	0	0	0	81	0	0
Liquefaction Facility Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**987**	**901**	**0**
Total	**7,251**	**1,420**	**3,499**	**14,185**	**4,353**	**6,218**	**5,081**	**2,117**	**1,424**

Sources: NRCS, 2017d

Const = Construction; Oper = Operation; Perm = Permanent Surface Alteration

[a] The data in the table do not include areas of open water.

[b] The numbers in this table have been rounded for presentation purposes. As a result, the totals may not reflect the sum of the addends. The values in each row do not add up to the total acreage for each facility because the soils may occur in more than one characteristic class or may not occur in any class listed in the table.

[c] Includes access roads, ATWS, associated transfer pipelines, construction camps, a helipad, Mainline valve, and pipe storage yard.

[d] Includes ATWS, construction camps, pipe storage yards, disposal sites, double joining yards, material sites, railroad spurs, railroad work pads, helipads, and selected access roads that would be retained during operation.

TABLE 4.2.4-3 **Acres of Permafrost Extent Associated with Project Construction and Operation [a,b]**										
	Continuous		Discontinuous		Sporadic		Isolated		Absent or Water	
Facilities	Const	Oper	Const	Oper	Const	Oper	Const	Oper	Const	Oper
Gas Treatment Facilities										
GTP	284	284	0	0	0	0	0	0	0	0
West Dock Causeway	253	0	0	0	0	0	0	0	0	0
Gravel mine	141	141	0	0	0	0	0	0	0	0
Water reservoir	35	35	0	0	0	0	0	0	0	0
PBTL Pipeline	7	7	0	0	0	0	0	0	0	0
PTTL Pipeline	1,696	609	0	0	0	0	0	0	0	0
Additional work areas [c]	674	265	0	0	0	0	0	0	0	0
Gas Treatment Facilities Subtotal	**3,090**	**1,341**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Mainline Facilities										
Onshore pipeline right-of-way	3,911	2,672	1,644	1,060	184	128	1,424	964	5,310	192
Aboveground facilities	148	148	63	63	0	0	55	53	4	0
Additional work areas [d]	5,744	28	3,583	326	680	0	1,870	270	408	12
Mainline Facilities Subtotal	**9,803**	**2,848**	**5,290**	**1,449**	**864**	**128**	**3,349**	**1,287**	**5,722**	**204**
Liquefaction Facilities										
LNG Plant	0	0	0	0	0	0	0	0	902	902
Marine Terminal	0	0	0	0	0	0	0	0	100	19
Construction camp	0	0	0	0	0	0	0	0	81	0
Liquefaction Facilities Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1,083**	**921**
Total	**12,893**	**4,189**	**5,290**	**1,449**	**864**	**128**	**3,349**	**1,287**	**6,805**	**1,125**

Sources: NRCS, 2017d
Const = Construction; Oper = Operation
[a] The data in the table do not include areas of open water.
[b] The numbers in this table have been rounded for presentation purposes. As a result, the totals may not reflect the sum of the addends. The values in each row do not add up to the total acreage for each facility because the soils may occur in more than one characteristic class or may not occur in any class listed in the table.
[c] Includes access roads, ATWS, associated transfer pipelines, construction camps, a helipad, Mainline valve, and pipe storage yard.
[d] Includes ATWS, construction camps, pipe storage yards, disposal sites, double joining yards, material sites, railroad spurs, railroad work pads, helipads, and selected access roads that would be retained during operation.

The thaw-sensitivity permafrost calculations presented in table 4.2.4-2 are based on the results of the 2018 Golder Associates, Inc. thaw-sensitivity analysis and Subject Matter Expert workshop held in Anchorage in April 2018. The values in the table are based on soil proneness to subsidence or volumetric change in the event of thawing. The Golder Associates, Inc. analysis used four classifications of thaw sensitivity which were then joined with landform polygons in GIS to provide a compressive dataset for the Project. The thaw-sensitivity classifications are described below.

- Thaw-Stable – These are permafrost soils that, upon thawing, do not experience significant thaw settlement or loss of strength (van Everdingen, 2005). Soil characteristics that typically favor thaw-stable permafrost soils include the presence of coarse-textured soils (e.g., gravel) in better-drained landscape positions; however, thaw-stable permafrost may also have the same particle size and mineral composition as thaw-sensitive permafrost soils on low-gradient slopes, and soils with south and west aspects (Hunter et al., 1981; Williams and Smith, 1989). As shown in table 4.2.4-2, there would be about 7,251 acres of construction impacts, 1,420 acres of operational impacts, and 3,499 acres of permanent impacts on thaw stable permafrost.

- Thaw-Sensitive – These are permafrost soils that, upon thawing, could experience significant thaw settlement and suffer loss of strength to a value much lower than that for similar material in an unfrozen condition (van Everdingen, 2005). Soil properties that could lead to thaw-sensitive soils include the presence of stratified, fine-textured sediments in poorly drained positions, thin soils on steeply sloping ground, and soils with north and east aspects. Unstable active layers can lead to gelifluction (i.e., the slow downslope flow of unfrozen earth material on a frozen substrate) or solifluction, soil creep, slumps, and mass-wasting events. These events can range from slow, viscous movement to sudden detachment and transport (Hunter et al., 1981; Jorgenson et al., 2008; Williams and Smith, 1989). As shown in table 4.2.4-2, there would be about 14,185 acres of construction impacts, 4,353 acres of operational impacts, and 6,218 acres of permanent impacts on thaw sensitive permafrost.

- Seasonal Frost – These soils were generally identified by AGDC as having absent or isolated permafrost distribution where ground ice is estimated to be primarily related to seasonal frost processes. Landforms present can be classified in terms of frost design soil classifications, including frost susceptible and non-frost susceptible. As shown in table 4.2.4-2, there would be about 5,081 acres of construction impacts, 2,117 acres of operational impacts, and 1,424 acres of permanent impacts on seasonal frost soils.

- Water – These are mapped units identified as water. Numbers for these areas are not provided in table 4.2.4-2.

Permafrost extent information presented in table 4.2.4-3 was based on the Permafrost Characteristics of Alaska Map (Jorgenson et al., 2008) dataset that details the continuity, thickness, and range of permafrost in Alaska. While permafrost continuity and thaw sensitivity are related, they are not identical as seen in tables 4.2.4-2 and 4.2.4-3.

Construction measures presented in the Project Winter and Permafrost Construction Plan include but are not limited to:

- constructing in thaw-sensitive permafrost during the winter where possible;

- use of granular work pads or temporary ice pads along the right-of-way, extra work spaces, and aboveground facilities, and for construction of access roads, to provide structural support for construction;

- snow management, including drifting snow removal, using snow blowers and bulldozers; and

- use of permanent erosion and sediment controls, including pipe ditch plugs, diversion berms, and revegetation of the ditch line, right-of-way, or granular work pad.

In its Geohazard Mitigation Approach, AGDC stated that it would adopt a Field Design Change Manual to guide field decisions during construction, implement any design changes, and tailor mitigation measures to the site-specific conditions encountered. The general procedures that would be followed in the

Field Design Change Manual would include identifying construction-induced geohazards or adverse geotechnical conditions, inspecting and observing the hazard, assessing conditions and environmental triggers, and selecting appropriate mitigation measures for that specific area. AGDC filed a preliminary flowchart and risk matrix outlining criteria and procedures that would be used to guide field assessments of existing geohazards, identification of construction-induced geohazards and adverse geotechnical conditions, and the selection of mitigation measures that would be implemented during construction. AGDC would file the Field Design Change Manual with FERC prior to the start of construction. This manual would be used to implement site-specific mitigation measures outlined in the Geohazard Mitigation Approach.

As indicated in the Project Revegetation Plan, adaptive management would be incorporated for all aspects of restoration of Project workspaces. This could require applying new treatments or mitigation methods in response to site conditions. The adaptive management strategy would also be used to respond to surface stability concerns, including thaw settlement or soil wasting once Mainline Pipeline installation is complete.

AGDC proposes to use granular work pads (section 2.2.2) during both summer and winter construction and to leave the granular fill in place afterwards. The use of granular fill is subject to multiple modifications to FERC's Plan (sections IV.A.1, V.A.2) and Procedures (sections VI.B.2.i, VI.B.2.j, and VI.B.2.k), as outlined in section 2.2 and appendix D. Mode 4 would use granular fill on flat or sloping terrain (upland and wetland) underlain by fine-grained thaw-sensitive permafrost, thaw-stable permafrost with a thick organic mat, or other organic or fine-grained soils. AGDC stated that granular work pads would provide a stable and safe construction workspace, maximize utilization of construction personnel and equipment, minimize construction costs, provide access to remote areas, and protect permafrost. AGDC also stated that granular fill would provide thermal insulation to the existing tundra, thereby reducing the likelihood of thermokarst occurring in areas of thaw-sensitive soils, and that removing the fill after construction would destroy the vegetative mat, negatively affecting permafrost and wetland/upland terrain. AGDC has indicated that during winter, granular work pads for construction would be compacted prior to use to provide a safe surface to support vehicle and equipment loads.

Based on our analysis, we have found that installing granular work pads would conduct solar radiation to the underlying permafrost, thereby causing changes to the subsurface thermal regime and drainage patterns in thaw-sensitive permafrost areas. Using granular fill in permafrost areas could raise the soil surface temperature by between about 3.6 to 5.4ºF (2 to 3ºC) compared to the original vegetative layer, thereby increasing the thickness of the active layer. Additionally, granular pads are heat sources that can become up to 50-percent warmer than surrounding areas during the summer (Romanovsky, 2018), which in turn would affect wetland hydrology by increasing wetness through the melting of ground ice and causing thermokarst. As currently proposed, the granular work pads and travel lanes would create a continuous linear granular fill feature that could intercept natural drainage, resulting in ponding that could thicken the active layer and cause thermokarst. AGDC has indicated that they would install cross-drainage and recontour the granular fill areas to better allow for surface drainage to occur.

The National Academy of Sciences recommends that granular fill depth be thicker than the thickness of the active layer to properly insulate thaw-sensitive permafrost and prevent thermokarst. Accepted industry standards on the North Slope are for a minimum of 5 feet of granular fill, as the thickness of the active layer varies from 8 to 80 inches (National Research Council, 2003). AGDC proposes granular work pads that range from 12 to 36 inches depending on the site-specific permafrost conditions in the area. Site-specific work pad design conditions would be developed during the Project detailed design using terrain unit mapping, existing soils information, and site-specific investigations prior to each year of construction, as needed. According to AGDC, some conditions that would influence pad thickness include the ruggedness and evenness of the terrain and depth of the thaw layer.

Based on past construction issues in permafrost in Alaska and our own review of scientific research discussed in the sections below, we cannot conclude with certainty that granular fill would protect permafrost or minimize impacts on wetlands. Therefore, the primary justification for granular work pads would be to provide a stable and safe construction workspace. We concur with AGDC that granular fill would provide a more stable and safe construction working surface. Safety is the primary consideration for approval of this construction method.

Our review of Mode 4 construction indicates that about 179.2 miles of the total 290.9 miles selected for this right-of-way mode would be constructed during the summer months when there is a greater risk to affect the organic layer. Additionally, an estimated maximum of 139.7 miles would be constructed on slopes less than 2 percent that may be stable enough to be constructed from timber/synthetic mats. Winter construction would preserve the integrity of the organic layer by preventing soil mixing when equipment travels across the right-of-way to spread granular fill. For those areas where summer construction is the only feasible option, timber or synthetic mats could be used to create a stable work surface on permafrost, which reduces the effects on the active layer in thaw-sensitive permafrost. Additionally, mats would be removed during restoration to allow hydrologic connectivity. Therefore, to minimize the impacts associated with the placement of granular fill, including permafrost thaw, creation of thermokarst, and impacts on vegetation and wetlands, as discussed below, **we recommend that:**

- **<u>Prior to construction of the Mainline Facilities</u>, AGDC should review areas proposed for Mode 4 construction in the summer and confirm that winter construction would not be feasible in low slope areas (0 to 2 percent). Additionally, AGDC should use timber/synthetic mats in place of granular fill in wetlands proposed for Mode 4 construction on slopes of 0 to 2 percent and in uplands proposed for Mode 4 summer construction on slopes of 0 to 2 percent that are underlain by thaw-stable permafrost. AGDC should prepare revised alignment sheets and resource impact tables adopting changes to Mode 4 areas reflecting the increase in winter construction segments and the replacement of granular fill with timber/synthetic mats. <u>Prior to construction of the Mainline Facilities</u>, AGDC should file the revised sheets and resource impact tables with the Secretary for the review and written approval of the Director of the OEP.**

In its comments on the draft EIS, AGDC requested a modification of this recommendation to allow for site-specific assessments of the feasibility of using timber/synthetic mats just prior to construction. AGDC stated, for example, that if the work surface was not level, the use of mats would create unsafe working conditions. AGDC also said that matting could cause permafrost surface layer organics damage and that, in some cases, the areas may be too small to warrant switching the construction mode. We agree that the surface needs to be nearly level and limited this recommendation to areas with slopes of 2 percent or less. Our assessment is that damage to the organic surface layer would be more severe by covering it with granular fill rather than timber mats. Therefore, areas where timber mats could be used should be defined prior to construction. If field conditions require a change (e.g., if site-specific conditions do not allow for the use of timber/synthetic mats in accordance with this recommendation), then AGDC could request a variance that would be reviewed by FERC and the appropriate permitting agencies.

Granular work pads would remain in place following construction and allowed to settle, saturate, and possibly revegetate. The length of this revegetation process could take decades depending on site-specific factors, including ground ice content, ground temperature, thermal boundary conditions at the ground surface, and work pad material type and pad properties such as fines content, moisture content, thickness, and thermal conductivity. AGDC has stated that fill gradation requirements would vary with location, anticipated loads, expected duration of use, and the properties and conditions of underlying soils. In general, imported fill for the Project (e.g., work pads, access roads, pipe storage yards, camps, and contractor yards) would consist of sand and gravel with less than 12 percent of material passing through a No. 200 sieve (i.e., 0.074 millimeter particle size). This is the minimum particle size of sands under the Unified and AASHTO systems.

Revegetation on gravel and rocky soil could be enhanced with a higher proportion of fines or small particles in the granular fill. The *Interior Alaska Revegetation & Erosion Control Guide* states that species adapted to gravelly soils could establish on granular fill in the Project area if some fines (fine grained soil particles that can pass through a No. 200 sieve [i.e., silt or clay]) are present (Bishop and Max, 2002; Czapla and Wright, 2012), as this correlates with increased water-holding capacity (Bishop and Max, 2002). The presence of silt has been identified as the most important soil feature for successful plant succession (Native Plants, 1980, as cited in McKendrick, 2002). McKendrick (2002) found diverse plant communities after about 30 years in soils with up to 70-percent gravel (presumably up to about 30-percent fines) along the TAPS right-of-way in interior Alaska. The surface course (layer)[30] for a gravel road based on federal and local specifications would have fines comprising between about 4 to 20 percent of the gravel (DOT, 2015a; Fairbanks North Star Borough, 2012). AGDC plans to use granular fill consisting of sands and gravels with less than 12-percent fines.[31] Given that a greater proportion of fines could improve the likelihood for successful plant establishment, **we recommend that:**

- **<u>Prior to placement of any granular fill</u>, AGDC should conduct aggregate testing using sieve analysis to select granular fill with at least 20-percent fines for the surface layer used on all construction workspace, including Mode 4 work pads, temporary aboveground facilities, temporary access roads, etc. AGDC should include the results of the aggregate tests in its construction status reports filed with the Commission.**

In its comments on the draft EIS, AGDC said that our recommendation to use a higher percentage of fine material in the granular fill would not be operationally sound and would have potential for increasing environmental impacts in the form of fugitive dust and increased sediment in runoff without improving the potential for revegetation. In addition, AGDC said that fines in granular fill for the surface layer would decrease load capacities and would not improve the potential for revegetation because much of the fine material would run off or blow away during construction activities.

While we acknowledge the operational concerns cited by AGDC, the recommended percentage of fines in the granular fill for the surface layer of construction workspace and temporary access roads is consistent with that used in the surface layer for gravel roads. A lower percentage of fines can still be used in the base layer to provide the necessary load capacities, as would be done for a gravel road. The potential for fugitive dust, increased sediment in runoff, or loss of fines through wind and water erosion would not likely be any greater than what would occur with an exposed soil surface in construction areas without granular fill. Implementation of the Project's Fugitive Dust Plan would address dust concerns, while the use of proper erosion control measures outlined in the Project Plan would mitigate potential sediment in runoff. Therefore, given the potential for increased plant establishment, the use of granular fill with a higher percentage of fines through increased water holding capacity would be more likely to benefit restoration than granular fill with a lower percentage of fines and lower water-holding capacity. If conditions in the field require a change from this recommendation, AGDC could request a variance that would be reviewed by FERC and the appropriate permitting agencies.

[30] The surface course is the top layer of gravel on a gravel road, recommended to be a minimum of 3 inches deep (DOT, 2015a). The surface course covers the base course or bottom layer of gravel, which should be of a depth adequate to carry anticipated loads and generally has a lower percentage of fines than the surface course (DOT, 2015a; Fairbanks North Star Borough, 2012).

[31] Information regarding AGDC's plans for granular fill was included in our information requests Nos. 45, 101, 102, 103, 104, 105, 108, 110, and 111 (Accession No. 20180713-5057). This information can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180713-5057 in the "Numbers: Accession Number" field.

Equipment and vehicle traffic could permanently affect permafrost soils by creating fugitive dust. The ASAP Final Supplemental EIS assumed that fugitive dust could travel up to 50 feet from gravel roads and up to 350 feet from material sites depending on the prevailing wind direction (COE, 2018a). Fugitive dust would be deposited onto adjacent ground. Over long periods, dust deposition could result in thermokarst because the darker surface would absorb more solar radiation than adjacent snow-covered areas, thereby increasing surface temperatures. These increased temperatures could result in earlier snowmelt, which could contribute to warming permafrost soils and cause thermokarst (COE, 2018a; National Research Council, 2003). A Walker and Everett (1987) study observed an increase in thaw depth within 32 feet of gravel roads as a result of fugitive dust, possibly due to decreased plant cover and earlier initiation of thaw. Thermokarst impacts caused by fugitive dust would not be reversed within a short timeframe and could result in permanent impacts on permafrost soils. These impacts would be reduced with AGDC's implementation of dust control measures outlined in the Project Fugitive Dust Control Plan, including:

- using dust control abatement measures as needed during construction and operation;
- applying water to affected unpaved roads and staging areas;
- applying approved dust suppressants such as calcium chloride or water/magnesium chloride mixture; and
- reducing speed limits on unpaved roads.

As discussed in section 2.2, AGDC's Project Plan includes modifications to FERC's Plan. The modifications that we determined were acceptable as proposed by AGDC, or acceptable with revisions or recommendations from the draft EIS, are provided in appendix D. On September 9, 2019, AGDC filed an update to the Project Plan that incorporates our revisions and recommendations.

Operational activities with the potential to impact soil properties include pipeline maintenance activities, geohazard monitoring and intervention, permanent granular fill placement, vegetation maintenance, drainage control structure maintenance (e.g., interception ditches, culverts, and subdrains), equipment traffic, and the operation of a belowground pipeline through permafrost. These activities would be primarily associated with the Mainline and Liquefaction Facilities. Operational impacts associated with the GTP would be the conversion of soil and vegetative cover to impervious surfaces. Operational impacts on permafrost would be minimized by the use of VSM technology for the PTTL and PBTL and granular/ice pads for the GTP. Tables 4.2.4-1 through 4.2.4-3 provide a summary of areas subject to potential soil impacts during Project operation. For more information on the Project's granular fill use, see section 2.1. AGDC would continue to implement applicable portions of the Project Revegetation Plan during Project operation and maintenance.

4.2.5 Facility-Specific Impacts and Mitigation

4.2.5.1 Gas Treatment Facilities

As discussed in section 2.3.1, construction of the Gas Treatment Facilities would occur over the course of 90 months (7.5 years). None of the soils associated with the Gas Treatment Facilities are highly erodible by wind. Operational impacts associated with the Gas Treatment Facilities would primarily be limited to the conversion of soil to impervious surfaces. Discussions associated with the conversion of land use types can be found in section 4.9.1.2. Impacts associated with the addition of impervious surfaces with regard to groundwater recharge can be found in section 4.3.1.5. Operational impacts on permafrost would be minimized by use of VSM technology for the PTTL and PBTL and aboveground pipelines for the GTP.

GTP

Soil disturbance associated with construction of the GTP would primarily be limited to the pad construction with piles installed to support GTP facilities. The soils associated with the GTP are classified as continuous thaw-sensitive permafrost and are all poorly drained. The work pads and roads associated with the GTP would be installed primarily during the winter to avoid direct impacts on permafrost. The GTP would be constructed on granular pads of sufficient thickness (minimum of 5 feet) to reduce the potential for heat transfer to the permafrost and minimize impacts on the tundra. Construction of associated facilities would incorporate proven arctic design techniques of granular work pads, piles, VSMs, and thermosiphons to preserve the active layer thickness and underlying permafrost.

While none of the soils associated with the GTP are classified as compaction prone or highly erodible by water or wind, Project Plan implementation would minimize potential impacts associated with wind and water erosion. The use of winter construction to install work pads and access roads would minimize soil compaction. Summer construction associated with the GTP would be limited to use of the roads and work pads installed during the winter. As noted in table 4.2.4-1, soils associated with the GTP have revegetation concerns, the majority of which would be permanently covered by Project facilities and granular work pads. See section 4.5.2.3 for further discussion of the GTP construction area restoration and revegetation.

The granular material required for GTP construction would be obtained from existing local mine sites and the planned gravel mine site and water reservoir. The gravel mine site would be constructed and operated in accordance with the Project Gravel Sourcing Plan and Reclamation Measures. This plan provides potential BMPs for all Project mining activities and reclamation strategies that would minimize impacts on soils. Final reclamation plans would be approved by the ADNR and/or COE as appropriate. Potential reclamation BMPs to be used at the gravel mine site include those described below.

- Overburden material (rock and soil) pile storage would be properly constructed for good slope stability and vegetated to prevent erosion. Separate stockpiles would be used for organic layer segregation and other overburden materials. Backfilling the material site would reduce slope angles, thereby reducing erosion and long-term stability concerns.

- Berms would be used around the perimeter of the property, extraction site, or adjacent to sensitive areas such as wetlands and waterbodies to help reduce noise, dust, and visual impacts. In addition, a berm can be used to control surface water entering or leaving a site or provide insulation to existing ground ice.

- Final slopes would be between 2H:1V and 3H:1V or flatter. Slope designs would be optimized with the help of qualified professionals.

- Proper organic layer replacement strategies would be implemented to aid in revegetation.

- Excess overburden material would be disposed of carefully and would not be placed in natural drainages (i.e., drainage hollows on slopes) where it would be more likely to fail and affect surface water.

West Dock Causeway

No dredging is proposed for construction of Dock Head 4 or to accommodate the larger vessels for module offloading. Sediments would be covered by granular fill (sourced from the gravel mine) at two locations along the West Dock Causeway. The 650-foot-breach bridge area would be screeded (i.e., raked) to a suitable level grade as well as the berthing areas ahead of barge deliveries. Surface sediments would be pushed around during the screeding process, but buried sediments would not be disturbed or lifted into the water column. While the West Dock Causeway would only be used during construction, impacts would be permanent because granular fill would be left in place. For more information on impacts associated with screeding, material fill, and seafloor disturbance, see section 4.3.3.3.

PTTL

Minor impacts on soils would be expected from PTTL construction because the pipeline would be built aboveground using VSMs, and direct impacts would be limited to the location of each support. The majority of soils associated with the PTTL are thaw-sensitive, but VSM construction would reduce heat transfer to the underlying soils, thereby minimizing impacts on areas of thaw-sensitive permafrost. Given the flat topography of the North Slope, the risk that solifluction, soil creep, or thawed layer detachment would be encountered during PTTL construction is low. There is the potential for thaw-induced subsidence to occur during PTTL construction and operation depending on site-specific conditions, including natural drainage patterns.

AGDC anticipates that potential operational impacts associated with VSMs for the PTTL and PBTL would be similar to the impacts from TAPS and other aboveground oil and gas pipelines in the Greater Prudhoe Bay area. There are approximately 78,000 VSMs across the length of TAPS, a small fraction of which have tilted over time primarily as a result of frost heave; the vast majority of VSMs have not moved. If warming continues for the next 30 years, it could change local permafrost and groundwater conditions sufficiently to result in mechanically weaker soils. AGDC intends to take a proactive approach, similar to that used by TAPS, to monitor, mitigate, and manage potential permafrost degradation and the resulting impacts. TAPS continuously monitors climate and ground temperature via more than 40 instrumented thermal monitoring sites constructed along the TAPS pipeline corridor from the Brooks Range to Thompson Pass. TAPS also analyzes local weather station data available from the Western Regional Climate Center along the pipeline corridor and monitors soil moisture consistently with thermistor strings installed in the ground along the pipeline right-of-way. In areas where permafrost has been thermally degraded, TAPS has replaced or modified some pipeline components (such as thermal VSMs with standard friction VSMs). For TAPs, heat pipe recharge monitoring and other thermal studies, in addition to settlement surveys, indicate whether ground conditions around VSM pilings are effectively being maintained in a frozen state, where needed, and that the VSMs are stable. AGDC would monitor VSMs as part of their Project Pipeline Operation and Maintenance Plan, as discussed in section 4.2.5.2.

Pipe storage yards, access roads, construction camps, and ATWS would be built to support PTTL construction. Pipe storage yards and construction camps would be built on granular work pads. The soils associated with these facilities are all prone to compaction. Use of winter construction, granular work pads, and ice roads as described in the Project Winter and Permafrost Construction Plan would minimize typical construction impacts associated with compaction-prone soils as discussed below for the Mainline Facilities. Minor impacts on soils would be anticipated from PTTL operation.

PBTL

As discussed above for the PTTL, minor soils impacts would be expected from PBTL construction because the pipeline would be built aboveground using VSMs; direct impacts would be limited to the location of each support. The use of ice road winter construction would minimize soil compaction. Minor impacts on soils would be anticipated from PBTL operation.

4.2.5.2 Mainline Facilities

Construction of the Mainline Pipeline would be divided into four construction spreads that would span up to 57 months (4 years and 9 months) for any one spread. This includes 30 months of pre-construction activities and 15 to 27 months for pipelay. Pre-construction activities include clearing, grading, and installation of the granular work pads.

Table 4.2.5-1 provides the miles of onshore Mainline Pipeline construction across permafrost soils by season. The categories of permafrost soils used in the table are described in section 4.2.2.1.

TABLE 4.2.5-1

Miles of Onshore Mainline Pipeline Construction Season by Soil Type

	Coarse-Grained Soil		Fine-Grained Soil		
Permafrost Type	Winter	Summer	Winter	Summer	Total
Continuous	62.7	98.6	110.4	143.0	414.7
Discontinuous	48.6	48.7	53.3	14.3	164.9
Isolated	77.1	51.6	17.4	3.7	149.8
Sporadic	0	18.6	0	1.2	19.8
Unfrozen	7.8	17.1	1.3	2.4	28.6
Water	0.4	0.2	0.8	0.4	1.8
Total	**196.6**	**234.8**	**183.2**	**165.0**	**779.6**

Sources: NRCS, 2017b; Golder Associates, Inc., 2018

Soils subject to seasonal thawing where the active layer may rise above 32°F are grouped into four frozen soil categories: frozen coarse-grained soils, frozen fine-grained soils, unfrozen coarse-grained soils, and unfrozen fine-grained soils. Table 4.2.5-2 shows the seasonal construction considerations for coarse-grained and fine-grained soils, including impacts and mitigation measures that would be implemented during summer versus winter construction. In general, Mainline Pipeline construction would start in a given season and would be completed in that same season. For additional information on Mainline Pipeline construction and construction spreads see section 2.2.2.

Operation of the Mainline Facilities would cause the permanent conversion of soils due to installation of impervious surfaces (i.e., aboveground facilities) or granular fill and soil compaction due to operational monitoring equipment. Potential additional impacts on soil resources as a result of Mainline Facilities operation could include:

- hydrologic and vegetation impacts related to permafrost degradation;
- surface, backfill, and piping erosion;
- differential thaw settlement along and across the right-of-way within thaw-sensitive permafrost;
- long-term permafrost degradation and deepening of the active layer; and
- frost bulb development and frost heave in susceptible unfrozen soils.

Permafrost

Clearing, grading, and trenching of the construction work area would affect permafrost and thermal energy balance due to the removal of vegetation and snow cover. The effects of permafrost alteration due to construction of the Mainline Pipeline could include hydrologic impacts; subsidence and thermokarst development; solifluction, soil creep, and thawed-layer detachment on steep slopes; increased erosion; and vegetation impacts. Water resource impacts are discussed in section 4.3 and vegetation impacts are discussed in section 4.5.

As discussed in section 2.2.2 and in the Project Winter and Permafrost Construction Plan, there are five different construction methods, referred to as modes, proposed for pipeline installation. AGDC proposes to construct about 46 percent of the Mainline Pipeline in the winter and 54 percent in the summer. In thaw-sensitive permafrost, use of ice or frost-packed work pads in the winter would reduce effects from construction, including compaction, rutting, and mixing of vegetation and the active layer. Winter construction with the use of ice work pads would occur for the first 56.6 miles on the Mainline Pipeline. An additional approximately 69.4 miles of the Mainline Pipeline are proposed to be constructed using Mode 2 (frost packed). AGDC has proposed the use of granular work pads during both summer and winter construction. A discussion of granular work pads and our proposed recommendation measures can be found in section 4.2.4.

The principal geothermal impact of clearing and/or ground disturbance is the removal of naturally insulating materials, leading to increased heat flux into and out of the ground for summer and winter conditions, respectively. In a cleared or disturbed state, summer warming would have greater impact than winter cooling, causing an increase in the active layer depth. AGDC is proposing for right-of-way pre-clearing activities, including cutting down trees and brush, to occur in the winter season between 1 and 1.5 years prior to each scheduled construction season. AGDC has stated that this clearing would be done with hydro-axes and brush hogs and that the soil and surface organic layer would not be disturbed or stripped during this process. In areas without trees and brushy vegetation, no pre-clearing activities would occur. Clearing vegetation in thaw-sensitive permafrost areas prior to placing granular work pads would increase the likelihood of permafrost thawing and creation of thermokarst. While limiting pre-clearing to the winter would reduce effects on permafrost, permanent impacts would still occur as the overstory vegetation would be removed within the right-of-way for between 1 and 1.5 years prior to active construction. Impacts on permafrost would be reduced by leaving the understory vegetation and organic mats in place until the time of active construction.

AGDC would reduce impacts on the vegetative matting and the organic layer by minimizing the trench area to a 5- to 6-foot-wide section where trenching would occur. Additionally, the pipe would be bedded with thaw-stable, non-frost susceptible materials that would minimize permafrost degradation, pipe thaw settlement, and surface slumping. AGDC would maintain existing surface water channels in their natural state to avoid water seepage into the trench. Frost bulb and/or frost heave formation are typically long-term processes driven by freezing of previously unfrozen soils. During construction, there is no thermal process other than the normal seasonal freeze/thaw cycle driving the freezing of unfrozen soils. Thus, the short-term risk of frost bulb and/or frost heave formation during construction is very low.

TABLE 4.2.5-2

Seasonal Mainline Pipeline Construction Considerations by Soil Type

Soil Type	Construction Methods	Construction Season	Generalized Impacts	AGDC's Proposed Mitigation
Frozen coarse-grained	Trenching by conventional means could require blasting prior to excavation. Trench blasting would precede pipe stringing and welding, but would occur as close to pipe laying as practical to limit the amount of time the trench remains open.	Winter	Trench wall stability is dependent on ice bonding. Snow accumulation within the trench could mix with backfill material and loose soils could freeze in the trench bottom.	Remove and control snow within the open trench. Trench dewatering as needed.
		Summer	Trench wall stability is dependent on ice bonding. Water flow into the trench from seasonal thawing and thawing within the trench could affect trench bedding and trench wall stability.	Maintain a pipelay rate with the trench excavation rate to minimize the duration of open trench. Install and maintain erosion and sediment controls to control surface water. Install ditch plugs to prevent drainage along the pipe trench. Restore natural cross drainage after construction by returning ground contours to as close as practicable to the original contours. Trench dewatering as needed.
Unfrozen coarse-grained	Trenching by conventional means (hydraulic excavator or trencher). Pipe stringing and welding would occur prior to trench excavation to minimize the length of time the trench is open.	All seasons	Trench wall stability is more dependent on groundwater saturation and excavation parameters (trench width and slope).	Install temporary conventional erosion and sediment controls prior to trenching. Trench dewatering as needed.
Frozen fine-grained	The right-of-way would not be graded except when constructing across a side slope greater than 10 percent. Instead, an ice work pad, frost-packed work pad, or granular work pad would be used, depending on permafrost continuity.	Winter	Disturbance of soils along the trench line excavation and where the tundra is removed and trench backfill is placed and mounded. For granular work pad construction, effects would include hydraulic, thermal, and mechanical impacts on soils including cross drainage patterns along the right-of-way, thermal changes to the active layer, consolidation associated with placement of fill, and thaw settlement.	Minimize the length of time the trench is open to reduce snow removal from the trench and prevent snow from being mixed with the backfill material. Place snow on either side of the construction right-of-way with gaps between piles for water drainage and wildlife passage. Workspaces for snow storage would not be cleared or graded. After construction, restore cross drainage and spread and revegetate granular work pads evenly in accordance with the Revegetation Plan. Dewater trenches as needed.
	Excavation with continuous chain trenchers or excavators following pipe stringing and welding to reduce the duration of an open trench. Trenching could require blasting to loosen the soil prior to excavation.	Summer	For granular work pad construction, effects would include hydraulic, thermal, and mechanical impacts on soils such as cross drainage patterns along the right-of-way, thermal changes to the active layer, consolidation associated with placement of fill, and thaw settlement.	Minimize the length of time the trench would remain open to maintain thermal stability and reduce the risk of trench wall failure. Place right-of-way cross drainage and erosion and sediment controls in accordance with the Project Plan. After construction, restore cross drainage and spread and revegetate granular work pads evenly in accordance with the Revegetation Plan. Trench dewatering as needed.
Unfrozen fine-grained	Frost packing or light grading for winter construction or timber matting for summer construction. Trenching by conventional means (hydraulic excavator or trencher).	All seasons	Impacts during granular work pad construction include thermal, hydraulic, and mechanical changes to soils including changes to cross drainage along the right-of-way; compaction of organic and fine-grained soil during placement of fill within the right-of-way; impacts on the stability of fine-grained backfill; and settlement of the backfill mounded along the trench line.	Use low ground pressure equipment and vehicles for frost packing in early winter and summer to place erosion and sediment controls, repair damage to organic materials, and re-establish natural drainage. Minimize the amount of time the trench is open, to minimize snow mitigation in the winter and sidewall sloughing and surface water management during the summer. Trench dewatering as needed.

As stated in section 2.1.4.3, the organic or surface layer was defined by AGDC as the top 12 inches of soil (or less) where the majority of soil organic materials reside. AGDC has worked with the ADNR to determine areas where surface organic layer segregation could occur along the Mainline Pipeline. AGDC's goal of organic layer segregation is for land stabilization through reestablishment of vegetation. AGDC would segregate the surface organics at material sites and use these materials during reclamation activities. AGDC is proposing to segregate surface organic layer soils in the conditions identified below along the Mainline Pipeline during summer construction.

- Thaw-stable permafrost where the right-of-way preparation mode would require grading (e.g., cut/fill).
  - Where the cross slope and/or longitudinal slope is less than or equal to 2 percent, the surface organic layer would be segregated and stockpiled near the edge of the right-of-way.
  - Where slopes are greater than 2 percent and less than 20 percent, only the soils in the cut area would be salvaged. Fill areas would not have the surface organic layer segregated.
- Thaw-sensitive permafrost where the cross slope and/or longitudinal slope is greater than 10 percent and the right-of-way preparation mode would require grading on the uphill side.
  - The surface organic layer would be segregated from the excavated area only.
- Non-permafrost areas where the right-of-way preparation mode would require grading (e.g., cut/fill).
  - Where the cross slope and/or longitudinal slope is less than or equal to 2 percent, the surface organic layer would be segregated and stockpiled near the edge of the right-of-way.
  - Where slopes are greater than 2 percent and less than 20 percent, only the soils in the cut area would be salvaged. Fill areas would not have the surface organic layer segregated.

Following these criteria, about 186 miles of the Mainline Pipeline would be segregated between MPs 0 and 607, while that the remaining 200 miles have yet to be evaluated. According to the *Segregation of Surface Layer* Project document, the surface organics would be used for enhancing revegetation in areas where land stabilization could benefit from application of the stockpiled material. Therefore, the segregated surface organics would not always be replaced in the exact location or condition from where they were removed. For the DNPP, the stockpiled materials used for enhancing revegetation would be removed within 6 km of the enhancement areas, in accordance with the Denali Revegetation Manual (Densmore et al., 2000). AGDC has also stated that surface organic layer soil segregation would not occur in the winter, as the surface organic layer profile would be frozen and bonded to the underlying mineral soil. Additionally, AGDC has stated that tundra blocks can only be segregated intact when the active layer is thawed, and that the placement of tundra blocks is not feasible in winter conditions due to the crowned material placed over the trench to account for thaw settlement.

AGDC has noted that conventional excavation equipment would not be able to fully separate frozen organics from the mineral soil underneath unless the active layer is thawed. In areas where the surface organic layer would not be segregated, the organic layer would be mixed with subsoil layers during stockpiling and soils would not be put back into the trench in the same order as they were removed, thereby causing permanent impacts on permafrost. By not segregating and saving the surface organic layer along a large portion of the Mainline Pipeline right-of-way, erosion and permafrost thaw related impacts would be significantly increased.

The Project Revegetation Plan does not currently provide a comprehensive set of information on surface segregation. To address this, AGDC would provide a final Revegetation Plan that would incorporate all surface layer segregation information, including the milepost ranges in which surface layer segregation would be executed between MPs 0 and 607, and an analysis and justification of where the surface layer would and would not be segregated between MPs 607 and 807. The final Revegetation Plan would be filed with the Secretary, for the review and written approval of the Director of the OEP, prior to construction of the Mainline Facilities.

We received comments on the draft EIS from the USFWS regarding the discharge of hydrostatic test water and impacts on permafrost. Test water for the pipeline facilities would have an average residence time of approximately 48 hours in the pipeline. At the time of discharge, the water temperature would be expected to be within a few degrees of the surrounding ground temperature. Test water would be discharged at the ground surface and, in the majority of locations, would be separated from the frozen subgrade by the depth of the active layer. Dispersion devices would be used at all hydrostatic test water discharge points, which would be designed to capture water to limit erosion and scour. While some impacts on permafrost could occur due to the discharge of hydrostatic test water, significant impacts on permafrost are not anticipated.

Solifluction and soil creep are naturally occurring processes in frost-bonded sloping terrain. The forces of gravity and seasonal expansion or contraction of water and ice in the active layer combine to slowly move a soil mass down slope. Solifluction and soil creep hazards were avoided or minimized by routing the pipeline to avoid cross-sloping terrain. Pipeline construction involves summer and winter construction spreads; construction across solifluction and creep-prone areas would generally occur during winter months when the terrain is stabilized by freezing conditions. Solifluction is discussed in more detail in section 4.1.3.

Thaw layer detachment occurs when the active layer in a thawing slope overcomes the shear strength of the underlying soil, and the thawed layer detaches to slide relatively quickly downslope. Thaw layer detachment outside the right-of-way is an additional hazard if detachment occurs naturally upslope of the pipeline in terrain undisturbed by construction and the soil mass flows onto the right-of-way. As shown in table 4.1.3-2, about 28 miles of the Mainline Pipeline have been identified as susceptible to thaw layer detachment. If thaw layer detachment occurs during or after construction, right-of-way maintenance would be required to remove the soil mass and restore local site conditions to prevent ongoing geothermal degradation beyond that accommodated in the baseline design. The need for mitigation of the thaw layer detachment site would be based on monitoring pipe displacement and curvature, and geothermal modeling of future conditions.

In 2017, ADEC began inspections of two 240-mile-long sections of fiber optic cable that run parallel to the Dalton Highway after citizen complaints were received. ADEC found that in several locations, there was slope failure, thermokarsting, subsidence, insufficient backfill, and erosion as a result of construction that could lead to continued thermal degradation (Alaska Public Media, 2018c; Anchorage Daily News, 2018). According to comments we received from the State of Alaska, the impacts on soils that occurred from the fiber optic cable projects were a result of the contractor's lack of experience constructing in permafrost and failure to implement BMPs outlined in permits. Among the key lessons learned from these projects were that use of poor and shallow trenching techniques and ice-rich backfill materials combined with the absence of erosion control measures can lead to permafrost degradation.

Additionally, no measures were taken to avoid thermokarsting, there was water accumulation in the trench, construction monitoring was not adequate, and restoration was not properly completed.

To minimize the potential for similar impacts to occur during construction of the Project, AGDC reviewed the fiber optic cable projects with ADOT&PF to discuss construction techniques, mitigation practices, and rehabilitation plans. AGDC has stated that all lessons learned from those projects have been incorporated into the Project design, execution plans, and post-construction revegetation plans. AGDC has stated that while frozen material would be used to backfill the trench depending on right-of-way mode and season of construction, the proposed mitigation measures (e.g., sufficient thickness of thaw-stable backfill to compensate for settlement of the original ice-rich soils; providing an insulating layer on the right-of-way; construction maintenance and operational monitoring; creating post-construction rehabilitation plans for additional surface preparation or revegetation efforts; and controlling gas temperatures to limit changes in permafrost temperatures) would help minimize impacts on permafrost degradation. The Mainline Pipeline would run parallel to and intersect with the recently constructed fiber optic cables in multiple locations. AGDC would address those crossings in detail during the final Project design to determine if any additional mitigation measures or different construction techniques would be required due to the presence of affected permafrost.

Construction of aboveground facilities along the Mainline Pipeline would include clearing of trees and brushy vegetation that would cause permanent impacts on permafrost. As discussed in more detail in section 2.2.2, aboveground facilities would be constructed on granular pads. Compressor and heater station structures would be supported on pile foundations with the stations elevated above the pad elevation. This airspace between the structure and the ground surface would serve as a thermal break to minimize thawing in permafrost areas.

Operation of the Mainline Pipeline could cause long-term changes to the thermal energy balance throughout the soil profile, thereby affecting subsurface hydrologic connectivity and groundwater flow exchange between aquifers above and below permafrost (Walvoord and Kurylyk, 2016). At the surface, effects from vegetation removal and granular work pad construction would continue for decades as the workspace is left to naturally revegetate. Areas with warm (30 to 32°F) discontinuous permafrost and a warm pipeline temperature, such as at the outlet of compressor stations where the gas has been warmed by compression, are most susceptible to long-term progressive thaw and thaw settlement. As gas travels along the pipeline from the outlet of one compressor station, a process known as Joule-Thomson effect occurs, and the pipe temperature would cool significantly before arrival at the next compressor station. Therefore, the expected thaw depth at any particular location along the pipeline route can be affected by the local mean annual ground temperature and the local mean annual pipe temperature (Matrix Solutions, 2016a). The Joule-Thomson effect could cause frost bulbs in waterbodies if they are upstream of a compressor station. See section 4.3.2 for additional discussion of frost bulbs in waterbodies.

AGDC conducted thermal modelling to simulate heat energy exchange at the ground surface to determine the expected thaw depth and frost bulb depth after 30 years of pipeline operation. The assumptions used and described below do not capture site-specific conditions along the Mainline Pipeline, and results would differ in many locations. Specifically, the model assumed revegetation would occur over 20 years, which would not capture revegetation of forested areas or in areas north of the Interior Brooks Range Mountains. The modeling input included the following assumptions:

- The Project would use a 110-foot-wide temporary construction workspace and a 53.5-foot-wide permanent easement.
- On the spoil storage side of the right-of-way, the ground would be cleared of trees and the upper organic soil horizon left intact but somewhat compacted during soil stockpiling.

- On the working side of the right-of-way, a 1.5-foot-thick granular work pad would be placed over the organic soil for the length of the right-of-way.

- Within the temporary construction workspace, revegetation would occur over 20 years following construction.

- Within the permanent easement, low vegetation would revegetate over 5 years as the permanent easement would remain cleared of trees.

Models of the 30-year thaw depth across the right-of-way are provided as cross sections of the pipeline and surrounding soil on figures 4.2.5-1 and 4.2.5-2. Unless otherwise noted, all units displayed in these figures are metric (i.e., International System of Units including meters or degrees Celsius [°C]), but the discussion is based on the United States customary system (i.e., feet or degrees Fahrenheit). The maximum depth of the active layer is displayed as a blue line, which represents the 32°F isotherm or contour line. Each additional line above or below the blue isotherm line (as well as the area between) indicates the difference in temperature from 32°F. Figure 4.2.5-1 provides thermal modeling for warm permafrost (average temperature of 31°F) with a warm pipe near a compressor station outlet. The thaw depth below the right-of-way after 30 years is deeper below the granular work pad (working side) than where no granular work pad was placed (spoil side). The thawed permafrost extends a short horizontal distance (less than 20 feet) beyond both sides of the construction right-of-way. A permafrost "pedestal" remains below the pipe because the pipe removes heat from the surrounding soils, thus preserving permafrost below the pipe (Matrix Solutions, 2016b).

Figure 4.2.5-2 provides thermal modeling for warm permafrost (average temperature of 31°F) with a cold pipe near the inlet of the next compressor station. The model conditions for figures 4.2.5-1 and 4.2.5-2 were the same with the exception that one is representing a warm pipe and one a cold pipe as the gas moves away from the compressor station. The heat extracted by the cooler pipe temperature near the inlet preserves the permafrost on the spoil side of the pipeline and decreases the 30-year thaw depth below the granular work pad on the working side of the right-of-way by about 6 to 7 feet compared to the outlet. In addition, the horizontal distance of the thaw-affected zone beyond the right-of-way on the working side is reduced to less than 6 feet (Matrix Solutions, 2016b).

Modeling was conducted at a compressor station outlet and inlet considering the effects of climate warming on permafrost degradation. Thaw depth results without climate warming are presented in the top panels of figures 4.2.5-3 and 4.2.5-4, while results with an assumed climate warming increase of 0.08°F per year are presented in the bottom panel of each figure. The depth of the active layer is shown as a blue line, which represents the 32°F isotherm. Thaw depth below the undisturbed and disturbed portion of the right-of-way after 30 years with climate warming is about 3 feet deeper than without climate warming at each location. In addition, the size of the "pedestal" of permafrost below the warm pipe and the frost bulb below the cold pipe decreased, and the permafrost degradation extended farther horizontally beyond the disturbed area under the climate warming scenario (Matrix Solutions, 2017). This thermal modeling assumed that gravel pad revegetation would occur in 1 to 5 years, and cleared right-of-way revegetation would occur in 1 to 20 years. As noted in section 4.5.2, pioneer herbaceous plants could establish over granular fill within 10 years, with shrubs taking 10 to 30 years; therefore, thaw depths presented in these figures could vary from actual thaw depths occurring along the Mainline Pipeline.

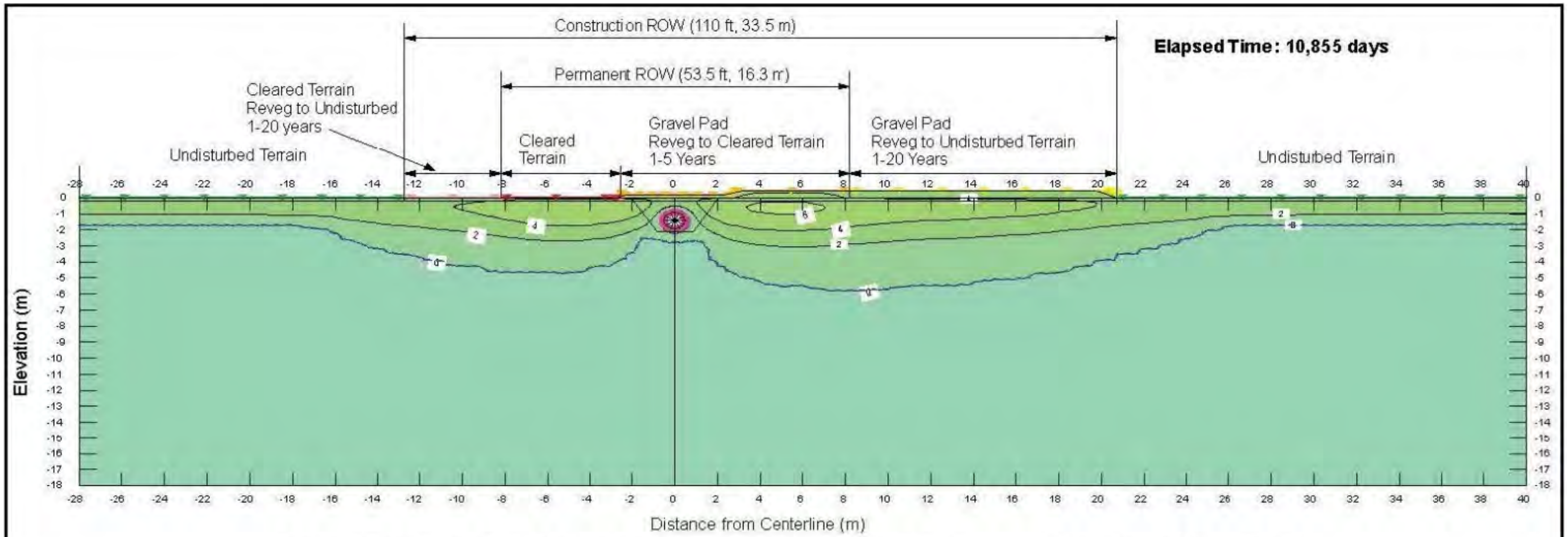


Figure 4.2.5-1 - 30-year Thaw Depth, Warm Permafrost (31 °F), Warm Pipe near Compressor Station Outlet (MP 430)

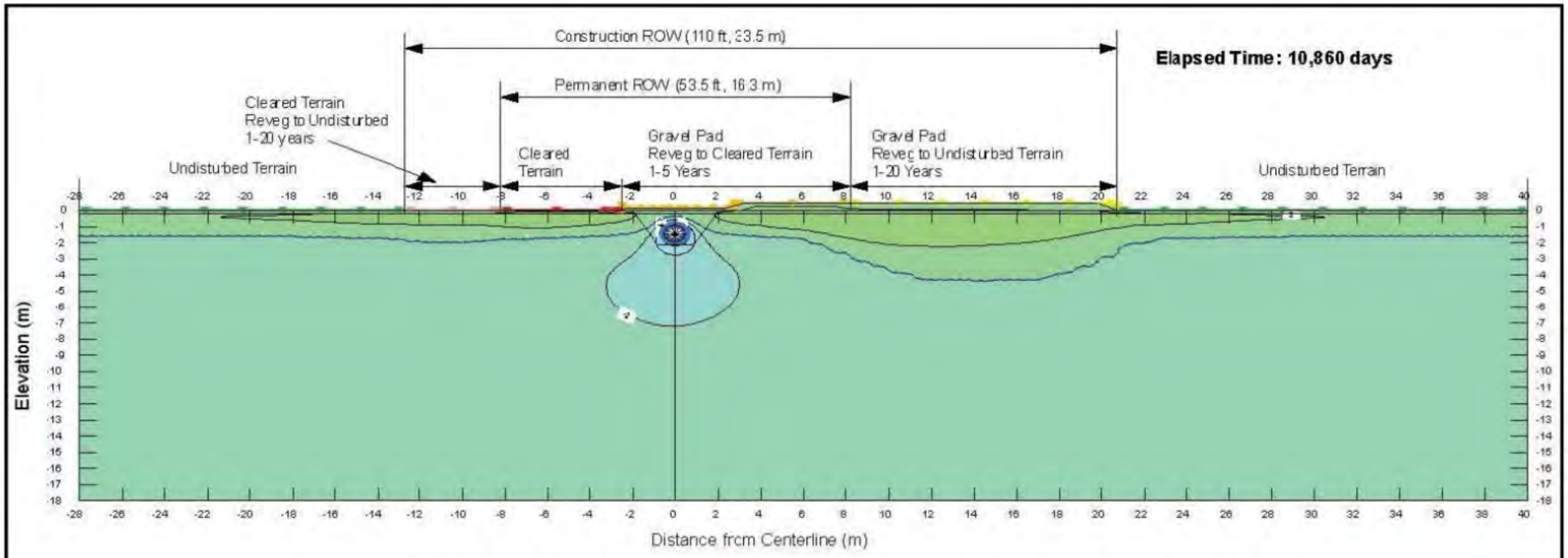
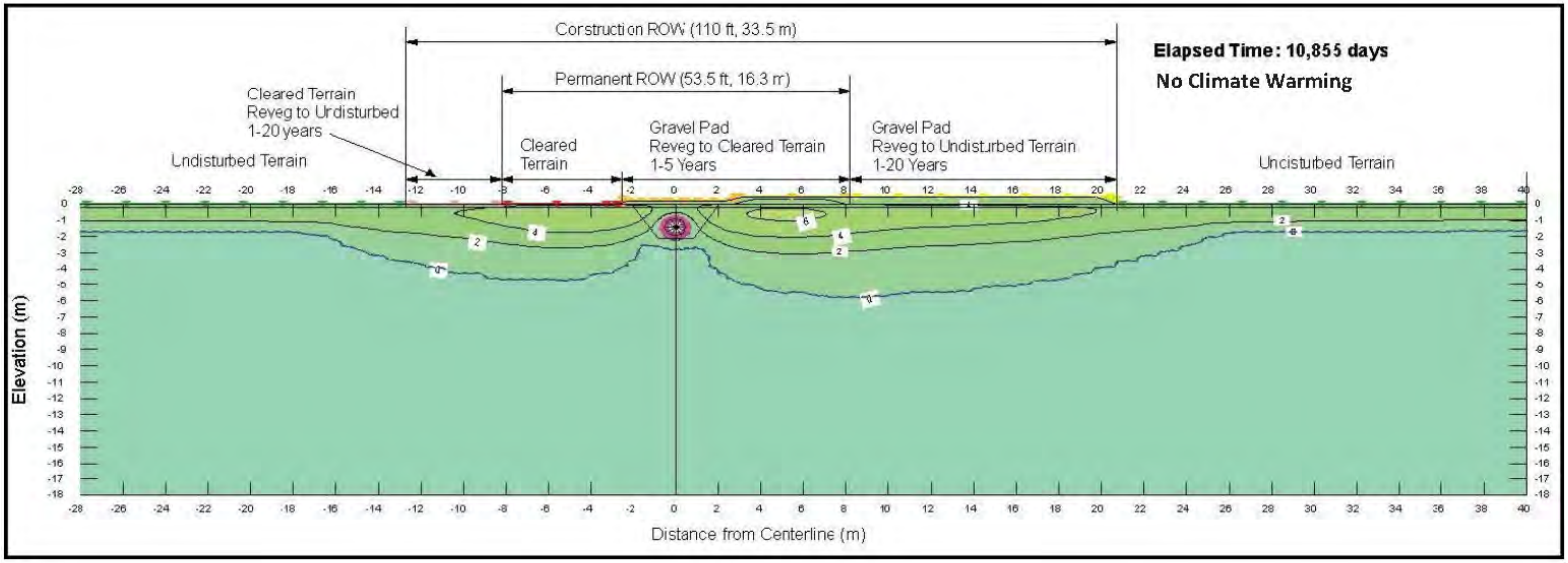


Figure 4.2.5-2 - 30-year Thaw Depth, Warm Permafrost (31 °F), Cold Pipe near Compressor Station Inlet (MP 510)



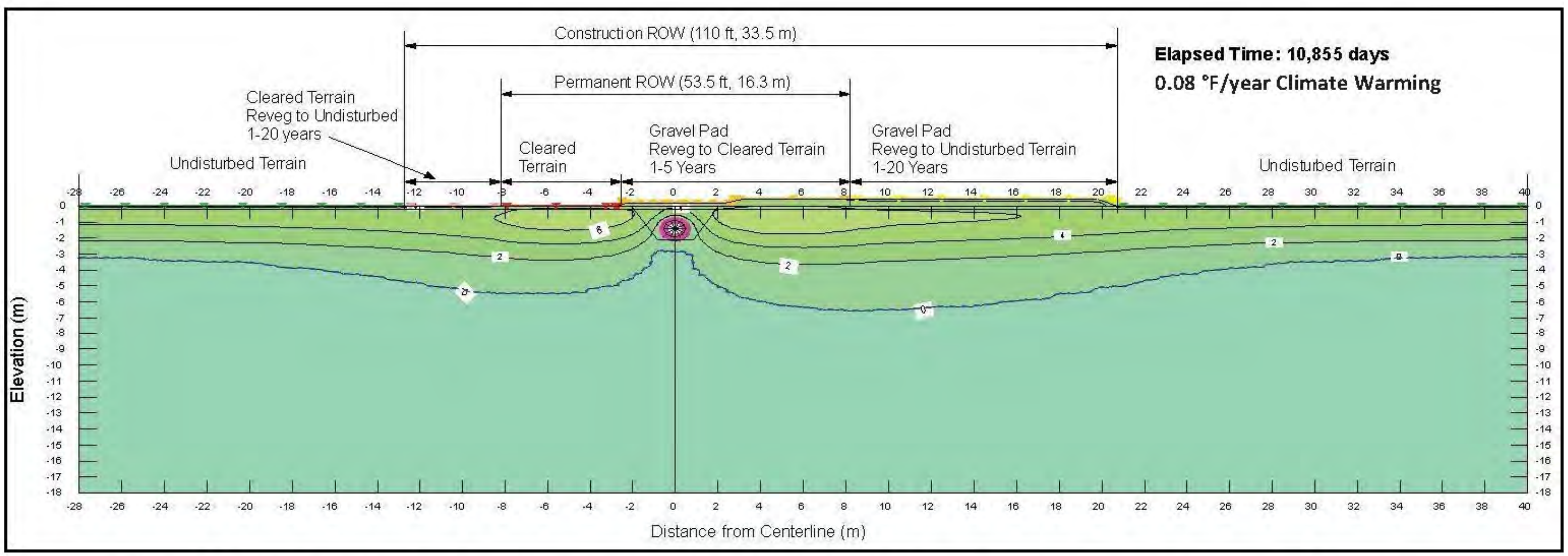


Figure 4.2.5-3 – 30-year Thaw Depth and Climate Warming, Warm Permafrost (31 °F), Warm Pipe near Compressor Station Outlet (MP 430)

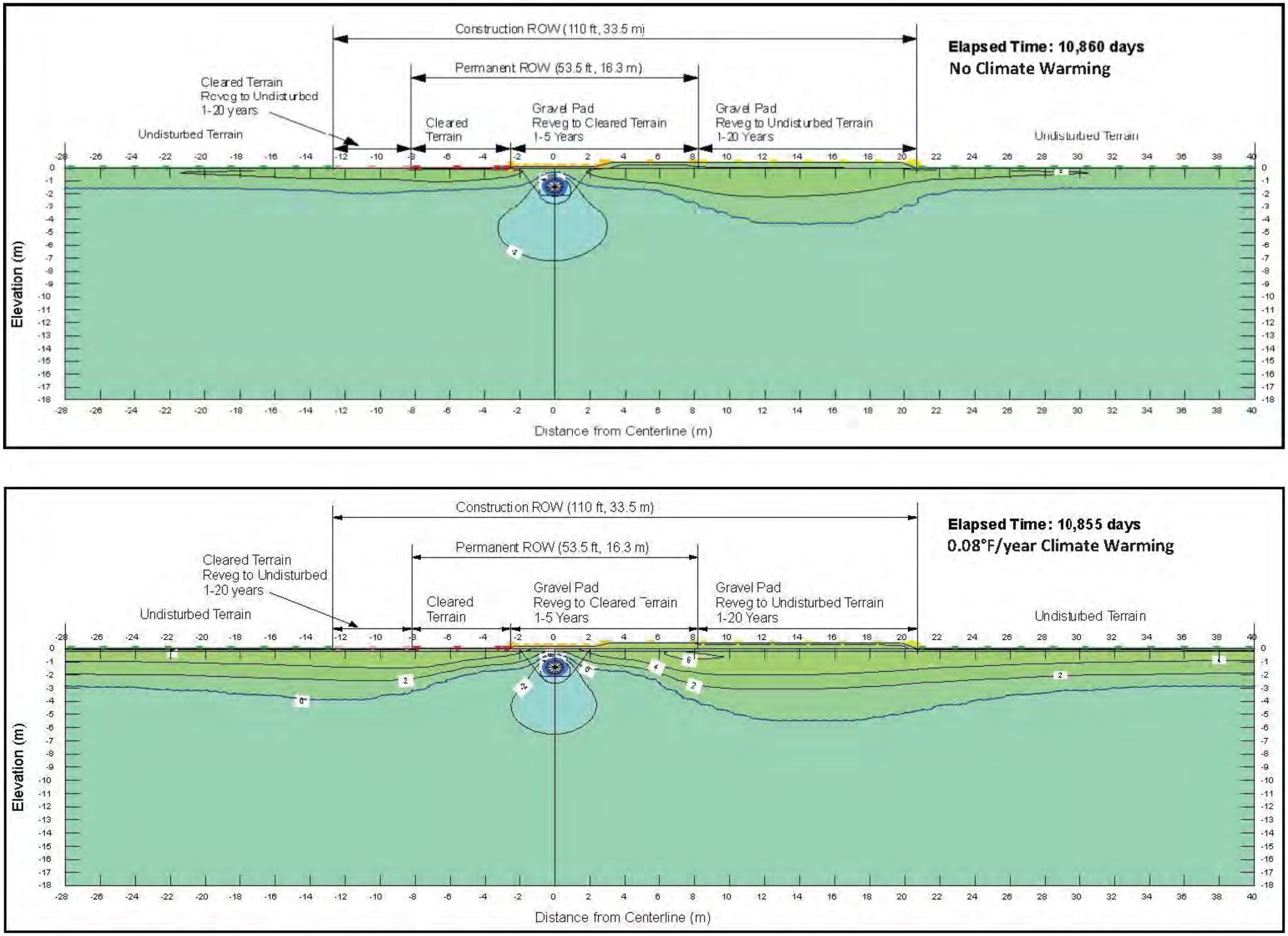


Figure 4.2.5-4 – 30-year Thaw Depth and Climate Warming, Warm Permafrost (31 °F), Cold Pipe near Compressor Station Inlet (MP 510)

Depending on site-specific conditions including active layer depth, soil moisture, surface and subsurface hydrologic connectivity, and both Project and climate change induced permafrost thaw, the exchange between aquifers found above and below permafrost could increase. Additionally, thawing of permafrost can cause shifts in vegetation composition due to changes in soil moisture and surface water conditions. It has been observed in areas with permafrost thaw that birch forests and black spruce forests have shifted to fens and bogs, and areas with shrub vegetation have shifted to graminoid dominance (Walvoord and Kurylyk, 2016).

Frost heaves are associated with the growth of a frost bulb around a chilled pipeline. The amount of heave is influenced by the type of soils, availability of moisture, speed at which the frost bulb grows, thermal gradient, and the bearing pressure exerted by the pipe at the ditch bottom. Two types of frost heave have the potential of occurring along the Mainline Pipeline: pipe frost heave, which could cause bending strain in the pipe as it transitions from frozen to unfrozen soil conditions, and frost heave of the ditch area, which could cause a disruption to natural drainage patterns and in turn could affect right-of-way integrity. Any areas identified as potentially exceeding the pipe strain limits would require mitigation through the PHMSA-approved Strain-Based Design Special Permit as described in section 4.18.10.

In areas of discontinuous permafrost, the seasonal variations of ground and pipeline temperature could lead to frost heave and cryoturbation or thaw settlement hazards. This is not expected to be a concern in areas of continuous permafrost where the pipeline temperature would be consistently chilled. AGDC used a geothermal model to estimate the seasonal frost bulb extent for varying depths of cover and connective cross-flow beneath a typical active channel and neighboring floodplain, and evaluated the geothermal influence of hydraulic cross-flow by varying the hydraulic conductivity. The model was run for a 10-year period after which AGDC determined the Mainline Pipeline would be at equilibrium with climatic and site conditions. The geothermal modeling assumptions, which encompass the conditions required for frost bulbs to form, include:

- an active waterbody channel with sufficient depth and hydraulic loading to maintain flow during the winter;
- a floodplain with no free water covering the surface; and
- the pipeline buried in granular soil.

Results of the geothermal model indicate that the pipeline frost bulb would coalesce with the active layer each winter season. The active layer would freeze faster and thaw more slowly over the pipe trench due to the subgrade below the trench being chilled by the pipeline and having less sensible heat available for phase change in seasonably thawed soils. The rate of freeze in the active layer would vary depending on soil type and moisture content; silty soils with higher moisture content would freeze more slowly than the granular soils used in the geothermal analysis. In general, model results show that the pipeline's thermal influence extends laterally away from the pipeline between about 7 and 11 feet on either side. As distance increases from the pipeline, the influence of climate conditions and ground disturbance increases over the influence of the pipeline on the freeze/thaw of the active layer. Without convective heat transfer, additional insulation could be required to maintain unfrozen soils around the pipeline, and concrete coating or other buoyancy compensation would be required where the pipeline is buried across saturated floodplains or active channels. These site-specific mitigation measures would be developed during the detailed design phase of the Project, implementing the Geohazard Mitigation Approach.

Frost heave and frost bulb formation over the Mainline Pipeline could occur where the Pipeline transitions from frozen to unfrozen soil and ground ice development occurs due to the chilled pipeline, placing additional tensile or compressive strain on the pipeline. Cryoturbation is a natural process of soil mixing in the active layer. Cryoturbation can cause coarse soil particles to move upward relative to surrounding finer grained soils with each freeze/thaw cycle. Frost heave of the ditch area, including soils above the pipe, could result in changes in surface topography and interrupt cross drainage, resulting in ponding on the upslope side of the ditch area. Ponding could affect right-of-way integrity, revegetation potential, and could elevate the groundwater table at the toe of slopes. It is unlikely that frost heave would directly affect pipeline integrity, but it could be a contributing factor to cross-slope instability or soil liquefaction when active layer movement due to subsurface frost heave occurs.

Depending on site-specific conditions, groundwater flow across or parallel to the Mainline Pipeline route in sloping unfrozen terrain could occur. Because the pipeline and any associated frost bulbs would be impermeable, groundwater flow would be deflected below or above the pipeline and frost bulb. Where the frost bulb and active layer coalesce seasonally and site conditions prevent or restrict groundwater flow beneath the pipeline, groundwater could be forced to the surface and cause thick accumulations of ice on the surface (i.e., aufeis formation: sheet-like masses of layered ice that form from successive flows of groundwater). As the frost bulb persists into spring and summer, local ponding could occur adjacent to the pipeline route. Local ponding can influence active layer depth and base flow of neighboring waterbodies, and result in saturated conditions within the operational right-of-way.

As a mitigation measure in areas where the pipeline route is parallel with slopes, AGDC would install periodic ditch plugs or water bars to stop ditch flow and direct ground and surface water away from the pipeline. In areas where the slope is perpendicular to the pipeline, aufeis formation could influence erosion through episodic alternation of surface water drainage patterns and prolonged soil saturation from ice melt runoff. The creation of aufeis would be handled on a case-by-case basis to determine the source, cause, and potential impact on the Project. Potential mitigation measures for aufeis include, but are not limited to, installation of erosion and sediment controls; mechanical removal of accumulated ice with heavy equipment; construction of ice fences, subsurface drains, culverts, and basins to divert and store water and ice; application of insulation to delay or eliminate build-up in problem areas; or thawing of ice with steam or electric cables.

Frost heave and thaw settlement predictions and pipe strain modeling conducted for the Project identified several segments of the Mainline Pipeline route between MPs 194 and 563, totaling about 34 miles (see section 2.1.4 and section 4.18.10), that would require the use of heavy-walled steel and/or additional design and monitoring requirements per the Strain-Based Design Special Permit. According to the permit conditions, additional areas of permafrost resulting in thaw settlement and pipe strains could be identified as Project engineering continues. If such areas are identified and cannot be addressed using engineering and construction techniques, AGDC would implement a Design Change Process for these areas to be added to the Strain-Based Design Segments covered in the permit. Additionally, to reduce the impacts associated with the formation of frost bulbs, AGDC would install periodic ditch plugs or water bars to stop ditch flow and direct seepage and surface flow away from the pipeline.

Thaw settlement occurs when frozen soils with an ice volume greater than the available pore space melt. AGDC reviewed the potential for thaw settlement of the pipe, ditch backfill, and right-of-way to occur based on the *Geotechnical Report on Thaw Settlement Design Approach* developed by Hardy Associates (Hardy Associates, 1982). Components of thaw settlement design include: assessment of initial thermal condition of the soil (i.e., extent of frozen ground); thaw settlement data for different soil types; thermal predictive modeling to determine depth of thaw under a given pipe (including effectiveness of any proposed design measures to inhibit or prevent thawing); and calculations to integrate settlement behavior of individual soil layers and settlement behavior of individual terrain units. Settlement values can be presented based on pipe temperatures for a given area, various burial depths, terrain units, or individual boreholes. Thaw settlement of the pipe could cause significant pipe strain. Any areas identified as potentially exceeding the pipe strain limits would be designed and constructed per the PHMSA-approved Strain-Based Design Special Permit as described in section 4.18.10.3.

Ditch backfill thaw settlement could occur as a result of melting interstitial ice and ice lenses. If the ditch backfill area settles more than the surrounding right-of-way, changes to natural drainage patterns could occur. AGDC identified about 21.6 miles of Mainline Pipeline where ditch backfill thaw settlement is possible and could require mitigation. The majority of these areas (16.3 miles) are within the first 50 miles of the Mainline Pipeline. Mitigation measures identified to address areas susceptible to ditch backfill settlement include importing additional fill, trench crowning, and operational monitoring and maintenance. The remainder of the Mainline Pipeline is not expected to have thaw settlement requiring additional mitigation measures (WorleyParsons, 2018).

Right-of-way thaw settlement can cause changes in surface topography, thereby interrupting cross drainage and causing ponding on the right-of-way. Ponding could then impact right-of-way integrity and surface vegetation, and could raise the groundwater table in certain locations. The areas that are most prone to right-of-way thaw settlement are those with a cross slope and no longitudinal slope. Mitigation identified to address areas of right-of-way thaw settlement include right-of-way protection measures such as granular work pad or embankment fill, snow/ice pad, or installation of a gravel blanket with or without insulation (WorleyParsons, 2018). Insulation includes the use of foam pillows or imported fill material that would be placed along the bottom of the trench prior to pipe placement. We received comments from the USFWS regarding the use of foam insulation and the potential for foam to become exposed over the life of the Project. The USFWS indicated that certain types of foam could then breakdown into small pieces and spread across the landscape, becoming a hazard for fish and wildlife, and that closed cell extruded foams would minimize these impacts. To address this concern, AGDC would use closed cell extruded polystyrene or other closed cell foams rather than non-extruded expanded polystyrene foams during construction of the Mainline Facilities.

Thawing of discrete massive ice or excess ice features within permafrost can lead to thermokarst development. The settlement of thermokarst topography can then cause changes to natural drainage patterns, increase erosion, and increase thaw induced slope instability. Thermokarsting during Mainline Pipeline operation could cause strain on the pipeline. If settling causes thermokarst, AGDC would assess the area for stability and erosion potential and either fill the area or allow it to come to equilibrium, forming a ponded area. Ponding would only be allowed to occur if it does not pose a threat to the stability of nearby permanent facilities.

AGDC would contour granular fill work pads to minimize impacts on natural drainage and hydrologic connectivity. In some instances, natural drainage features that intersect with a granular fill area would be diverted into a single feature to facilitate connectivity from the uphill side of the pad to the downhill side of the pad. Additionally, work pads would be scarified to improve the possible establishment of natural revegetation, to help stabilize the pad, and to reduce the potential for thermokarst. Thermokarst also has the potential to occur adjacent to granular fill work pads, and permafrost thaw could extend up to 20 feet outside of the construction right-of-way. AGDC would monitor conditions adjacent to granular work pads as outlined in the Revegetation Plan. In some instances, when the thermokarst feature is not a threat to the stability of the work pad or road, AGDC could allow the thermokarst feature to remain in place. If the thermokarst feature is observed to be expanding in size and depth, AGDC would backfill the thermokarst feature with organic soil to promote revegetation. Any backfilling would be subject to review and approval from the land-managing agency, and other agencies, as necessary.

The Mainline Pipeline would be bedded with thaw-stable, non-frost susceptible materials, which would mitigate against permafrost degradation, pipe thaw settlement, and surface slumping. Continuous monitoring and operation of Project facilities would be conducted through the SCADA system, which is a computer system used for gathering and analyzing data from real-time systems and operating remote facilities. The SCADA system would compile pipeline operating data (e.g., pressure, temperature, flow, compressor data, revolutions per minute, and vibration) from Project facilities and transmit the data to the Gas Control Center. The Gas Control Center would control gas temperature during operation of Mainline Facilities by heating and/or cooling gas at compressor and heater stations to maintain the geographic temperatures outlined above. This would include adjusting gas temperatures for seasonal variations in discontinuous permafrost areas to match ground temperatures to the extent possible.

Over the life of the Project, AGDC anticipates that impacts on permafrost thawing from Project operation and climate change would be similar to those that have occurred on TAPS. These impacts include heaving, subsidence, thermokarst, and solifluction of soils near the pipeline, access roads, work pads, and operational material sites. Given the much larger quantity of belowground pipeline construction proposed for the Project in comparison with TAPS, these impacts would likely be increased.

We received comments from the EPA to review the extent of impacts on permafrost due to the Project and provide an estimate of the CO_2 equivalent (CO_2e) emissions resulting from the loss of permafrost. Permafrost degradation and thaw during Project construction and operation would be expected to release GHGs into the atmosphere. As permafrost soils warm, organic carbon reservoirs that are currently trapped in the frozen subsurface would be mobilized, thereby causing CO_2 and CH_4 to be released into the atmosphere. While these impacts could occur across all Project Facilities, the focus of our analysis is on the Mainline Pipeline. For the permafrost data presented in table 4.2.5-1, our calculations assumed the maximum percentage of permafrost coverage as defined in section 4.2.2.1 (i.e., 100 percent for continuous, 90 percent for discontinuous, 50 percent for isolated, and 10 percent for sporadic). An average soil density was estimated as 1.5 mg/m^3 based on moist bulk density of soils sampled in the interior Alaska Range (Kawasaki et al., 1983). We assumed the trench would be 6 feet wide and 8 feet deep along the entire route and for the basis of these calculations, assumed all permafrost within the trench would be degraded; however, not all permafrost within the trench would be anticipated to degrade. Therefore, the estimated amount of permafrost impacts and emissions are higher than those anticipated for the Project. Using these parameters, an estimated total of about 7.1 million tons of permafrost would be affected by Mainline Pipeline trenching, translating into about 85 tons (77 metric tons) of CH_4 emissions and 2,136 tons (1,938 metric tons) of CO_2e emissions (COE, 2018c).

In addition, we assumed a nominal 145-foot-wide right-of-way along 126 miles of ice work pad/frost pack construction in continuous permafrost. For the remainder of the Mainline Pipeline, we used thaw projections for Mode 4 (granular work pad) presented by Matrix Solutions for the ASAP Project (Matrix Solutions 2016b, 2017). The total estimated amount of permafrost thaw that could occur during the life of the Project without climate change is estimated to be about 221 billion tons, translating to 2,680 tons (2,431 metric tons) of CH_4 emissions and 67,012 tons (60,792 metric tons) of CO_2e emissions. For additional discussion on Project GHG emissions, see section 4.15.5, and for a discussion of potential climate change effects, see section 4.19.4.

In addition to the SCADA monitoring, AGDC has stated it would conduct routine aerial and ground surveys via a combination of flying, driving, and walking to monitor the Mainline Pipeline right-of-way for visual evidence of effects related to permafrost alteration, such as settlement, thermokarst formation, ponding, erosion, or frost heave during Project operation. Additionally, AGDC has stated that right-of-way monitoring would include the effects of frost action, precipitation, bank stabilization, slope failure, ground settlement caused by thermal and physical erosion, pipe cover settlement and stabilization, trench subsidence, surface drainage patterns, and slope breaker conditions.

AGDC has developed a Project Pipeline Operation and Maintenance Plan that describes operational monitoring methods that would be used on the Mainline Pipeline to determine if altering conditions (including permafrost changes) create an unacceptable risk to the pipeline. This plan states that operational monitoring would occur in areas of Class 1, 2, and 3 locations (as defined in section 4.18.10.2), which cover the entire 806.9 miles of the Mainline Pipeline. The plan states that surveillance for the Mainline Pipeline would be at intervals not to exceed 45 days, and would occur a minimum of 12 times each year. AGDC would implement a quality-based adaptive management approach to assess maintenance issues identified during SCADA inspections and surveys. Potential maintenance techniques that would be used based on site-specific conditions include:

- adjustment of pipeline gas temperatures to match ground temperatures to the extent possible;
- techniques to minimize soil movement caused by permafrost thawing, including allowing ice-rich soils to thaw until the slope stabilizes on its own and installing a gravel buttress (fertilized to promote natural revegetation) at the top of the fill;
- thermal erosion control techniques such as self-stabilization and filter buttresses;
- filling depressions and cracks with sand, gravel, and/or rock;
- covering slopes with temporary erosion protection to assist with vegetation establishment;
- backfilling exposed pipe; and
- continued restoration and revegetation measures as identified in the Project Revegetation Plan.

Impacts on permafrost during construction and operation would be minimized through the implementation of measures outlined in various Project plans, our recommendations discussed in section 4.2.4 above, and through implementation of the Pipeline Operation and Maintenance Plan, which includes measures for monitoring impacts on permafrost and erosion. While use of granular fill would minimize direct impacts on permafrost, installation of the granular work pads would conduct solar radiation to the underlying permafrost, thereby causing changes to the subsurface thermal regime, drainage patterns, and vegetation in thaw-sensitive permafrost areas.

AGDC is proposing to clear trees and brush between 1.0 and 1.5 years prior to construction. Clearing vegetation in thaw-sensitive permafrost areas prior to placing granular work pads would increase the potential for permafrost thaw and the creation of thermokarst. Additionally, AGDC has proposed to segregate the surface layer of the Mainline Pipeline for about 186 of the 806.9 miles. In areas where the surface organic layer would not be segregated, soils would be mixed, thereby causing permanent impacts on permafrost. By not segregating and saving the surface organic layer, erosion and permafrost thaw related impacts would be significantly increased.

Given the scale and location of the Facilities, the potential for permafrost degradation to affect hydrology and vegetation, and the fact that permafrost degradation could spread laterally past the Project footprint, we conclude that significant permanent impacts would occur.

Soil Erosion

As shown in table 4.2.4-1, about 10,185 acres of soils associated with construction of the Mainline Facilities are classified as highly erodible by wind, and 17,701 acres are classified as highly erodible by water. AGDC would implement the measures specified in both the Project Plan and Winter and Permafrost Construction Plan to minimize or avoid potential impacts due to soil erosion and sedimentation. As outlined in the Project Plan, AGDC would have an EI monitor all phases of construction to ensure that Project plans are followed and that erosion and sediment controls and construction practices are implemented to minimize erosion during and after construction.

Right-of-way pre-clearing activities, including cutting down trees and brush, would occur in the winter season between 1 and 1.5 years prior to each scheduled construction season. AGDC has stated that this clearing would be done with hydro-axes and brush hogs and that the soil and surface organic layer would not be disturbed or stripped during this process. The majority of pre-clearing activities (with the exception of aboveground facility site preparation) would remove overstory vegetation and leave understory vegetation in place until active construction occurs. Additionally, root structures from trees and larger shrubs would be left in place until grading occurs. Leaving understory vegetation and root structures intact would minimize the potential for erosion during this period. In areas free of trees and brushy vegetation, no pre-clearing activities would occur. In instances where the vegetative mat and tree root systems are inadvertently removed during clearing, AGDC would install temporary erosion and sediment controls if site-specific conditions indicate the potential for erosion prior to the next construction phase. These temporary devices would be regularly inspected and maintained until final clearing and grading. For additional information on vegetation clearing, see sections 4.5.2 and 4.5.3.

During right-of-way grading and pipeline installation, temporary erosion and sediment controls would be installed before the onset of conditions that could cause erosion (e.g., spring thaw) or when such conditions exist immediately after initial ground disturbance. The controls would be left in place and repaired, replaced, or supplemented, as needed, through the end of construction to reduce impacts on surface erosion from spring thaw, snowmelt, and summer precipitation. Erosion and sediment control inspection and monitoring would be conducted in accordance with the SWPPP, which takes into account precipitation levels, annual ice conditions, and the current state of site stabilization. Trench dewatering pumps would be used as needed. A draft for the Project SWPPP was included in AGDC's application, providing an overview of potential sources and measures for construction, but the draft did not incorporate the requirements of the Project Plan and Procedures and other applicable state or federal standards. Prior to construction, AGDC would develop a Project-wide SWPPP that would cover all facilities and activities, including construction and operation.

During construction, AGDC would stockpile erosion and sediment controls in secure moveable storage containers at each camp location, pipe storage yard, and material site (spaced at an average of 20-mile intervals). These storage containers would be moved between construction sections. Use of erosion and sediment controls would be documented on a daily basis with inventory managed and replenished as needed.

AGDC would implement trench crowning along portions of the Mainline Pipeline (specifically in permafrost areas). Excess trench material would be used to create a slight mounding over the pipe (crowning), which is critical to stabilizing soils and direct ponding away from the right-of-way, thereby reducing potential erosion and drainage impacts. Crowning promotes water movement along a desired gradient and, as ditch soils thaw in spring, the weight of the extra material would compact the soil and bring the surface to a nearly flat condition. AGDC would take soil samples along the Mainline Pipeline route during construction to determine the proper height and shape of the crown. Additional fill could be placed in ice-rich areas where greater subsidence could occur. Specific mitigation measures to direct flow from the crowned trench line would be assessed on a site-specific basis during construction. Options include:

- installation of intentional depressions (wattles) at an angle and predetermined spacing based on slope angle;

- installation of flexible piping to carry upgradient water across the ditch line to off-site vegetated downslope areas;

- installation of armored flow breaks in the crown to transfer water from one side of the ditchline to the other;

- installation of native fill berms to direct flow away from the crown installed at intervals based on slope;
- construction of drainage channels to direct flow away from the right-of-way;
- installation of permanent culverts;
- creation of earthen ditch blocks to retain or redirect water; and
- creation of gravel or gabion channels or swales.

At the end of construction, AGDC would return the construction right-of-way to stable contours with the surface soils in a suitable condition for restoration. AGDC would reestablish vegetation as soon as possible following final grading and would inspect the right-of-way and maintain erosion and sediment controls as necessary until final stabilization is achieved. Once restoration and revegetation are satisfactory, temporary erosion and sediment controls would be removed.

After construction of a specific spread and before pipeline operation begins, the Mainline Pipeline would lay dormant at ambient temperature for about 2 to 3 years without any gas flow. The Mainline Pipeline and surrounding materials would remain frozen in place each year until spring/summer thaw. The crown and backfilled trench materials would thaw slightly around the portion of the trench that thaws during this period. It is expected that the crown would only remain for 1 to 2 years of freeze-thaw cycles due to this settlement. Permafrost conditions can influence erosion and sediment control in frozen soils given that their cohesive nature in an undisturbed state makes them typically less erodible than unfrozen soils. As outlined in the Project Winter and Permafrost Construction Plan, where right-of-way grading or pipeline trenching disturbs and exposes ice-rich soils, the erosion potential could be increased in these areas. This is due to the presence of the seasonal active layer. Thermal erosion would likely intensify erosion of mineral soils through the thawing of ice present in the exposed soils. Permanent erosion and sediment controls would be used in areas where physical or climatic conditions exist for erosion and sediment transport. These controls would be similar to those used in non-permafrost areas, including pipe ditch plugs, diversion berms, mulch, use of granular work pads, revegetation of the ditch line, and erosion and sediment control matting. AGDC would use ditch plugs/trench breakers in sloped wetlands (which develop in permafrost) to maintain hydrology and slope stability.

In thaw-sensitive permafrost terrain, for safety reasons, drill and shoot (blasting) of the ditch line (where necessary) would occur before pipeline stringing. Where possible, to reduce the amount of time the trench would be open between blasting and lowering in of the pipe, the ditch would be excavated and backfilled with backhoes before pipe stringing, then re-excavated for lowering-in and backfilling. This would reduce the amount of time that soils and permafrost are exposed to weather and wind, thereby minimizing soil erosion. In locations where an excavator can be used to dig the trench without the use of blasting, the pipe string would be positioned and assembled before digging the trench to reduce ditch exposure. See section 2.2.2 for more information on general Mainline Pipeline construction procedures.

AGDC would provide continued ground surveillance and monitoring and corrective erosion and sediment control maintenance throughout Project construction. During the detailed design phase, the Project would develop appropriate methods to respond to site-specific conditions based on terrain, geology, slope, thermal regime, hydrology, climate, and other factors.

As shown in table 4.2.4-1, about 2,527 acres associated with operation of the Mainline Facilities are considered highly erodible by wind, and about 4,409 acres are considered highly erodible by water.

AGDC assessed operational erosion potential (including ice content) as part of their geohazards assessment for the Project. This analysis focused on three erosion zones associated with pipelines, as described below.

- Surface erosion involves water (in the form of rainfall or meltwater in thawing ice-rich areas) dislodging and transporting surficial sediments. Surface erosion includes particle dislodgement, the movement of those particles over the ground surface (sheet erosion), and rill formation.

- Backfill erosion depends on the backfill material used and soil material placed back into the pipeline ditch that could be susceptible to erosion. This is particularly true if the backfill material contains a significant amount of ice-rich soil or permafrost. Backfill erosion is more likely to have particles dislodge from the soil thereby making soils more susceptible to rill development.

- Piping erosion occurs when water conveys fine sands and silts in certain non-cohesive soils between coarse soils particles. This results in fines being removed from the soil matrix, which could lead to the development of voids underneath the pipeline. Piping erosion is most likely to occur in areas next to steep slopes where sufficient hydraulic gradient allows water movement through the soil matrix, and where a discharge point for the water and conveyed fines exists. Piping erosion only occurs in soils with particular gradational characteristics, requiring the correct mix of non-cohesive fine particles and coarser particles such as gravel.

AGDC used the Terrain Erodibility Index approach for measuring potential surface and backfill erosion. This approach uses three parameters (soil erodibility, terrain slope, and thermal condition) to calculate an overall ranking. A fourth parameter was added to the analysis to account for annual precipitation. The piping erosion assessment was primarily based on identifying the soil erodibility and topographical conditions, such as where fine-grained cohesionless soils exist within floodplain areas, whether they are close to waterbodies, or whether they are near the toe of a steep slope. As part of the analysis, it was assumed that all areas of potential piping erosion within the Mainline Pipeline right-of-way would thaw during operation.

The surface erosion geohazard assessment considered the long-term stability of the onshore Mainline Pipeline and how erosion from water in the form of rainfall or meltwater in thawing permafrost areas could potentially cause loss of pipeline integrity. The analysis indicated that about 663 miles of the onshore Mainline Pipeline have a high to low surface erosion potential, while the remaining 133 miles would have a negligible potential for surface erosion that would cause a loss of pipeline integrity. Of the 663 miles, about 26 miles were estimated to have a high erosion potential, the majority of which are between MPs 150.0 and 250.0, with other areas distributed across the Mainline Pipeline. Permanent erosion and sediment controls, including pipe ditch plugs, diversion berms, mulch, revegetation (of ditch line, graded right-of-way, or granular work pads), and erosion and sediment control matting and blankets would be used along the Mainline Pipeline (WorleyParsons, 2018).

Operational monitoring and maintenance would address localized erosion issues over the life of the Project. It is expected that these primary mitigation measures would protect the right-of-way, thereby reducing soil movement and rill development. Additional proposed mitigation measures to protect the cut and fill cross slopes along the route include the installation of mulching or Coconut Jute Mat, depending on site-specific conditions.

The backfill erosion analysis indicated that about 613 miles of the route have low to high backfill erosion potential. The remaining 164 miles have a negligible potential for backfill erosion. Of the

613 miles, about 114 miles were considered to have high backfill erosion potential. Potential mitigation in these areas would include installation of additional ditch plugs beyond those specified by standard design and construction requirements. In other areas where backfill erosion could occur, but would not be severe enough to require the use of additional ditch plugs, standard mitigation would be required to maintain backfill of the pipe ditch. In addition to the standard use of ditch plugs, these mitigation measures would include enhancing right-of-way revegetation to aid in the long-term stability of the right-of-way and ditch (WorleyParsons, 2018).

Areas with sediment deposited by water or material moved by glaciers and subsequently deposited along drainage paths are more prone to subsurface piping erosion. Additionally, climate conditions play a role in initiating piping erosion. Long dry spells with periods of short rainfall and the thawing of frozen soil can lead to piping erosion. AGDC identified areas of potential piping erosion based on a desktop study using GIS, Google Earth, and the Alaska National Gas Transportation System terrain mapping of the Mainline Pipeline route. AGDC identified 12 areas as having piping erosion potential. Four of these locations (MPs 364.4 to 364.6; MPs 370.2 to 370.4; MPs 380.5 to 381.0; and MPs 393.6 to 393.8) are where the Mainline Pipeline route crosses through steep cross slopes and gully areas, and where the soils underneath the ditch bottom are highly erodible with the potential for thaw conditions due to ground disturbance. The remaining eight areas were considered a low threat to the Mainline Pipeline given the presence of bedrock or coarser grained soils beneath the pipeline.

Mitigation measures to be used in areas identified with the potential for piping erosion include the use of subdrains to control meltwater and groundwater recharge as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipe. Standard practices along the Mainline Pipeline would include controlling surface water and infiltration in cut slope areas with inceptor ditches and revegetation. Operational monitoring would identify areas of localized erosion issues over the life of the Project (WorleyParsons, 2018). AGDC did not complete the same level of analysis for piping erosion potential for the portion of the Mainline Pipeline between MPs 536.1 and 544.3. Therefore, **we recommend that:**

- **<u>Prior to construction of the Mainline Facilities</u>, AGDC should file with the Secretary, for the review and written approval of the Director of the OEP, an updated assessment of piping erosion potential between MPs 536.1 and 544.3 using the same methodology used for the rest of the Mainline Pipeline (Onshore Geohazard Assessment Methodology and Results summary). If any new areas of piping erosion potential are identified, AGDC should implement the same mitigation measures that would be implemented for other areas with the potential for piping erosion, including the use of subdrains to control meltwater and groundwater recharge as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipe.**

Through the implementation of the measures described above, impacts on soils with erosion concerns during construction and operation would be minimized; however, given the scale and location of the Project in permafrost rich areas, long-term impacts would occur.

Farmland of Local Importance

The loss of the organic layer due to erosion or the mixing of the organic layer with the subsoil during construction could result in a loss of soil fertility and impair revegetation. As previously stated, SSURGO data is only available for a small portion of the Project area. As shown in table 4.2.4-1, a minimum of about 1,748 acres of soils of local importance would be affected by Mainline Facilities construction and 499 acres by operation of these facilities. The actual area of impact is likely higher as

SSURGO data is only available for about 170 miles of the Mainline Pipeline. As discussed in more detail in section 4.9.1, about 3 acres of active agricultural land would be affected by the Mainline Facilities. Along the Mainline Pipeline, these impacts would occur in the Kenai Peninsula Borough near MPs 758 and 799. Additional impacts on agricultural lands would occur along access roads in the MSB near MPs 745 and 749. According to the 2012 Alaska Agricultural Census, 29,140 acres on the Kenai Peninsula and 36,378 acres in the Anchorage Area were farmed, which encompasses the MSB and Valdez-Cordova Boroughs (USDA, 2014).

To minimize impacts on farmlands, AGDC would coordinate restoration efforts with the affected landowners. These efforts would include surface organic layer segregation during summer construction of Mode 5A (graded). Where the surface organic layer is segregated, AGDC would follow measures outlined in the Project Plan to ensure that proper erosion and sediment control and segregation measures are used until the soil is replaced and revegetated. To maximize organic layer salvage in agricultural areas, AGDC would adhere to the following measures:

- Pedestals of topsoil would be used to verify soil removal depth.

- A qualified soil scientist or EI would be consulted to verify organic layer thickness and to oversee salvage operations.

- An experienced soil salvage contractor would be consulted to minimize soil disturbance and mixing of soil layers.

- To minimize loss of soil productivity, salvaged surface soils would be applied concurrently with construction activities where possible. If surface soils need to be stored prior to application they would be stored to minimize sun exposure, increase surface area, and minimize storage depth.

Refer to section 4.9.1 for more information on impacts and mitigation for agricultural land. Given the minor impact on active agricultural land and the implementation of mitigation measures, significant impacts on farmland of local importance would not be expected during Project construction and operation.

Compaction Potential

As discussed in section 4.2.2.4, very poorly drained soils are prone to compaction and structural damage if disturbed due to permanent or frequent saturation at or near the soil surface. Compaction potential would increase during summer construction due to the potential of permafrost thawing, thereby increasing soil saturation. As shown in table 4.2.4-1, about 492 acres of soils associated with Mainline Facilities construction are prone to compaction, but this number does not take into account active layer thawing during the summer and the subsequent increase in compaction prone soils. Therefore, the actual area of compaction-prone soils affected by the Mainline Facilities is likely higher. Construction would occur during the winter for about one-quarter to one-third of the identified 492 acres of impact, allowing permafrost to remain stable, thereby minimizing impacts on compaction-prone soils. During summer construction, the majority of direct impacts would be expected to be temporary to short term since the active layer freeze-and-thaw processes in somewhat poorly drained to poorly drained soils would help to naturally remediate compaction.

Of the identified 492 acres of compaction-prone soils affected by construction, about 74 acres would be permanently affected through Mainline Facilities operation. Operational impacts associated with hydric soils would primarily be associated with the permanent fill of wetlands from the use of granular fill during construction. Sections 4.4.3, 4.4.4, and 4.4.5 include detailed discussions on these impacts and proposed mitigation measures.

Uplift forces associated with buoyancy could occur in areas where the Mainline Pipeline would be in a high ground water table with low density soil above the pipe. As identified in AGDC's Geohazard Mitigation Approach, where there is a high groundwater table with low density soil above the pipe, an engineering analysis would be required to determine the expected buoyant force distribution. This analysis would compare the buoyant uplift force on the pipe to the external forces required to keep the pipeline from floating. In areas where the force resisting flotation is less than 110 percent of the buoyant force, buoyancy control measures would be required. These mitigation measures would be determined based on site-specific conditions and could include pipesacks, bag weights, swamp weights, continuous concrete coating, operational monitoring and maintenance, and pipeline monitoring.

AGDC would implement the measures specified in the Project Plan, Winter and Permafrost Construction Plan, and Revegetation Plan to minimize or avoid potential construction and operational impacts on compaction-prone soils. While Project effects would be minimized, impacts would occur given the large quantity of compaction-prone soils present in the areas associated with the Mainline Facilities. These impacts would not likely be significant.

Post-construction Revegetation

As shown in table 4.2.4-1, about 23,356 acres of soils associated with Mainline Facilities construction have revegetation concerns. The short growing season along the northern portion of the Mainline Pipeline would affect revegetation efforts and could require additional efforts to stabilize the ground before revegetation. To minimize impacts on soils with revegetation concerns, AGDC would implement the measures specified in its Project Plan, Winter and Permafrost Construction Plan, and Revegetation Plan. A summary of AGDC's restoration and revegetation approach is provided in section 4.5.2.

AGDC does not propose additional mitigation measures for areas with low revegetation potential beyond the general measures planned for the Project. If required by a landowner or land management agency, AGDC would apply a slurry mixture of water, fertilizer, seed, mulch, and a tackifier (i.e., adhesive) to disturbed soils. This slurry mixture would be applied by hydroseeding or aerial seeding and would increase the available water-holding capacity of the soil and encourage seed establishment. For granular work pads not needed for Project operation and maintenance, and where landowners would like the land to be revegetated, AGDC would rip the compacted granular material, grade the area to assist with drainage, and scarify to improve the possible establishment of natural revegetation. If the performance standards defined in the FERC-approved Project Revegetation Plan are not met, AGDC would apply corrective actions as needed, such as fertilizing the area and applying seeding, until the performance standard is met.

AGDC stated that the majority of granular work pads associated with Modes 4 and 5A would be left in place following construction. An exception to this would include waterbody approaches where granular fill would be removed up to the ordinary high-water mark. Use of granular work pads during construction would minimize direct impacts on tundra and permafrost, but granular work pads would conduct heat to the underlying permafrost and could cause long-term changes to the surface and subsurface drainage and thermal regimes. When combined with annual temperature variations, these impacts could either extend or shorten the time it takes for conditions to reestablish.

Given the amount of soils with revegetation concerns along the Mainline Facilities and the restoration results of past Alaska pipeline projects, we conclude that permanent impacts would occur.

However, through implementation of measures outlined in the Project plans and adherence to the restoration guidelines in the Revegetation Plan, the impacts would not be significant.

Shallow Bedrock

Given the Project area and landscape, widespread areas of soils with shallow bedrock or permafrost would be encountered during construction. As a result, rock excavation and/or rock blasting during construction activities would be necessary. As outlined in the Project Blasting Plan, about 501.0 miles of the Mainline Pipeline have been identified as potentially needing blasting. The introduction of subsoil rocks into surface soil layers could affect revegetation efforts by reducing soil moisture-holding capacity, thereby reducing soil productivity. To reduce impacts, AGDC would follow measures outlined in the Project Blasting Plan (see section 4.1.4) and the Project Plan, including the following measures.

- The drilling pattern would be designed to effectuate smaller rock fragments (maximum 1-foot diameter) for use as suitable backfill material.
- Rock or permafrost excavated from the trench could be used to backfill the trench only to the top of the existing bedrock or permafrost profile. Except for agricultural and residential areas, excess trench rock could be spoiled on the right-of-way in a manner that does not impede restoration.
- Excess rock would be removed from at least the top 12 inches of soil in all residential areas and other areas at the landowner's request. The size, density, and distribution of rock on the construction work area would be similar to adjacent areas not disturbed by construction. The landowner or land management agency could approve other provisions in writing.
- Specific blasting procedures would be developed and implemented in coordination with the appropriate agencies. These procedures would address advanced public notification, pre- and post-blast inspections, and blasting mitigation measures.
- To support proper design of blasting in permafrost areas, site-specific permafrost information would be collected using conventional methods of geotechnical investigation including:
    - landform mapping to identify geomorphology of permafrost landforms;
    - seismic refraction survey(s) to define soils/overburden thickness and depth of bedrock to determine the need for blasting;
    - direct subsurface investigations including borehole drilling, test pit excavations, and geotechnical trenching to characterize subsurface conditions, and collect samples for laboratory analysis of soil type and ice content; and
    - test blasting (developed based on site-specific conditions) to measure ground accelerations and record deformations and blast sequencing.

Blasting could also be required in certain permafrost terrain conditions where mechanized fracturing and excavating are not suitable. These areas are also included in the totals presented above and in table 4.1.4-1. The blasted trench would be controlled to limit the amount of disturbed materials and would not be anticipated to result in a shift in the soil or permafrost profile. Blasting operations in permafrost would be conducted in the winter, which would dissipate any heating due to blasting or other conventional trenching construction methods. Additional information on resource impacts from blasting can be found in sections 4.3.1.5 (Groundwater Resources), 4.3.2.4 (Freshwater), 4.4.2 (Wetlands), 4.6.1.2 (Terrestrial Wildlife), 4.6.2.3 (Avian Resources), 4.6.3.2 (Marine Mammals), 4.7.1.6 and 4.7.1.7 (Fisheries Resources), 4.8.2.2 (Threatened, Endangered, and Special Status Species), 4.14.2.6 and 4.14.3.2 (Subsistence), and 4.16.3 (Noise).

No impacts on shallow bedrock soils would occur from Project operation. Excavated rock material that is not used as backfill would be considered construction debris and would either be used in other construction areas along the Mainline Pipeline right-of-way (as approved by the land management agency or landowner) or hauled off-site to a permanent disposal area. The excess rock not hauled off-site would be stockpiled on the non-traffic side of the right-of-way and eventually used for soil stabilization, right-of-way recontouring, ditch berm construction, or blended across the construction corridor. Through implementation of the Project Blasting Plan and Revegetation Plan, we find that impacts on soils from blasting would be adequately minimized and no significant impacts would occur.

Sediments

The Mainline Pipeline crosses Cook Inlet for about 27.3 miles where the pipeline would be laid on the seafloor. The pipeline would need to be open cut and buried for about the first 6,600 feet on the Suneva Lake Shore Approach side of the inlet and about 8,800 feet on the opposite Beluga Landing South Shore Approach to ensure the pipe is buried to a depth such that the top of the pipe is protected from major hazards. This depth is expected to be about -35 to -45 feet MLLW. Nearshore trenching for the pipeline would be conducted between April and October to minimize potential impacts from sea ice on trenching activities. Dredging, defined as excavating and removing materials offsite, would not occur for construction of the offshore portion of the Mainline Pipeline. Material would be excavated/trenched, placed to the side of the construction area, and then returned manually or through the natural process of tidal activity. About 207,600 cubic yards of material would need to be removed for the offshore portion of the Suneva Lake Shore Approach, and about 274,940 cubic yards of material would need to be removed for the offshore portion of the Beluga Landing South Shore Approach. No dredging would be necessary to construct or operate the Mainline MOF.

The nearshore trench is expected to backfill naturally and passively over the course of several days due to the high energy environment that exists within Cook Inlet (i.e., strong tides and currents). To comply with 49 CFR 192, the Mainline Pipeline would need to be buried to a depth of 12 feet below MLLW, with a minimum soil cover of 3 feet or covered with concrete or mats. If natural backfilling does not provide adequate cover over the pipe, supplemental manual backfilling with the removed materials would occur to meet PHMSA requirements. Turbidity and sedimentation levels would increase during pipelay trenching and pipeline backfilling. A discussion of construction and operational impacts associated with the shoreline crossings and offshore pipeline, including turbidity, can be found in section 4.3.3.

To evaluate the sediment disturbance that would occur during the pipelay across Cook Inlet, AGDC developed base criteria to be used in calculations. These criteria included: 27.3 miles of pipelay laid at a rate of 2,500 feet per day, 12 acres for offshore pipelay barge, 4 acres for cable anchor drop, and 5,035 acres of cable sweep impacts. Using these criteria, an estimated 5,070 acres of seafloor sediment impacts would occur during offshore pipelay.

4.2.5.3 Liquefaction Facilities

Construction of the Liquefaction Facilities is expected to occur over about 7 years. Impacts on soils due to this construction would occur from clearing and grubbing, overburden soils excavation, foundation construction, aboveground facility construction, and general infrastructure activities. Soils at the LNG Plant are predominantly well drained silts and loams, and the primary construction concern would be soil erosion. None of the soils present at the site have shallow depth to bedrock. As previously discussed, no permafrost soils are present at the site.

As shown in table 4.2.4-1, about 978 acres of soils associated with construction of the Liquefaction Facilities are highly erodible by water and 970 acres are highly erodible by wind. Exposed soils have a higher potential to be eroded by wind and water. Work would be completed in stages at the LNG Plant to limit the surface area of cleared and exposed soils, thereby minimizing potential erosion. AGDC would strip the surface organic layer and stockpile it for reuse on the site, as needed.

As construction progresses on the site, stabilizing surfacing materials (i.e., granular materials, asphalt, and concrete) would be placed as soon as practical to minimize soil exposure and erosion risk. In areas where surfaces remain exposed for extended durations, dust suppressants and/or soil binders would be used to provide protection. Additionally, stable contour grading would be used to minimize soil runoff from the LNG Plant site. During construction, AGDC would follow construction methods outlined in the Project Plan to reduce impacts due to soil erosion and sedimentation. The majority of operational impacts on soils associated with the Liquefaction Facilities would be limited to the conversion of soil to impervious surfaces. Discussions associated with the conversion of land use types can be found in section 4.9.1. Impacts associated with the addition of impervious surfaces regarding groundwater recharge can be found in section 4.3.1.

To minimize impacts on wind-erodible soils, AGDC has developed a Project Fugitive Dust Control Plan that outlines dust control measures to be used as needed during construction and operation of the LNG Plant as discussed above in section 4.2.4.

While none of the soils at the LNG Plant site are classified as compaction prone, construction activities could cause soil compaction. To minimize these potential impacts, AGDC would prepare soil after final grading to facilitate revegetation in undeveloped portions of the LNG Plant. As outlined in the Project Plan, these preparations could include plowing or tilling compacted soils and performing additional measures as needed in severely compacted areas.

For the Marine Terminal MOF construction, dredging would be required. A combination of mechanical and hydraulic cutter head dredging is planned. Dredging would occur from April to October when sea ice levels should not impede dredging operations. Dredging activities, as discussed in sections 2.1.5 and 4.3.3, would cause temporary increases in turbidity and sedimentation in Cook Inlet. AGDC would submit a Project Dredging Plan to the Secretary, for review and written approval of the Director of the OEP, prior to construction.

As discussed in section 4.2.3, copper, nickel, and silver were detected at concentrations exceeding the NOAA SQuiRT TEL values. Arsenic, chromium, nickel, and selenium were detected at concentrations exceeding the ADEC Method 2 Cleanup Levels for migration to groundwater. As the results do not meet the standards identified in the Dredged Material User Manual, upland disposal and beneficial reuse would not be the appropriate disposal method for the dredged sediment material (CH2M Hill, 2016c). AGDC is completing additional sediment characterization sampling to complete its dredging plan. As proposed, either of two offshore dredged material disposal sites would be used for dredged material from the Marine Terminal MOF. These sites are identified as being 230 acres each and, based on the 2018 *Alaska LNG Sediment Modeling Study*, they have enough space to accommodate the anticipated volume of material. Additional information on the offshore dredged material disposal sites can be found in section 4.3.3.

Comments were received during the public scoping period about bluff erosion in the Project area associated with the Liquefaction Facilities. Bluff retreat is an ongoing process with multiple variables in play, including wave erosion, stormwater runoff, sloughing or raveling of vegetation, and mass wasting events. The 2016 *Risk Report for Kenai Peninsula Borough* (FEMA, 2016) estimates average coastal erosion rates from 0.8 foot to 2.2 feet per year along the Kenai to Nikiski coastline, with areas as high as 4.0 to 5.7 feet per year.

In the vicinity of the Liquefaction Facilities, a number of erosion protection structures are in place, including three long piers/seawalls made of steel sheet piles at the base of the bluff stretching across about 1,500 feet of coastline. Additionally, a 250-foot gabion structure is beneath the second pier/seawall. While these structures appear to have slowed the rates of erosion of the top of the bluff, seepage in the gap between the gabion and pier/seawall has caused local erosion. Additionally, storm debris found on the gabion structure indicates that waves have reached an elevation of about 23 feet (North American Vertical Datum of 1988) since installation of the structure.

Based on the Shoreline Protection Requirements Assessment (Jacobs, 2017) of the existing bluff erosion structures, AGDC proposed that the Marine Terminal MOF be constructed using a combi-wall structure from the toe of the bluff extending offshore and tied back to a sheet pile anchor wall that would be buried under the MOF fill. During operation of the Liquefaction Facilities, AGDC has proposed to conduct annual LiDAR surveys to identify significant changes from baseline conditions along the bluffs. The timing of surveys would take into account any significant weather events that could require more frequent surveys. AGDC has identified potential mitigation measures for bluff erosion, including the use of steel sheet piles, armor rock, gabion structures, geocells, geomat, and sand/gravel bags, which would add to the existing structures to help reduce bluff erosion rates. For more information on bluff erosion in the vicinity of the Liquefaction Facilities, see section 4.18.

4.2.6 Soil and Sediment Contamination

Soil contamination could result from at least two sources: areas of pre-existing contamination that are disturbed by construction, or spills of fuel or hazardous materials that occur during construction or operation. AGDC conducted a desktop review to locate existing landfills, mines, and spill/release sites that have the potential for containing contaminants that could be encountered by the Project. Additional information on these sites and impacts and mitigation measures for existing contaminated sites are further discussed in section 4.9.6. Contaminated offshore sediments are discussed in section 4.2.3.

Contamination from spills or leaks of fuels, lubricants, and coolant from construction equipment could adversely affect soils. AGDC has developed a Project SPCC Plan that specifies instructions to minimize the potential for soil contamination from spills or leaks. Facility-specific SPCC Plans would be developed by construction contractors. AGDC and its contractors would use these SPCC Plans to minimize accidental spills of materials that could contaminate soils, and to ensure that inadvertent spills are contained, cleaned up, and disposed of as quickly as possible and in an appropriate manner. AGDC would develop facility/work site-specific SPCC plans prior to construction for the following locations:

- facilities that are non-transportation related;
- facilities that have aggregate aboveground storage capacity greater than 1,320 gallons or a completely buried storage capacity greater than 42,000 gallons; and
- locations that have a reasonable expectation of a discharge into or upon navigable waters of the United States or adjoining shorelines.

These plans would be made available in the field on each construction spread or facility in accordance with 40 CFR 112. Contractors would be required to develop their own site-specific construction and operational SPCC plans that would be subject to FERC and AGDC review and approval.

AGDC has developed a Project Unanticipated Contamination Discovery Plan to provide guidance for ensuring worker safety and preventing the spread of contamination in the event contaminants are found during construction. The plan outlines contamination discovery, initial response procedures, site characterization, and hazard assessment to determine the extent, nature, and disposition of the contamination; proper agency and local official notifications; and recordkeeping procedures. As noted in this plan, the final disposition of contaminated soils would be determined through discussions with the appropriate regulatory agencies and affected landowners. Depending on the extent and characteristics of the identified contamination, the Project would either seek a route adjustment to avoid the contamination or make plans with the appropriate landowner and ADEC for excavating or reducing the contamination with disposal at an approved waste disposal site. AGDC would consult with ADEC and/or the EPA if a site is characterized as hazardous.

In comments on the draft EIS, the State of Alaska noted that given the history of the Prudhoe Bay area, a plan should be in place in case historical contamination is found during dredging. The Project Unanticipated Contamination Discovery Plan provides general procedures for the unanticipated discovery of contamination on land or water. Specific measures that would be taken for the unanticipated discovery of contaminated sediment in a marine water environment (e.g. dredging, screeding, and construction of the Mainline Pipeline across Cook Inlet) have not been provided. Additionally, no Project-specific offshore testing has occurred along the Mainline Pipeline alignment at either side of Cook Inlet and the extent of potential existing sediment contamination is unknown. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, AGDC should file with the Secretary, for the review and written approval of the Director of the OEP, an updated Unanticipated Contamination Discovery Plan that indicates the measures that would be taken in the event that contaminated sediments are discovered in marine water environments, including the appropriate agency notification requirements. Additionally, this plan should be updated to include notification to the NPS in the event of an unanticipated discovery of contamination on NPS property.**

4.2.7 Conclusion

Project construction and operation would result in the permanent disturbance of thousands of acres of soils. With the exception of permafrost, impacts on soil resources associated with construction and operation of the Gas Treatment Facilities, Mainline Facilities, and Liquefaction Facilities would be less than significant with implementation of the mitigation measures described above, AGDC's commitments, and our recommendations. We additionally note that AGDC has agreed to implement two of our recommendations from section 4.2 of the draft EIS (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

Permafrost degradation resulting from trenching and granular fill for the Mainline Facilities would permanently alter hydrology (e.g., by causing subsidence and thermokarst development, solifluction, soil creep, thawed layer detachment, and increased erosion) and vegetation, effects that, in addition to continued permafrost thaw, could spread laterally past the Project footprint. Therefore, we conclude that significant permanent impacts on permafrost soils would occur from construction and operation of the Mainline Facilities, including the permanent use of granular fill.

4.3 WATER RESOURCES

4.3.1 Groundwater Resources

The availability of groundwater in Alaska is influenced by many factors, including average annual precipitation, infiltration through frozen soils, and evapotranspiration. Average annual precipitation in the Project area ranges from about 4 inches of rain and 39 inches of snow in Prudhoe Bay to about 17 inches of rain and 74 inches of snow in Anchorage. In more northern mountainous regions, such as Wiseman in the Brooks Range, annual precipitation was last reported in 2018 as about 12 inches of rain and 58 inches of snow (NOAA, 2018b; The Alaska Climate Research Center, 2018).

As shown on figure 4.3.1-1, the Project would cross three primary hydrologic regions in Alaska; the Arctic, Interior, and South-Central Hydrologic Regions (Callegary et al., 2013). These regions are defined by climatic and topographic characteristics, which influence the presence or absence of permafrost and groundwater availability and quality. The following section describes the characteristics of the aquifers crossed by the Project.

4.3.1.1 Aquifer Characteristics

According to the USGS, an aquifer or aquifer system with a regional expanse and the potential to be a potable water source is considered a principal aquifer (USGS, 2003b). In 2016, unconsolidated sand and gravel aquifers in Alaska were added as principal aquifers in the glacial aquifer system (USGS, 2016a). This system, which extends from Maine to Alaska, is comprised of glacial material deposited by the Laurentide and Cordilleran ice sheets, which extended into North America in a series of advances and retreats of continental glaciers between about 2.5 million and 12,000 years ago. The unconsolidated glacial aquifers may exhibit confined, semi-confined (leaky), and unconfined conditions. Generally, individual private-supply wells that are completed in the alluvial and glacial outwash deposits of the unconsolidated aquifer are between 50 and 200 feet deep and yield an average of 20 gallons per minute (USGS, 1985). In contrast, major supply wells completed in thick glacial outwash and alluvial deposits are between 100 and 400 feet deep and yield an average of 3,000 gallons per minute (USGS, 1985).

The continuous permafrost prevalent in the Arctic Hydrologic Region generally confines the unconsolidated alluvium and colluvium deposits and restricts groundwater movement (Callegary et al., 2013). All of the Gas Treatment Facilities and about 146 miles of the Mainline Facilities would be within the Arctic Hydrologic Region, but no unconsolidated deposit aquifers would be crossed. Groundwater in soils within the active zone above permafrost is unreliable as a water source due to seasonal freezes; lack of connection to deeper, subpermafrost groundwater supplies; and high organic content (Sloan and van Everdingen, 1988; Kane et al., 2012). A local aquifer is present under and adjacent to the Sagavanirktok River within the Brooks Range, and there is one known well north of the Brooks Range at the Toolik Field Station where a filtration system is in place. No untreated potable groundwater resources exist north of the Brooks Range due to high salinity levels and concentrations of total dissolved solids that may exceed 7,000 milligrams per liter (mg/L) (AOGCC, 1986).

Based on the groundwater characteristics in the Arctic Hydrologic Region, including the lack of underground sources of drinking water, aquifer depth between 2,000 and 7,000 feet below ground surface, and high total dissolved solid concentrations, the EPA and AOGCC concluded that there are no freshwater aquifers in the area of the PBU on the North Slope. This area encompasses the Gas Treatment Facilities and first 9.8 miles of the Mainline Facilities (AOGCC, 1986).

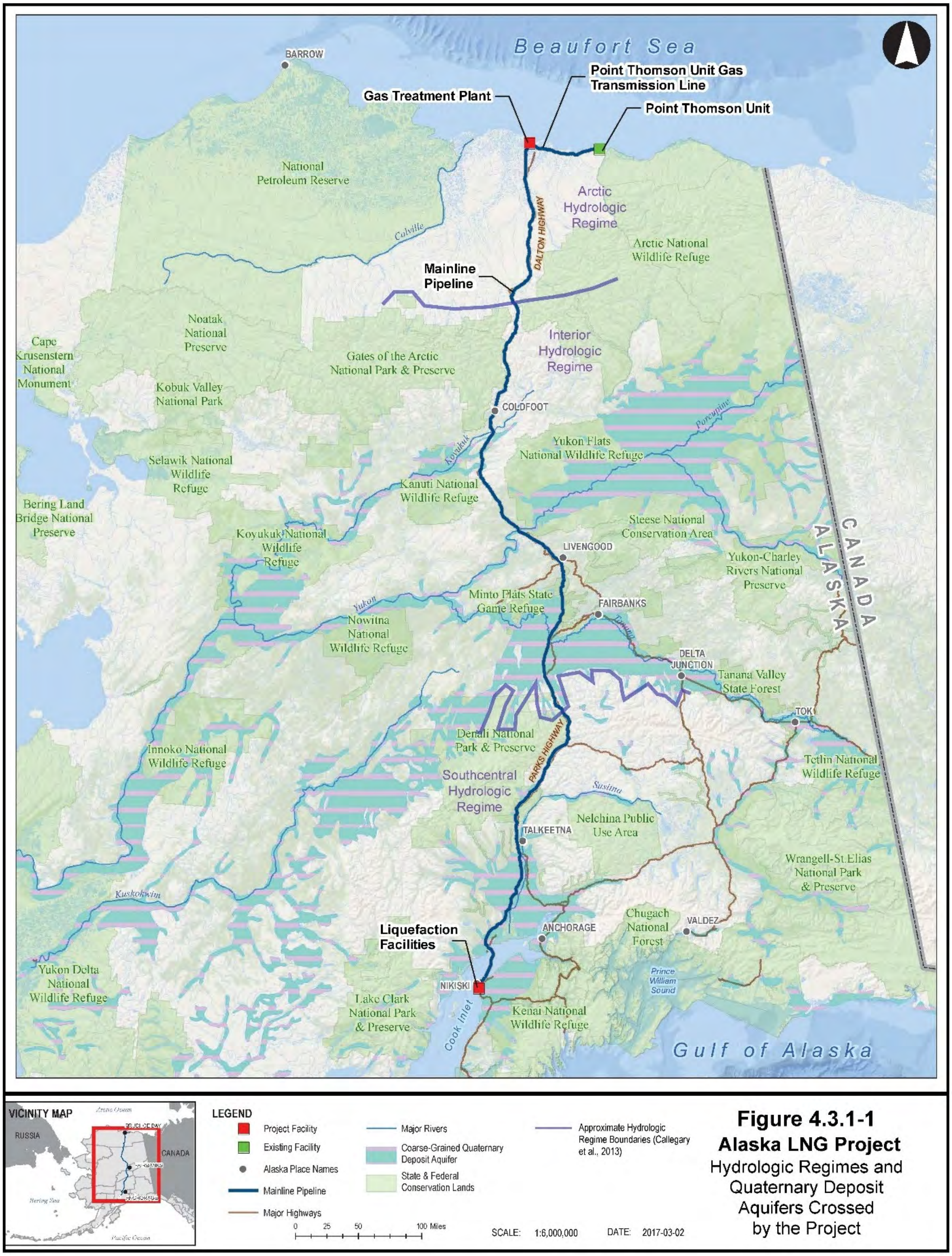


Figure 4.3.1-1
Alaska LNG Project
Hydrologic Regimes and Quaternary Deposit Aquifers Crossed by the Project

The Interior Hydrologic Region, between the Brooks Range and the Alaska Range, is underlain by discontinuous permafrost, the base of which may be between 155 and 265 feet below ground surface (Ferrians, 1965). In permafrost areas, groundwater can exist both above permafrost (suprapermafrost groundwater) and below permafrost (subpermafrost groundwater). Large groundwater yields can be found in suprapermafrost and subpermafrost aquifers (USGS, 1955). South of the Brooks Range, shallow unconsolidated-deposit aquifers are primarily associated with the Tanana River and its tributaries and with river valley deposits that are not associated with large alluvial fans (Miller and Whitehead, 1999). In addition, metamorphic bedrock aquifers are present north of the Tanana River Basin that may yield groundwater in areas where the bedrock is fractured (Miller and Whitehead, 1999). Permafrost and glacial features have been documented in the Alaska Range, but potential aquifers in this area are not well defined (Miller and Whitehead, 1999). In areas of discontinuous permafrost, taliks and thaw bulbs may host groundwater. Taliks are areas of unfrozen ground beneath rivers and lakes that connect water above and below permafrost (van Everdingen, 2005). Thaw bulbs are areas where permafrost has thawed due to a localized heat source, often associated with manmade structures such as buildings or pipelines (van Everdingen, 2005).

As shown in table 4.3.1-1, the Mainline Facilities would cross about 65.2 miles of unconsolidated-deposit aquifers in the Interior Hydrologic Region. In addition to these unconsolidated-deposit aquifers, fractured metamorphic bedrock or carbonate bedrock that contains dissolution cavities in the Brooks Range and Alaska Range may yield limited quantities of groundwater (Miller and Whitehead, 1999).

The South-Central Hydrologic Region is bounded by the Alaska and Chugach-St. Elias mountain ranges to the north. The regional aquifer is characterized by unconsolidated glacially-derived, alluvial, or colluvial clay, silt, sand, gravel, and boulder deposits in low-lying valleys. Due to the variability in grain size and discontinuity of interbedded lenses, the hydraulic characteristics of the regional aquifer are highly variable (Miller and Whitehead, 1999). The unconsolidated aquifer deposits in the South-Central Hydrologic Region supply the public water system (PWS) of many municipalities near the coast, including Anchorage, Seward, Palmer, and Soldotna. The Mainline Facilities would cross about 124.8 miles of unconsolidated-deposit aquifers in the South-Central Hydrologic Region (see table 4.3.1-1 and figure 4.3.1-1). The Liquefaction Facilities would also be in the South-Central Hydrologic Region.

In Cook Inlet, the South-Central Hydrologic Region supports domestic wells (Miller and Whitehead, 1999). The Cook Inlet aquifer system underlies the lowland areas on either shore of the northern part of the inlet along with the lower reaches of the Matanuska and Susitna Rivers. Between 2014 and 2016, AGDC conducted a hydrogeological investigation of the Cook Inlet aquifer system at the LNG Plant site that included the installation of 33 monitoring wells to collect baseline groundwater quality data and delineate aquifers and aquitards. The investigation identified two principal water-bearing formations underlying the LNG Plant. The uppermost unit, referred to as the Killey formation, consists of sand and gravel glacial outwash deposits that overlie the sub-estuarine deposits of the lower Moosehorn formation. The Moosehorn formation is finer-grained with lower permeability than the Killey formation. The hydrogeological investigation found that there is a leaky discontinuous aquitard (semi-confining unit) marked by iron-rich staining at the contact between the Killey and Moosehorn formations. The investigation also found that there is a continuous aquitard within the Moosehorn formation that marks the barrier between the middle and lower aquifer units described below.[32]

[32] The *Summary of LNG Onshore Facilities 2016 Hydrogeology Program* was included as Part 3 of appendix S to Resource Report 2 (Accession No. 20170417-5357), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

TABLE 4.3.1-1

Quaternary Unconsolidated Deposit Aquifers Crossed by the Project

Physiographic Region	Start Milepost	End Milepost	Length of Aquifer Crossed (miles)	Hydrologic Region [a]
Gas Treatment Facilities				
Arctic Coastal Plain	N/A	N/A	N/A	Arctic
Mainline Facilities				
Arctic Coastal Plain	N/A	N/A	N/A	Arctic
Northern Plateaus	263.1	266.2	3.1	Interior
Northern Plateaus	278.6	281.8	3.2	Interior
Northern Plateaus	290.0	294.3	4.3	Interior
Northern Plateaus	354.8	359.5	4.7	Interior
Northern Plateaus	432.7	441.6	8.9	Interior
Western Alaska	456.3	497.3	41.0	Interior
Coastal Trough	629.7	637.6	7.9	South-Central
Coastal Trough	642.2	645.8	3.6	South-Central
Coastal Trough	656.3	670.0	13.7	South-Central
Coastal Trough	674.9	739.9	65.0	South-Central
Coastal Trough	745.4	766.3	20.9	South-Central
Coastal Trough	792.9	806.6	13.7	South-Central
Liquefaction Facilities				
Coastal Trough	N/A	N/A	N/A	South-Central
Total			**190.0**	

Sources: Miller and Whitehead, 1999
N/A = Not applicable
[a] Hydrologic regions from Callegary et al., 2013

There are three discrete glacial aquifers underlying the LNG Plant site and Nikiski area. The uppermost aquifer unit (Unit 1) is unconfined, associated with the Killey formation, and under the influence of surface waters in the area, including Bishop and Beaver Creeks (USGS, 1972). The base of the uppermost unit represents the transition between the Killey and Moosehorn formations and consists of discontinuous lenses of silt and clay (semi-confining unit). Rainwater and snowmelt percolate through the poorly consolidated sediments of the Killey formation until they reach the Killey-Moosehorn transition zone, which ranges in depth from 25 to 50 feet at the LNG Plant. The middle aquifer unit (Unit 2) is semi-confined due to the low permeability silts and clays between the Killey and the Moosehorn formations, while the lower aquifer unit (Unit 3) is confined. Units 2 and 3 primarily receive recharge from upland sources to the east. Based on AGDC’s field investigations, the transitional contact zone between Units 2 and 3 represents the prominent surface present in the Kenai-Nikiski area. The upper and middle aquifer units appear to be hydraulically connected due to the discontinuous, downward leaky aquitard between the aquifers, and water levels measured in wells completed in the different aquifers (see section 4.3.1.2).

Beneath Unit 3 another lower confined aquifer consisting of gravel, silt, sand, and clay is reported to be present within the Moosehorn formation at least 400 feet below ground surface (USGS, 1981). This lower aquifer unit was not encountered during AGDC’s field investigations at the LNG Plant.

4.3.1.2 Groundwater Quality

As discussed in section 4.3.4.1, groundwater in Alaska is used for agriculture and aquaculture as well as commercial, industrial, and domestic purposes (ADEC, 2017b). The groundwater is generally considered to be good quality, although certain areas have naturally high concentrations of iron, arsenic, manganese, and total dissolved solids in the form of calcium or calcium magnesium bicarbonate (hard water). In general, water quality in unconsolidated aquifers south of the Brooks Range includes concentrations of total dissolved solids of less than 400 mg/L; however, the total dissolved solids concentrations in bedrock aquifers are more variable and depend on local bedrock composition and the length of time (residence time) the groundwater is in contact with bedrock (Miller and Whitehead, 1999).

ADEC enforces the Alaska Water Quality Standards (AWQS) criteria, including but not limited to maximum contaminant levels for water supply (including drinking, agriculture, aquaculture, and industrial), water recreation (including both marine and inland waters), and marine aquatic life criteria (ADEC, 2008, 2012b). For drinking water, the AWQS indicate that total dissolved solids may not exceed 500 mg/L, and neither chlorides nor sulfates may exceed 250 mg/L. These water quality standards are used in the development of waterbody recovery goals, wastewater permits, and waterbody monitoring plans and differ from standards used for the regulation of public drinking water.

Groundwater quality data for aquifers in Alaska are limited, and in some locations aquifers have not been identified or characterized (ADEC, 2008). Information that is generally known regarding aquifer water quality where the Project would cross each region, as well as groundwater quality data collected from site-specific investigations for the Project, are summarized below.

Although groundwater exists in the Arctic Hydrologic Region, which is an area of continuous permafrost, available volumes are low and have high concentrations of total dissolved solids which create conditions of moderately saline water (Miller and Whitehead, 1999). Untreated, groundwater is not suitable for use as a drinking water supply in the area of the Gas Treatment Facilities. Lakes are used as primary water sources in areas of continuous permafrost.

As discussed in section 4.3.1.1, due to the presence of continuous permafrost within the Arctic Hydrologic Region north of the Brooks Range, this portion of the Mainline Facilities would not cross an area with groundwater. Although there are no documented potable unconsolidated-deposit aquifers within the Brooks Range, the presence of limestone bedrock in the eastern Brooks Range suggests that groundwater from fractures or solution conduits may occur, but would have a potential hydrogen (pH) greater than 7 (Miller and Whitehead, 1999). The one known well at the Toolik Field Station (north of the Brooks Range) is only potable with use of a filtration system.

South of the Brooks Range, in the Interior Hydrologic Region, where the Project would cross the Tanana River and tributaries, groundwater originates in large alluvial fans associated with the Alaska Range and floodplain alluvium along the Tanana River system. Locally, iron and manganese concentrations exceed the EPA drinking water recommendations and the groundwater is characterized as calcium and magnesium bicarbonate type groundwater (Miller and Whitehead, 1999).

Groundwater in the Cook Inlet aquifer system is influenced by the tides, where a tidal fluctuation of 37 feet may result in a 4-foot water level shift in nearby wells due to pressure changes. Although locally high concentrations of iron, manganese, and arsenic have been encountered in the area, most water quality parameters, including nutrients, pesticides, and VOCs (from industrial and agricultural activities in the Cook Inlet area), do not exceed EPA drinking water recommendations (Glass, 2001). As described in section 4.3.1.1, there are two principal aquifer units in Cook Inlet. In general, the high hydraulic heads for the water-bearing zones prevent saltwater intrusion into the groundwater (Miller and Whitehead, 1999). Several scoping comments expressed concerns about saltwater intrusion, particularly in the Cook Inlet aquifer system. Project operation is unlikely to cause or contribute to saltwater intrusion because regular groundwater withdrawals near Cook Inlet would not be required.

A 2001 study of groundwater quality at the LNG Plant site found that, apart from elevated levels of naturally occurring arsenic, iron, and manganese, water quality parameters that were analyzed (metals, VOCs, total dissolved solids, and pesticides) did not exceed EPA drinking water recommendations (Glass, 2001). To augment this previous study, AGDC conducted a groundwater testing program in 2016 that involved two groundwater sampling events and aquifer pumping tests at seven observation wells installed at the Liquefaction Facilities site. The observation wells were completed in the three aquifer units where the static groundwater level ranged in depth from a minimum of about 15 feet below ground surface in the shallowest unconfined aquifer to a maximum of about 73 feet below ground surface in the deepest aquifer.

The sampling program determined that arsenic concentrations in aquifer Units 2 and 3 exceeded arsenic concentrations found in aquifer Unit 1, and trichloroethene was detected in aquifer Units 2 and 3 but not in aquifer Unit 1. The trichloroethene concentration, the source of which is unknown, exceeded the ADEC table C groundwater cleanup concentration of 0.005 mg/L in two wells screened in aquifer Unit 2 and in the well that was completed in aquifer Unit 3. Concentrations of antimony in groundwater also exceeded regulatory water quality standards. In addition, wells installed in aquifer Unit 2 near the former quarry pit area in the east-central portion of the LNG Plant site detected petroleum hydrocarbons, benzene, and arsenic above groundwater cleanup standards set by the ADEC.

4.3.1.3 Drinking Water Supply Wells and Protection

The SDWA authorizes the EPA to designate sensitive groundwater resources as sole source aquifers (SSA). The EPA defines an SSA as an aquifer that supplies at least 50 percent of the drinking water consumed in the area overlying the aquifer, where contamination of the aquifer could create a significant hazard to public health, and where there are no available alternative water sources that could reasonably serve as a substitute water supply. According to the EPA, there are no SSAs in Alaska (EPA, 2017d).

Under the SDWA, the ADEC Division of Environmental Health has the authority to implement the Drinking Water Program (DWP) for a PWS, but the drinking water protections provided by the SDWA do not apply to private wells that provide water for fewer than 25 people.

Through its Drinking Water Source Protection group, the DWP completes Source Water Assessments for all PWS sources. One primary component of the Source Water Assessment is the delineation of a Drinking Water Protection Area (DWPA) for each PWS source. The DWPA is generally defined as representing the area that contributes water to the PWS source and varies in shape depending on the PWS source type (e.g., well, intake, and spring) and water type (e.g., surface water, groundwater, or groundwater under the direct influence of surface water). DWPAs are classified into zones based on groundwater time of travel or distance from surface water and the immediate contributing tributaries or watershed boundary (see section 4.3.2.2). For PWS sources using groundwater, a Zone A designation is used for DWPAs where several months or less travel time is required for groundwater to reach the PWS source, and Zone B is used for DWPAs where 2 years or less travel time is required for groundwater to reach the PWS source. Provisional DWPAs, which are identified as a circle with a 1,000-foot radius from the PWS source, are used as a temporary placeholder designation until a full delineation can be completed. DWPAs continue to be maintained and delineated by the Drinking Water Source Protection group.[33]

Table 4.3.1-2 provides the names and relative locations of DWPAs for active PWS sources that use groundwater and would be crossed by the Project; the table also provides the DWPA zone classification for the PWS sources. Prior to working within permitted PWS DWP areas, AGDC would notify the appropriate PWS contact.

[33] The PWS source locations and their associated DWPAs can be reviewed using the interactive web map found at http://dec.alaska.gov/das/gis/apps, titled *Alaska DEC Drinking Water Protection Areas*.

TABLE 4.3.1-2

Public Water Systems Crossed by the Mainline Facilities [a]

Facilities	Milepost	Public Water System Name	DWPA Zone Type [b]	Distance to Facilities (feet/direction)
Construction access road	109.5	Alyeska MCCF #2 Camp – PS3 Well PW-3	A	318 / S
Material site	522.6	Denali North Star Inn	A	229 / N
Material site	525.7	McKinley RV & Campground	A	244 / E
Material site	525.7	McKinley RV & Campground	A	246 / E
Material site	525.9	Stampede Lodge	B	322 / E
Material site	526.1	McKinley RV & Campground	B	245 / E
Material site	526.1	McKinley RV & Campground	B	246 / E
Construction access road	528.6	Park Hotel	A	91 / E
Construction right-of-way	536.2	Aramark Lynx Creek Store	A	126 / SW
Construction right-of-way	536.2	Denali Rainbow Village	A	126 / W
Construction right-of-way	536.2	Denali Crows Nest Cabins	A	127 / SW
Construction right-of-way	536.3	Denali Rainbow Lodge	A	120 / W
Construction right-of-way	536.3	Denali Camp	A	115 / W
Construction right-of-way	536.4	Grand Denali Lodge	A	230 / SW
Construction right-of-way	536.6	Grand Denali Lodge	A	245 / SW
Construction right-of-way	536.6	Ford Reeves	A	254 / W
Construction right-of-way	537.0	Lynx Creek Campground	A	267 / SW
Construction right-of-way	547.4	Denali Cabins South / Mile 229	A	38 / SE
Material site	566.1	Denali B SD Cantwell	A	397 / E
Construction access road	663.7	Trapper Creek Pizza Pub	A	120 / W
Construction right-of-way	657.8	Chulitna Campground	A	80 / W
Construction access road	664.0	Trapper Creek Trading Post	B	86 / NW
Double joining yard	709.8	Alaska Trails RV Park	A	383 / N
Double joining yard	709.8	Alaska Trails RV Park	B	383 / N
Double joining yard	709.8	B&J Rainbow Center	B	327 / E
ATWS	764.8	Veco Beluga Lodge	B	488 / SW
ATWS	798.4	Offshore Systems Kenai	A	367 / SE
ATWS	798.4	Offshore Systems Kenai	A	367 / SE
ATWS	805.1	Tesoro Refinery	A	244 / N

Source: ADEC, 2017b

[a] No PWS' would be affected by the Gas Treatment Facilities or Liquefaction Facilities.

[b] Zone A: Travel time to the well is several months or less. Zone B: Travel time to the well is 2 years or less.

Appendix H identifies public water wells within 500 feet and private wells within 150 feet of Project facilities identified to date in the ADNR's Well Log Tracking System (WELTS) (ADNR, 2017h). In accordance with the Project Procedures, AGDC would contact landowners during easement negotiations to identify undocumented water supplies in proximity to Project facilities.

As no potable groundwater sources exist in the Arctic Hydrologic Region near the Gas Treatment Facilities, these facilities would not cross DWPA zones for PWS sources using groundwater. No public wells were identified within 500 feet and no private water wells were identified within 150 feet of the Gas Treatment Facilities.

The Mainline Facilities footprint would be within 500 feet of 20 DWPA zones for PWS sources using groundwater. Of these, 13 are classified as being within Zone A and 7 within Zone B. None of these DWPA zones for PWS sources using groundwater would be crossed by the Mainline Facilities. According to the WELTS database, there are 6 public wells within 500 feet and 27 private water wells within 150 feet of the Mainline Facilities (see appendix H). Of these 33 wells, 16 are within the Mainline Pipeline construction right-of-way or additional work areas. There are 3 wells within the Interior Hydrologic Region and 30 wells in the South-Central Hydrologic Region. Water wells were identified to have the following uses: test or exploratory (2 wells), monitoring or observation (8 wells), commercial (4 wells), domestic (13 wells), and public water supply (6 wells).

The Liquefaction Facilities would not cross any identified DWPA zones for PWS sources using groundwater, but the LNG Plant would be within 500 feet of 6 known public wells and 150 feet of 98 private water wells identified in the WELTS database (see appendix H). Of these wells, 96 are within the LNG Plant site. Water wells were identified to have the following uses: test or exploratory (27 wells), monitoring or observation (30 wells), commercial (7 wells), domestic (31 wells), public water supply (6 wells), and other or abandoned (3 wells).

4.3.1.4 Seeps and Springs

Information available from the ADNR was used to identify known seeps and springs in the vicinity of the Project footprint. No seeps or springs were identified within 150 feet of the Gas Treatment, Mainline, or Liquefaction Facilities based on review of this information.[34] Because previously undocumented springs and seeps could be present near the Project facilities, however, AGDC would conduct field surveys for these features prior to construction where the Mainline Facilities would cross the Interior and South-Central Hydrologic Regions and in the Liquefaction Facilities area (see section 4.3.1.5).

4.3.1.5 Impacts and Mitigation

The potential impacts on groundwater resources during Project construction could result from one or a combination of several different proposed activities, including trenching and dewatering, grading and site preparation, foundation construction, potential drilling fluid release, hazardous material spills, encountering ARD/ML, encountering contaminated soils and/or groundwater, hydrostatic testing discharge, groundwater withdrawal, water well construction, wastewater disposal, underground injection, and blasting. During Project operation, AGDC anticipates using groundwater to support activities at the Liquefaction Facilities and the Mainline Facilities.

Aquifer Characteristics

As described in section 4.3.1.1, there are no subsurface freshwater resources on the North Slope due to the high total dissolved solid concentrations of shallow groundwater and unreliability of the water supply. Therefore, groundwater resources would not be used during construction or operation of the Gas Treatment Facilities. Taliks could be encountered near thermal anomalies such as lakes and rivers along the PTTL and Mainline Facilities. AGDC would minimize potential impacts on shallow groundwater and taliks, which could include contamination due to leaks or excessive thawing of permafrost, by implementing the Project Winter and Permafrost Construction Plan. Impacts on permafrost are discussed in section 4.2.

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[34] The draft EIS identified a spring near MP 537.2 of the Mainline Pipeline. With AGDC's adoption of the Denali Alternative (see section 3.6.2), this spring is now about 2,000 feet from the Mainline Pipeline.

If a talik is encountered during Mainline Facilities or PTTL construction, or a borrow source and talik discharge is ongoing such that dewatering is required, AGDC would implement its BMPs, as described in the Project Procedures and Gravel Sourcing Plan and Reclamation Measures. The Project Gravel Sourcing Plan and Reclamation Measures describes dewatering procedures that could be used where excessive water is encountered for extended periods of time, such as during material site operations. These procedures would include:

- consideration of potential contaminated sites nearby and the likelihood that extended dewatering could cause contaminated plumes to migrate;
- using infiltration trenches or wells to monitor potential drawdown of shallow aquifers; and
- dewatering in such a way as to avoid re-suspension of sediments in receiving waters, and preventing fuels or other contaminants from being incorporated into the dewatering fluid.

Surface drainage and groundwater recharge patterns could be temporarily altered by clearing, grading, trenching, and soil stockpiling activities, potentially causing minor fluctuations in groundwater levels and/or increased turbidity, particularly in shallow surficial aquifers and areas with higher concentrations of fine sediments. The trenching depth for the Mainline Pipeline is anticipated to be about 6 to 8 feet to ensure the minimum 3 feet of cover over the pipeline, but could extend up to 15 feet or more below ground surface. In areas where groundwater (including suprapermafrost groundwater in the active layer) is near the surface and unfrozen, trench excavation could intersect the shallow water table and dewatering or other permanent water control methods could be required. Dewatering of trenches could result in temporary fluctuations in local groundwater levels, but trench water would be discharged into well-vegetated upland areas to allow infiltration or to nearby surface waters in accordance with ADEC requirements. We expect the resulting changes in water levels and/or turbidity in aquifers to be localized and temporary.

AGDC would evaluate the potential to intersect suprapermafrost groundwater prior to construction, which could include the use of methods such as electrical resistivity studies. Suprapermafrost groundwater is not anticipated to be affected during construction in areas using ice work pads. If suprapermafrost groundwater is encountered outside these areas, AGDC would use trench plugs to prevent flows along the trench and dewater in accordance with the Project Procedures.

Trenches would be backfilled immediately following pipeline installation with the same and/or similar material that was excavated from the site (see section 2.2.2). If an unidentified talik is encountered during winter construction and discharges into the trench, AGDC would allow the water to freeze before excavating the material and removing it from the trench. Similarly, grading, site preparation, and foundation construction could intersect the shallow water table and/or cause temporary soil compaction and decreased infiltration. After installation of the Mainline Pipeline, AGDC would restore the ground surface as close as practicable to original contours.

Where AGDC would install the Mainline Pipeline beneath waterbodies using DMT, the inadvertent release of drilling fluid could increase local groundwater turbidity concentrations. To minimize the potential impact on groundwater due to an inadvertent release, AGDC would implement the mitigation measures identified in the Project DMT Plans. Waterbodies crossed by the PTTL and PBTL would use aboveground aerial spans; therefore, inadvertent drilling fluid releases would not occur in waterbodies along these pipelines. Impacts on groundwater quality are discussed in the subsection below.

For the operational Mainline Pipeline to impede groundwater flow, the pipeline would have to encompass an area within the aquifer that extends both vertically and laterally to impermeable barriers (i.e., it would have to seal off the aquifer). Otherwise, groundwater would flow around the pipeline. An aquifer's thickness and lateral extent can vary, but are much greater than the space that would be occupied by the Mainline Pipeline. The physical pipeline would occupy only a small fraction of the aquifer and have limited influence on groundwater flow. As discussed in section 4.2.4, permanent impacts on permafrost would occur as a result of the Project. These impacts could cause permanent alterations to surface and groundwater hydrology. During Project operation, maintenance and repair activities could require minimal ground disturbance, but impacts on groundwater would be expected to be intermittent and minor.

In summary, with the exception of the permanent impacts on permafrost discussed in section 4.2.4, construction and operational activities are not likely to significantly affect aquifer characteristics. The majority of construction and operational activities would involve temporary and localized excavation. Mitigation measures include monitoring groundwater to ensure it does not exceed the aquifer's safe-yield capacity or average annual recharge rates; restoring natural (pre-construction) surface contours and vegetation to the extent practicable; and monitoring groundwater wells, springs, seeps, and nearby streams for water-level drawdown during construction.

Groundwater Quality

Shallow, unconfined aquifers are susceptible to contamination from human activities, including localized point sources such as underground storage tanks, hazardous material spills, and injection wells, or non-point sources that could occur over a larger area, such as saltwater intrusion due to over-pumping near coastal areas and agricultural applications of pesticides and herbicides. For Project facilities that require pile driving, the piles could become conduits for contaminants to affect groundwater. If a pile encounters an aquifer where groundwater contamination already exists, or if a spill of fuel or other hazardous material occurs at the pile, the pile could cause the spread of contamination into or through aquifer units.

AGDC would employ BMPs to minimize the spread of contaminated groundwater into non-contaminated aquifer units. As discussed in section 4.3.1.2, monitoring wells installed in the Liquefaction Facilities area in aquifer Unit 2 near the former quarry pit detected petroleum hydrocarbons, benzene, and arsenic levels above ADEC groundwater cleanup standards. AGDC has stated that no pilings would be placed/driven into Units 1 or 2 and that the majority of piles would be driven to a depth of 50 feet or less. In this area, Unit 1 ranges in depth from 72 to 99 feet below the surface, with Unit 2 deeper than Unit 1. Additionally, AGDC would drive, rather than auger, deep piles to minimize contact between water bearing units separated by natural restrictive layers.

AGDC prepared an SPCC Plan to minimize the risk of a hazardous material spill occurring during Project construction or operation. The SPCC Plan includes:

- a description of key personnel responsibilities;
- guidance for use of surface liners/drip pans for parked vehicles in work areas on the North Slope;
- guidelines for staging and storing equipment and hazardous liquids (i.e., parking equipment overnight at least 100 feet from streams, wetlands, or other waterbodies unless an EI determines, in advance, that there is no reasonable alternative and that steps are taken to prevent spills and provide for prompt cleanup in the event of a spill) and handling of fuel and hazardous liquids;

- specifications for tank farms at construction camps, contractor yards, and other designated fuel depot sites, which include required dimensions of containment berms (i.e., minimum containment volume equal to 110 percent of the largest tank);

- procedures for collection and transport of hazardous wastes from construction; and

- spill response procedures and appropriate notifications.

In addition to the SPCC Plan, to prevent the spread of existing potentially contaminated groundwater, AGDC prepared a Groundwater Monitoring Plan to be implemented where dewatering or discharging water is required within 1,500 feet of a known contaminated site. As discussed in section 4.9.6, there are 123 known or potential sources of contamination within 0.25 mile of the Project, 28 of which are in the Project footprint. Dewatering within 1,500 feet of a known contaminated site would be avoided to the extent practicable; should dewatering within the 1,500-foot buffer be deemed necessary, AGDC would prepare and implement a site-specific Groundwater Monitoring Plan, including site-specific conditions or requirements associated with authorization under the ADEC Statewide Oil and Gas Pipelines General Permit (AKG320000).

The Project Groundwater Monitoring Plan includes temporary and long-term engineering controls that AGDC could employ to prevent the creation of preferential pathways for contaminated groundwater migration. These include keeping extra pumps and tanks on site during construction to remove and store contaminated groundwater, installing groundwater recovery wells, constructing groundwater barriers or cut-off walls along excavations, using low permeability trench plugs, and using synthetic trench liners to isolate backfilled material from surrounding soils. AGDC would further develop the Groundwater Monitoring Plan during Project permitting, construction execution planning, and agency consultations with the ADEC Contaminated Sites Program. AGDC would file a final plan with the Secretary prior to construction.

As discussed in section 4.1.3, AGDC would file their Project-wide ARD/ML Management Plan prior to construction. The plan would identify prevention and mitigation measures specific to areas of high ARD/ML potential, including surface and groundwater monitoring. In response to a comment from the EPA, we are recommending in section 4.1.3.10 that, prior to construction, AGDC should file an ARD/ML Management Plan that also includes details for surface and groundwater monitoring in areas of moderate ARD/ML potential.

Where dewatering occurs, daily visual observations for sheen and/or odor would be conducted. AGDC would initiate pre-construction groundwater sampling within 1,500 feet of a known contaminated site to assess for the presence of contaminants, and groundwater monitoring results would be communicated to the ADEC. If unknown contamination is encountered during construction activities, AGDC would implement its Unanticipated Contamination Discovery Plan, which provides guidance to the contractors and proper notification steps to report undocumented contamination and characterize the site. There is minimal chance of Mainline Pipeline operation contributing to groundwater contamination. Because CH_4 is lighter than air, it would generally dissipate rapidly in the event of a pipeline leak, thereby causing little to no impact on groundwater.

Based on the above discussion, we conclude that potential impacts on groundwater quality would be adequately minimized through implementation of the mitigation measures described above, AGDC's commitments, our recommendations, and compliance with applicable regulatory approvals and requirements.

Active Public Water System Sources Using Groundwater and Private Water Wells

To address and prevent impacts due to construction of the Project on nearby private water wells and springs or active PWS sources using groundwater, AGDC prepared a Water Well Monitoring Plan. According to this plan, AGDC would identify PWS sources within 500 feet of the Project per ADEC APDES permit requirements defined in 18 AAC 80.020(a)(b). AGDC would conduct pre- and post-construction monitoring for active PWS sources using groundwater and private water wells and springs within 150 feet of the Project footprint. The primary parameters selected for monitoring include decreased water yield and impaired water quality, which would involve sampling for total coliform bacteria, nitrates, and arsenic. At landowner request, additional parameters could be tested, including pH, copper, lead, and VOCs. If it is determined that the Project adversely affects a groundwater source, AGDC would consult with the landowner and provide a new temporary or permanent water source, repair the source, or compensate the owner for a new comparable water source. AGDC would file a report with the Secretary within 30 days of construction completion detailing landowner complaints received and how those complaints have been addressed and/or resolved.

We received scoping comments related to concerns about impacts on water wells within or near the Project workspaces. Although many wells have been identified using the ADNR WELTS database, it is our understanding that wells have not been surveyed and that there could be other wells not identified through the database. AGDC would conduct pre-construction private and public well surveys where the Mainline Facilities cross the Interior and South-Central Hydrologic Regions and in the Liquefaction Facilities area, contingent on landowner approval. AGDC would file an updated list of public water wells within 500 feet of the Project (to meet the requests of the ADEC Division of Environmental Health DWP and address public scoping comments) and private water wells and springs within 150 feet of construction workspaces based on survey results.

With implementation of the mitigation measures described above and AGDC's commitments, potential impacts on water wells would be adequately minimized.

Seeps and Springs

While no springs or seeps have been identified to date in the Project footprint, AGDC would conduct a spring/seep survey where the Mainline Facilities would cross the Interior and South-Central Hydrologic Regions and in the Liquefaction Facilities area. If springs or seeps are identified as a result of this survey and/or during Project construction, AGDC would evaluate the crossing of each spring or seep on a case-by-case basis to assess impacts and identify mitigation that may be required.

Potential impacts on springs due to Mainline Pipeline construction could include localized ponding, upwelling, and/or diversion caused by halting or diverting the natural flow path within the Mainline Pipeline right-of-way. Mitigation measures that would minimize impacts on springs include installing a springhead drain that would redirect a spring away from the Mainline Pipeline right-of-way. The springhead would consist of porous material within a geotextile layer that would collect the spring water on the upslope side of the Mainline Pipeline. A trench drain would then transport the water across the right-of-way to the downslope side of the Mainline Pipeline. If the springhead drain system becomes overwhelmed by the volume of spring water, AGDC would implement alternative measures, such as installing small-diameter culverts across the right-of-way or containing and pumping spring water to the downslope side of the Mainline Pipeline. If spring water cannot be diverted from the pipeline trench, AGDC would use dewatering pumps to relocate the water from the trench to the downslope side of the Mainline Pipeline.

As discussed above, AGDC would offer to conduct pre- and post-construction monitoring of private and public springs for quality and yield in the Interior and South-Central Hydrologic Regions and

Liquefaction Facilities area. During Mainline Pipeline operation, springs or seeps near the Project could cause increased erosion of backfill over the pipeline. As described in section 4.2.5, AGDC has developed a Project Pipeline Operation and Maintenance Plan, which includes corrective measures to reduce erosion. Measures would be determined on a site-by-site basis but could include use of compactible nonorganic earth, gravel, or sand to fill gullies and shape the ground to reestablish surface drainage. With implementation of these measures, potential impacts on identified and unidentified springs that are encountered during construction would be adequately minimized.

Blasting

Blasting could temporarily affect well and/or spring yields where water wells or springs are close to the blasting area, and/or increase groundwater turbidity in wells and springs near the construction right-of-way. Rock particles and sediment in well and spring water would be expected to settle out of suspension quickly. In permafrost areas where larger quantities of fine sediments are prevalent, the sedimentation process would take more time.

While AGDC would use non-blasting techniques (e.g., rock ripping equipment) where practicable, they identified several areas along the Mainline Pipeline where blasting could be required (see section 4.1.4). If blasting is necessary, it typically involves a small scale, controlled, rolling detonation procedure resulting in limited ground upheaval. The blasts do not typically result in large, aboveground explosions. Blasting would be conducted in accordance with federal, state, and local regulations. If seeps or springs should be identified in areas that require blasting, AGDC would evaluate them on a case-by-case basis to identify potential impacts and mitigation that would be required and to develop site-specific blasting plans.

For areas that require blasting, AGDC would implement its Project Blasting Plan (see section 4.1.4), which would minimize impacts on groundwater. Per the Blasting Plan, AGDC would obtain the required federal, state, and local permits and would employ licensed blasting contractors to conduct blasting activities in accordance with applicable regulations.

As described in section 4.1.4, AGDC would offer landowners well yield and water quality monitoring for wells within 1,000 feet of Mainline Pipeline trench and material site blasting activities, subject to landowner approval. AGDC provided results of a peak particle velocity analysis for typical trench blasting layouts showing that in wells as close as 65 feet to blasting, well pressure was maintained and cement casing undamaged. Based on these results, impacts on water wells from blasting are not expected to occur. In the event that a construction-related activity does affect the yield or water quality of a well, AGDC would provide a temporary potable water source, and either a new well or a permanent alternate source of water. With the implementation of these measures, we conclude that construction activities would not significantly affect water wells or groundwater users in the Project area.

4.3.2 Freshwater

Freshwater resources crossed by Project facilities include naturally occurring waterbodies such as streams, rivers, lakes, and ponds. Alaska’s water resources are generally considered to be of high quality due to the absence of human disturbance and resulting pollutants. Freshwaters support multiple uses including drinking, culinary, and food processing; agriculture; aquaculture; industry; contact recreation; secondary recreation; and growth and propagation of fish, shellfish, other aquatic life, and wildlife (ADEC, 2018e).

4.3.2.1 Watersheds

A watershed is an area of land that drains surface waters and rainfall to a common outlet such as the outflow of a reservoir, mouth of a bay, or any point along a stream channel (USGS, 2016c). Watersheds in Alaska are delineated by the USGS using a hierarchical system that classifies drainage areas. Hydrologic Unit Code (HUC) is a unique numeric identifier that describes the level of the watershed (i.e., first-level to fourth-level) and geographic location. The Project facilities would occur within 12 third-level watersheds, which are further divided into 22 fourth-level sub-watersheds identified by an 8-digit HUC (HUC8) (see table 4.3.2-1 and figure 4.3.2-1). Marine waters within the Cook Inlet Watershed are discussed in section 4.3.3.2.

Prudhoe Bay and Eastern Arctic Watersheds

The Gas Treatment Facilities and about 168.9 miles of Mainline Facilities would occur within the Prudhoe Bay Watershed which includes the Kuparuk River, Sagavanirktok River, and Mikkelsen Bay Sub-watersheds. About 1.0 mile of the PTTL would also be within the Eastern Arctic Watershed, which includes the Canning River Sub-watershed. The Prudhoe Bay Watershed originates in the Brooks Range mountains and flows north through the foothills across the coastal plain to the Beaufort Sea. Smaller streams within the Eastern Arctic Watershed between the Canning and Shaviovik Rivers originate on the Canning River alluvial fan and are completely within the coastal plain (COE, 2012). Wetlands, rivers, beaded channels, lakes, and tundra ponds dominate the landscape within the Prudhoe Bay and Eastern Arctic Watersheds. The terrain consists of nearly flat and poorly drained low-lying tundra underlain by continuous permafrost that gradually rises to the south with an average gradient of about 10 feet per mile.

Larger streams in the coastal plain have gravel bars and well-defined banks, while smaller streams may flow through grass-lined swales or exhibit poorly defined or beaded channels (COE, 2012). The majority of streams originating in the Eastern Arctic Watershed are not expected to produce large ice floes or ice damming because these streams are typically dry during late fall and early winter when the ice would form. Major rivers such as the Sagavanirktok and Shaviovik East Rivers are expected to sustain winter base flows and have higher potential for ice dams and ice debris during breakup than smaller streams. Fall storm events in the Brooks Range mountains can cause extensive flooding and erosion of the major rivers with headwaters in the mountains, such as the Sagavanirktok River.

Participants in the traditional knowledge workshops on the North Slope indicated that changes in waterbody width and depth, increasing erosion along waterways, and drier wetlands and waterbodies are occurring within the area (Braund, 2016).

Spring snowmelt, or breakup, in this region is the accumulation of extensive areas of standing water and rapid runoff that can occur over a period of a few days due to the limited infiltration of water into the frozen tundra soils. At this time of the year, stream and river main channels are commonly filled with snow and ice, which can reduce the ability of the channel to contain peak flows. Mean annual runoff in this region is lowest near the Beaufort Sea coast and increases somewhat in the foothills of the Brooks Range mountains. The annual runoff peak generally occurs as a result of snowmelt runoff between late May and early June, but late summer and fall rains in August can also produce substantial runoff events. Low flow and freeze up begins as early as late September and continues into January for major rivers and earlier for smaller streams.

TABLE 4.3.2-1

Project Watersheds

Facility	Ecoregion Subregion [a]	Watershed	Sub-watershed (HUC8)	Mileposts Crossed [b]
Gas Treatment Facilities				
GTP	Beaufort Coastal Plain	Prudhoe Bay	Kuparuk River (19060401)	N/A
PBTL	Beaufort Coastal Plain	Prudhoe Bay	Kuparuk River (19060401)	N/A
PTTL	Beaufort Coastal Plain	Eastern Arctic	Canning River (19060501)	PTMP 0.0–1.0
		Prudhoe Bay	Mikkelsen Bay (19060403)	PTMP 1.0–37.0
			Sagavanirktok River (19060402)	PTMP 37.0–56.0
			Kuparuk River (19060401)	PTMP 56.0–62.5
Mainline Facilities				
Mainline Pipeline, aboveground facilities, and additional work areas	Beaufort Coastal Plain Brooks Foothills Brooks Range	Prudhoe Bay	Kuparuk River (19060401)	0.0–20.1 126.4–137.4
			Sagavanirktok River (19060402)	20.1–126.4 138.4–169.9
	Brooks Foothills	Colville River	Lower Colville River (19060304)	137.4–138.4
	Brooks Range	Chandalar-Christian River	Middle Fork-North Fork Chandalar Rivers (19040301)	169.9–177.3
	Brooks Range Kobuk Ridges and Valleys Ray Mountains	Koyukuk River	Upper Koyukuk River (19040601)	177.3–257.8
			South Fork Koyukuk River (19040602)	257.8–303.6
			Kanuti River (19040604)	303.6–315.3
	Ray Mountains	Beaver Creek-Yukon River	Yukon Flats-Yukon River (19040403)	315.3–324.7
			Ramparts-Yukon River (19040404)	324.7–394.0
	Ray Mountains Tanana-Kuskokwim Lowlands Yukon-Tanana Uplands Alaska Range	Tanana River	Tolovana River (19040509)	394.0–466.6
			Lower Tanana River (19040511)	466.6–473.2
			Nenana River (19040508)	473.2–579.6
			Chena River (19040506)	445.2 [c]
	Alaska Range Cook Inlet Basin	Susitna River	Chulitna River (19020502)	579.6–660.9
			Lower Susitna River (19020505)	660.9–720.6 721.9–748.1
			Yentna River (19020504)	720.6–721.9
	Cook Inlet Basin	Knik Arm	Anchorage (19020401)	709.8 [c]
	Cook Inlet Basin	Western Cook Inlet	Redoubt–Trading Bay (19020601)	748.1–767.2
	Cook Inlet Basin	Cook Inlet	Cook Inlet (19020800)	767.2–791.4
	Cook Inlet Basin	Kenai Peninsula	Upper Kenai Peninsula (19020302)	791.4–806.6
Liquefaction Facilities				
LNG Plant	Cook Inlet Basin	Kenai Peninsula	Upper Kenai Peninsula (19020302)	N/A
Marine Terminal	Cook Inlet Basin	Kenai Peninsula	Upper Kenai Peninsula (19020302)	N/A

Sources: Waterbodies based on Project mapping, supplemented by USGS National Hydrography and Watershed Boundary Datasets, aerial photography, and LiDAR.

N/A = Not applicable

[a] Subregions are based on the Unified Ecoregions of Alaska classification system delineated by Nowacki et al. (2001a), as described by the ADF&G (2015a).

[b] Some facilities would cross multiple watersheds within ecoregion subregions. Mileposts are for the Mainline Pipeline centerline unless noted as PTMP for the PTTL. N/A represents a facility where there is no milepost.

[c] Milepost range is not given because these are standalone additional work areas (a pipe coating yard and a double joining yard) within the sub-watershed (HUC8).

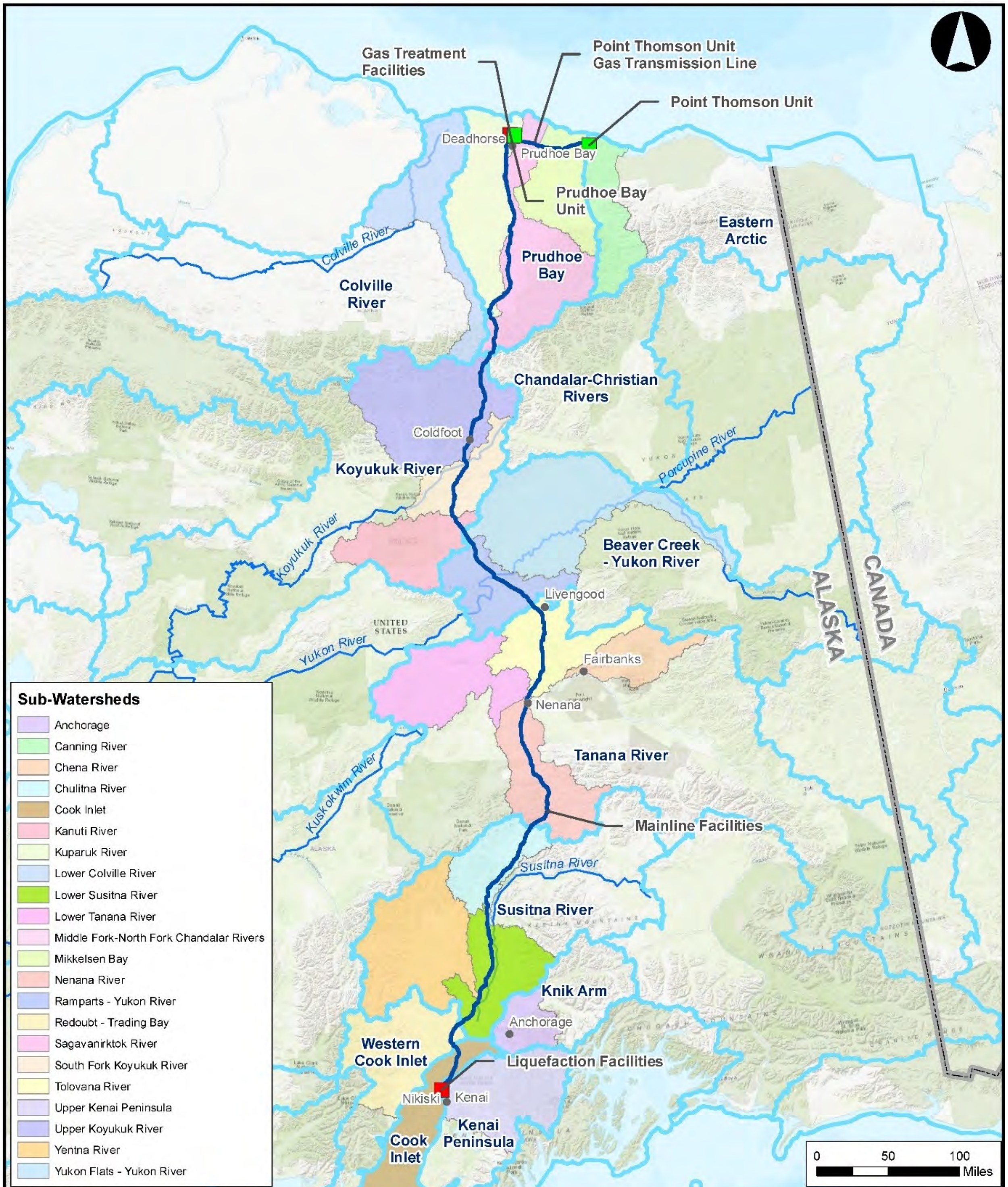

Figure 4.3.2-1
Alaska LNG Project
Watersheds and Sub-watersheds

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Beaded channels (beaded streams) are regularly spaced, deep, elliptical pools connected by narrow runs. The term "beaded stream" refers to the waterbodies' resemblance to "bead on a string" during the summer low flow period (Arp et al., 2014). Beaded streams are regionally unique features in northern Alaska, occurring in both the coastal plain and the Brooks Range foothills. Within the coastal plain, beaded streams can account for half of the drainage density (Arp et al., 2014). Beaded streams are important for connecting and providing seasonally productive migratory fish habitats during spring breakup and prior to freeze-up (Morris, 2003). AGDC identified and documented beaded streams during summer field surveys, but only 7 percent of the route was field surveyed.

Lakes and tundra ponds are abundant but generally too small and shallow to provide significant volumes of water. When frozen, these lakes could be used as a source of ice chips for winter ice road and ice pad construction activities. The natural freshwater resources within and adjacent to the Gas Treatment Facilities are shown on figures 4.3.2-2 and 4.3.2-3.

Near the Project area, flooded gravel mine sites are also a freshwater source. Historically, deep mine sites were developed to provide the gravel material needed for road and pad construction for development. When a gravel mine site was exhausted of materials, it was converted, either naturally or by fabricated diversions, to water reservoirs (Ott et al., 2014). Although many of these flooded gravel mine sites provide habitat for fish, state regulatory agencies allow the water to be used by industry. Flooded gravel mine sites do not completely freeze to the substrate in the winter due to the depths being greater than the naturally formed lakes. Six flooded gravel mine sites are within 10 miles of the Gas Treatment Facilities (see figure 4.3.2-4). Despite year-round water withdrawal, the flooded gravel mine sites typically recharge to full capacity each year during the spring breakup event. Ice chip removal is typically prohibited from these deep-water sources for safety reasons.

Waterbodies with headwaters in the Brooks Range mountains contain coarser streambed sediments consisting of large grain materials such as cobbles and boulders. On the flatter terrain of the coastal plain, much of the stream sediment originates from streambed, bank, and gully erosion of unconsolidated deposits. Tundra vegetation and permafrost in these areas inhibit erosion except near streambanks, where water can thaw the banks and remove material from beneath the vegetative cover. Smaller tributary streams in the foothills and tundra generally contain sediments composed of finer grain materials, such as sand and organic materials. In this region, sediment transport in streams and rivers occurs between May and October. Peak sediment concentrations and discharges generally occur during spring breakup, when the majority of the annual sediment discharge normally occurs.

In the Prudhoe Bay Watershed, the concentration of total suspended solids (TSS) in streams and rivers typically increases from headwaters to mouth. Minimal glacial input to the tributaries of the major rivers occur in this watershed and, consequently, the stream water has high clarity in the Sagavanirktok and Kuparuk Rivers (Rember and Trefy, 2004). A 2002 study of dissolved and suspended matter transported by the Sagavanirktok and Kuparuk Rivers reported that arctic rivers typically transport 40 to 80 percent of the annual volume of water during spring floods in May, June, and July. The Kuparuk River's average concentrations of dissolved metals and dissolved organic carbon (DOC) were higher than the Sagavanirktok River during spring floods, which is related to regional differences in lithology and soil pH (Rember and Trefy, 2004). The Kuparuk and Sagavanirktok Rivers' peak discharge transported more than 80 percent of suspended sediment; more than 33 percent of annual inputs of dissolved copper, iron, lead, zinc, and DOC were discharged to the Beaufort Sea (Rember and Trefy, 2004). Representative water temperatures for the Sagavanirktok and Kuparuk Rivers between early June and early September range from a low of about 35ºF to a high of about 60ºF (USGS, 2015d,f).

Figure 4.3.2-2
Alaska LNG Project
Lakes Within and Adjacent to the GTP

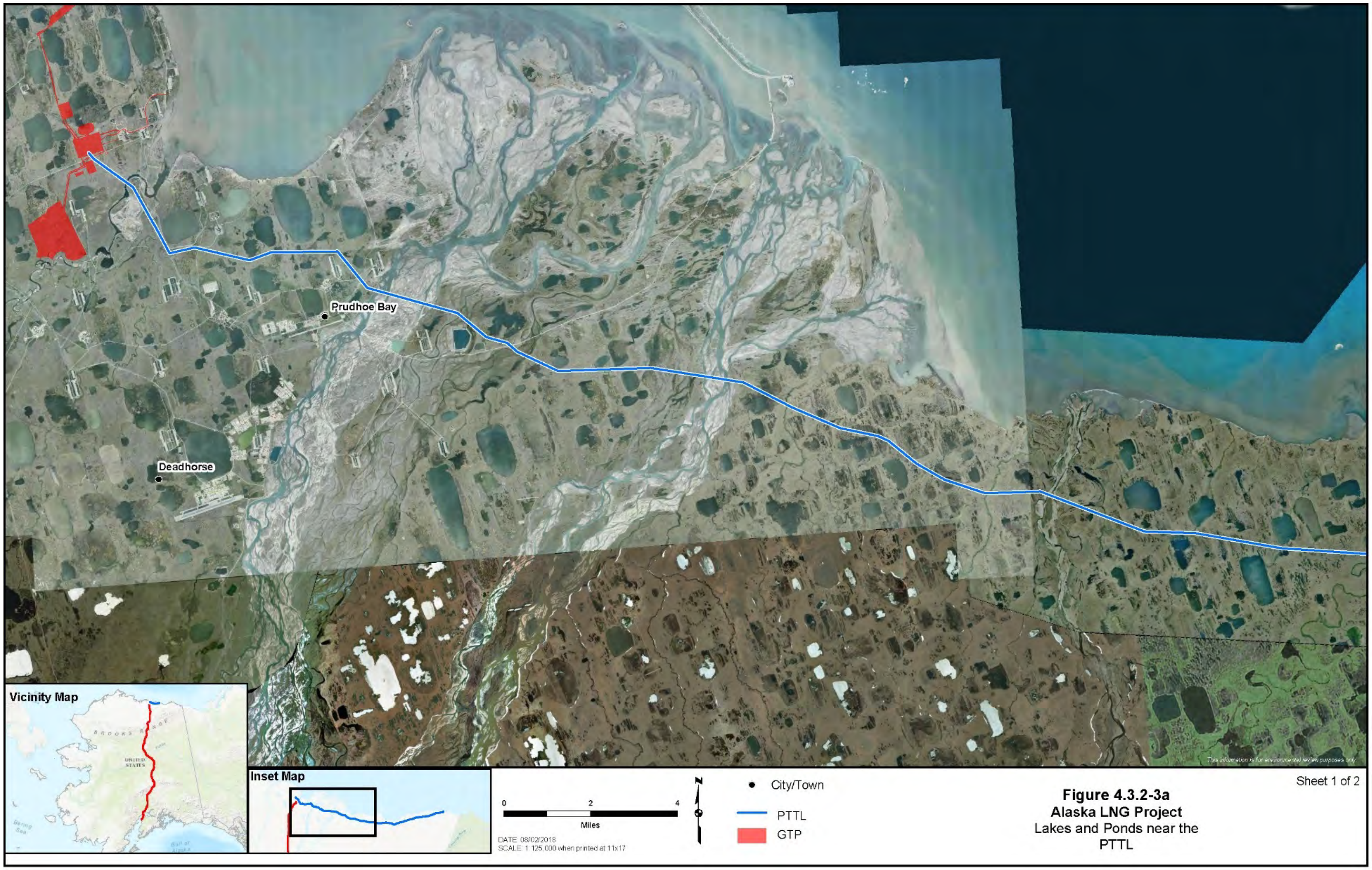


Figure 4.3.2-3a
Alaska LNG Project
Lakes and Ponds near the PTTL

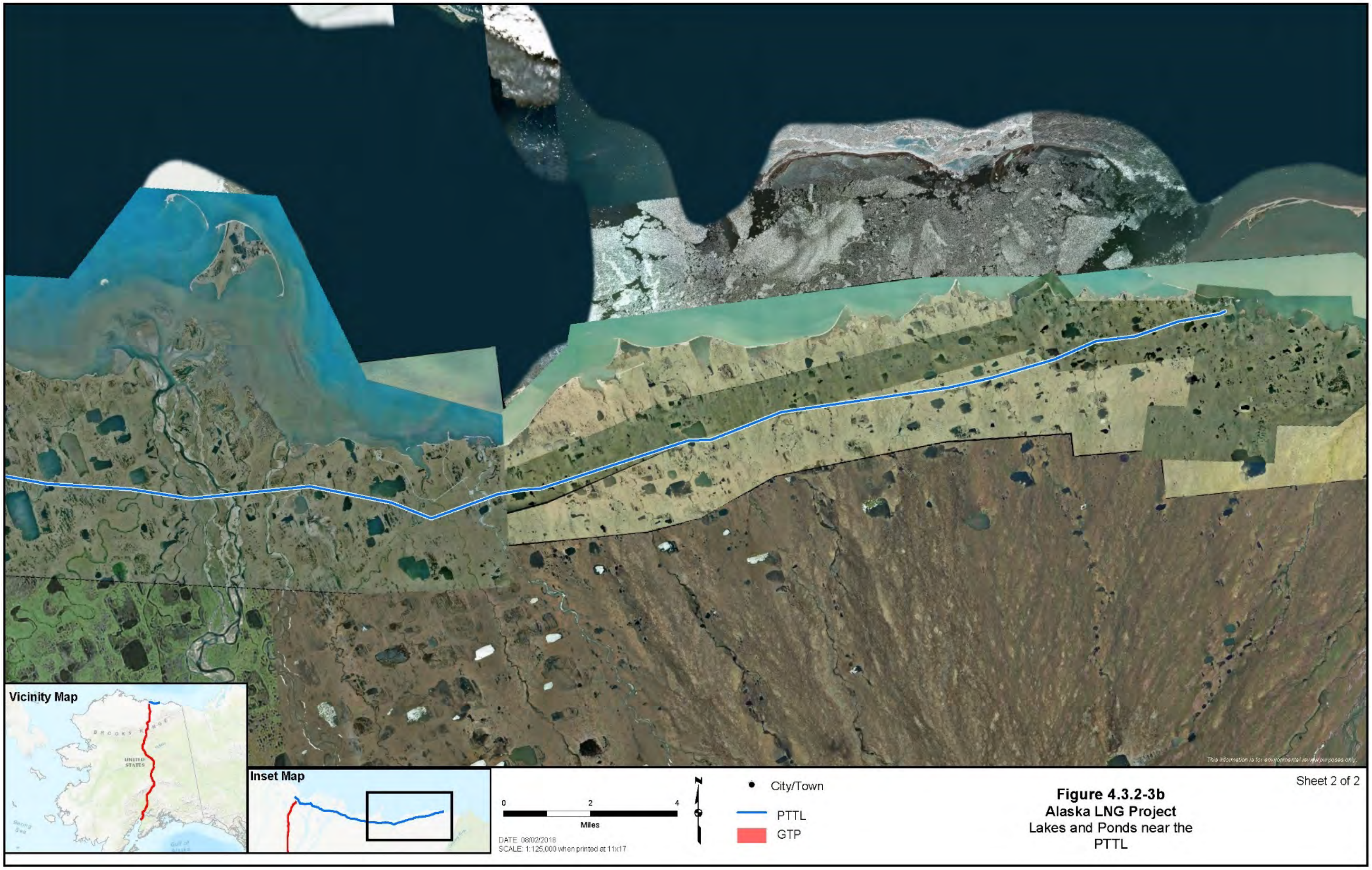


Figure 4.3.2-3b
Alaska LNG Project
Lakes and Ponds near the PTTL

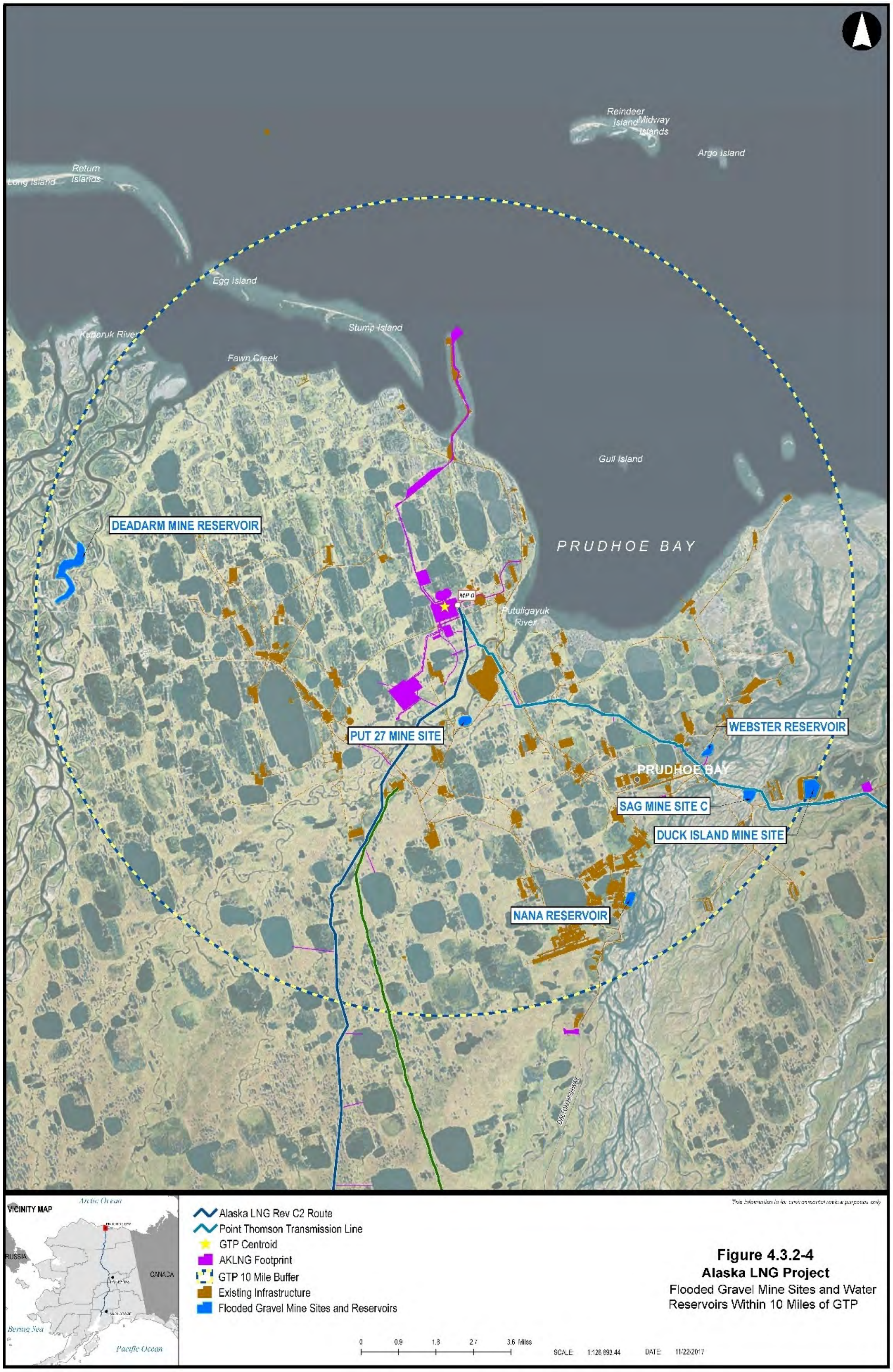


Figure 4.3.2-4
Alaska LNG Project
Flooded Gravel Mine Sites and Water Reservoirs Within 10 Miles of GTP

In the Eastern Arctic Watershed, pH levels in the streams are near neutral to slightly alkaline (COE, 2012). In the winter, dissolved oxygen concentrations in lakes and ponds are high when ice is first formed. As winter progresses, the dissolved oxygen concentrations can decrease due to oxygen requirements for organic matter decomposition that occurs in lake and pond bottom sediments, and for consumption by fish if any are present (COE, 2012). The biochemical oxygen demand of 10 of the 13 waterbodies sampled around the PTTL were undetectable except for waterbodies that were smaller and surrounded by vegetation, which could create higher concentrations of organic material on waterbody sediments. The highest biochemical oxygen demand concentration reported for the sampled waterbodies around the PTTL was 6.2 micrograms per liter (URS, 2002).

Colville River Watershed

About 1.0 mile of the Mainline Pipeline would cross the Lower Colville Sub-watershed in the Colville River Watershed. In the foothills of the Brooks Range east of the Prudhoe Bay Watershed, lakes are less common, river valleys are narrower, and streams generally have a steeper gradient. The landscape of the foothills consists of longer, flat-topped ridges in the northern area and more rugged, isolated hills in the southern area. Within these ridges, hills, and valleys, continuous permafrost soils contain well-drained sand and gravel with occasional exposures of weathered bedrock (Kostohrys et al., 2003). Many of the rivers within the Lower Colville Sub-watershed are within confined channels due to the bedrock substrate.

Spring floods in May, June, and July are responsible for the majority (40 to 80 percent) of the annual discharge in the Lower Colville Sub-watershed. Concentrations of dissolved copper, lead, zinc, iron, and DOC increase 30 to 250 percent at peak discharge, which is related to regional differences in lithology and soil pH (Rember and Trefy, 2004).

Chandalar-Christian River and Koyukuk River Watersheds

The Mainline Facilities would cross the Chandalar-Christian River and Koyukuk River Watersheds by about 7.4 miles and 138.0 miles, respectively. The Mainline Facilities would also cross the Middle Fork-North Fork Chandalar River, Upper Koyukuk River, South Fork Koyukuk River, and Kanuti River Sub-watersheds. The landscapes within these watersheds include rugged snow-capped mountains to lower sloped mountains and narrow ravines with steep headwalls to broad u-shaped valleys (Nowacki et al., 2001a). Permafrost is contiguous in the northern portion of the watershed and discontinuous in the southern portion. Within the Brooks Range mountains, soils consist of well-drained sand and gravel. South of the Brooks Range mountains, the soils in broad valleys contain alluvial and glacial sediments while ridges are covered with rubble.

Peak runoff is the result of spring snowmelt and precipitation during the summer. The rivers in this region are virtually inactive from October to April. Although seasonality changes are typical of large rivers, this phenomenon is especially pronounced in these rivers because they are frozen during the winter.

Streams within the Koyukuk River Watershed commonly carry minimal settleable (non-colloidal) solids. Glacial input to stream flows is minimal; therefore, water clarity during periods of non-peak flows is high. Non-glacier-fed tributaries have beds composed of sand, pebbles, and cobbles; coarser materials, such as cobbles, are found in the upper reaches of streams within the watershed, while the finer materials are found in the lower reaches of the larger rivers and streams. Water currents progressively sort and round bed material downstream. The bed material consists of cobbles in the main channel and sand on the bars. Concentrations of dissolved solids range from less than 50 to nearly 200 mg/L in major rivers such as the Koyukuk. Streams discharge more than 95 percent of the suspended sediment load during the months of May through September (USGS, 2001a).

Beaver Creek-Yukon River Watershed

The Mainline Facilities would cross about 78.7 miles of the Beaver Creek-Yukon River Watershed in the Yukon Flats and Rampart Sub-watersheds. The terrain within this watershed consists of mountainous and flat areas. The Yukon River is the major river within the watershed and is largely underlain by permafrost (O'Donnell et al., 2010). From October through late April, runoff is generally minimal and streamflow gradually decreases as the temperatures drop substantially below freezing. The greatest volume of runoff typically occurs between May and September as a result of snowmelt. River levels generally decrease after snowmelt and then rise again in response to seasonal rainfall and glacial melt.

Participants at traditional knowledge workshops in the Yukon River area noted that although rivers in the area change naturally from year to year, they have noticed long-term changes in the watershed. Several respondents noted that increased siltation and erosion have affected depth and clarity along local river drainages. This in turn has hindered residents' ability to travel to subsistence use areas and other communities (Braund, 2016).

The dissolved solids content of streams in the region south of the Brooks Range mountains averages less than 200 mg/L (USGS, 2001a). Smaller streams, with their meandering courses, lower gradients, and tributaries that drain wetland areas and organic soils, contribute tea-colored water to some watersheds. The Yukon River's main channel is a very large, turbid river with water quality that varies between summer and winter, with the highest flows and turbidity from suspended sediment occurring during the summer (USGS, 2001a).

The Yukon River transports about 60 million tons of suspended sediment annually into the Bering Sea. Measured suspended sediment concentrations for the main channel of the Yukon River averaged about 365 mg/L (USGS, 2015g). Sediment particles carried in suspension in the Yukon River are finer than 0.5 millimeter and 90 percent of the suspended sand is finer than 0.25 millimeter (USGS, 2000). Streams that are tributaries to the Yukon River in this portion of the watershed commonly carry less than 100 mg/L of suspended sediment. Yukon River Watershed streams near the more mountainous borders may carry sediment loads of up to 500 mg/L (USGS, 2001a).

Tanana River Watershed

The Mainline Facilities would cross about 185.6 miles of the Tanana River Watershed. Within the this watershed, the Mainline Facilities would cross the Tolovana River, Lower Tanana River, Nenana River, and Chena River Sub-watersheds. The terrain of the watershed ranges from flat in areas such as the Minto Flats SGR to mountainous within the Alaska Range. The Tanana River Watershed is underlain by discontinuous permafrost and covered by mountainous glacierized regions, forests, and wetlands (Wada et al., 2018). Rivers within flatter portions of this watershed can be slow flowing and meandering (Burkholder and Bernard, 1994). Discharge levels within the Tanana River Watershed vary, as similarly discussed for the Beaver Creek-Yukon River Watershed.

According to participants at traditional knowledge workshops in the Tanana River area, the rivers in the Minto Flats SGR occasionally dry up, become over-run with vegetation, or become blocked by logjams. Logjams can specifically occur in the Tolovana River and Little Goldstream Creek (Braund, 2016).

Waterbodies within the Tanana River Watershed have a high suspended sediment load, but the non-glacial tributaries from the north carry lower amounts of sediment. Within the watershed, freshwater resources generally contain between 60 and 500 mg/L of dissolved solids, with most waterbodies having less than 200 mg/L (USGS, 1970a). For example, dissolved solid concentrations in the Tanana River near

Tanacross averaged between 109 and 214 mg/L, between 72 and 152 mg/L in the Chena River near Fairbanks, and between 105 and 219 mg/L in the Nenana River near Healy (USGS, 1970a). Logging, mining, increased land development, U.S. Department of Defense (DOD) sites, and contaminated sites in the Fairbanks area contribute to decreased water quality and sedimentation in the watershed (USGS, 2000).

Susitna River Watershed

About 168.5 miles of the Mainline Facilities would occur within the Chulitna River, Yentna River, and Lower Susitna River Sub-watersheds, which all lie within the larger Susitna River Watershed. In this watershed, the Talkeetna Range and Alaska Range mountains dominate above wide valley lowlands. Tributaries in the watershed include silty glacial rivers and non-glacial clear water tributaries. Rivers such as the Yentna River are wide and turbid with discharge levels that fluctuate in response to rainfall (ADF&G, 2018m). The lower portions of the Susitna River Watershed are low-lying, low-gradient areas that moderate the influence of mountainous terrain (DOT, 2011; COE, 2018a).

Discharge rates are low during the winter for both glacial and non-glacial fed streams due to ice formation. Discharge declines in non-glacial streams during the warm summer months compared to glacial fed streams because of the continuous melting of snow and ice upstream. The unit discharge for streams in watersheds with glacial ice coverage is generally larger than for streams in watersheds without glacial ice (USGS, 2001b). Streams that occur within the Susitna River Watershed are classified as either glacial or non-glacial streams. Glacial streams have high turbidity from fine sediment during the meltwater season from May through September, but are typically lower in turbidity during winter months. Streams in this watershed are either completely frozen or generally remain frozen during the winter. The Susitna River is generally silty and becomes more silt laden with rain or snowmelt or when the river runs high during breakup (Braund, 2016). Non-glacial fed streams are characterized by having lower turbidity and higher water temperatures than glacial fed streams, particularly during the summer meltwater periods.

Knik Arm Watershed

AGDC plans to place one Mainline additional work area, a double joining yard, within the Knik Arm Watershed. The Knik Arm Watershed includes the Knik Arm; the Knik, Matanuska, Susitna, Eagle, and Eklutna Rivers; and numerous smaller creeks and tributaries. The Knik, Matanuska, and Susitna Rivers provide the majority of the fresh water entering Upper Cook Inlet during spring, summer, and fall (MSB, 1983). These glacier-fed rivers originate in the surrounding mountains. The flat, low-lying terrain around Knik Arm contains abundant lakes, streams, and wetland areas. The highest flow rates within this watershed occur from May through September due to rainfall and peak glacier and snow melt.

The discharge for freshwater streams typically exceeds the monthly average in the Knik Arm Watershed between May through September when rainfall, glacier melt, and snowmelt are at a maximum. As temperatures decrease in October and precipitation turns to snow, glacier melt and snowmelt decrease. Lowest flows typically occur in February and March. Most streams have clear water and do not carry a high silt load. The Knik and Matanuska Rivers contribute the largest suspended load to Knik Arm, with average summer sediment loads estimated at 6.5 million and 5.5 million tons, respectively (Knik Arm Bridge and Toll Authority, 2006). Near population centers water quality in freshwater resources may not meet water quality standards (e.g., impaired waterbodies), but streams and lakes south of Knik Arm (outside population centers) have good water quality.

Western Cook Inlet Watershed

About 19.1 miles of the Mainline Facilities would occur within the Redoubt-Trading Bay Sub-watershed, which lies within the larger Western Cook Inlet Watershed. This watershed consists of mountains of the Alaska and Aleutian Ranges that drain to rolling hills and glaciated flat areas dominated by wetlands and streams (ADNR, 2001b). The drainages are generally short and steep in the mountains and braided and meandering in the flat areas (USGS, 1999). Peak flooding occurs in August and September due to heavy precipitation (Nature Conservancy of Alaska, 2003). Within the headwaters of the watershed is Mount Spurr, an active volcano where past eruptions have caused glacial melt and downstream flooding.

The Western Cook Inlet Watershed contributes about 22 percent of the total discharge to Cook Inlet due to its many glaciers and high precipitation (USGS, 1999). Concentrations of suspended sediment vary (less than 10 to 1,000 mg/L) based on the presence of glaciers that contribute sediment, lakes that act as sediment traps, and flow conditions. The majority of sediment is transported during the high runoff period from May through September (USGS, 1999).

Kenai Peninsula Watershed

About 15.5 miles of the Mainline Facilities, as well as the Liquefaction Facilities, occur within the Upper Kenai Peninsula Sub-watershed, which lies within the larger Kenai Peninsula Watershed. This watershed includes glaciated lowlands created by outwash plains from the Kenai Mountains (USGS, 1999). The area is generally free from permafrost. Freshwaters within the Kenai Peninsula Watershed consist of glacial and non-glacial streams and numerous ponds and lakes. Snowmelt and rainfall often cause the isolated lakes and ponds to combine through surface water flow. Figure 4.3.2-5 shows lakes within and adjacent to the footprint of the Liquefaction Facilities.

Peak discharge for glacial streams occurs in the beginning of summer (mid-June) with high flows sustained throughout most of the summer due to glacier ice melt. Non-glacial streams have highest flows in the beginning of summer as well, but high flows are the result of snowmelt and rainfall events. In general, water quality in the watershed is good, with the exception of localized areas or seasonal periods where high concentrations of iron, silica, color, and dissolved organic material may be present (DOI, 2003b; Kenai Peninsula Fish Habitat Partnership, 2008). Most of the water contains calcium magnesium bicarbonate and is generally low in dissolved solids, chloride, and hardness. Most surface waters meet known drinking water standards except for iron and color (Kenai Peninsula Fish Habitat Partnership, 2008). Contaminants have been discovered in all major cities, communities, and rural areas in the Kenai Peninsula associated with petrochemical production, refining, or storage where oil and gas activities have taken place (Kenai Peninsula Fish Habitat Partnership, 2008).

Participants in the traditional knowledge workshops in the Kenai Peninsula expressed concern over water quality in the area and attributed it to pollution, contamination from development projects, small-scale oil spills, natural disasters, and climate change (Braund, 2016).

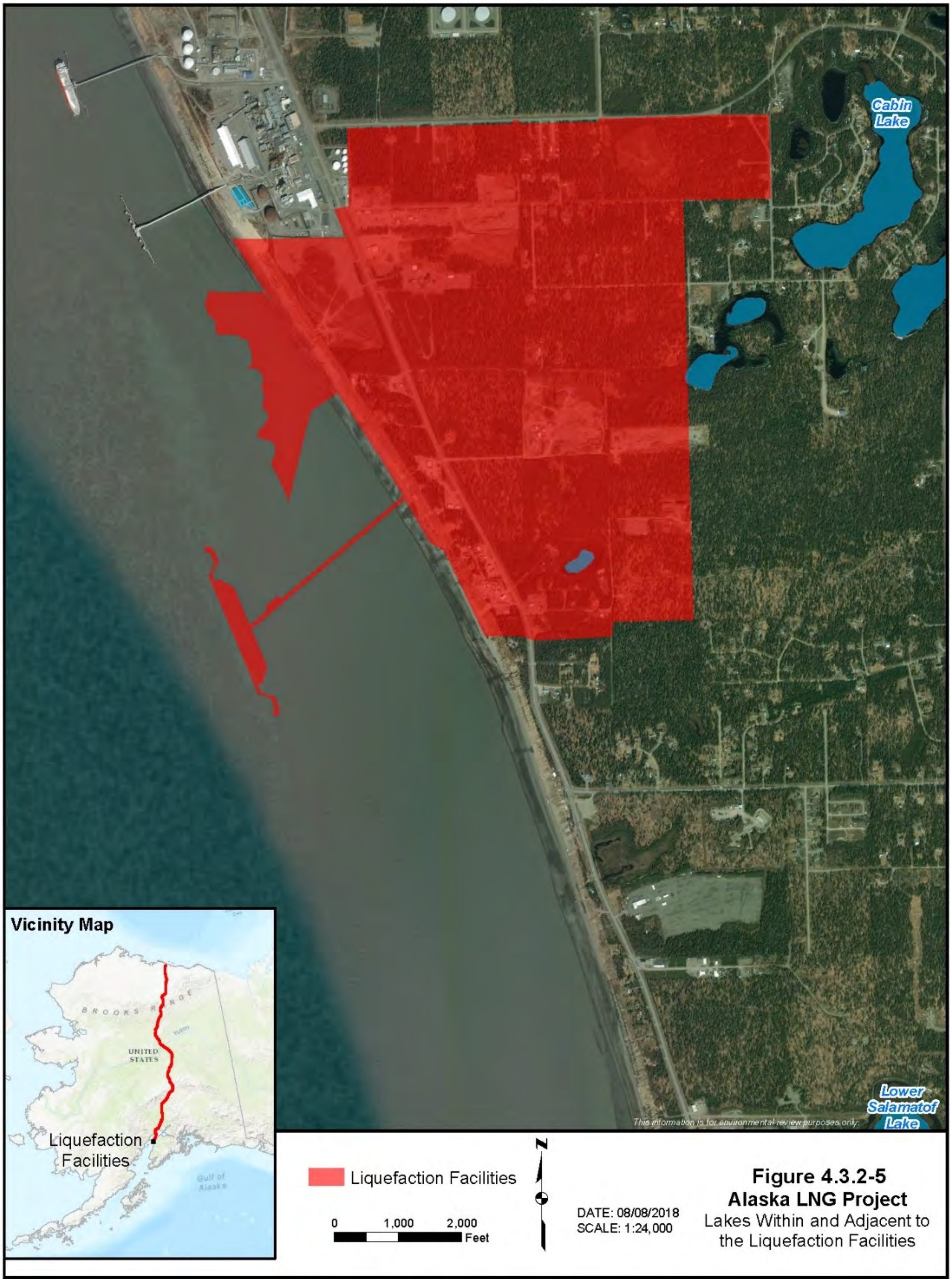


Figure 4.3.2-5
Alaska LNG Project
Lakes Within and Adjacent to the Liquefaction Facilities

4.3.2.2 Water Quality

Sections 305(b) and 303(d) of the CWA mandate that states develop programs to monitor and report on the quality of their waters. The resulting *Integrated Water Quality Monitoring and Assessment Report* (Integrated Report) is a comprehensive statewide evaluation of water quality. ADEC published the ADEC 2014/2016 Integrated Report in 2018 (ADEC, 2018d), which assigned waterbodies to five categories. Only three categories (1, 2, and 3) are relevant to the freshwater resources crossed by the Project, as listed below.

- Category 1: AWQS for all designated uses are attained.
- Category 2: AWQS for some criteria are attained, but there is insufficient data and information to determine if the AWQS for the remaining criteria are attained.
- Category 3: Data or information is insufficient to determine whether the AWQS for any designated uses are attained. These waterbodies have been added to this category because they have been nominated for assessment for suspected pollution or for impairment. These waterbodies undergo an inter-agency review process to determine what future actions are necessary (e.g., at risk and needing recovery, protect and maintain, or adequately protected.)

ADEC sets the AWQS to ensure that existing water uses and the level of water quality necessary to protect existing uses are maintained and protected. If a waterbody is not classified in one of the other categories, it is assumed to be a Category 1 waterbody. The ADEC 2014/2016 Integrated Report states that the majority of Alaskan waters are not subject to human-caused stressors and are classified as Category 1 waterbodies. The AWQS specify the degree of degradation that may not be exceeded in a waterbody as a result of human actions. Project facilities would cross two Category 2 waterbodies (Chatanika River and Cook Inlet) and three Category 3 waterbodies (Kuparuk River, Deshka River, Sagavanirktok River [West Channel, Main Channel, and West Anabranch crossings]). Project activities would affect the water quality of these waterbodies, as discussed in sections 4.3.2.4 and 4.3.2.5. The Project would not likely change the status of these waterbodies because the crossing construction measures (e.g., winter, DMT, and aerial crossings) would minimize effects on water quality.

Section 303(d) of the CWA also requires states to develop lists of impaired waterbodies that do not meet water quality standards. There are no waterbodies within the Project area identified as impaired waters on the Section 303(d) list.

The DWP analyzes surface water resources to identify PWS sources and associated DWPAs. Active PWS sources that use groundwater and have protections within the Project area are described in section 4.3.1.3. Figures 4.3.2-6 through 4.3.2-8 show active PWS sources that use surface water and have associated Zone A and Zone B DWPAs, where zones are categorized by distance from the drinking water source. Zone A identifies a distance of 1,000 feet or less from the edge of the contributing surface waterbody and its immediate tributaries, while Zone B identifies a distance of 1 mile or less (ADEC, 2017a, 2018a). Portions of the Mainline Pipeline, a material site, an access road, a pipe storage yard, and a camp are within Zone B. Portions of the PTTL, two additional material sites, and an access road are within both Zones A and B. AGDC would notify the PWS contacts prior to Project activities within these DWPAs for active PWS sources. The DWP would review and comment on AGDC's permit applications to various federal, state, and local agencies for activities that could affect active PWS sources (ADEC, 2019b).

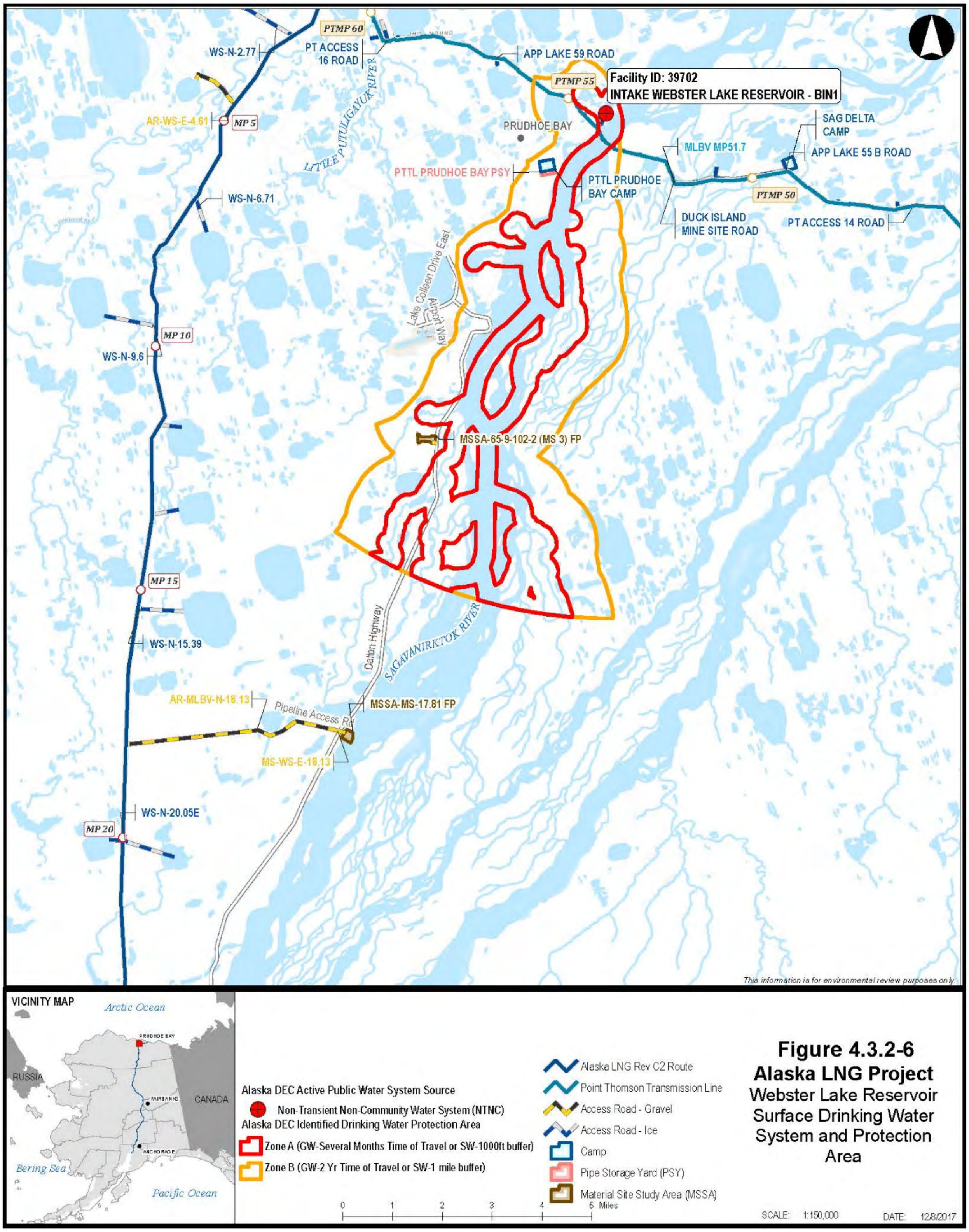
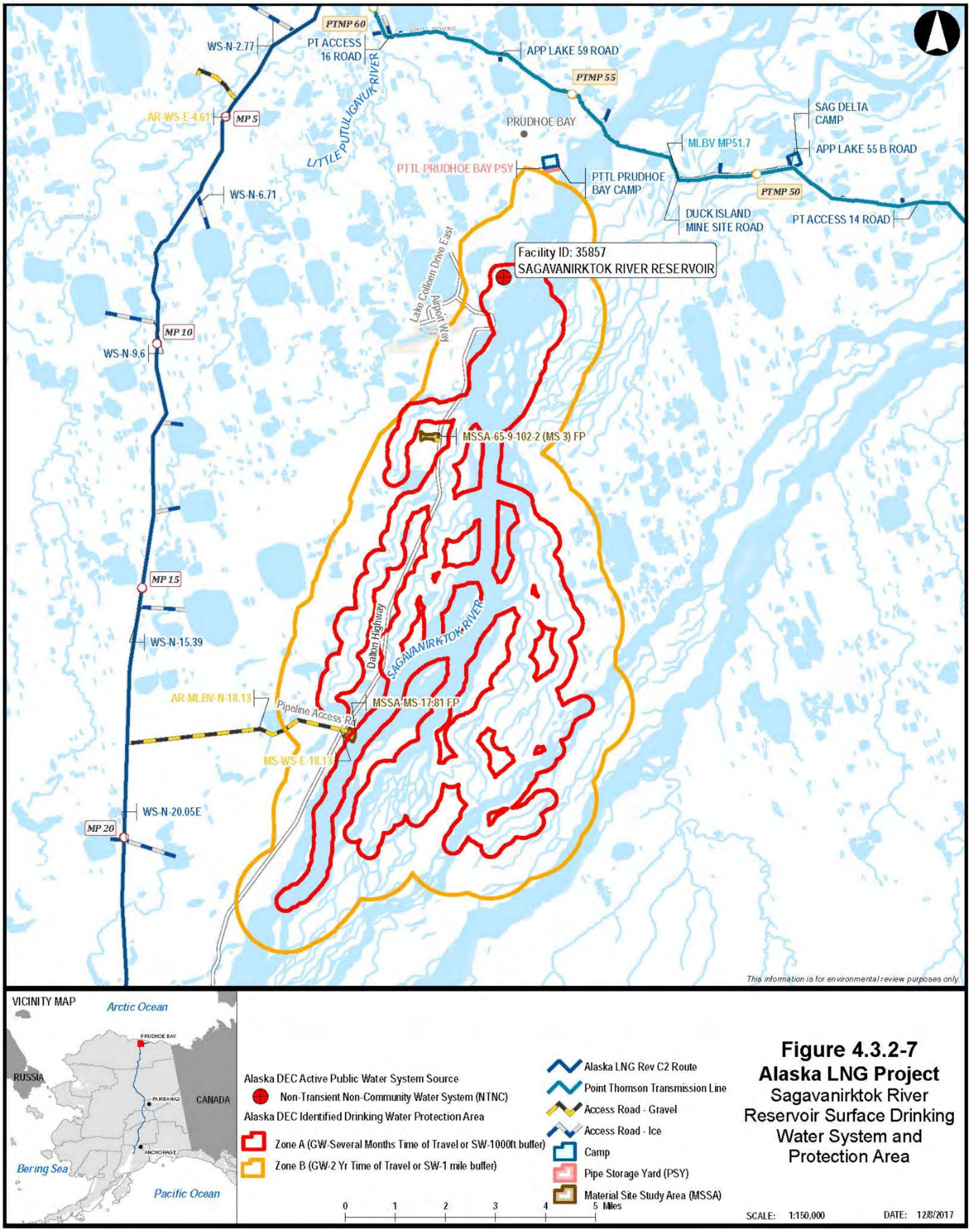


Figure 4.3.2-6
Alaska LNG Project
Webster Lake Reservoir Surface Drinking Water System and Protection Area



WS-N-2.77
PTMP 60
PT ACCESS 16 ROAD
APP LAKE 59 ROAD
PTMP 55
AR-WS-E-4.61
MP 5
LITTLE PUTULIGAYUK RIVER
PRUDHOE BAY
SAG DELTA CAMP
MLBV MP51.7
APP LAKE 55 B ROAD
PTTL PRUDHOE BAY PSY
PTTL PRUDHOE BAY CAMP
PTMP 50
WS-N-6.71
DUCK ISLAND MINE SITE ROAD
PT ACCESS 14 ROAD
Facility ID: 35857
SAGAVANIRKTOK RIVER RESERVOIR
Lake Colleen Drive East
Airport Way
MP 10
WS-N-9.6
MSSA-65-9-102-2 (MS 3) FP
MP 15
Dalton Highway
SAGAVANIRKTOK RIVER
WS-N-15.39
AR-MLBV-N-18.13
Pipeline Access Rd
MSSA-MS-17.81 FP
MS-WS-E-18.13
WS-N-20.05E
MP 20
This information is for environmental review purposes only.
VICINITY MAP
Arctic Ocean
RUSSIA
CANADA
PRUDHOE BAY
FAIRBANKS
ANCHORAGE
Bering Sea
Pacific Ocean
Alaska DEC Active Public Water System Source
Non-Transient Non-Community Water System (NTNC)
Alaska DEC Identified Drinking Water Protection Area
Zone A (GW-Several Months Time of Travel or SW-1000ft buffer)
Zone B (GW-2 Yr Time of Travel or SW-1 mile buffer)
Alaska LNG Rev C2 Route
Point Thomson Transmission Line
Access Road - Gravel
Access Road - Ice
Camp
Pipe Storage Yard (PSY)
Material Site Study Area (MSSA)
0 1 2 3 4 5 Miles
Figure 4.3.2-7
Alaska LNG Project
Sagavanirktok River Reservoir Surface Drinking Water System and Protection Area
SCALE: 1:150,000
DATE: 12/8/2017

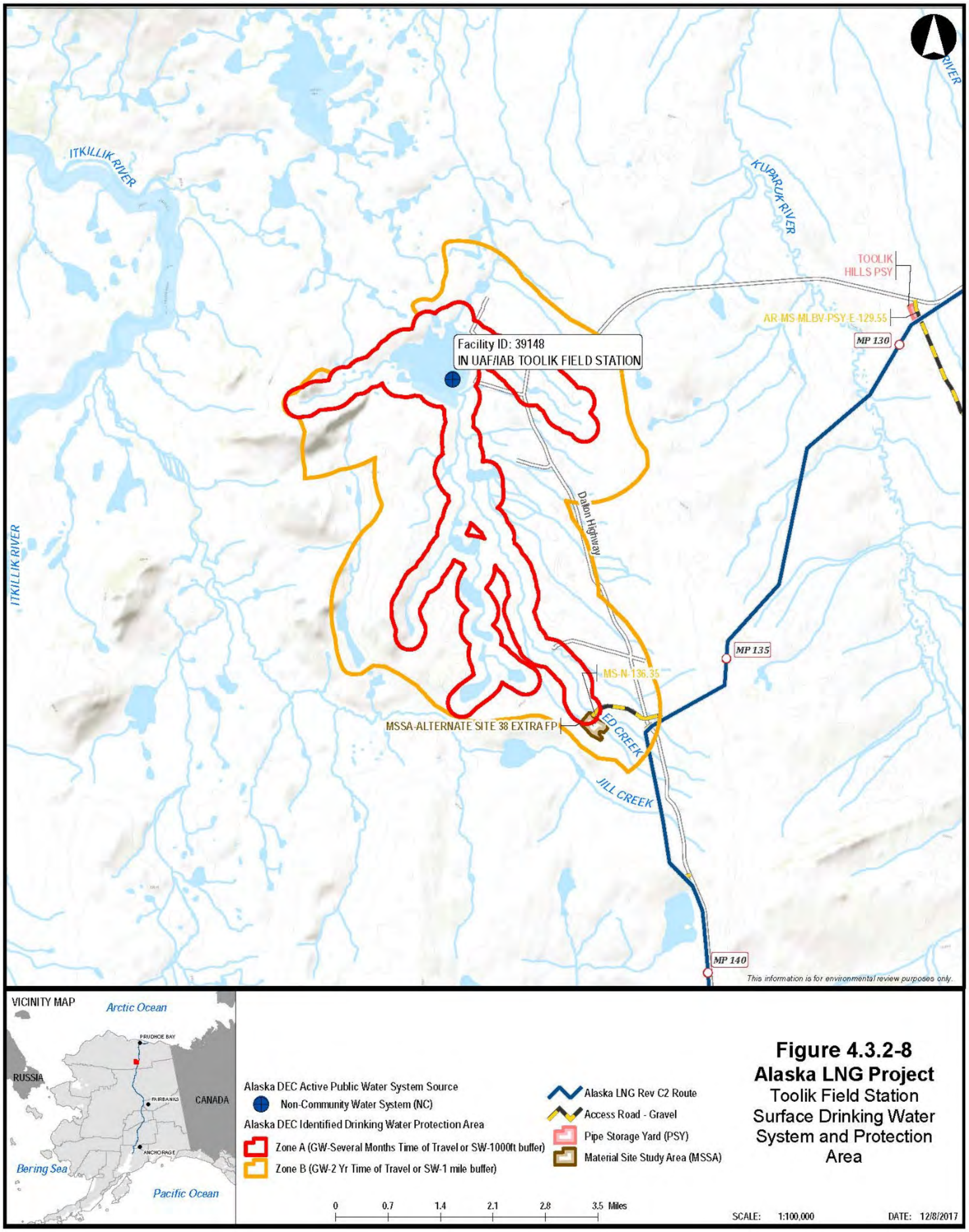


Figure 4.3.2-8
Alaska LNG Project
Toolik Field Station Surface Drinking Water System and Protection Area

We received a scoping comment from a stakeholder near Boulder Point that private surface water drinking sources could be affected by Project activities within the watershed. ADEC and ADNR online maps do not identify private surface water drinking sources near Boulder Point (ADEC, 2019a; ADNR, 2019a). Users that do not meet the threshold of a significant amount of water, as defined in 11 AAC 93.035(a) and (b), are not reflected in the mapping. Impacts on freshwater resources from Project activities are discussed in sections 4.3.2.4 and 4.3.2.5.

4.3.2.3 Waterbody Crossings

We define waterbodies as any natural or artificial stream, river, or drainage with perceptible flow at the time of crossing, including lakes and ponds (FERC, 2013). We further classify waterbodies by width and flow. Minor waterbodies are 10 feet wide or less, intermediate waterbodies are between 10 and 100 feet wide, and major waterbodies are greater than 100 feet wide at the water's edge at the crossing location. Flow classifications are provided below.

- Perennial: Contains water throughout the year, except for infrequent periods of severe drought.
- Perennial-Multiple (not a standard National Hydrography Dataset category): A subset of perennial waterbodies where there are braided or anastomosed channels and where channels are considered part of the waterbody at that location.
- Intermittent: Contains water for only part of the year, but more than just after rainstorms and at snowmelt.
- Pond/Open Water: A standing body of water with a predominantly natural shoreline surrounded by land; includes lakes and ponds.

The analysis conducted by AGDC did not delineate any ephemeral streams that would be crossed or affected by the Project. The Mainline Pipeline would require 553 waterbody crossings, and the PTTL would require 106 waterbody crossings. Access roads constructed for the Mainline Facilities and GTP would require 102 and 2 crossings of waterbodies, respectively. Additional work areas for the Mainline Facilities (e.g., material sites, pipe storage yards, and disposal sites) would be within 14 waterbodies. GTP infrastructure would affect three waterbodies. LNG Plant construction would affect one waterbody. Table 4.3.2-2 summarizes the number of minor, intermediate, and major waterbodies, as well as the perennial, perennial-multiple, intermittent, and pond or open water waterbodies crossed by the Project. The waterbodies affected by different Project components are identified in tables I-1 through I-7 in appendix I.

The Project would require structures (e.g., aerial pipeline spans and equipment bridges) and work (pipeline installation) affecting navigable waters subject to federal regulatory authority. The aerial span crossings would essentially be bridges installed across the waterbody for the pipe. The Coast Guard has authority under the General Bridge Act of 1946 (33 USC 525 et seq.) and Section 9 of the RHA (33 USC 401) to authorize and issue permits and amendments for all permanent and temporary roadway and pipeline bridges across navigable waterways. Under Section 9 of the RHA, navigable waterways are defined as internal waterways of the United States that are subject to tidal influence, and those that are not subject to tidal influence but are found susceptible for substantial interstate or foreign commerce use by the Coast Guard. The Project facilities would require permits under the General Bridge Act for eight bridge crossings of navigable waterways, as determined by the Coast Guard (see table 4.3.2-3).

TABLE 4.3.2-2

Number of Waterbodies Crossed by the Project

	Size Classification			Flow Classification			
Facility	Major	Intermediate	Minor	Perennial	Perennial-Multiple	Intermittent	Pond/Open Water
Gas Treatment Facilities							
GTP [a, b]	N/A	N/A	N/A	1	N/A	N/A	2
Access roads	N/A	N/A	2	1	N/A	N/A	1
PTTL	2	1	103	39	N/A	16	51
Mainline Facilities							
Mainline Pipeline [c]	13	87	453	207	17	303	25
Access roads	8	23	71	61	2	18	21
Additional work areas [b, d]	N/A	N/A	N/A	10	N/A	4	N/A
Liquefaction Facilities							
LNG Plant [b]	N/A	N/A	N/A	N/A	N/A	N/A	1
Total [b, c]	**23**	**111**	**629**	**319**	**19**	**341**	**101**

Sources: Waterbodies based on Project mapping supplemented by USGS National Hydrography and Watershed Boundary Datasets, aerial photography, and LiDAR.

N/A = Not applicable

[a] Includes the GTP, water reservoir pad, and associated transfer pipelines.

[b] Size classification is not provided for waterbodies crossed by these facilities; therefore, the totals for size classification and flow classification are different.

[c] Flow classification for the Cook Inlet crossing by the Mainline Pipeline is not applicable and is not included; therefore, the totals for size classification and flow classification are different.

[d] Additional work areas for the Mainline Facilities include contractor, pipe, and double joining yards; disposal sites; and material sites.

Section 10 of the RHA requires authorization from the COE for any work in, over, or under navigable waters of the United States; or that affects the course, condition, location, or capacity of such waters. Under Section 10, navigable waters are defined as waters subject to the ebb and flow of the tide and/or that are presently used, have been used in the past, or could be susceptible for use to transport interstate or foreign commerce. The Project facilities and associated Section 10 navigable waters are identified in table 4.3.2-4. In addition, Section 404 of the CWA gives the COE the authority to issue permits for the discharge of dredged or fill material into waters of the United States, which includes waters listed in 33 CFR 328.3, including streams.

The Coast Guard and COE would permit Project crossings of navigable waters subject to their jurisdiction under the General Bridge Act and Section 10 of the RHA, respectively, in accordance with agency authorization requirements, including mitigation measures to minimize impacts.

4.3.2.4 General Impacts and Mitigation

Constructing and operating the Project would temporarily and permanently affect freshwater resources. Based on the resource, facility, and method of construction, freshwater resources could either experience minor effects on water quality and streamflow or have permanent impacts, including the loss of waterbodies caused by granular fill placement.

TABLE 4.3.2-3

Project Bridge Crossings Regulated by the General Bridge Act

Facility	Waterbody Name	Permanent Bridge Crossing Structure	Temporary Bridge Crossing Structure	Approximate Milepost [a]
Gas Treatment Facilities				
PTTL	Sagavanirktok River (Main Channel)	Aerial pipeline	Ice road [b]	PTMP 44.2
	Sagavanirktok River (West Channel)	Aerial pipeline on existing bridge [c]	Ice road [b]	PTMP 53.6
Mainline Facilities				
Mainline Pipeline	Tolovana River	N/A	Steel prefabricated bridge	402.2
	Nenana River No. 3	Aerial plate girder bridge	N/A	532.1
	Nenana River No. 5	Aerial pipeline on existing bridge [c]	N/A	537.1
	Middle Fork Chulitna River	N/A	Steel prefabricated bridge	586.3
	East Fork Chulitna River	N/A	Steel prefabricated bridge	589.8
Access Roads	Deshka River	N/A	Steel prefabricated aerial vehicular bridge	704.7

Sources: Waterbodies based on Project mapping supplemented by USGS National Hydrography and Watershed Boundary Datasets, aerial photography, and LiDAR.

N/A = Not applicable

[a] PTMP indicates PTTL mileposts; all other values indicate Mainline Pipeline mileposts.

[b] Temporary ice road crossings over Section 9 navigable waters that are removed prior to spring breakup would not require Coast Guard permits.

[c] Modification of the existing bridge would not require a permit; however, the bridge would still be regulated by the General Bridge Act and be processed by administrative action.

As described in section 2.2.2, based on waterbody characteristics and site-specific conditions, AGDC would use one of the following methods to install the pipeline facilities across waterbodies: wet-ditch open-cut, dry-ditch open-cut, frozen-cut, aerial span, or DMT. The PTTL, PBTL, and GTP support pipelines would be installed aboveground on VSMs. Discussion on the impacts of DMT (Mainline Pipeline) and VSM crossings (Gas Treatment Facilities) on freshwater resources is provided in section 4.3.2.

In general, the use of the open-cut crossing method would disturb waterbodies (stream bottoms and banks) affecting water quality by causing a temporary increase in turbidity and sedimentation rates. Disturbed sediment would settle out and disperse downstream by the current depending on the nature of the waterbody (e.g., stream flows and duration of disturbance) and construction method (e.g., wet-ditch, dry-ditch, and frozen-cut).

The effect of turbidity and sedimentation when flow is present (wet-ditch) could be localized and quickly diluted by the waterbody's flow or could extend further downstream depending on factors such as sediment load and particle size. Sediment would not travel as far downstream in smaller, slow moving, and low flow waterbodies. Turbidity would be highest right at the stream crossing location and during the period of active trenching. Turbidity would dissipate downstream of the crossing and over time. In streams where background suspended sediment levels are elevated, the impact would be minor, but in higher clarity streams (e.g., where glacial input is minimal), the impact would be more pronounced.

TABLE 4.3.2-4 **Section 10 Navigable Waters Crossed by the Project**				
Facility	Waterbody Name	Pipeline Crossing Method	Work or Structure	Approximate Milepost [a]
Gas Treatment Facilities				
West Dock Causeway	Beaufort Sea [b]	N/A	Causeway expansion and Dock Head 4	N/A
PTTL	Sagavanirktok River (Main Channel)	Aerial	Ice road [c]	PTMP 44.2
	Sagavanirktok River (West Channel)	Aerial	Ice road [c]	PTMP 53.6
Mainline Facilities				
Mainline Pipeline	Middle Fork Koyukuk River	DMT	N/A	211.1
	South Fork Koyukuk River	Dry-ditch open-cut	N/A	260.7
	Yukon River	DMT	N/A	356.5
	Tolovana River	Dry-ditch open-cut	Temporary bridge	402.2
	Chatanika River	Dry-ditch open-cut	N/A	439.1
	Tanana River	DMT	N/A	473.0
	Nenana River No. 1	Dry-ditch open-cut	N/A	476.0
	Nenana River No. 2	Dry-ditch open-cut	N/A	489.2
	Nenana River No. 5	Aerial	Existing bridge	537.1
	Nenana River No. 6	Wet-ditch open-cut	Temporary bridge	543.1
	Cook Inlet [b]	Open-cut / pipelay	N/A	779.5
Access roads	Nenana River	N/A	Temporary access road	473.8
Liquefaction Facilities				
Marine Terminal	Cook Inlet [b]	N/A	PLF, MOF with shoreline protection, dredging	N/A

Sources: Waterbodies based on Project mapping supplemented by USGS National Hydrography and Watershed Boundary Datasets, aerial photography, and LiDAR.
N/A = Not applicable
[a] PTMP indicates PTTL mileposts: all other values indicate Mainline Pipeline mileposts.
[b] Facilities within the Beaufort Sea and Cook Inlet are discussed in section 4.3.3.
[c] Temporary ice road crossings over Section 10 navigable waters that are removed prior to spring breakup would not require COE permits.

Because data was unavailable to quantify impacts on turbidity and sedimentation from wet-ditch open-cut crossings, AGDC conducted a sediment transport study on 11 minor and intermediate waterbodies representative of waterbodies that the Project would affect (including the East Fork of the Chulitna River and Trapper Creek).[35] The study assumed that AGDC would store excavated spoil at least 10 feet from the water's edge and that construction would take 24 or 48 hours across each waterbody (consistent with the Project Procedures). According to the sediment transport model, the average sediment accumulation would range from 0.02 to 0.4 inch about 160 feet downstream of excavation. AGDC's model predicted that

[35] Results of AGDC's sediment transport study are available in AGDC's *Alaska LNG Sediment Modeling Study: Mainline Stream Crossings*, provided in the response to information request No. 106 dated August 15, 2018 (Accession No. 20180815-5078), along with supplemental materials provided in the response to information request No. 85 dated November 19, 2018 (Accession No. 20181022-5218). These documents can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180815-5078 or 20181022-5218 in the "Numbers: Accession Number" field.

trenching would lead to a localized exceedance of the designated use water quality standard during construction activities.[36] The maximum downstream distance exceeding water quality standards would be about 290 feet, which would last about 1 hour after excavation ceases.

The use of dry-ditch open-cut crossing methods (e.g., flume, dam-and-pump, or channel diversion) would also temporarily affect crossed waterbodies. Dry-ditch open-cut methods would isolate flow or occur when there is low or no flow, thereby minimizing turbidity and sedimentation.

Construction of waterbody crossings using the frozen-cut method during winter would minimize turbidity and sedimentation due to frozen soil conditions and lack of flowing water. Relative to background breakup turbidity and sedimentation levels, construction would cause minor transport of disturbed sediment during spring breakup.

Because the aerial span construction method is placed above the waterbody on bridge-type structures, direct impacts on waterbodies are typically avoided or minimized. The clearing and grading of waterbody streambanks for new aerial span construction could temporarily increase turbidity and sedimentation.

To facilitate Mainline Pipeline construction, AGDC would install temporary bridges across waterbodies along the entire route. In-stream equipment during bridge installation and removal and installation of bulkheads or footings in the waterbody would disturb the substrate materials and adjacent streambanks, which in turn would temporarily affect water quality by increasing turbidity and sedimentation. Once bridges are installed, construction equipment would avoid in-water impacts by crossing the waterbodies on the bridges.

To minimize turbidity and sedimentation impacts from the waterbody crossing methods described above, AGDC would implement erosion and sediment control measures in accordance with the Project Plan and Procedures, SWPPP, and Revegetation Plan. AGDC would stabilize streambanks with native vegetation (such as seeding and fertilizer applications or transplanting of shrubs and dormant willow [*Salix* spp.] cuttings) and materials such as root wads and boulders within 24 to 48 hours of completion of in-stream work (see section 4.5.2). For waterbodies crossed during winter, interim streambank stabilization measures would include grading of disturbed areas to pre-construction contours, reuse of existing substrate material as backfill, installation of synthetic (geotextile) silt fencing, and initial spread of riprap, if warranted. Where additional work is required after the area has thawed, AGDC would complete final placement of riprap, revegetation efforts (e.g., seeding or sprigging), and replacement of synthetic sediment controls with long-term and/or bioengineering techniques. Federal, state, and local regulations or approvals may have additional restoration standards (e.g., BLM Technical Reference 1735-2). Implementation of these mitigation measures would result in localized and/or downstream freshwater resource impacts that are minor and temporary.

Other construction activities, such as clearing and use of additional work areas (e.g., pipe storage yards, disposal sites, and material sites), would temporarily affect water quality by increasing turbidity and sedimentation in adjacent waterbodies. Stormwater runoff would transport sediment from disturbed soils and cleared areas into adjacent waterbodies. To minimize turbidity and sedimentation from runoff, AGDC would implement measures in the Project SWPPP. These measures would reduce turbidity and sedimentation from runoff by identifying sources of pollution associated with the construction or operational activity and prescribing measures to reduce those pollutants in the runoff. AGDC would provide a Project-wide SWPPP that would cover all facilities and activities during construction and

[36] The relevant AWQS for turbidity (assuming the streams' designated use of Growth and Propagation of Fish, Shellfish, Other Aquatic Life, and Wildlife) is not to exceed 25 NTUs above natural conditions (ADEC, 2018e).

operation. AGDC would obtain coverage for construction and operational activities from ADEC under the APDES program for activities outside the DNPP and from EPA under the NPDES program for activities within the DNPP. Retention basins to settle out sediment would further manage runoff from material site development activities, and AGDC would adhere to ADEC's *Best Management Practices for Gravel/Rock Aggregate Extraction Projects User Manua*l (ADEC, 2012a).

Fugitive dust generated from equipment traffic could affect water quality of adjacent freshwater resources (e.g., ponds and lakes). Vehicles and equipment driving on granular fill (i.e., construction camp pads, access roads, and construction right-of-way) could deposit fugitive dust particles in adjacent waterbodies, increasing suspended sediment levels and turbidity. AGDC would reduce Project-related dust by implementing the measures outlined in its Project Fugitive Dust Control Plan, thereby reducing impacts on water quality. Fugitive dust is further addressed in section 4.2.4.

The use of mechanical equipment to construct and operate the Project could result in accidental spills or releases of fuel and other hazardous materials adversely affecting water quality in freshwater resources. The magnitude of impact would depend on fluid type, volume, season, and response. To minimize the potential for an inadvertent equipment fluid release, AGDC would adhere to the fueling, storage, containment, and cleanup measures described in the Project SPCC Plan, Procedures, and Waste Management Plan; and comply with applicable federal, state, and local regulatory approvals and requirements. A draft for the Project SPCC Plan describing generic practices and procedures to protect freshwater resources from a potential release of fuel or hazardous materials was included in AGDC's application, but the draft did not provide specific measures for construction or facility-specific operational plans. AGDC would develop facility/work site-specific SPCC plans prior to construction, as discussed in section 4.2.6. Hazardous materials would be handled in accordance with the Project Procedures as well as the Project Waste Management Plan (see section 4.9.6). Implementation of the Project SPCC Plan, Procedures, and Waste Management Plan would reduce impacts on freshwater resources to less than significant levels depending on the severity of the discharge.

Construction dewatering activities (e.g., material site development and pipeline trenching) would temporarily affect water quality. Water from dewatering activities could be discharged into freshwater resources, increasing turbidity and sedimentation and potentially introducing pollutants that could decrease water quality. AGDC would conduct dewatering under the supervision of EIs and in accordance with the Project Plan and Procedures, as well as applicable federal and state requirements. AGDC would monitor material site excavation dewatering activities in accordance with APDES permit requirements, which could include monitoring prior to, during, and following mining activities. Temporary, localized, and minor dewatering impacts would occur, given the large scale of the watersheds and with implementation of these measures.

Blasting during construction (e.g., material site development and waterbody crossings) would temporarily affect freshwater resource water quality. Potential waterbodies planned for in-stream blasting are listed in table I-2 in appendix I. Blasting would cause flyrock to land in freshwater resources, temporarily disturbing substrate sediment and increasing turbidity. The Project Blasting Plan, which includes the use of stemming and blasting mats and other measures, would minimize the effect on waterbodies. Where in-stream blasting would be conducted, the waterbody substrate would be restored to natural grade after pipe installation is complete in accordance with the Project Procedures. Impacts on fisheries due to altered stream flow from in-stream blasting are discussed in section 4.7.1, including a commitment by AGDC to update the Project Blasting Plan to include monitoring and contingency measures if stream flow is affected. Construction would use specialized trench-blasting explosives that do not contain perchlorate or ammonium nitrate fuel oil to avoid the discharge of remnant residues into the waterbody.

The placement of granular fill and in-stream structures for access roads could permanently affect streamflow by disrupting river and stream flow paths. AGDC would install appropriately sized culverts within access roads to maintain streamflow during construction and operation. Culverts and gravel placed below the ordinary high-water mark of streams and rivers would be removed following construction if requested by the landowner or land management agency, or required by COE permitting. Abandoned roads and pads that require granular fill subject to COE permitting would be monitored for erosion and sedimentation in accordance with COE permitting requirements. Impacts on fisheries due to impeded flow are discussed in section 4.7.1, including a commitment by AGDC to develop a Fisheries Conservation Plan that includes design and maintenance of culverts and bridges and follow the *Anadromous Salmonid Passage Facility Design* (NMFS, 2011a) for all fish bearing streams. Proper installation and maintenance of culverts would result in minor impacts on freshwater resources.

Construction in permafrost could affect surface drainage patterns. Trench trials were conducted in March 2002 at the Washington Creek Trenching Test Site north of Fairbanks, Alaska to test the effectiveness of various trenching techniques that could be used to construct a buried natural gas pipeline (ABR, Inc. and BP Exploration [Alaska], Inc., et al., 2013). Open black spruce (*Picea mariana*) forest that had dominated the area was cleared and 10 trenches were excavated parallel to the slope. Each trench was backfilled to a height of about 3.6 feet above ground level with native material from the trench, and additional fill (e.g., gravel) was added where needed. The trenches were fertilized and seeded in June 2002 to promote revegetation. Following these treatments, heavy precipitation caused increased flow through natural drainages that intersected two of the trenches, causing flow to move along each trench. The movement of water along these trenches caused thawing of the backfilled material, resulting in collapse of the trench (thermokarst) and soil erosion in the adjacent area. Stabilization measures (e.g., fiber mats) and flow re-direction measures (e.g., hay bales and ditch plugs) were installed to stabilize the trenches and prevent further soil erosion. No erosion occurred where trenches did not intersect existing natural drainages.

AGDC would implement mitigation measures to minimize effects on permafrost and maintain natural drainage. AGDC would bed the pipe with thaw-stable, non-frost susceptible materials to reduce permafrost degradation, pipe thaw settlement, and surface slumping. AGDC would install ditch plugs in slope wetlands at the beginning and end of individual wetlands to avoid water seepage into the trench. AGDC would maintain existing surface water channels in their natural state where possible and contour granular fill work pads to allow natural drainage and hydrologic connectivity. In some cases where multiple natural drainage features intersect the granular fill, AGDC would divert drainage into one drainage feature to facilitate hydrologic connectivity. Modifications to natural drainage patterns could occur, but with the implementation of mitigation measures proposed by AGDC, the effects would be localized and minor.

Construction and operation of the Project would result in the permanent loss of freshwater resources. The placement of granular fill for infrastructure such as granular pads, access roads, pipe storage yards, and disposal sites would permanently remove ponds and lakes (see tables I-4a, I-4b, I-5, and I-7 in appendix I). In total, Project activities at Mainline additional work areas, the Gas Treatment Facilities, and the Liquefaction Facilities would affect about 208 acres of waterbodies (see tables I-5 and I-7 in appendix I; additional information on the Liquefaction Facilities is provided in section 4.3.2.5). AGDC has stated that it would avoid placing permanent granular fill in streams and rivers; however, four additional work areas (two pipe storage yards and two disposal sites) could encroach upon four individual waterbodies (see table I-5 of appendix I) where placement of granular fill or spoil could interrupt streamflow. To avoid affecting water flow and quality within these four waterbodies, **we recommend that:**

- **<u>During construction of the Mainline Facilities</u>, AGDC should restrict the placement of granular fill, spoil, or other materials in waterbodies within the following workspaces:**

  a. pipe storage yards "Chandalar PSY" in the Unnamed Tributary to North Fork Chandalar River near MP 174.6 and "65-9-078-2 FP" in the Unnamed Tributary to North Fork Ray River near MP 337.0; and

  b. disposal sites "WD-043" in Ninety-Six Creek near MP 251.8 and "WD-050" in the Unnamed Tributary to Prospect Creek near MP 281.5.

  In the event that the use of fill is unavoidable, then AGDC should file with the Secretary, for the review and written approval of the Director of the OEP, site-specific justifications and measures it would use to preserve water flow and quality within the affected streams.

Development of material sites would result in impacts on waterbodies during excavation where ponds, lakes, or streams are within the facility footprint. Following granular material extraction, the excavated depressions could flood and retain water, creating new ponds or lakes that could provide similar functions (e.g., stormwater retention or wildlife habitat). Material extraction would also occur within waterbodies (see table I-5 in appendix I). Disturbance of the streambed during material site development would increase turbidity and sedimentation, resulting in a temporary and minor impact; however, channel morphology could be modified, resulting in unstable conditions, which could affect water quality and negatively affect fish habitat (see section 4.7.1). To reduce the potential for adverse effects, AGDC would implement the BMPs detailed in the Project Gravel Sourcing Plan and Reclamation Measures, SWPPP, SPCC Plan, and permit requirements.

As discussed in section 2.2, the Project Procedures include modifications to FERC's Procedures. These modifications, which we have reviewed and accepted with some revisions, are provided in appendix D. AGDC added two new sections to its Project Procedures that are not included in FERC's Procedures. Section V.B.6.d of the Project Procedures includes a channel diversion waterbody crossing method. AGDC indicates that they could use the channel diversion method at waterbodies with one or more channels, such as braided streams, and in wide, high gradient alluvial floodplains where the flowing channel location can vary between alternate locations within the floodplain. Section V.B.8 of the Project Procedures addresses the aerial span waterbody crossing method. While AGDC indicated that they would provide site-specific crossing plans for each waterbody crossed using channel diversion or aerial span methods, they have not yet filed those plans with FERC. In addition, section V.B.11 of the Project Procedures proposes minor text changes related to major waterbody crossings. Although FERC staff concludes the text changes proposed in section V.B.11 are acceptable, AGDC has not yet addressed navigational issues associated with major waterbody crossings. To address these issues, prior to construction, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, site-specific waterbody crossing plans and mitigation measures that address, as applicable:

- channel diversion crossings (e.g., locations of dams and diversion channels, construction procedures, justification that disturbed areas are limited to the minimum needed to construct the crossing, and identification of any aboveground disturbance or clearing) (section V.B.6.d of the Project Procedures);

- aerial span crossings (e.g., locations of abutments and piers and all areas to be disturbed or cleared for construction) (section V.B.8 of the Project Procedures); and

- navigational issues for major waterbody crossings (e.g., compliance with Coast Guard, COE, and PHMSA requirements) (section V.B.11 of the Project Procedures).

4.3.2.5 Facility-Specific Impacts and Mitigation

The effect on freshwater resources from construction and operation of each facility are dependent on the activities required for each facility. Facility-specific freshwater resource impacts and mitigation discussions are provided below.

Gas Treatment Facilities

Construction of the Gas Treatment Facilities would temporarily and permanently affect rivers, streams, ponds, and lakes, as described in section 4.3.2. Additionally, these facilities would require two permanent aerial crossings of the Sagavanirktok River (Main and West Channels), which are both classified as major waterbodies. The crossing of the Sagavanirktok River (West Channel) would use an existing bridge, avoiding in-stream impacts.

The installation of VSMs would require the placement of more than 360 VSMs within rivers, lakes, and ponds, resulting in less than 0.1 acre of permanent fill (see table I-6 in appendix I). This filling would occur in the winter when waterbodies are frozen, which would result in a temporary increase in turbidity and sedimentation during the following spring/summer when surface flows move the disturbed sediments. This impact would be temporary and minor due to the localized area of impact.

Construction, operation, and maintenance activities for the Gas Treatment Facilities would require access by ice roads, ice pads, or tundra travel. Ice road and ice pad construction could temporarily block streamflow and cause flooding when ice melts slower than the surrounding ice in the waterbody. AGDC would slot, breach, or weaken the ice at stream crossings prior to breakup to reduce flooding and impacts on waterbodies. Operational ice roads and ice pads would have temporary impacts similar to those resulting from construction but of a smaller magnitude. AGDC would conduct tundra travel across waterbodies using approved equipment during summer or winter in accordance with state permit requirements. State regulatory authorities approve and monitor tundra travel activities to avoid damage to ponds, lakes, streams, and rivers. Because AGDC would conduct tundra travel in accordance with state regulatory requirements, impacts from accessing Project facilities during construction and operation would not be significant.

Mainline Facilities

Mainline Facilities (e.g., Mainline Pipeline, access roads, material sites, disposal sites, and ATWS) would affect freshwater resources permanently and temporarily as discussed in section 4.3.2. Mainline Pipeline and access road crossings would also affect waterbodies, as described below.

<u>Mainline Pipeline</u>

The Mainline Pipeline would have 553 waterbody crossings, including 13 major waterbody crossings, 87 intermediate waterbody crossings, and 453 minor waterbody crossings. AGDC would cross some waterbodies more than once. Open-cut crossings (wet, dry, and frozen-cut) are proposed for 545 waterbody crossings. Of the remaining eight crossings, AGDC would use the aerial span method to cross two waterbodies, the DMT method to cross five, and the pipelay method for Cook Inlet. Construction and operational impacts on waterbodies would vary based on the flow classification and selected crossing method. Impacts from open-cut crossings are discussed in section 4.3.2.

Of the 13 major waterbody crossings, construction would cross 9 distinct waterbodies because the Nenana River would be crossed five times (see table 4.3.2-5). Construction of the Nenana River No. 5 crossing (existing aerial span) and Nenana River No. 6 crossing (wet-ditch open-cut) would begin in late September and continue into winter. Of the remaining five open-cut major waterbody crossings, AGDC would construct three during winter and two in summer. The Cook Inlet crossing is discussed in section 4.3.3. Construction for the DMT and new aerial span crossings would occur in summer.

TABLE 4.3.2-5

Major Waterbody Crossings Along the Mainline Pipeline [a]

Approximate Milepost	Waterbody Name	Construction Wetted Width (feet)	Crossing Method	Construction Season	Sub-watershed (HUC8)
211.1	Middle Fork Koyukuk River	280	DMT	Summer	Upper Koyukuk River
356.5	Yukon River	2,000	DMT	Summer	Ramparts-Yukon River
473.0	Tanana River	2,200	DMT	Summer	Lower Tanana River
476.0	Nenana River No. 1	180	Dry-ditch open-cut	Winter	Nenana River
532.1	Nenana River No. 3	160	Aerial span	Summer	Nenana River
537.1	Nenana River No. 5	230	Existing aerial span	Winter [c]	Nenana River
543.1	Nenana River No. 6	230	Wet-ditch open-cut	Winter [c]	Nenana River
561.0	Nenana River No. 4	200	Wet-ditch open-cut	Summer	Nenana River
641.8	Chulitna River	1,830	DMT	Summer	Chulitna River
704.7	Deshka River	220	DMT	Summer	Lower Susitna River
720.9	Yentna River	400	Dry-ditch open-cut	Winter	Yentna River
757.2	Beluga River	120	Dry-ditch open-cut	Winter	Redoubt-Trading Bay
779.5	Cook Inlet [b]	141,400	Open-cut / pipelay	Summer	Redoubt-Trading Bay and Upper Kenai Peninsula

Sources: Waterbodies based on Project mapping supplemented by USGS National Hydrography and Watershed Boundary Datasets, aerial photography, and LiDAR.

[a] A major waterbody is greater than 100 feet wide at the water's edge at the time of crossing.

[b] The Cook Inlet crossing is discussed in section 4.3.3.

[c] Construction would begin in late September (the last month of summer) and continue into winter.

New aerial span construction, which would be used for the Nenana River No. 3 crossing, would result in minimal impacts on this waterbody. AGDC would construct aerial span support structures above the ordinary high-water mark, thereby avoiding direct impacts on this freshwater resource. Turbidity and sedimentation from potential erosion for clearing and grading activities adjacent to the river could potentially affect water quality, but erosion and sediment control measures would minimize impacts, as discussed in section 4.3.2. The Nenana River No. 5 crossing, as indicated above, would use an existing bridge, avoiding in-stream impacts.

DMT crossings are proposed for five major waterbody crossings. The use of the DMT method would significantly reduce potential impacts on waterbodies. DMT crossings would avoid in-water work, stream bottom and bank disturbance, and would generally preclude erosion, turbidity, and sedimentation impacts. As described in section 2.2.2, the use of these methods could result in an inadvertent release of drilling fluid into the waterbody being crossed. An inadvertent release of drilling fluid would increase turbidity and sedimentation and possibly introduce non-petrochemical-based and non-hazardous additives, temporarily reducing water quality. The effects of releasing drilling fluid could concentrate at the release point in small or slow-moving waterbodies where low flow or partially frozen conditions prevent dispersal. Large-scale drilling fluid releases could result in long-term impacts capable of increasing sedimentation, altering water chemistry, and altering stream substrate.

As discussed in section 4.1.5, implementation of FERC-approved DMT Plans would effectively minimize impacts on freshwater resources if an inadvertent release occurs. We additionally note that relative to HDD, use of the DMT method would reduce the likelihood of an inadvertent release because the drilling fluid or slurry is used only at the cutting face and is recirculated back into slurry return lines inside the pipe, as opposed to circulating through the borehole under pressure. Drilling fluid in the borehole is primarily used as a means of lubricating the borehole to facilitate advancing the pipe.

Operation of the Mainline Pipeline could affect freshwater resources by changing physical characteristics of the channel. The buried pipeline would carry chilled natural gas that could create a frost bulb, as discussed in section 4.2.5, resulting in a raised obstruction to waterbody flow. The buried pipeline could also affect downstream water temperatures in very low-flow streams. Due to the Joule-Thompson effect (cooling of the gas between compressor stations), a frost bulb could form at a river crossing immediately upstream of a compressor station (Oswell, 2010).

AGDC would implement several measures to prevent and monitor frost bulb obstructions, including conducting investigations along the Mainline Pipeline to determine areas susceptible to frost bulb formation and to ensure adequate burial depth of the pipeline at those locations to minimize waterbody impacts. AGDC would also identify raised obstructions and pipe displacement during seasonal field inspections and in-line inspection surveys required for pipeline integrity monitoring. AGDC would re-route any overland flows or cross drainage if any waterbodies susceptible to frost bulbs from the Joule-Thompson effect are identified.

Mainline Pipeline operation could also create a thaw bulb potentially affecting freshwater resources or taliks (unfrozen ground near freshwater resources). As discussed in section 4.2, warmer pipeline temperatures could increase the temperature of permafrost soils (e.g., at the outlet of a compressor station). Warmer soil temperatures adjacent to freshwater resources could cause both a thaw bulb and thermokarst in surrounding permafrost. Although thaw bulbs are dependent on ground temperature and pipe temperature, the exact locations where this would occur are unknown.

To minimize impacts on freshwater resources, AGDC would conduct maintenance at waterbody crossings along the Mainline Pipeline in accordance with the Project Plan and Procedures, SWPPP, SPCC Plan, Fugitive Dust Control Plan, Waste Management Plan, and Revegetation Plan. These requirements include restricting both vegetation clearing and herbicide use near waterbodies.

To facilitate periodic corrosion/leak surveys, AGDC would maintain a cleared corridor up to 10 feet wide centered on the pipeline in an herbaceous state. In addition, AGDC would cut and remove trees from the permanent right-of-way within 15 feet of the pipeline that could compromise the integrity of the pipeline coating.

AGDC would not apply herbicides within 100 feet of freshwater resources and, where practicable, would mix chemicals at a distance greater than 200 feet from open or flowing water, wetlands, or other sensitive resources. Where permitted and agreed upon by the appropriate land management agency, AGDC would use herbicide treatment methods to carry out pre-construction noxious weed control. AGDC would only use herbicides and application methods that are permitted by the respective land management agencies in accordance with applicable regulations.

Access Roads

Mainline access roads would require 102 waterbody crossings, including 71 minor, 23 intermediate, and 8 major waterbody crossings. As described in section 4.3.2, construction of access roads could affect streamflow and result in the loss of freshwater resources (e.g., ponds and lakes).

Use of temporary bridges on access roads and across waterbodies during construction could affect streamflow and would require Coast Guard approval for navigable water crossings. Bridge structures that constrict flow during high streamflow events could temporarily affect waterbody flow. AGDC would install temporary bridges concurrent with clearing activities to provide access; the bridges would remain in place for multiple construction seasons until restoration is complete. During spring breakup, high peak streamflow levels could potentially wash out bridge structures, resulting in downstream sedimentation and debris. AGDC would remove temporary bridges before spring breakup or would install the temporary bridges high enough above predicted spring streamflow levels to minimize impacts. Flood events could displace bridge structures if the bridge is not designed appropriately. To reduce this risk, AGDC would design temporary bridges to withstand at least a 10-year flood event or file with the Secretary, for the review and written approval of the Director of the OEP, site-specific justifications prior to construction showing that a design for a 2-year flood event is adequate. AGDC would repair and/or upgrade the bridges, where necessary, for the duration of Project use.

Additional Temporary Workspaces

AGDC would implement waterbody crossing procedures and mitigation measures that are based on our Procedures, but has requested a modification to allow ATWS within 50 feet of waterbodies, as listed in table I-1 in appendix I. The most prevalent justifications include the need for ATWS for waterbody crossings (e.g., DMT exit and entry sites), ice roads and ice pads, and spoil storage where sufficient space would not be available to meet our setback requirements. Clearing and spoil storage adjacent to a waterbody could affect water quality through sediment discharges into the waterbody, but implementation of mitigation measures, such as streambank stabilization and the use of sediment controls, would minimize potential turbidity and sedimentation. Impacts from ice roads and ice pads were discussed previously under Gas Treatment Facilities. Based on our review of the ATWS, we determine that the modifications are justified and that AGDC would implement adequate measures to minimize the potential for freshwater resource impacts.

Liquefaction Facilities

Construction and operation of the LNG Plant would affect one unnamed freshwater pond (see table I-7 of appendix I). A nearby pond that appears to be a remnant of Cabin Lake is about 300 feet away from the eastern boundary of the proposed LNG Plant, but it would not be affected. A pond crossed by the eastern boundary of the LNG Plant would not be filled or graded; however, ground-disturbing activities adjacent to the pond could temporarily increase turbidity and sedimentation. AGDC would minimize sedimentation and pond turbidity through implementation of the SWPPP, including erosion control devices, resulting in temporary and minor water quality impacts on the pond.

Construction would permanently convert one pond to a sediment catch basin. By converting the 2-acre pond into a sediment catch basin, it would contain stormwater runoff while the LNG Plant is under construction (e.g., grading and filling). During operation, the sediment catch basin (pond) would collect stormwater runoff from impermeable surfaces (e.g., concrete and asphalt) before the stormwater is discharged via an outfall into Cook Inlet. Although using the pond as a sediment catch basin would increase sedimentation and turbidity in a natural waterbody, implementation of the SWPPP would minimize impacts on adjacent water quality. Due to the local beneficial effect on water quality, this would cause an overall minor impact on freshwater resources.

4.3.2.6 Sensitive Waters

The Project facilities would cross sensitive waters such as:

- waterbodies supporting anadromous fish species, threatened or endangered species, and critical habitat;
- rivers on or designated to be added to the NRI; and
- state-designated Recreational Rivers.

Anadromous waters and species are addressed in section 4.7.1. Federally listed endangered and threatened species are addressed in section 4.8.

As discussed in section 1.6, the WSR System was created by Congress in 1968 to preserve certain rivers with outstanding natural, cultural, and recreational values in free-flowing condition for the enjoyment of present and future generations. This program is administered by the NPS to protect and enhance river resources. The Project would not cross any federally designated Wild and Scenic Rivers.[37]

Under the WSRA (16 USC 28), federal agencies must seek to avoid or mitigate actions that would adversely affect rivers included on the NRI. Rivers listed on the NRI are free flowing and possess one or more ORVs based on the river's hydrology and inventory of its natural, cultural, and recreational resources (16 USC 28.1271). The Mainline Pipeline would cross the Deshka River and Alexander Creek, which are NRI waterbodies (DOI, 2017). The Deshka River (MP 704.7) is listed with ORVs related to recreational, fish, and cultural values. Alexander Creek (MP 727.8) is listed with ORVs related to scenery, recreation, fish, wildlife, and cultural values.

The Deshka River and Alexander Creek are also designated by the State of Alaska as Recreation Rivers under the Recreation Rivers Act of 1988 (AS 41.23.400), which established Recreational Rivers for the maintenance and enhancement of the land and water for recreation. These rivers are managed to protect and maintain fish and wildlife populations and habitat, allow continued recreation and economic use, manage upland activities within the recreation river corridor, and accommodate access for resource uses.

AGDC would use DMT to cross the Deshka River (summer construction) and a dry-ditch method to cross Alexander Creek (winter construction). Construction impacts on scenery, recreation, fish, wildlife, and cultural resources are discussed in sections 4.10, 4.9, 4.7, 4.6, and 4.13, respectively. AGDC would implement the mitigation measures described below to maintain the NRI designation, which would not prevent classifying these portions of the NRI segments as Wild and Scenic or Recreational Rivers.

By using a DMT method to cross the Deshka River, AGDC would avoid impacts on the river and adjacent buffer areas and would not adversely affect the ORVs of recreation, fish, and cultural values.

Dry-ditch construction across Alexander Creek in the winter would avoid impacts on summer-related ORVs (e.g., recreation, fish, and wildlife). Construction would affect winter recreation activities such as snow machining, but as discussed in section 4.9, these temporary impacts would not affect recreation activities beyond that winter season. During operation, the cleared right-of-way could create new views and access points to the rivers and disturb wildlife and riparian habitat. AGDC would mitigate impacts on scenery, fish, and wildlife at Alexander Creek by maintaining vegetative screening where

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[37] The current status of a segment of the Atigun River near the Project is discussed in section 4.9.5.

possible, stabilizing and revegetating streambanks and riparian areas, and implementing measures from the *Alaska LNG Streambed and Bank Restoration Manual.*[38]

Based on consultation with the NPS, AGDC would adequately mitigate the impacts on the Deshka River and Alexander Creek such that the status of the rivers would not be affected (Kluwe and Babb, 2018). AGDC also proposes to mitigate impacts so that the areas would remain consistent with the State Recreation Rivers (SRR) management plans.

4.3.2.7 Floodplains

Floodplains are generally defined as low-lying areas adjacent to rivers and streams susceptible to inundation during periods of high flow or discharge. Floodplains attenuate stormwater flow and provide erosion and sediment control, nutrient input, and wildlife habitat. A flood occurs when the level in a stream or river channel overflows the natural or constructed bank.

Figure 4.3.2-9 shows the geographic extent of available FEMA FIRM for the Project area, which are based on historic, meteorological, hydrologic, and hydraulic data. Mapped flood zones occurring in the Project area include:

- Zone A: areas subject to inundation by the 1-percent-annual-chance flood event (100-year flood);
- Zone X (unshaded) (also shown on some FIRMs as Zone C): areas subject to minimal flood hazard, usually depicted on FIRMs as above the 500-year flood level;
- Zone X (shaded): areas of moderate flood hazard, usually the area between the limits of the 100- and 500-year floods;
- Zone D: areas with possible but undetermined flood hazards, but no flood hazard analysis has been conducted; and
- Zone VE: areas along the coast with velocity hazards from wave action and a 1-percent annual chance of flooding.

In Project areas where FIRMs are not available, AGDC conducted a historic peak flow analysis using available data to provide preliminary flooding information. Where FIRM data is unavailable, AGDC's analysis determined that there are construction and operational Project facilities within areas subject to flooding (e.g., resulting from severe storms and aufeis).[39] Impacts within the 100-year floodplain were evaluated for Project construction and operational facilities.

[38] The *Alaska LNG Streambed and Bank Restoration Manual* was included in AGDC's Information Request Response No. 87 (Accession No. 20180122-5070). The document can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180122-5070 in the "Numbers: Accession Number" field.

[39] Aufeis is an ice jam formed by frozen groundwater welling up, flowing upward on the surface of the ice jam and then freezing, forming a blockage of the channel.

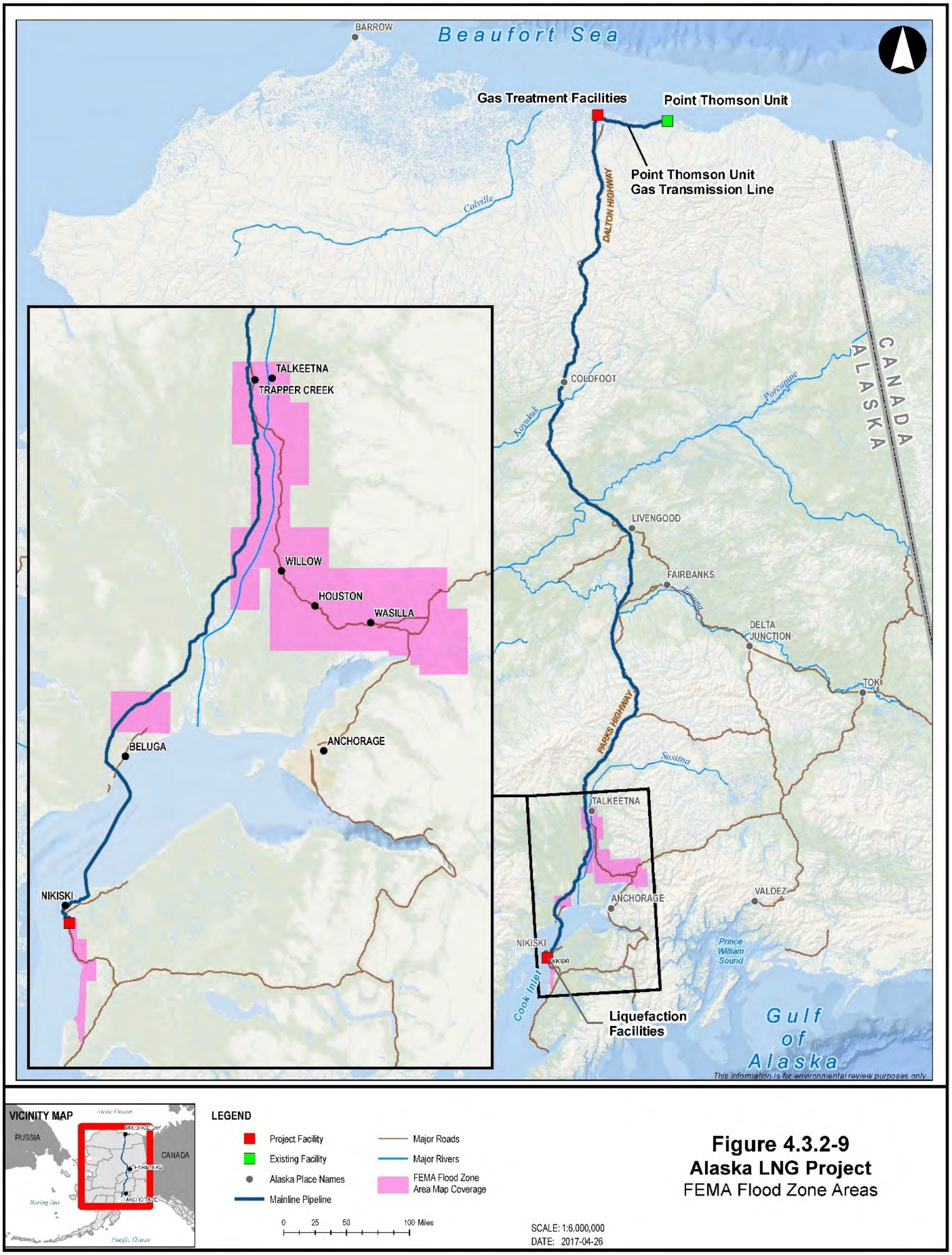


Figure 4.3.2-9
Alaska LNG Project
FEMA Flood Zone Areas

The Project would result in minor short-term, long-term, and permanent impacts on floodplains. Clearing and ground disturbing activities would affect surface flow patterns. Post-construction restoration activities would reestablish flood storage capacity and surface flow patterns, resulting in short-term and minor impacts. Decreased evapotranspiration from clearing trees and shrubs would change subsurface flow patterns until vegetation could be established, which could be a short- or long-term effect depending on the revegetation rate. Clearing vegetation would also decrease the filtering capacity of the floodplain, thereby increasing sedimentation and erosion from these areas. Clearing and ground-disturbing activities would occur across the right-of-way (up to 185 feet), reducing the flood attenuation function of the floodplain. Winter construction methods and adherence to the Project Plan and Procedures would minimize sedimentation and erosion within the floodplain. With the implementation of these measures, impacts on floodplains would be minor.

In comments on the draft EIS, the BLM said that refueling equipment and storing/maintaining equipment within 100 feet of the active floodplain of any waterbody on BLM lands is prohibited, except for watercraft and aircraft, and that fuel storage stations should be located outside the 100-year floodplain of waterbodies, unless otherwise approved by the BLM Authorized Officer. In comments on the draft EIS, the State of Alaska said that it is standard practice to prohibit vehicle refueling within the annual floodplain or within tidelands on state-owned lands.

On lands where granular fill would be placed, construction would permanently reduce flood storage capacity slightly because the granular fill would permanently displace soil, and soil has a greater storage capacity than granular fill. FEMA FIRM mapping is unavailable for 98 percent of the Project area (see figure 4.3.2-9). Based on the available FEMA FIRM mapping, AGDC identified about 11 acres within the 100-year floodplain where Mainline aboveground facilities would permanently affect the floodplain by displacing about 55,000 cubic yards of flood storage capacity. Placement of granular fill for work pads within the construction right-of-way would also affect surface flow patterns by modifying natural drainage patterns. AGDC would contour granular fill work pads following construction to restore drainage and hydrologic connectivity through floodplains. Access road culverts would be designed and maintained in accordance with AGDC's Culvert Design and Maintenance Plan, as discussed in section 4.7.1.6 (or removed for roads not required for Project operation if requested by the landowner or land management agency or required by COE permitting) to maintain floodplain connectivity. While limited floodplain information exists for the Project area affecting our ability to quantify the total impact on floodplains, the Project area is relatively undeveloped resulting in an overall minor impact on flood storage capacity. Implementation of post-construction mitigation measures would adequately reduce impacts on surface flow.

Flood events caused by severe storms could affect construction activities and operation of permanent facilities. Severe storms and heavy rainfall would cause coastal, riverine, and local lake expansion flooding. Aufeis could also be a source of riverine flooding and is difficult to predict. Aufeis has been primarily observed in the eastern Brooks Range, including in the upstream reaches of the Sagavanirktok River (Yoshikawa et al., 2007). Aufeis has also been observed in the Kuparuk and Sagavanirktok Rivers where the channel splits into west and main channels (Kane, 1981; Kane et al., 2012). High flows caused by flooding while construction is underway would increase runoff and erosion at construction sites, increasing turbidity and sedimentation in waterbodies at or adjacent to the site. To minimize these potential impacts, AGDC would, as discussed previously, implement erosion and sediment control measures.

Flood events during operation could affect geologic resources on the Mainline Pipeline by causing vertical scour of waterbody substrate, as discussed in section 4.1.3. While vertical scour could expose or damage the pipeline, AGDC would provide adequate depth of cover to avoid or minimize the erosion process. Waterbodies susceptible to vertical scour are identified in appendix I, table I-2.

4.3.3 Marine Waters

Marine waters in two subregions, the Beaufort Coastal Plain and Cook Inlet Basin, would contain Project infrastructure. The Gas Treatment Facilities would be in the Beaufort Coastal Plain Subregion, which is adjacent to Prudhoe Bay and the Beaufort Sea coast. This subregion is characterized by a dry, polar climate that produces short, cool summers and long, cold winters (ADF&G, 2015a). The Liquefaction Facilities and a portion of the Mainline Facilities would be in the Cook Inlet Basin Subregion, which opens into Cook Inlet and the GOA. This subregion is characterized by a mix of continental and maritime climates, with moderate seasonal fluctuations in temperature, frequent precipitation, and an ice-free period from about April through October. The following sections provide descriptions of the marine environments in Prudhoe Bay and Cook Inlet and outline the different Project components potentially affecting these marine surface waters.

4.3.3.1 Beaufort Sea and Prudhoe Bay

Prudhoe Bay is a relatively shallow marine lagoon that is part of the Beaufort Sea. It is situated south and east of a barrier island complex named the Return Islands. A barrier island coastal region about 40 miles long that includes Cross Island and the Midway Islands (Argo and Reindeer Islands), continues westerly to form a nearly continuous barrier island chain stretching from Stump Island to Thetis Island (Gibbs and Richmond, 2015). The island chain trends southeast–northwest and increases in distance from the mainland from east to west, from about 0.6 mile near Stump Island (closest to the West Dock Causeway) to more than 5 miles at Thetis Island. Most of the islands are low-lying and unvegetated to sparsely vegetated.

AGDC proposes to construct and operate the Gas Treatment Facilities in the PBU near the Beaufort Sea coast. The marine waters of the Kuparuk River Watershed would contain portions of these facilities (EPA, 2017b). AGDC proposes to widen the West Dock Causeway on the northwest corner of Prudhoe Bay and install an additional dock head, Dock Head 4, for use during construction of the Gas Treatment Facilities. The remaining land-based facilities constructed to support the Project would not affect marine waters.

Physical Environment

The sections below provide a summary of physical forces that influence conditions in and along the Beaufort Coastal Plain Subregion, such as temperature, wind and wave action, currents, water depth, and similar abiotic factors that shape the environment, specifically as it pertains to the Beaufort Sea marine water environment.

<u>Bathymetry and Sea Level</u>

Prudhoe Bay has relatively shallow water, weak tidal forcing, and frequent passage of strong storms that move through the region. In general, daily water levels are significantly affected by barometric pressure changes and wind stress (Sprenke et al., 2011). Water depths typically range from 1 to 10 feet in Prudhoe Bay and from 10 to 15 feet in the vicinity of the West Dock Causeway (see figure 4.3.3-1). Barometric water level variation in this region often exceeds the local tidal range, even during calm periods with no storm activity. In their 17-year study of North Slope sea level time series data from 1993 to 2010 and analysis of tide gage data at Prudhoe Bay, Sultan et al. (2010) found no significant changes in observed sea level, storm intensity, and storm duration within Prudhoe Bay.

Figure 4.3.3-1
Alaska LNG Project
Prudhoe Bay Bathymetry

Participants at traditional knowledge workshops on the North Slope commented that Prudhoe Bay is shallow; several workshop participants noted that nearshore areas are becoming increasingly shallow (Braund, 2016). Respondents noted lower water levels with the increasing appearance of boulders, sandbars, and land bridges between islands in the summer months and changes in location and size of ice ridges during winter months. These changes were specifically noted in the Point Thomson area east of the Project. Other respondents commented on how the ocean and coastal conditions are constantly changing, with barrier islands that shift over time, and weather conditions that can be unpredictable.

Tides, Waves, Winds, Currents, and General Circulation

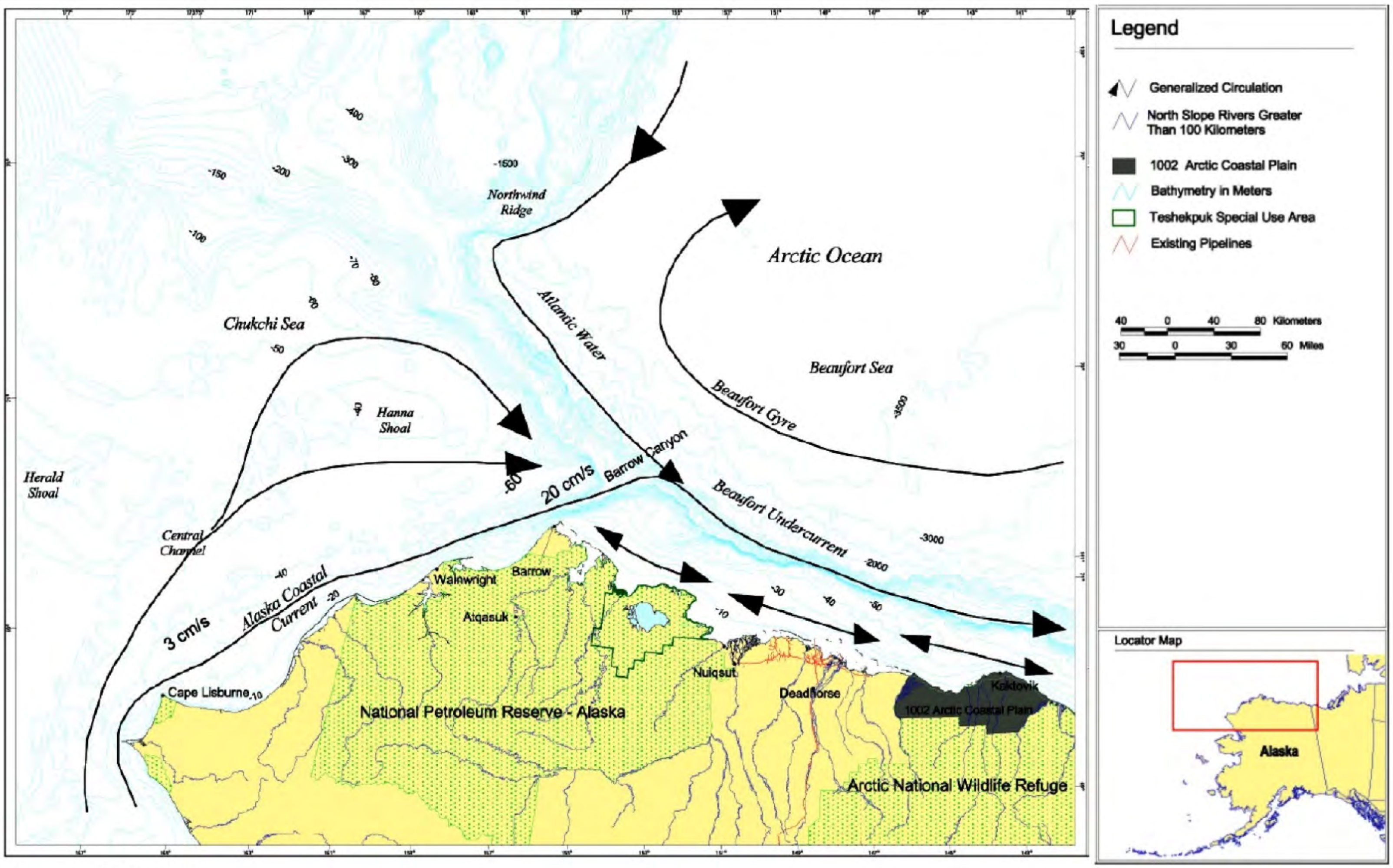
At Prudhoe Bay (NOAA Station ID 9497645), the average tide ranges from 0.1 feet mean low water to 0.6 feet mean high water (MHW) based on a local MLLW[40] datum, with the highest observed astronomical tide of 1.5 feet (NOAA, 2017g). Storm surges (storm-induced wave run-up) in Prudhoe Bay, however, can be large compared to the small tidal fluctuations. The 100-year return period storm surge (i.e., average amount of time between a specific sea level return exceeded in a particular region) is estimated at +4.9 feet MLLW and the 100-year storm set-down (i.e., drop in the water level; occurs when the body of water recedes from the upwind shoreline) is estimated at -3.6 feet MLLW (Sultan et al., 2010). Positive storm surges are associated with westerly winds, and negative storm surges are associated with easterly winds (U.S. Minerals Management Service [MMS], 2003). Wind-generated waves and currents are not well documented in Prudhoe Bay. In shallow waters, such as nearby Foggy Island Bay, wave height increases as a function of water depth (MMS, 2002). Therefore, shallow waters around the West Dock Causeway would limit the height of wind-generated waves.

Nearshore circulation in the Beaufort Sea consists of two distinct periods: open water (typically August and September) and ice covered (typically October to July) (MMS, 2003; ADNR, 2009a). Open water nearshore circulation is dependent primarily on wind, with wind direction more influential than wind speed (Short et al., 1990, as cited in MMS, 2003). The nearshore circulation is driven by wind, particularly in the summer; the winter nearshore circulation is not as energetic, but still wind-driven (Aagaard et al., 1989) (see figure 4.3.3-2) (MMS, 2003). The wind direction and how often it changes controls the direction of surface currents, the length of time water masses remain, and the amount of mixing that occurs between different water masses (MMS, 2003).

The two dominant wind directions in nearshore Beaufort Sea are northeast and southwest (Morehead et al., 1992; MMS, 2003). Under the influence of westerly trending winds, which are common in the fall and winter seasons, surface water moves to the east (MMS, 2003). On the other hand, the mean surface current direction year-round is to the west, which parallels the bathymetry (MMS, 2003). The nearshore surface water responds quickly (within 1 to 3 hours) when the wind direction changes from a sustained easterly (or westerly) and vice versa (Hanzlick et al., 1990 as cited in MMS, 2003).

Water moves toward or away from the shore in addition to it moving in an eastward and westward motion. Following periods of easterly winds, water moves from nearshore to offshore, causing a gradual removal of warm, brackish water from the nearshore, which is replaced by colder, saltier (marine) water. Water moves from offshore to nearshore under westerly winds, causing an accumulation of warm, less salty water along the coast and a depression of cold, saline marine water away from shore (MMS, 2003).

[40] MLLW is the lowest of the two low tides per day (or the one low tide) averaged over a 19-year period.



Source: MMS, 2002

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Figure 4.3.3-2
Alaska LNG Project
Generalized Circulation and Currents in Beaufort and Chukchi Seas

The West Dock and Endicott Causeways, to the east and west of Prudhoe Bay, are human-made structures that act as barriers (MMS, 1985). Development of these causeways (which occurred between 1975 and 1981) reduced water circulation and limited the mixing water masses in the nearshore Beaufort Sea near Prudhoe Bay (MMS, 2003). Specifically, the Endicott causeway in the Sagavanirktok River delta caused increased sedimentation in the lagoon area landward of the causeway within a few years of its construction. A study by Yager and Ravens (2013) indicated that fine-grained sediment has continued to deposit in the lagoon, and the deposition is related to the placement of the causeway. The depositing sediments were observed to be significantly finer than the native sediments. Further modeling and analysis indicated that the deposition rate has been decreasing, however, and would continue to decrease in the future if the structure remains in its current state (Yager and Ravens, 2013).

Unlike during the open-water season, when landfast ice (i.e., relatively immobile sea ice attached to shore) is present in nearshore areas, the ice insulates water and its circulation from the effect of winds (MMS, 2003). Other factors influencing the water circulation pattern in nearshore Beaufort Sea and Prudhoe Bay include storms and brine drainage (Weingartner and Okkonen, 2001; MMS, 2003).

During the open-water season, currents within the inner shelf (i.e., from the coast to the 65-foot depth contour) of the Beaufort Sea range from zero to more than 2.2 feet per second with the highest speeds occurring in summer and fall (Woodward-Clyde Consultants, 1998; Weingartner and Okkonen, 2001; MMS, 2003). Current speeds do not often exceed 0.3 feet per second during the ice-covered months of mid-October through June (MMS, 2003; Weingartner et al., 2009). The under-ice currents are typically slow moving, weakly sheared, and are not affected by the wind. Local residents' comments about nearshore currents are consistent with the aforementioned description of minimal nearshore current activity, especially inside the barrier islands, with wind being the primary driver of water movement close to shore. Traditional knowledge workshop participants also noted that more significant currents exist offshore about 15 miles in a strong west-to-east direction (Braund, 2016).

Stream and River Discharge

The Putuligayuk River, with a total basin area of 182 square miles, affects marine waters near the GTP and the PBTL corridor. This area is a low-gradient basin contained entirely within the coastal plain, contained by the Kuparuk River to the west and the Sagavanirktok River to the east (Kane et al., 2014). The Putuligayuk River has two primary tributaries to the south of the GTP, with the shorter tributary about 30 miles in length discharging directly into the Beaufort Sea west of the Sagavanirktok River (Hemming, 1993). Marine water can make its way upstream in this river near the coast, especially during low stream flow and/or high waters caused by storm surges. Regarding the seasonality of the Putuligayuk River, which ultimately also affects the two tributaries south of the GTP, the USGS Streamer website (USGS, 2018h) indicates that the river is completely frozen in winter showing no flow at their stream gauge. During breakup in the late spring/early summer, water levels in most rivers and streams on the North Slope reach or exceed their high-water marks and, in some cases, over-top the banks as the snow melts. Then, after breakup, the water levels drop down to normal flow, which is 42.3 cubic feet per second in the case of the Putuligayuk River (USGS, 2018h). According to Petrik and Reger (1991), the Putuligayuk River is extremely responsive to precipitation and snowmelt events and can be "flashy" under these circumstances. Ice jams also occur causing localized flooding (Kane et al., 2014).

The PTTL corridor would cross two other main waterbodies that affect Beaufort Sea marine waters: the Shaviovik and Kadleroshilik Rivers. The Shaviovik River is a braided stream system with headwaters flowing from the eastern Brooks Range, north through the Beaufort Coastal Plain Subregion, and discharging into the Beaufort Sea. The Kadleroshilik River is a coastal stream system that originates in the Brooks Foothills Subregion, flowing north through the Beaufort Coastal Plain Subregion, and discharging into Foggy Island Bay.

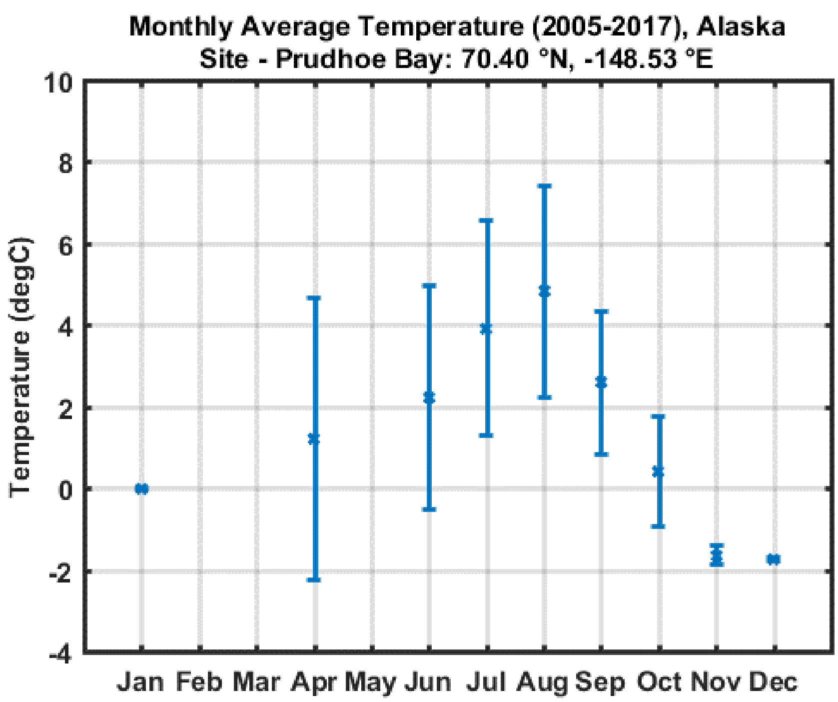
Water Column Temperature and Salinity

Between 1999 and 2007, temperature and salinity were measured in Prudhoe Bay as part of a larger study of the marine environment of the Alaskan Beaufort Sea (Weingartner et al., 2009). This study found that temperature and salinity vary seasonally in response to annual events (e.g., ice formation and melting, spring ice breakup, and wind mixing during the open-water season) and follow an annual cyclic pattern (Weingartner et al., 2009).

Based on data from 1999 to 2007 (Weingartner et al., 2009), salinity in Prudhoe Bay generally increases from about 26 to 28 parts per thousand (ppt) in September to a maximum of 34 to 35 ppt by January due to ice formation forcing a concentration of salt into the liquid water column. From January to May, salinity remains relatively consistent and decreases in June because of the large amount of fresh water flowing offshore during spring breakup. In August, salinity decreases to its lowest level of 15 ppt as wind mixes the fresh water into the full water column. Salinity returns to the September values of 26 to 28 ppt and repeats the annual cycle.

Temperature generally remains at or below the freezing point from October through July (Weingartner et al., 2009). As the open-water season begins, water temperature increases to about 40 to 45°F in July and August and fluctuates with weather patterns before returning to freezing conditions as ice cover returns.

NOAA has maintained a weather and water data buoy (National Ocean Service Station PRDA2) at Prudhoe Bay, and records are available online from 2005 to present. Figure 4.3.3-3 illustrates the monthly mean and standard deviation of temperatures in Celsius from the data gathered at National Ocean Service Station PRDA2 between April 2005 and December 2017 (NOAA, 2017a). Note that there were several months (February, March, and May) where temperature was not recorded for the entire period and there were few or no records in 2006 and 2007.



Source: NOAA, 2017a

Figure 4.3.3-3 Mean Monthly Sea Temperatures Recorded at Prudhoe Bay

Shoreline and Bottom Sediments

The shoreline of the Prudhoe Bay region between the Sagavanirktok River and Colville River deltas is characterized by low to moderately high tundra mainland coast with a chain of barrier islands in front of the shoreline (Gibbs and Richmond, 2015). The mainland coast has predominantly low to moderately high bluffs (less than 10 feet high) and low-lying landscape (less than 6 feet high) associated with drained thermokarst lakes and adjacent rivers, creeks, and drainages. Relatively higher bluffs (up to 15 feet high) are found near Heald Point on the eastern coast of Prudhoe Bay. Narrow beaches, composed of fine-to-coarse sand and fine granular material, are frozen most of the year and thaw during the summer months, but maintain permafrost underneath the thawed active layer.

Coastal currents generated by the predominant northeasterly winds drive sediment westward, while occasional northwesterly autumn storms drive sediment in the opposite direction.

The coast of Prudhoe Bay between Heald Point and Point McIntyre is partially exposed to open-ocean energy conditions; however, Cross Island and the Midway Islands, which are about 10 miles offshore, and the West Dock Causeway could dampen incident wave energy. Between Point McIntyre and the Colville River, the mainland coast is separated from the barrier island chain by Gwydyr Bay and Simpson Lagoon (Gibbs and Richmond, 2015).

Shoreline change along the Prudhoe Bay coast between Heald Point and Point McIntyre are predominantly erosional with shoreline erosion rates averaging -2.6 feet per year and ranging from -8.2 to +3.6 feet per year (Gibbs and Richmond, 2015). The only significant accretion (greater than +1.0 feet per year) along the shoreline, measured at Heald Point, was associated with an artificially hardened shoreline from oil and gas development (Gibbs and Richmond, 2015). Additional details regarding bottom and subsurface soil and sediment conditions are provided in section 4.2.3.

Sea Ice

Sea ice, a dominant feature of the Arctic Region marine environment, generally covers or is present within the Beaufort Sea shelf for about 10 months of the year (October to July). Ice encroachments, referred to as *ivu* in the local Inupiat language, occur when sea ice is forced onshore by strong winds or currents (Rozell, 2015). The wind can push a sheet of ice or pile of debris forward (ride-up) or cause it to form a pile of ice near the shore (pile-up). Ivu events usually consist of a combination of pile-up and ride-up. Ice pile-up occurs when the incoming ice floe encroaches upon the shoreline and breaks into pieces forming a rubble pile. Then, the ice floe tends to continue to break apart at the same location, causing a rubble pile to grow vertically and horizontally as rubble falls down the pile slopes. In contrast, ice ride-up occurs when the ice deforms like plastic, or becomes broken without overturning, and overruns the land while remaining basically an intact ice sheet, sometimes resulting in ice rubble and sediment being shoved as much as several hundred feet inland during extreme conditions (ADNR, 2009a; DOI, 2003a).

While the Prudhoe Bay area is partially protected by barrier islands, ice pileup has been known to occur on the West Dock Causeway, where ice rubble up to 20 feet high was reported in the late 1970s (Kovacs, 1983; DOI, 2003a). Generally, landfast sea ice protects the coastline from ivu events and limits coastal erosion. Arctic coastal communities recognize that sea ice conditions are not what they once were due to a variety of reasons, however, such as the ocean freezing later in the fall and the ice melting earlier in the spring; landfast ice being less stable; less thick multiyear ice occurring than in the past; and environmental conditions overall being less predictable (Environment Canada, 2013). Later freezing and earlier thawing of sea ice was also noted by local residents during traditional knowledge workshops, with consistent records that refer to less ice and shorter duration of landfast ice along the coast (Braund, 2016). The formation and breakup of the landfast ice appears to be a complex interaction of several forces in any number of combinations. These forces may include wind vectors; currents; air and ocean temperatures; storm surges; pieces of moving ice floes acting like a chisel (*tuuq* in Inupiat) on the landfast ice; a sudden drop in sea level, tides, ice-surface melt, and bottom melt; and the weak points in shorefast ice where new sections of ice were most recently added (George et al., 2004). Figure 4.3.3-4 depicts ice conditions for Prudhoe Bay for July and August 2015 and 2016, which are the months during which marine resources would be affected by shipping during Project construction.

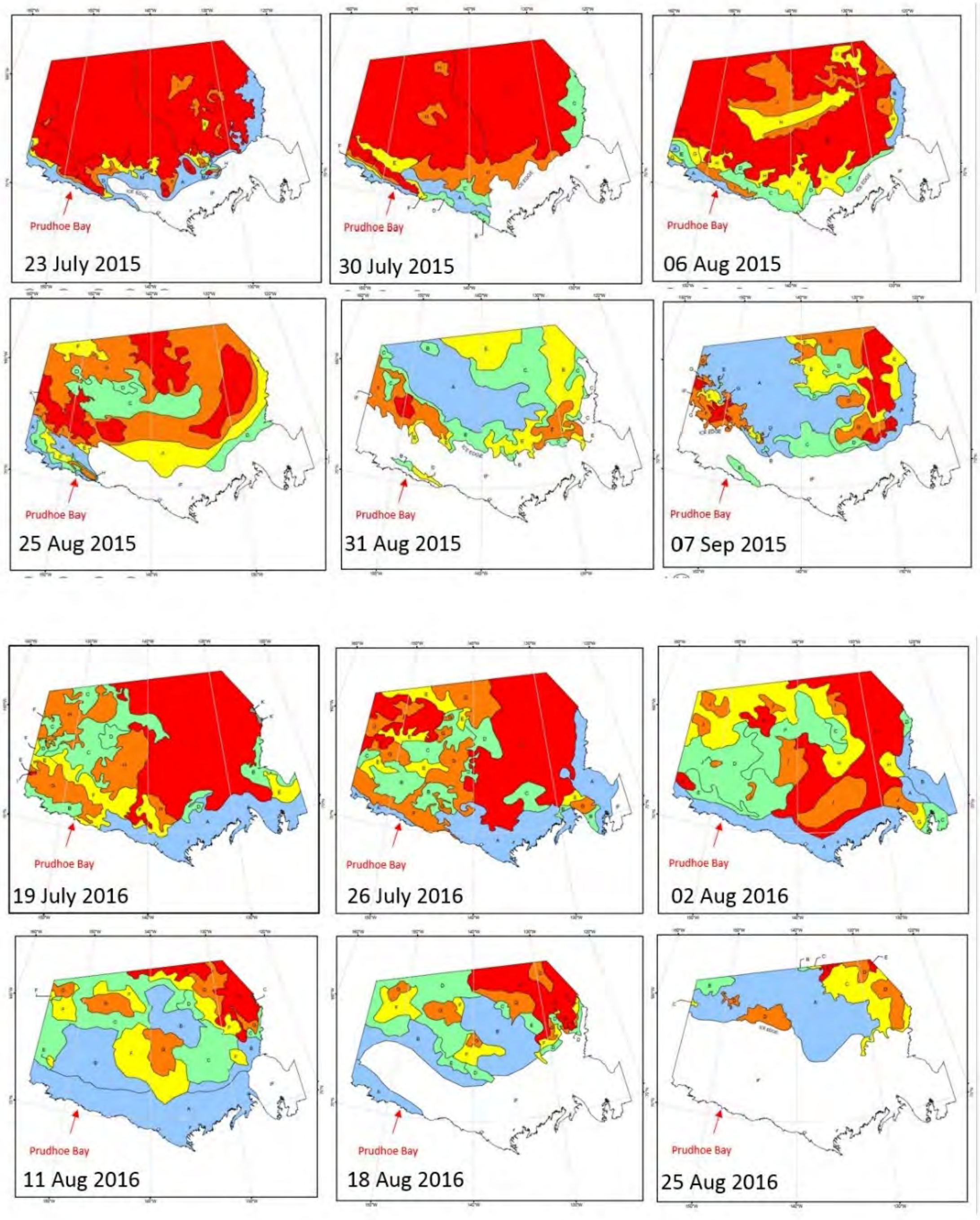
Typically, grounded ice extends to depths of 6 or 7 feet. In the spring, floating landfast ice can extend up to about 40 miles from the shore (DOI, 2003a). In the summer, the ice pack retreats up to about 50 miles from shore, but winds can bring floes back at any time (LGL Alaska Research Associates, Inc. et al., 1998). The *stamukhi* zone, or shear zone, is seaward of the landfast ice and is the zone where the mobile pack ice covering the Arctic Ocean grinds from east to west past the landfast ice (DOI, 2003a). Intense ice gouging of the seafloor, generally within 60 and 100 feet of water depth, can occur from ice ridges and keels moved by the mobile pack (ADNR, 2009a).

Water Quality

Seawater in Prudhoe Bay contains naturally occurring constituents derived from atmospheric, terrestrial, and freshwater environments, as well as those derived from human activities. Most contaminants in the Beaufort Sea and on the Beaufort Coastal Plain Subregion occur in low levels (EPA, 2009a). Sampling results for water, sediment, and fauna collected as part of the Arctic Nearshore Impact Monitoring in Development Area Project corroborate that conclusion (Brown et al., 2005; Neff, 2010). Concentrations of dissolved metals in seawater throughout the coastal Beaufort Sea are similar to, or less than, world average values in coastal and marine areas (EPA, 2009a). Regional sediment samples collected for the Arctic Nearshore Impact Monitoring in Development Area Project in 1999 were analyzed for metals, PAHs, and other organic compounds. Using older data for comparison, the concentrations of metals in the sediment samples were found to be representative of natural background conditions.

Possible sources of hydrocarbons in marine waters are natural occurrences such as exposed coal seams, natural outcrops, and peat erosion that are transferred by streams and along the coast to the ocean (MMS, 1996c). Two marine water samples were collected in Lion Bay near the Project area in 2002 as part of the Point Thomson Project and analyzed for total aromatic hydrocarbons, polynuclear aromatic hydrocarbons, and total aqueous hydrocarbons (COE, 2012). None of these parameters were detected.

Trace metals naturally occur in the Beaufort Sea and are introduced from coastal erosion, fresh water inputs, and atmospheric deposition. The background concentrations of trace metals in Lion Bay are relatively low or below detection limits. During 1998, trace metals were analyzed in water samples from Lion Bay as part of the Point Thomson Project. Of the metals analyzed (arsenic, barium, chromium, lead, and mercury), only barium was detected. Barium concentrations ranged from 0.015 to 0.020 mg/L. There are no aquatic life water quality standards in a marine environment for barium. Arsenic, barium, cadmium, chromium, lead, magnesium, nickel, and zinc were analyzed in two marine water samples collected from Lion Bay near the Project area in 2002 (COE, 2012). Arsenic and nickel were not detected. The other metals were detected in at least one of the samples at concentrations that were in compliance with water quality standards.



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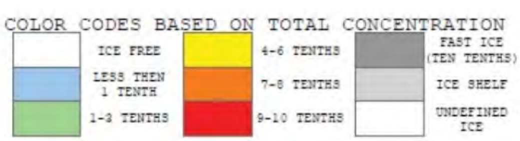


Figure 4.3.3-4
Alaska LNG Project
Selected National Ice Center Weekly Ice Charts,
Summers 2015 (top) and 2016 (bottom)

4.3.3.2 Cook Inlet

Cook Inlet is a tidal estuary extending south from the Anchorage area and that opens into the GOA with a basin area of about 12,000 square miles. There are two extensions, the Turnagain Arm (an easterly extension) and the Knik Arm (a northerly extension), at the northern end of Cook Inlet. Cook Inlet is about 220 miles in length, ranging from 60 miles wide at the mouth to 15 to 20 miles wide in Upper Cook Inlet. A general description of Cook Inlet, which would contain the marine components of the Project, is provided in this section. AGDC proposes to construct, as part of the Liquefaction Facilities, a Marine Terminal that would include the PLF and a temporary Marine Terminal MOF adjacent to the LNG Plant in Cook Inlet. Additionally, AGDC would construct the Mainline MOF near Beluga Landing and the Mainline Pipeline across Cook Inlet from a point near Tyonek (also referred to as the Beluga Landing South Shore Approach) and a point near Nikiski (also referred to as the Suneva Lake Shore Approach).

Physical Environment

Bathymetry and Sea Level

The bottom of Cook Inlet is rugged with deep pockets and shallow shoals. The depths in the upper inlet north of the Forelands, where Cook Inlet narrows near the Liquefaction Facilities illustrated on figure 4.3.3-5, are generally less than 115 feet. The deepest portion of Cook Inlet north of the Forelands is within Trading Bay, east of the mouth of the McArthur River. South of the Forelands, two channels extend southward on either side of Kalgin Island and connect in an area west of Cape Ninilchik. South of the cape, this channel gradually deepens to about 475 feet and widens to extend across the mouth of Cook Inlet from Cape Douglas to Cape Elizabeth. Water depths in the center of the channel in Cook Inlet can range from 60 feet to more than 500 feet with some of the deepest portions at the strait between the Forelands, thus constricting Cook Inlet into two distinct regions, Upper Cook Inlet and Lower Cook Inlet (NOAA, 2017d).

Water depths along the Mainline Pipeline crossing of Cook Inlet range from 0 feet at each shore crossing to a maximum depth of about -139 feet MLLW. The deepest portion along the Mainline Pipeline crossing of Cook Inlet is generally slightly offset to the west of the center from west to east across Cook Inlet. Average water depth along the route is -80 feet MLLW. Most of the route is in water depths of -70 to -90 feet MLLW with the exceptions of the shore approaches and two locations where tidal channels have been incised into the seafloor to depths of about -140 and -130 feet, respectively. Water depths at the Marine Terminal extend to greater than -53 feet at the berthing pier and at the Mainline MOF range from -12 to -41 feet MLLW.

Researchers were able to determine that at high tide (MHW), the total volume of the inlet is 270.5 trillion gallons (1,024.1 cubic kilometers [km^3]) of water and the total surface area is 7,930.5 square miles (mi^2) (20,540 km^2). When the tide drops from MHW to MLLW, the Inlet loses 26.4 trillion gallons (99.7 km^3) of water, or 9.7 percent of its volume, and exposes 623.9 mi^2 (1,616 km^2) of seabed, or 7.9 percent of its surface area (Zimmerman and Prescott, 2014).

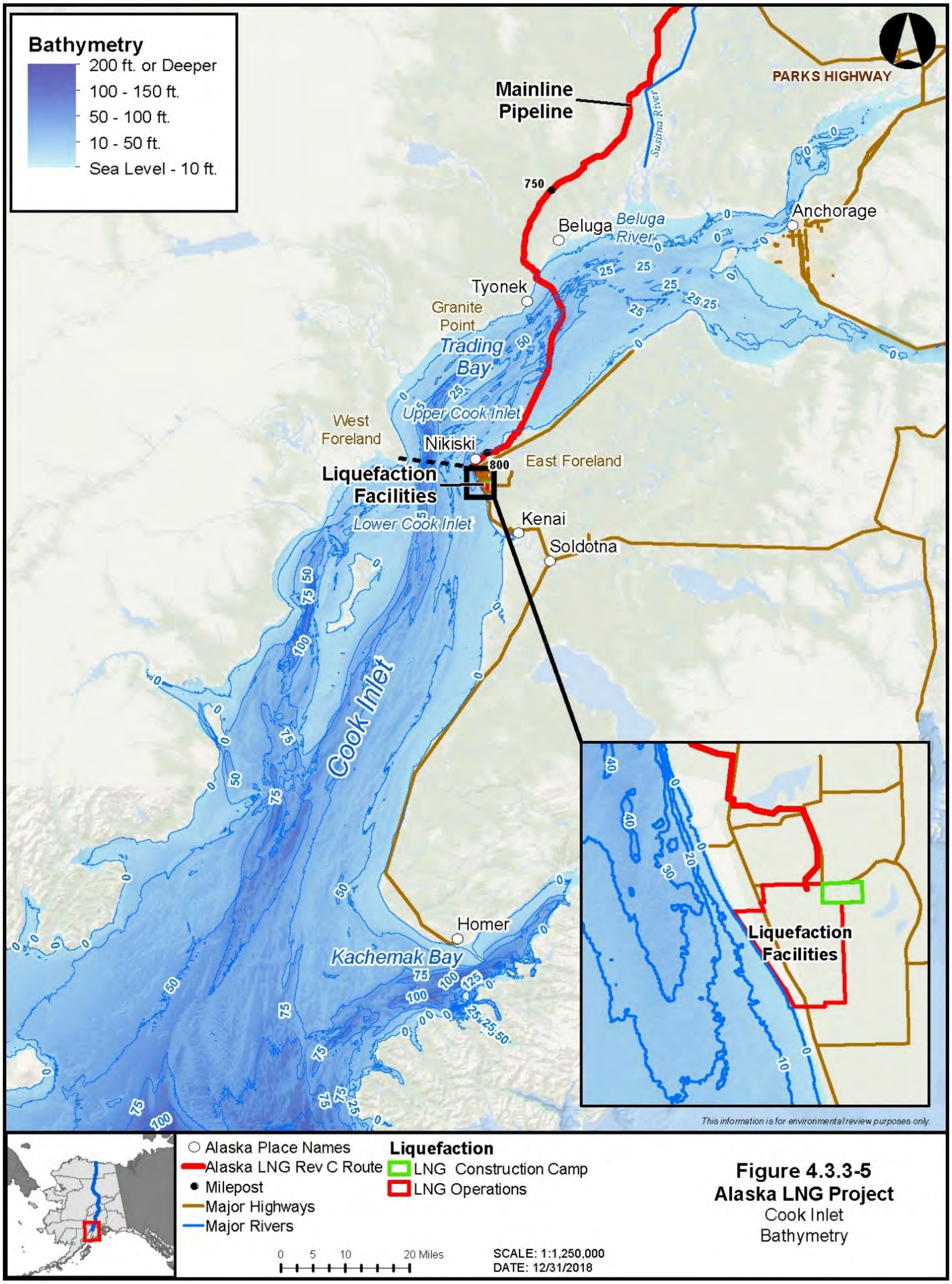


Figure 4.3.3-5
Alaska LNG Project
Cook Inlet
Bathymetry

Numerous features, including sand waves, scour depressions, channeling, lag deposits, and boulder fields have been mapped along the Mainline Pipeline route and are indicative of the inlet's significant tidal currents. The seafloor can generally be described as worn flat and current swept, interspersed with areas of sand waves, boulder fields, and channels. Several sand wave areas (dynamic features on the inlet floor that are low ridges of sand formed by wave action or water currents) of 0.2 mile to more than 3 miles in length are crossed by the route. The sand waves are oriented in a northeast to southwest dip direction paralleling the tidal currents. Wave lengths in the sand wave fields typically measure 40 to 50 feet, with some approaching 100 feet. The sand wave height is typically about 5 feet. While the surface of sand waves can be mobile, larger sand waves may remain static. Three distinct buried channels have also been mapped along the Mainline Pipeline route, which are geomorphic features that consist of relict erosional or alluvial sediment and typically consist of coarse granular substrate.

The permanent Marine Terminal PLF used for LNG export operations would consist of two mooring berths, breasting dolphins, and interconnecting walkways. The berths would be in natural water depths greater than -53 feet MLLW. The Marine Terminal MOF would be a temporary facility used for the duration of LNG Plant construction, which would last about 10 years. AGDC intends to remove the temporary facility after LNG Plant operation begins. The maneuvering area and berths at the Marine Terminal MOF would need to be dredged to the depths of -30 and -32 feet MLLW, respectively. Over-dredge could require an additional allowance of no more than -2 feet. Figure 2.1.5-6 shows the Marine Terminal MOF and associated bathymetry in the area.

AGDC evaluated options for dredged material disposal and identified an open-water disposal location about 4 miles offshore and west of the Marine Terminal MOF. An alternative open-water disposal location was identified in deeper water. Figure 2.1.5-7 provides the location of the two disposal locations and their bathymetry. DP1 is the shallower of the two disposal locations (between -60 and -85 feet MLLW); and DP2 is the deeper of the two disposal sites (between -85 and -110 feet MLLW).

<u>Tides, Waves, Winds, Currents, and General Circulation</u>

The Cook Inlet tidal range is among the largest in the United States (Molchan-Douthit, 2007). Traditional knowledge workshop participants commented on the large tides and strong currents within Cook Inlet, with tides that are the greatest in Alaska and some of the most dramatic worldwide (Braund, 2016). Tides are mixed semi-diurnal (two unequal high and two unequal low tides occur per tidal day [24 hours, 50 minutes long]) with the mean tidal range increasing northward (COE, 2013a). Mean daily tidal range varies from 13 feet at the inlet mouth to about 29 feet at Anchorage (COE, 2013a). Twice each month, tidal ranges are a little larger than average during either a full or a new moon. In both cases, the gravitational pull from the sun and moon combined make high tides slightly higher and low tides slightly lower. During spring tides, the highest and lowest tides may exceed the mean high and mean low tides by more than 6.5 feet (Wilson, 2006). Tidal ranges in Cook Inlet are higher on the east side of the inlet due to the Coriolis Effect (rotation of the Earth) on the advancing tidal wave.

At Nikiski (NOAA Station ID 9455760), the average tide ranges from the mean low water of 2.1 feet to the MHW of 19.9 feet, with a highest observed astronomical tide of 25.6 feet (all data values are relative to MLLW; NOAA, 2017f). Overall, Cook Inlet has a maximum tidal range of 13 to 39 feet depending on location, which produces rapid tidal flows and strong riptides. In addition, tidal bores of up to 10 feet sometimes occur in Turnagain Arm (Alaska Channel, 2017).

Cook Inlet storm surges (storm-induced wave run-up) are small compared to tidal fluctuations. The waves in upper and central Cook Inlet are fetch (i.e., the distance traveled by wind or waves across open water) and depth limited, and wave heights are generally less than 10 feet. In storms, waves in Upper Cook Inlet can reach as high as 15 feet with wave periods up to 6 to 8 seconds (EPA, 2009b).

At the Cook Inlet entrance, the tidal currents have an estimated velocity of 3.4 feet/second (2 knots) to 5.3 feet/second (3 knots). The tidal currents then increase toward the head of the inlet with very large velocities in the vicinities of Harriet Point, East and West Forelands, and the entrances to Knik and Turnagain Arms where they are reported to be strongest (NOAA, 2016). NOAA estimated that the velocity of the current during a large tide is as much as 13.5 feet/second (8 knots) to 15.2 feet/second (9 knots) between East and West Forelands and probably more between Harriet Point and the south end of Kalgin Island (NOAA, 2016). Current speeds of up to 20.0 feet/second (12 knots) have been reported, though not verified, near Kalgin Island and Drift River (ADEC, 2010). Near the Project area, tidal currents average 8.9 feet/second (5.3 knots) at the Forelands near Beluga Landing (NOAA, 2014; LaRoche and Kenai Borough, 2007). Strong currents are noted by local and traditional knowledge in the areas of the Forelands, Flat Island, Point Pogibshi, Point Adams, Kalgin Island, and Kennedy Entrance. Areas where there is a "choke point" are areas where the current can be strongest. In addition, local residents generally note that the current in Cook Inlet can also vary with water depth (Braund, 2016).

Many factors influence the circulation of water in Cook Inlet: the shape of the inlet, bathymetry, fresh water input from rivers, the Coriolis Effect, the Alaska Coastal Current, and semidiurnal tides. Marine water enters the inlet on the southeast during flood tide and progresses northward along the east shore with minor lateral mixing. This water is colder and has fewer suspended sediments than the waters of Cook Inlet. South of the Forelands, mixing with turbid inlet water becomes extensive. The major fresh water inputs come from rivers discharging into Upper Cook Inlet and along the west shore. Turbid water moves south primarily along the north shore during the ebb tide and a shear zone between the two water masses forms mid-inlet, south of Kalgin Island. Local shore configuration, bottom contours, and possibly wind effects in some shallow areas also influence current velocities.

Currents in Upper Cook Inlet (north of the Forelands; see figure 4.3.3-5) are classified as reversing currents: as the flow changes to the opposite direction, it is briefly near zero velocity at each high and low tide. The Upper Inlet, therefore, experiences strong turbulence and vertical mixing during each tidal cycle, resulting in relatively uniform water properties throughout the water column. Strong tidal currents in Upper Cook Inlet can oppose wind-generated waves, making the waves steeper and more chaotic (COE, 2013a).

Upwelling, the process in which deep, cold water rises toward the surface, occurs along the outer Kenai Peninsula coast northwest of the Chugach Islands. Fronts occur as GOA water encounters fresh water outflow from Upper Cook Inlet. These convergent zones are termed "tide rips." These are concentrations of longitudinal tidal currents in Cook Inlet that result in residual vertical circulation that forms lines of slicks and flotsam at laterally convergent zones and erratic steep wave motion in divergent zones (Haley et al., 2000). Three tide rips are often evident in central Cook Inlet, extending from the vicinity of the Forelands to beyond the southern tip of Kalgin Island. The surface expressions of the tide rips can change position and strength considerably during the tidal cycle. These tide rips can accumulate and deposit debris, ice, and other sediments.

Data from NOAA Current Station COI0802, which is the closest NOAA Acoustic Doppler Current Profiler (ADCP) station near the Project, shows that near the Marine Terminal site, the depth-averaged current maximum velocity is 5.0 feet/second (3 knots) with a probability of exceedance of 10 percent or 7.0 feet/second (4.1 knots) with a probability of exceedance of 2 percent. Farther offshore at NOAA Station CO10504 (about 1 nautical mile toward the center of Cook Inlet) the current speed slightly increases to 6.5 and 8.0 feet/second (3.5 and 4.7 knots). The locations of the two NOAA ADCP stations near the Marine Terminal are shown on figure 4.3.3-6.

Figure 4.3.3-6
Alaska LNG Project
NOAA ADCP Station Locations near the Marine Terminal

AGDC measured site-specific currents in 2015 and 2016. The subsequent Extreme Value Analysis[41] showed that depth-averaged current speed can reach 6.9 feet/second (4.1 knots) for a 1-year return period and 7.4 feet/second (4.4 knots) for a 100-year return period.

AGDC selected the two dredged material disposal locations (see figure 2.1.5-7) because of their deep water (between -60 to -110 feet MLLW) with strong currents (over 11 feet/second [6.5 knots] peak flood and over 9 feet/second [5.5 knots] peak ebb), which should disperse dredged sediment placed at either site and prevent mounding of the material. Each dredging material disposal sites has the capacity to receive all of the anticipated dredged material from the Project.

Stream and River Discharge

Fresh water input is important in determining the circulation within Cook Inlet. Only a few of the rivers are gauged for measuring discharges, however, and those measurements are not possible when the river is covered with ice. Through the summer, there is considerable variability in the discharge associated with rainfall within the drainage basin, but in general, the flow decreases from June through August. In September, it is dramatically reduced as snowmelt ceases and precipitation changes to snow (Okkonen et al., 2009).

Stream and river discharges near the Mainline Facilities include:

- Knik Arm area: Knik River (near Palmer), Matanuska River (near Palmer), Peters Creek (near Birchwood), Eagle River (northeast of Anchorage), Ship Creek (near Anchorage), and Chester Creek (at Arctic Boulevard);
- Turnagain Arm: Campbell Creek (at Anchorage), Glacier Creek (at Girdwood), Portage Creek (at Portage Lake outlet), and Resurrection Creek (near Hope); and
- Cook Inlet (west side): Susitna River (at Gold Creek), Susitna River (at Susitna Station), and Little Susitna River (near Palmer).

As summarized in the Bureau of Ocean Energy Management (BOEM) (formerly MMS) final EIS for the Cook Inlet Planning Area Oil and Gas Lease Sales (MMS, 1996b), the mean annual discharges from several of these major sediment sources into Cook Inlet are less than the mean discharge during the ice-free season. For the Knik, Matanuska, and Susitna Rivers, mean monthly discharge rates from November through March are about 2 to 9 percent of the peak discharge that occurs from these same rivers during June or July, and an estimated 99 percent of the suspended particulate matter is carried during the ice-free period (MMS, 1996b). Mean suspended sediment concentrations during the ice-free period from the Knik and Matanuska Rivers are 1,130 and 1,564 mg/L, respectively.

Stream and river discharges near the Liquefaction Facilities on the east side of Cook Inlet are much smaller than the discharges along the west side of Cook Inlet near the Mainline Facilities. Rivers that discharge along the eastern side of Cook Inlet include the Kenai River, Kasilof River (near Kasilof), Ninilchik (at Ninilchik), and Anchor River (at Anchor Point) (MMS, 1996b). For this region, one of the highest annual discharges is from the Kenai River at 5,939 cubic feet per second, which constitutes over half the discharge on the east side of Cook Inlet. As a comparative example of sediment load, during the

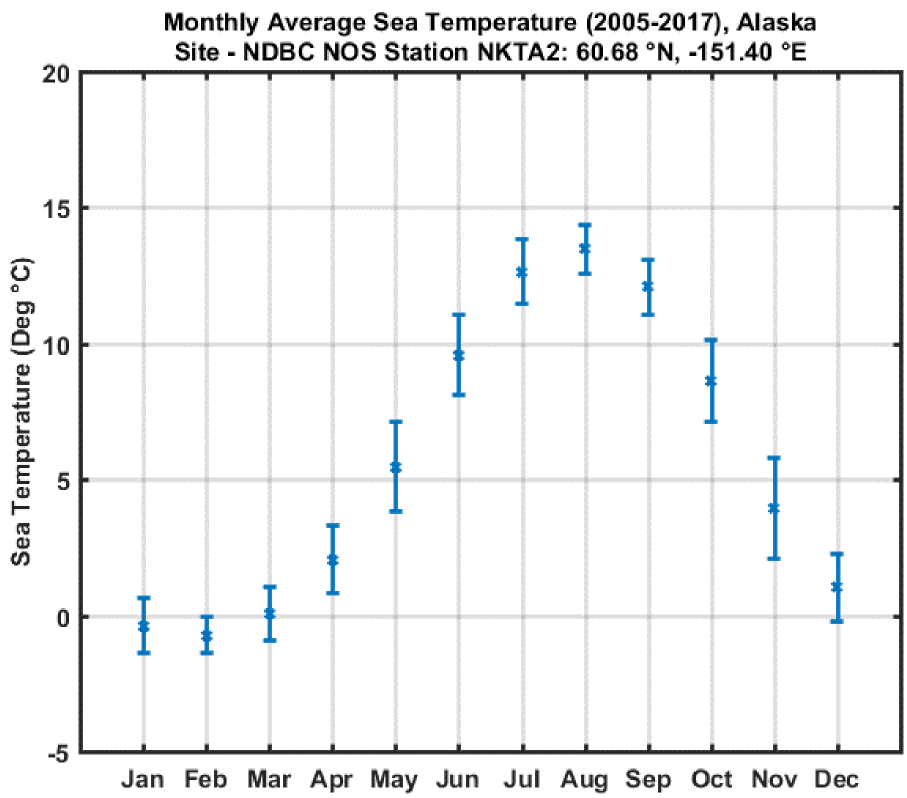
[41] Extreme Value Analysis is a statistical tool to estimate the likelihood of the occurrence of extreme values based on a few basic assumptions and observed/measured data (Benstock and Cegla, 2017).

ice-free period for this region, the mean suspended sediment concentration from the Ninilchik discharge area is 58 mg/L, which has a mean annual discharge of 121 cubic feet per second (MMS, 1996b).

Water Column Temperature and Salinity

Salinity increases rapidly and almost uniformly down Cook Inlet, from Point Possession to East and West Forelands. Slightly higher salinities are found on the east side of Cook Inlet. This rapid increase can be attributed to heavily loaded glacial runoff from the Matanuska, Susitna, and Knik Rivers, and subsequent sediment settling in Upper Cook Inlet. Local areas of depressed salinity occur off the mouth of large glacially fed streams, such as the Tuxedni, Kenai, and Kasilof Rivers (ADEC, 2010). Spring and fall mean salinities near the Project area (i.e., West and East Forelands) range from 22.6 ppt in the fall to 25.7 ppt in the spring (Okkonen and Howell, 2003).

NOAA has maintained a weather and water data buoy at Nikiski, and records are available online from 2005 to the present. The monthly mean and standard deviation of temperatures in Celsius from the data gathered from April 2005 to December 2017 are shown on figure 4.3.3-7 (NOAA, 2018c).



Source: NOAA, 2018c

Figure 4.3.3-7 Mean Monthly Sea Temperatures Recorded at Nikiski

Shoreline and Bottom Sediments

Seabed sediments for Upper Cook Inlet are dominated by sand, granular material, and large stones with isolated areas of higher silt concentration. The rivers entering Knik Arm annually discharge 13 million to 19 million tons of sediment, primarily in the summer (Gatto, 1976). Bluffs ranging from 20 to 120 feet in height span along both shores of Cook Inlet. The bluffs are composed of glacially deposited till, a widely graded mix of clay, silt, sand, granular material, and intermittent larger rocks. Additional details regarding bottom and subsurface soil and sediment conditions are provided in section 4.2.3.

The average sediment particle grain size at sites in the middle of Cook Inlet are coarser, while those on the west side of the inlet are finer. The predominance of coarser grains that occur in the middle of the inlet is influenced by the degree of exposure to wave action and currents at Kalgin Island and by the number of highly exposed shoals. In contrast, the west side of the inlet, especially toward the north, receives heavy loads of fine-grained, suspended sediments from the many river systems feeding from glaciers (Lees et al., 2001). Boulders are found as isolated boulders or in boulder fields with shallow depressions in the seafloor that are apparently scoured by currents moving around the boulders. Several erosional scarps have been mapped along the Mainline Pipeline route corridor, with the route crossing one scarp with a height of about 8 feet above the surrounding seafloor.

The coastal bluffs along the shore of Cook Inlet are receding in response to natural processes: wave action, precipitation, and wind. Eroding bluffs are a major source of sediment supply to Knik Arm and the rest of Cook Inlet (Smith and Hendee, 2011). The steep slopes are characteristic of the topography that would be crossed on both sides of Cook Inlet for the Mainline Pipeline crossing. The steep slopes, loose nature of the bedrock, and the tendency for the soils to become saturated with water make the Cook Inlet bluffs vulnerable to landslides. Intense tidal currents then redistribute this sediment. Most of the sediment is deposited on the extensive tidal flats or is carried offshore through Shelikof Strait. Longshore transport of sediment within Cook Inlet is generally up the inlet, although Kamishak, Tuxedni, and Kachemak Bays are areas where this trend is reversed. Homer Spit is maintained by longshore sediment transport from the north (LaRoche and Kenai Borough, 2007). Rain and snow events and glacial dam flooding also deposit significant amounts of sediment into Cook Inlet (ADEC, 2017c).

Geophysical surveys were conducted in the nearshore area around the Liquefaction Facilities. Sand waves were mapped throughout the marine facility area and in the approach channel where they occur in narrow strips all oriented in a north–south direction, paralleling the tidal currents. Rock ridges were observed paralleling the coastline extending out from the north edge of the nearshore Marine Terminal area. The parallel rock ridges generally display a relief of only a few feet rising up to 5 feet in height. The western section of the Marine Terminal area is generally smooth with scattered seafloor depressions and a few isolated boulders.

The suspended sediment concentration within Cook Inlet is temporally and spatially variable and heavily influenced by glacier and non-glacier fed streams that predominantly enter the basin at the northern arm. Sediment loading from these streams tends to increase in the summer (May through August) due to glacier runoff and storms and can frequently exceed 1,000 mg/L. In contrast, sediment concentrations are typically lower during the winter months when stream flow is small, on the order of 10 to 20 mg/L. The sediment concentration also tends to decrease over orders of magnitude from north to south within the inlet due to the high sediment load from streams at the northern end of Cook Inlet (CH2M Hill, 2016b). Shore-based field measurements in the Project area in September 2015 indicate total suspended solids (TSS) estimates ranging from 220 to 1,113 mg/L depending on the day measured and the tidal cycle (CH2M Hill, 2016b).

Sea Ice

Sea ice occurs in the central and northern Cook Inlet from late fall to early spring, and though construction would occur outside this period and thus not be affected by ice cover, certain aspects of operation (e.g., vessel traffic) could be affected by the presence of sea ice. Local observations and traditional knowledge workshop participants suggest that the northern portion of Cook Inlet near the communities of Kenai, Ninilchik, Nikiski, and Anchor Point experience more ice buildup than the rest of the Cook Inlet region (Braund, 2016). Sea ice has caused damage to docks and oil exploration platforms, broken mooring lines of vessels, or entrapped vessels during heavy ice conditions (Braund, 2016).

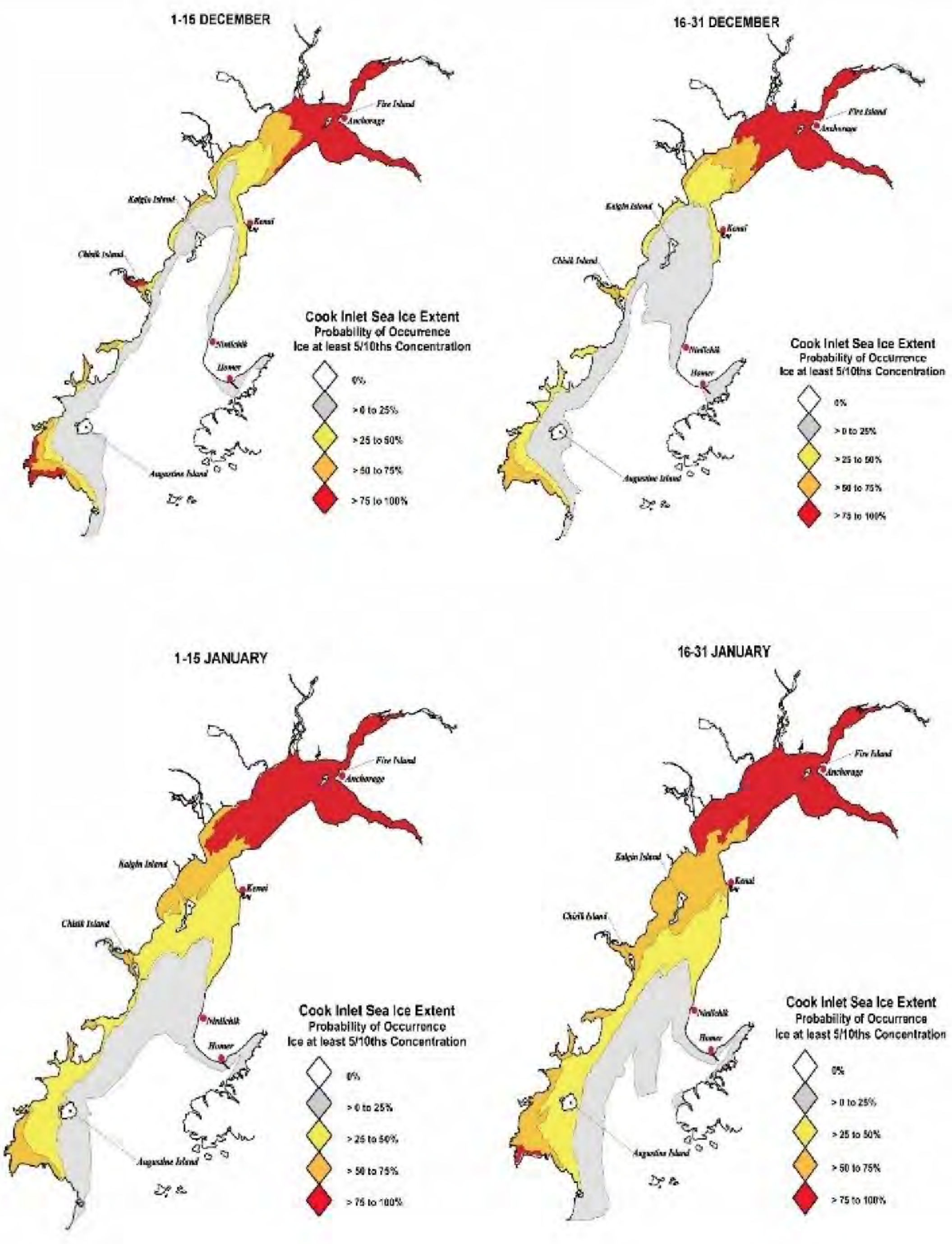
During winter, Cook Inlet can have significant ice coverage, especially in the northern inlet. The *Marine Ice Atlas for Cook Inlet, Alaska* prepared by the COE (Mulherin et al., 2001) contains ice coverage data in terms of ice thickness and concentration in the form of biweekly maps for the months of December through March based on a 13-year record between January 1986 and April 1999.

In late March or early April, the only ice remaining in the inlet are large chunks of beach ice and grounded pieces of pressure ridges formed offshore (Mulherin et al., 2001). The probability of occurrence for sea ice at least 5/10ths concentration (concentration is a relative measure of the water surface that is actually covered with ice) from December to March of any given year is depicted on figures 4.3.3-8 and 4.3.3-9.

Sea ice can occur in Cook Inlet as first-year medium stage and in the form of medium floes up to 1,000 feet wide. First-year ice is sea ice of not more than one winter's growth with thickness of about 12 inches to 2 yards. Medium first-year ice is typically between about 28 to 47 inches thick (NOAA, 2007). Other types of ice that form in Cook Inlet are beach, estuarine, and river ice. Beach ice (also known as shorefast ice) starts forming when frozen mud is exposed to the air by the ebbing tide. At flood tide, water in contact with the frozen mud also freezes. It can float away during extreme high tides and circulate throughout the inlet. Beach ice conglomerates are generally dark and can be difficult to see. Relatively thick beach ice is the last to melt in Cook Inlet in spring. Although blocks of floe ice generally reach a thickness of less than 3 feet in Cook Inlet, grounding of these blocks can form large piles (called *stamukhi*). Stamukha formation begins with the formation of beach ice when the incoming tide water forms thin, bottom-fast ice on cold-soaked mud flats. High tides then deposit floating cakes and brash on top of the bottom-fast ice, and then become stranded by the ebb tide (Smith, 2000 as cited in Mulherin et al., 2001). In the past, a single stamukha was reported exceeding 40 feet in thickness (Combellick et al., 1995; Hutcheon, 1972b). Floating stamukhi can represent a disturbance to the portion of the Mainline Pipeline that is not buried and a danger for ships traversing the inlet.

Freshwater ice that forms in estuaries and rivers also occurs in Cook Inlet near Knik and Turnagain Arms. Estuarine ice has similar characteristics as pack ice (sea ice) but is considerably stronger and tends to remain firmly attached to the surrounding shoreline (Mulherin et al., 2001). Wind-driven turbulence that occurs in the upper inlet (north of the Forelands) can entrain estuarine ice with moving pack ice, increasing the ice floe strength. River ice is significantly harder than sea ice and is unaffected by tidal action or wind until spring breakup. At that time, a considerable amount of river ice, with pieces up to 6 feet thick, may be discharged into the inlet (Hutcheon, 1972a).

Ice conditions specific to the Marine Terminal area in Lower Cook Inlet are less severe (e.g., shorter duration of ice and thinner ice) than those for the Upper Cook Inlet. The mean ice condition maps indicate that new ice (about 0 to 4 inches) typically encroaches the Nikiski terminal area in mid- to late-December and lasts through the end of March. The ice thickness and concentration at Nikiski from December through March for the maximum, mean, and minimum ice conditions is provided in table 4.3.3-1. As shown, the mean ice thickness at Nikiski is about 4 inches in January with 30- to 40-percent surface area coverage, and the thickness increases up to 12 inches with about 50-percent surface area coverage in February and the first half of March.



Mulherin et al., 2001

This information is for environmental review purposes only.

Figure 4.3.3-8
Alaska LNG Project
Probability of Occurrences 5/10th Ice Concentration in Cook Inlet for December and January

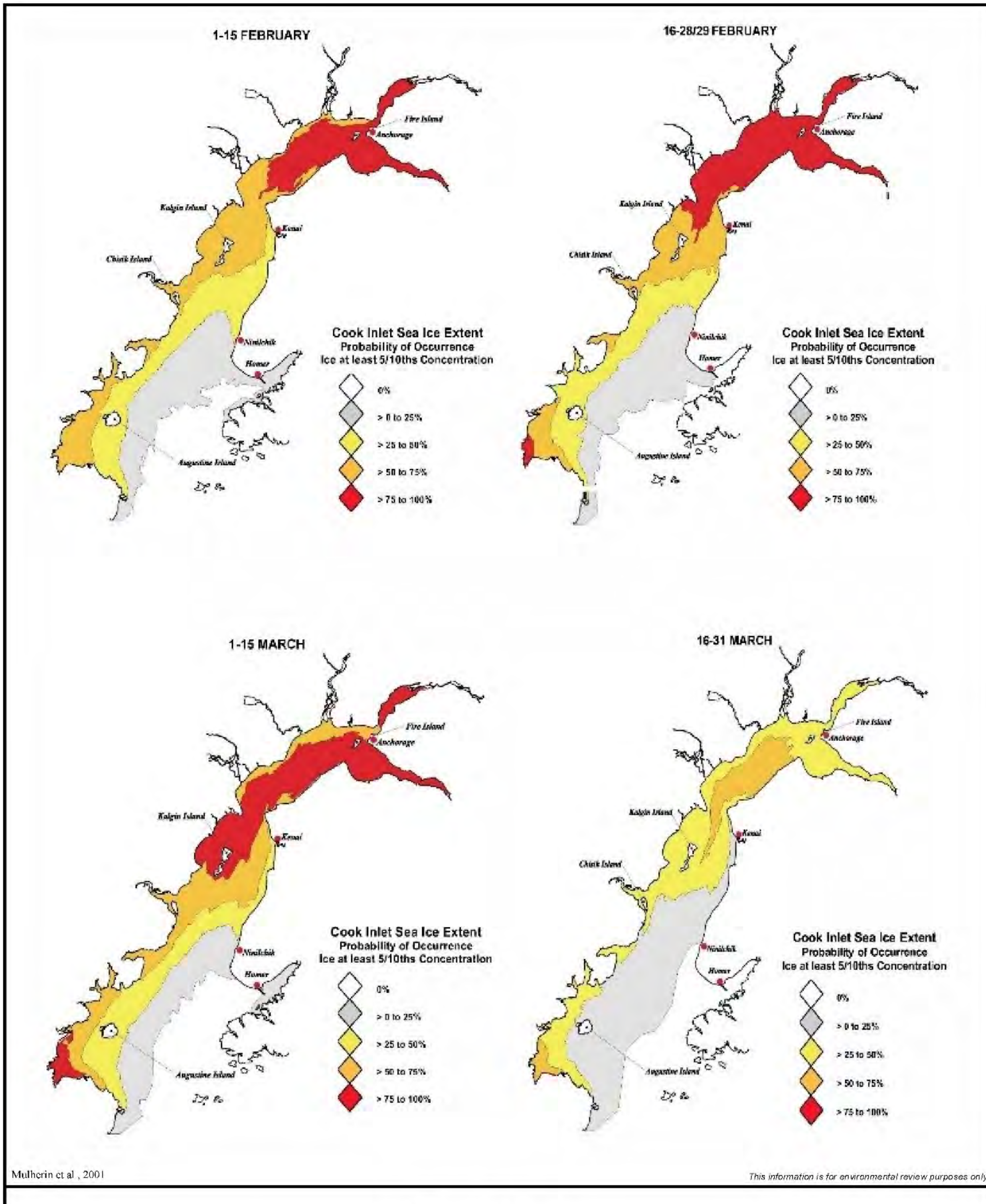


Figure 4.3.3-9
Alaska LNG Project
Probability of Occurrences 5/10th Ice Concentration in Cook Inlet for February and March

TABLE 4.3.3-1

Ice Thickness and Concentration from December through March with Bimonthly Interval for Nikiski

	Ice Thickness (inch)			Ice Concentration (as ratio [e.g., 1/10=10%])		
Date	Maximum	Mean	Minimum	Maximum	Mean	Minimum
Dec 01–15	0–4	0	0	6	0	0
Dec 16–31	0–4	0	0	5	0	0
Jan 01–15	>12	4	0	7	3	0
Jan 16–31	>12	4	0–4	8	4	1
Feb 01–15	>12	4–12	0–4	9	5	1
Feb 16–28	>12	4–12	0–4	8	5	1
Mar 01–15	>12	12	0–4	8	5	2
Mar 16–31	>12	0–4	0	7	3	0

For the Marine Terminal and approach area ice conditions analysis, long-term (1985 to 2014) ice data were extracted at three locations (Site N: N 60°39/ W 151°25; Site S1: N 60°30/ W 151°30; and Site S2: N 60°15/ W 151°30) from an ICE 98 database (a program developed by Canatec Consultants Ltd.). Source data of the Canatec ice database is primarily based on charts from the National Ice Center and National Snow and Ice Data Center (2017).

The database is in sea-ice gridded (SIGRID) format with 0.15-nautical-mile grid size and reported at weekly intervals. Ice data extracted from the Canatec database includes ice concentration value (in tenths) associated with each ice type as well as the total ice concentration. Ice types (different stages of ice development) include multi-year ice, second-year ice, and first-year ice (further categorized into five sub-types). Only first-year ice was present in Cook Inlet.

Extreme ice thicknesses were assessed by carrying out an Extreme Value Analysis of the weekly middle and high-end category ice thickness ranges at the site using the Canatec data. Table 4.3.3-2 summarizes the estimated extreme ice thicknesses associated with return periods for the middle and high-end extreme ice thickness ranges. The 10- and 100-year return period extreme ice thicknesses based on middle ice statistics were estimated to be about 27 and 35 inches, respectively. The high-end ice thickness and the 10- and 100-year return period extreme ice thicknesses were estimated to be about 36 and 43 inches, respectively.

TABLE 4.3.3-2

Extreme Ice Thickness for Marine Terminal and Approach Area (1985 to **2014)** [a]

Return Period (years)	Middle Range Extreme Ice Thickness (inches)	High-End Range Extreme Ice Thickness (inches)
1	12	26
5	25	33
10	27	36
30	31	39
60	34	42
100	35	43

Source: National Ice Center and National Snow and Ice Data Center, 2017
[a] Site N: 60°39/ W151°25; Site 1: N60°30/ W151°30; Site 2: N60°15/ W151°30

Water Quality

Water quality is generally considered good in the Cook Inlet Basin. Much of the water originates in the mountainous headwaters from melting snow and glaciers, and because the snow is relatively pure, much of the water is either free of, or contains only low concentrations of, contaminants (Glass et al., 2004). Due to the sediments present and the tides, however, waters within Cook Inlet have high turbidity. In general, turbidity and sedimentation rates are naturally high in Upper Cook Inlet due to the abundance of glacial sediments and strong currents. Suspended sediment concentrations in Upper Cook Inlet can range from 100 to 4,000 mg/L, increasing northward (MMS, 1996b; COE, 2013a). Turbidity in Upper Cook Inlet is noted throughout the literature as being naturally high, with a referenced natural background condition of between 400 to 600 NTUs (COE, 2013a).

Information gathered during meetings with local residents and traditional knowledge workshops documented a range of opinions regarding qualitative observations of water quality in Cook Inlet. Local residents that regularly observe Cook Inlet note consistent and good water quality, while others note an increase in sediment loads and subsequent siltation. Comments concerning increased pollution were noted during workshops, with reference to localized oil spills and industrial waste from canning, and poor waste management that residents believe have caused a decline in water quality. Overall, there seems to be agreement that, at least anecdotally from local resident accounts, the temperature in Cook Inlet is gradually getting warmer over time (Braund, 2016).

4.3.3.3 Impacts and Mitigation

The impacts and mitigation for each portion of the Project infrastructure associated with the marine waters of Prudhoe Bay and Cook Inlet can be categorized by these impact-causing factors:

- general impacts as a result of operating construction equipment and vessels associated with the Project including stormwater runoff and inadvertent spills;
- dredging, screeding, material fill, ocean disposal, and seafloor disturbance;
- water discharges[42] (e.g., hydrostatic test water, stormwater runoff, ballast water discharges, and facility operational wastewater); and
- navigation and vessel traffic.

The following sections outline the potential impacts and proposed mitigation under these impact-causing factors for the marine waters resource.

Stormwater Runoff

Stormwater runoff associated with planned construction at the West Dock Causeway, Mainline MOF, and the Liquefaction Facilities into marine waters is possible due to the proximity of these facilities to marine waters (Prudhoe Bay for the West Dock Causeway and Cook Inlet for the Mainline MOF and Liquefaction Facilities). Construction activities at the West Dock Causeway and Mainline MOF would involve installing granular fill behind sheet piling to develop these facilities. In both cases, the sheet piling would stabilize the granular fill and disturbance associated with the new facilities adjacent to marine waters.

[42] EPA defines wastewater as “any water which, during manufacturing or processing, comes into direct contact with, or results from the production or use of any raw material, intermediate product, finished product, byproduct, or waste product,” which includes all water discharge categories discussed in this section (e.g., cooling water, ballast water, stormwater runoff, and processed wastewater) (EPA, 2019). For clarity, this report maintains the descriptive categorical naming conventions (e.g., cooling water, ballast water, stormwater runoff, and processed wastewater).

Additionally, the lay barges, tugs, and other construction vessels used to lay the Mainline Pipeline across Cook Inlet would also contribute to stormwater runoff. To address activities in areas adjacent to marine waters, AGDC would seek coverage under the APDES General Permit AKG320000 – State Oil and Gas Pipelines and would be required to comply with the parameter limits and monitoring requirements of this general permit. In addition, AGDC would be required to follow erosion and sediment control requirements in the Project Plan. To comply with discharges to marine waters, AGDC would comply with AWQS limits (18 AAC 70) per ADEC regulations prior to discharge to marine waters.

Construction at the LNG Plant site would be susceptible to erosion and sedimentation due to storm events and construction activities. AGDC has prepared a draft construction SWPPP for the upland site, which includes a range of typical drawings and specifications for BMPs that would be implemented on a site-specific basis to reduce erosion during construction and capture sediment that could become mobilized and entrained in stormwater during rain events (e.g., silt fencing, sediment barriers, slope breakers, and wash-down areas to remove soil from vehicles before they exit the site). AGDC would also construct a wastewater treatment system at the Liquefaction Facilities that would segregate effluents from the facility by source. The treatment system would use selective recycling, as well as graded temporary sediment catch basins, that would collect stormwater runoff from the LNG Plant site to settle out suspended sediments and treat effluent discharges to Cook Inlet in compliance with AWQS. Undisturbed areas of the LNG Plant site would retain their existing natural drainage. Impacts from stormwater runoff into Cook Inlet would be temporary and localized to areas adjacent to the LNG Plant. Overall, impacts would be expected to be minor due to the use of the facility wastewater treatment system and settling basins planned, and the existing high turbidity levels in Cook Inlet at the discharge point.

During operation, all paved and non-paved surfaces outside the operational areas of the Liquefaction Facilities would drain into stormwater ponds. AGDC would develop a SWPPP for operation before the facilities would be placed in service. Water from these ponds would be discharged in accordance with APDES requirements via outfalls into Cook Inlet. Impacts would be permanent for the lifespan of the facilities, but minor due to stormwater treatment in the settling basins prior to discharge and high background turbidity levels in Cook Inlet.

Accidental and Unintentional Releases and Spills

Construction and operation would have a risk of unintentional releases and spills of construction equipment and vessel fluids into marine waters. Potential impacts at each of the three major facilities associated with marine waters are described in the sections below.

AGDC has developed an Emergency Response Vessel Assurance Execution Plan to establish a set of standards for contractors and vessel owners to maintain safe marine transportation. These standards are based on flag state and port state requirements, international industry standards, conventions, laws, regulations, treaties, and owner requirements. In the event of an oil spill or hazardous substance release, AGDC would be required to comply with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) under 40 CFR 300, including both reporting and response requirements. Additionally, AGDC would be required to comply with 18 AAC 75 for Oil and Other Hazardous Substances Pollution Control, which specifies various requirements including, but not limited to, pollution prevention, financial responsibilities for oil discharges, discharge or release notification and reporting, and discharge prevention and contingency plans.

As part of the requirements, regulations state that an Oil Discharge Prevention and Contingency Plan (ODPCP) is required for tank vessels, non-tank vessels (over 400 gross tons), pipelines, onshore or offshore production facilities, oil terminal/storage facilities, and railroad tank cars. Based on guidelines outlined by the International Maritime Organization under the Marine Environmental Protection

Committee, oil tankers of 150 gross tonnage and above and all vessels with 400 gross tonnage and above, such as LNG carriers, are also required to develop and implement a Coast Guard approved Shipboard Oil Pollution Emergency Plan (SOPEP). AGDC would confirm that vessels that are legally required to have a current and approved ODPCP and SOPEP would have these plans for all applicable facilities and vessels during construction and operation. The requirement for AGDC to obtain an ODPCP for applicable facilities is included in the list of permits, authorizations, and approvals in table 1.6-1.

To minimize the potential for an inadvertent equipment fluid release, AGDC would adhere to the fueling, storage, containment, and cleanup measures described in its SPCC Plans. The Project SPCC Plan describes generic practices and procedures to protect marine waters from a potential release of fuel or hazardous materials. AGDC would also develop facility/work site-specific SPCC plans prior to construction, as discussed in section 4.2.6. Hazardous materials would be handled in accordance with the Project Procedures as well as the Project Waste Management Plan (see section 4.9.6). In addition to these plans, AGDC would develop spill prevention and response plans based on the type of fuel carried by, and the quantity at risk for, vessels, and Emergency Response Plans (ERPs) in accordance with PHMSA regulations after construction is complete (see section 4.18).

<u>Gas Treatment Facilities</u>

Petroleum products associated with vessels would be the primary source of potential contamination of marine waters at the Gas Treatment Facilities. Vessel traffic within marine waters at the Gas Treatment Facilities would range from 9 to 12 barges with associated tugs in each open water season between Years 2 and 7 of construction. While each vessel would use marine gasoil (MGO), onboard fuel tank capacities would be variable, broadly ranging from 10,000 to 100,000 gallons or more. For example, tugboats Bering Wind, Glacier Wind, and Taku Wind, which operate in Cook Inlet, have respective fuel capacities of 10,000, 17,000, and 83,000 gallons (Cook Inlet Tug & Barge, 2019).

Ultra-low sulfur diesel (arctic diesel) would be trucked to the Gas Treatment Facilities and stored for use on the integrated operations center pad at the GTP. Double-walled tanks would have 110-percent secondary spill containment. All fuel and hazardous material handling needed for construction of the GTP and associated infrastructure would be in accordance with ADEC requirements and the Project SPCC Plan, such as the use of secondary containment systems for fuel pumps operating within 100 feet of a waterbody. While a spill has the potential for significant adverse environmental impacts, implementation of the plans described above and adherence to the protective measures described for groundwater impacts (e.g., the Project Plan and Procedures, SWPPP, and SPCC Plan; see section 4.3.1) would greatly reduce the likelihood of such impacts, as well as minimize the resulting impacts should a spill occur. In addition, any spill of oil or hazardous materials into a waterbody would be subject to both reporting and response according to the NCP and 18 AAC 75, as stated above.

Spills of hazardous materials, including fuels and lubricants, could affect marine surface water resources in Prudhoe Bay where these materials would be used or stored. However, storage of these materials would comply with regulatory requirements, and personnel would be trained for proper handling, storage, disposal, and spill response of potential contaminants. AGDC would develop a separate SPCC Plan for the Gas Treatment Facilities stating the handling requirements for petroleum, oil, and lubricant products during Project operation. Storage tanks and containers for fuels and hazardous liquids would be stored in secondary spill containments, and oil-filled operational equipment would be managed consistent with the requirements of 40 CFR 112. As such, significant adverse impacts on marine surface water due to contamination from spills or releases associated with the construction of the Gas Treatment Facilities would be unlikely.

Mainline Facilities

The Mainline Pipeline installation offshore requires the use of offshore vessels in an area that has existing vessel traffic. The Cook Inlet traffic intensity and dynamic environment increase the potential for vessel accidents that could result in accidental discharges of pollutants to marine waters. Any large construction project also presents the potential for spills of fuel or other hazardous liquids from storage containers, equipment working in or near waterbodies, and fuel transfers. A spill of fuel or other potential contaminant that reaches a waterbody would negatively affect water quality. Any spill of oil or hazardous materials into a waterbody would be subject to both reporting and response according to the NCP and 18 AAC 75, as stated above.

Vessel traffic associated with the Project within Cook Inlet would include a variety of vessel types (e.g., derrick barges, work boats, survey boats, tractor tugs, and ocean going tugs) during construction. Section 4.12.2 describes the types and numbers of vessels that would be used, and provides anticipated annual vessel trips or docking days at ports and Project-associated facilities.

AGDC would institute a number of measures that would be finalized during detailed design or provided by the contractors selected to carry out construction in Cook Inlet. These measures would include requiring contractors working in the marine environment to follow the Project Emergency Response Vessel Assurance Execution Plan and develop plans to mitigate incidents in the marine environment, which would include mitigation measures to prevent incidents and develop emergency response preparedness strategies applicable to the marine environment. AGDC's contractors would develop these prevention and preparedness plans during the detailed engineering phase that precedes the construction phase, with the plans based on fuel type and carrying capacity and including the considerations described below.

- Heavy oils (e.g., heavy crude oils, No. 6 fuel oil, Bunker C or heavy fuel oil [HFO], and intermediate fuel oil [IFO]) are highly persistent. Therefore, the potential fate of heavy oils and effects on the environment in the event of an oil spill include: 1) little to no evaporation or dissolution, 2) potential for heavy contamination of intertidal areas, 3) impacts on waterfowl and fur-bearing mammals, 4) possible long-term contamination of sediments (e.g., HFO has a specific gravity that could result in some constituents of the oil sinking in water), 5) slow weathering, and 6) difficult shoreline cleanup under all conditions. Construction-phase vessels carrying HFO and IFO to be employed include heavy module carriers, geared heavy lift ships, and handy size bulk carriers, with these vessels carrying up to 422,675 gallons of HFO or IFO and 79,252 gallons of MGO.

- Light oils (e.g., diesel MGO and marine diesel oil, No. 2 fuel oil, light crudes) are relatively non-persistent. Therefore, the potential fate of the light oils and effects on the environment in the event of an oil spill include: 1) moderate volatility leaving residue (up to one-third of spill amount) after a few days; 2) moderate concentrations of toxic [soluble] compounds; 3) effect on intertidal resources with long-term contamination potential; and 4) effective cleanup. Project vessels carrying MGO and marine diesel oil include pipe-laying vessels, fuel barges, tugs, anchor handling tugs, workboats, and survey vessels. The carrying capacity for these vessels varies from 825,010 gallons of MGO per pipe laying vessel to 273,947 gallons of diesel per fuel barge trip. The MGO fuel capacities for all tugs, anchor handling tugs, workboats, and survey vessels vary.

Specific risk mitigation measures would be included in the construction-phase prevention and response plans developed by contractors based on the vessel type and oil type carried. Example mitigation measures for large self-propelled vessels carrying HFO and IFO include comprehensive vetting of vessel management companies followed by vessel audits and inspections prior to use, and use of qualified pilots from the region, use of tugs during docking, and use of double-hulled fuel tanks.

Example mitigation measures specific to vessels carrying light oils include use of assist tugs for docking barges at the Mainline MOF and use of double-hulled fuel barges. Additionally, the *Cook Inlet Risk Assessment* (CIRA) (Nuka and Pearson, 2015), initiated and led by ADEC, the Coast Guard, and the Cook Inlet Regional Citizens Advisory Council, and accompanying *Cook Inlet Maritime Risk Assessment Spill Baseline and Accident Casualty Study* (The Glosten Associates and Environmental Research Consulting [ERC], 2012), would be consulted to focus on pertinent mitigation measures.

During construction infrastructure development, temporary fuel storage tanks would be set up at pioneer camps, construction spreads, construction camps, and each spread's active contractor yard. All fuel and hazardous material handling needed for construction of the Mainline Facilities would be in accordance with ADEC requirements and the current (not specific to marine waters) SPCC Plan and managed by the EIs. This includes the use of secondary containment for single-walled containers; maintenance and daily inspection of storage and construction equipment for leaks; overnight parking and refueling of all equipment at least 100 feet from waterbody boundaries; the use of secondary containment systems for fuel pumps should refueling need to occur within 100 feet of a waterbody; and the stocking of spill kits in vehicles. All waste would be handled in accordance with AGDC's Project Waste Management Plan.

While operational impacts on Cook Inlet due to contamination from spills is unlikely, determining the risk associated with these spills is important due to additional operational vessel activities (see section 4.12). Because oil is not the product being transported for this Project, the types of spills that could occur include oil releases into Cook Inlet caused by equipment upsets or failures during construction and operation. To determine the risk of such releases, both the probability of occurrence and the resulting consequences need to be considered. In 2014, NOAA published their *Assessment of Marine Oil Spill Risk and Environmental Vulnerability for the State of Alaska* (NMFS, 2014), in which they evaluated impacts and risks of potential spills in Alaskan waters. According to the report, the spill history for the years 1995 to 2012 showed spill volumes of less than 50 barrels for most of the incidents (8,667 out of 10,985 incidents) and a spill volume of 0 barrels for the remainder of the incidents (2,318 out of 10,985), thus indicating only the potential for a spill. The "most likely" spill volume, at 85 percent of the spills analyzed, was less than 1 barrel of oil, with 99 percent of the spills involving less than 50 barrels of oil, and only 0.1 percent of the spills involving more than 500 barrels of oil.

The CIRA (Nuka and Pearson, 2015) evaluated historic data specific to Cook Inlet. This evaluation considered oil spills from marine vessels ranging from more than 300 gross tons to smaller vessels with fuel capacities of at least 10,000 gallons, as well as tug boats and barges regardless of fuel volume. The assessment documented a historic spill rate of 3.4 spills per year for Cook Inlet, ranging from 0.7 spill per year for tanker ships to 1.3 spills per year for non-tanker/non-workboat vessels. The CIRA study additionally acknowledged the potential for low probability, high consequence incidents related to larger tanker vessels. The study identified a number of recommendations to reduce incidents and spills in Cook Inlet. AGDC would consult these to identify appropriate mitigation measures for Project vessel operation in Cook Inlet.

Accidental gas releases from the Mainline Pipeline within Cook Inlet would not be anticipated, but in the event of a natural gas release, gas would rise through the water column to the surface. Methane, the primary constituent of natural gas, is more water soluble in colder water and alternatively would volatilize once it reached the marine water and air interface. Although the gas plume location and radius (size) are dependent on the depth, duration, pressure, release aperture, and amount of gas released, it is expected that a natural gas release in the deeper cold water environments or at the surface in Cook Inlet would be localized in nature and dissipate once the release was stopped. During ice-free periods, some dissolution of methane in the water column would occur as gas bubbles rise; however, because of the relatively shallow depths in Cook Inlet, much of the gas would rise quickly and volatize in the atmosphere when it breached the water surface. Sea ice could result in the trapping of natural gas, but as noted in section 4.3.3, the portion of Cook Inlet that would be crossed by the Mainline Pipeline would not have 100-percent ice cover in a typical year, thus allowing some gas to escape. During infrequent years where ice concentrations may near 80- to 90-percent cover, gas could become trapped under larger expanses of sea ice during late winter months (late January and early March), which would limit atmospheric interactions and result in increased dissolution, dilution, and dispersion into the water column. During operation, the pipeline would employ industry standards for safety and pipeline monitoring, outlined in greater detail in sections 2.5.2 and 4.18. Additionally, MLVs on each side of Cook Inlet would be installed, one automated MLV and one remote MLV, which would minimize the duration of an accidental release and result in a brief and localized impact within marine waters.

Based on the assessed low probability of spills larger than 50 barrels related to construction or operational equipment failure (NMFS, 2014), and adherence to the protective measures previously outlined for groundwater impacts in section 4.3.1.5, there is a reduced likelihood of significant adverse environmental impacts if a petroleum spill should occur. As such, significant adverse impacts on Cook Inlet due to contamination from petroleum spills or natural gas releases associated with Mainline Facilities construction and operation would be unlikely.

Liquefaction Facilities

Vessel traffic associated with the Project within Cook Inlet would include a variety of vessel types (e.g., derrick barges, work boats, survey boats, tractor tugs, and ocean going tugs) during construction. Section 4.12.2 describes the types and numbers of vessels that would be utilized, and provides anticipated annual vessel trips or docking days at ports and Project associated facilities. Anticipated fuel and oil volumes by vessel type are provided in the previous two sections for the Gas Treatment and Mainline Facilities. Vessels operating during construction and operation at the Liquefaction Facilities have the potential to cause fuel and oil spills. LNG tanker operations and fuel storage used during operation at the Liquefaction Facilities also have the potential to cause unintended releases to the marine environment.

In addition to the contractors' plans that would be developed in compliance with the Project Emergency Response Vessel Assurance Execution Plan discussed in the Mainline Facilities section above, a separate SPCC Plan would be developed for Liquefaction Facilities operation. Spills of hazardous liquids, including fuels and lubricants, could occur in any area where these compounds are used or stored and have the potential to affect marine surface water resources in Cook Inlet. Storage of these materials would comply with current regulatory requirements, and personnel would be trained for proper handling, storage, disposal, and spill response of potential contaminants. Storage tanks and containers for fuels and hazardous liquids would be stored in secondary spill containment, and oil-filled operational equipment would be managed consistent with the requirements of 40 CFR 112. Operational waste materials would also be disposed of as required by federal, state, and local regulations. As noted previously, and in compliance with guidelines outlined by the International Maritime Organization under the Marine Environmental Protection Committee, vessels with 400 gross tonnage and above, like LNG carriers, are also required to develop and implement a Coast Guard approved SOPEP, which includes measures to be taken when an oil pollution incident has occurred or is at risk of occurring. An ODPCP would also be required for both tank vessels, which transport oil as cargo, and non-tank vessels over 400 gross tonnage, as noted previously. In addition, any spill of oil or hazardous materials into a waterbody would be subject to both reporting and response according to the NCP and 18 AAC 75, as stated above.

While an oil spill has the potential for significant adverse environmental impacts, the historically low probability of occurrence of spills larger than 50 barrels and the adherence to the protective measures previously outlined for the Mainline Facilities would reduce the likelihood of such impacts, as well as minimize the resulting impacts should a spill occur. As such, significant adverse impacts on Cook Inlet waters due to contamination from spills or releases related to the construction and operation of the Liquefaction Facilities is unlikely.

In addition to oil spills, the potential for a leak or spill of LNG or other hazardous materials from the Liquefaction Facilities during operation would exist (see section 4.18.5). LNG vaporizes rapidly when exposed to ambient heat sources such as water or soil. Due to this rapid vaporization, an LNG tank leak would not affect Cook Inlet marine waters. Because LNG would vaporize upon an inadvertent release from a pipe or storage tank, there is little potential for marine surface waters to become contaminated from an LNG release and, therefore, impacts on surface water would be minor and short term. In addition, spill containment systems, emergency response plans, and other measures would be in place during operation of the Liquefaction Facilities to ensure spill and release incidents are avoided or quickly contained (see section 4.18.5).

Spills, leaks, or other accidental releases of substances during construction of the LNG Plant could adversely affect surface water quality if these materials should wash into Cook Inlet from the LNG Plant site. Practices and procedures outlined in the description of construction impacts from the Mainline Facilities would also be implemented during the LNG Plant construction to reduce potential impacts on Cook Inlet.

Dredging, Screeding, Material Fill, and Seafloor Disturbance

<u>Gas Treatment Facilities</u>

Gas Treatment Facilities construction with potential impacts on marine waters would include planned improvements at the West Dock Causeway. Construction of Dock Head 4 and improvements along the causeway, including screeding (see section 2.1.3.2), would occur within marine waters in Prudhoe Bay during the ice-free season. Onshore, potential impacts on surface waterbodies could result from various construction activities such as earthmoving, trenching, and use of granular material fill. Construction activities for all Gas Treatment Facilities would be anticipated to last 7.5 years.

West Dock Causeway improvements would include constructing Dock Head 4 and widening the West Dock Causeway to accommodate the offloading of large modules for the Gas Treatment Facilities. Major components of the Gas Treatment Facilities would be built as modules off site and delivered in a series of sealifts requiring offloading of barges and other large oceangoing vessels. Six consecutive summer sealift seasons and corresponding construction periods are planned. The Dock Head 4 design does not require dredging a navigation channel, and no dredging is planned for the seasonal barge bridge. Bathymetric survey data from 2016 was used to determine the Dock Head 4 footprint. Because the seafloor could continue to change by sediment erosion or deposition before construction occurs, however, the Dock Head 4 footprint could require updates during future Project phases.

During Gas Treatment Facilities construction, in-water work would be required to expand the West Dock Causeway, to construct Dock Head 4, and to add an open-water season barge bridge to span a 650-foot breach between existing Dock Heads 2 and 3 to extend the causeway to Dock Head 4. Sheet piling would be installed during the initial construction of Dock Head 4, behind which granular fill would be added to raise the docking platform to about 8 feet above sea level. Sheet piling and granular fill would be added at each end of the 650-foot breach to accommodate the seasonal barge bridge, which would consist of two barges ballasted to the sea floor, disturbing about 3 acres. The barge bridge would include gaps at each bow and/or stern connection point to allow for up to three areas of fish passage. The barge bridge would be installed annually at the beginning of the open-water season and would be removed at the end of each summer season. Preparation of the seabed at this site, which could be performed in the summer and/or winter, would be influenced by the type of material encountered, the need to fill, and the amount of and method of placing fill. It is anticipated that gabion mattresses (a rock-filled wire mesh structure) would be used to stabilize the barge bridge placement.

A year prior to the first sealift, pre-work would be performed to prepare the seafloor and install breasting-dolphins for the bridge support. Gabion mattresses would be placed within the footprint of the barge bridge to prevent scour, and the gabion mattresses would be left in place. It is possible that ice pileup, which has been known to occur on the West Dock Causeway, could affect these gabion mattresses. Gabions can contribute to ice conditions when they freeze together with the ice and form ice and stone blocks enabling the gabions to float up, shift, and separate from the main ice cluster. When levels of spring ice-drift change, this can also cause the mesh structures to wear off by rubbing or to be cut by the moving ice (Maccaferri, 2017). Since landfast ice in the Prudhoe Bay area has become less stable and with less thick multi-year ice in the area than in the past (as described in section 4.3.3), the likelihood of ice affecting these gabions is expected to be relatively low. Over the course of six sealift seasons, however, it is a possibility. Therefore, the placement and conditions of the gabions would be monitored during Project construction.

Impacts from Gas Treatment Facilities construction would include filling 31 acres of marine waters, using granular fill behind sheet piling to construct Dock Head 4. In addition, 14 acres of fill in marine waters and 20 acres in estuarine waters would be required to expand the West Dock Causeway, 3 acres of fill in estuarine waters would be needed for the breach bulkheads, and 14 acres would be disturbed in marine waters by screeding. Altogether, constructing Dock Head 4 would result in the permanent loss of 68 acres of open water marine or estuarine habitat (the 14 acres of impacts due to screeding would be temporary). With the area of water in Prudhoe Bay at 114,240 acres (179 square miles) according to the 2017 U.S. Census (U.S. Census Bureau, 2017), the loss of 68 acres (0.1 square mile) of open water marine habitat would be equivalent to less than 0.1 percent of the total water environment in Prudhoe Bay; therefore, this impact would be insignificant. However, there is potential for a more significant impact on the nearshore environment of Prudhoe Bay (e.g., water depths less than 6 feet as shown on figure 4.3.3-1), because nearshore waters are more productive and therefore much more important to wildlife populations (see sections 4.7.1 and 4.7.2 for further discussion of nearshore habitat impacts).

There would be a temporary increase in turbidity during construction and annual use of Dock Head 4. Installing permanent sheet piling on the seafloor would disturb loose sediments, introduce them into the water column, and thereby increase the turbidity of the marine water at the work site. The plumes of elevated suspended sediment concentrations would not be expected to extend a significant distance from the work sites. This is supported by the results of the Project test trench excavation field study in 2015, in which turbidity was measured at Prudhoe Bay Test Trench Site #2.5 beneath the floating ice, within the excavated trench, and both 225 feet and 500 feet in cardinal directions from the trench (see figure 4.2.3-2). Maximum turbidity measurements recorded during the 3-day study were 75 NTUs in the trench, 75 NTUs measured 225 feet south of the trench, and 11 NTUs measured 500 feet south of the trench. By the morning following test trenching, background turbidity conditions (i.e., 0.3 NTUs) had returned to all sites except within the test trench. The installation of new sheet piling at Dock Head 4 and the West Dock Causeway is expected to have less impact in terms of the potential for increased turbidity within the water column than trench excavation. The increased turbidity would settle out of the water column or become dispersed in a matter of hours and would result in minor, localized impacts on water quality.

While dredging may not be required in Prudhoe Bay, bottom screeding is proposed at Dock Head 4 and the barge bridge (across the West Dock Causeway breach) prior to each of the six sealifts. Due to the shallow waters of Prudhoe Bay, minor screeding could also occur in summer months before the arrival of the barges. Sediments in the area to be screeded or disturbed are free of contaminants.[43] Screeding would be expected to have minimal impacts due to a temporary, localized increase in suspended sediment concentration that would likely return to background levels within hours as described above. Additionally, because the West Dock Causeway would not be used by AGDC during operation, and with the equipment offloading dock location at Dock Head 4, AGDC would not need to conduct any maintenance dredging or further road expansion during Project operation. A discussion of potential use of Dock Head 4 by others is presented in section 4.19.

Ground compaction caused by expansion of existing roads and new access roads could generate increased turbidity due to runoff. Erosion and sediment control measures would be implemented as outlined in the Project Plan and Procedures and the Project SWPPP to reduce any sedimentation and flow, thereby minimizing impacts on marine water resources. Therefore, any effects would be minor and short term.

The permanent extension of the West Dock Causeway and construction of Dock Head 4 could impede near-shore circulation and thus affect hydrographic conditions near the West Dock Causeway. Use of the seasonal barge bridge is intended to maintain the circulation of water flow near the newly constructed Dock Head 4. Nonetheless, during easterly winds (westward flowing currents), the construction and presence of the West Dock Causeway is known to have caused relatively significant cross-causeway differentials in salinity and temperature at the water surface (3.28-foot depth or less). These differentials involve colder and more saline waters of the west side and warmer and less saline waters on the east side, which are caused by a marine cell that develops west of the dock, and by the physical presence of the causeway itself. Results of a Before–After Control–Impact analysis by Fechhelm et al. (2001) indicated that the construction of breaches mitigates the cross-causeway hydrographic differentials during periods of east winds likely due to warm, low-salinity water flowing westward through the breach and diluting the marine cell just west of the causeway. While some studies recommend post-construction monitoring be conducted to determine whether a West Dock Causeway extension would influence cross-causeway differentials and whether additional breaches should be constructed to mitigate any potential effects (COE, 1980, 1984), full post-construction monitoring efforts would not be required for this action. Since the extension of the West Dock Causeway would primarily involve the widening of the existing causeway, no further obstructions of water flow across the causeway are planned; therefore, the impacts on the existing cross-causeway differentials would likely be minor.

With incorporation of the various procedures outlined herein, construction impacts would be minor, and the impact duration would be generally concentrated during construction and mostly limited to the immediate vicinity of the causeway. The primary impact associated with the installation and operation of the Gas Treatment Facilities would be the permanent loss of about 68 acres of open water marine habitat from the expansion of the West Dock Causeway and construction of Dock Head 4, less than 0.1 percent of the total marine environment of Prudhoe Bay. While these impacts would be minor overall to the entire Prudhoe Bay environment, impacts on the nearshore waters of Prudhoe Bay would be moderate and permanent.

Mainline Facilities

Mainline MOF

The Mainline MOF would be constructed on the west side of Cook Inlet near Beluga to support onshore and offshore Mainline Pipeline construction activities. The supporting equipment, materials, and supplies would be delivered by water or air because the west side of Cook Inlet, where the Project would

[43] The *Alaska Stand Alone Pipeline/ASAP Project: West Dock Dredge and Disposal Plan*, which provides results of sediment coring analysis at the West Dock Causeway in Prudhoe Bay, can be viewed online at: http://www.asapeis.com/documents/GDredgeandDisposalPlan.pdf.

cross, is not connected to any other area of the state by road. The Mainline MOF would provide a marine offloading and backhaul loading point for construction equipment and consumables, fuel, camp components, personnel, line pipe, and other construction materials. The Mainline MOF would be a permanent facility constructed adjacent to the existing Beluga barge landing facility and would remain in place following construction of the Project; however, it would not be used during operation.

The existing barge landing facility at Beluga would not be suitable to accommodate Project construction due to its current high level of utilization, poor existing infrastructure for offloading large equipment, and its lack of a robust landing area suitable for larger barges. Due to the limited infrastructure in this area, however, the existing barge landing (after several improvements) is planned for use as an initial offloading and backhaul point during construction of the permanent Mainline MOF.

The Mainline MOF would consist of a ramp and a pier. The pier would be 450 feet long by 310 feet wide, and extend into Cook Inlet, running parallel with the shoreline. The roll-on/roll-off ramp would be about 80 feet by 120 feet. Both the pier and ramp would be constructed of anchored sheet pile walls with granular fill behind the sheet piles.

No dredging is planned at the Mainline MOF site. Two 30-foot-wide access roads would be constructed to cut through the existing bluff and lead down to the quay. Access roads would also be constructed that lead from the Mainline MOF to a planned material laydown area that connects to the local road system. Construction along the shoreline could result in increased turbidity and sedimentation leading into Cook Inlet due to runoff originating from disturbed upland areas. Implementation of the erosion control measures in the Project Plan and Procedures and SWPP would minimize impacts associated with potential runoff.

Cook Inlet Crossing

The Cook Inlet pipeline crossing would include two methods of pipelay: two shoreline approaches, in which the pipeline would be buried, and the offshore portion, in which the pipeline would be laid directly on the seafloor. With regard to the former, the Beluga Landing South shoreline approach is on the west side of Cook Inlet, and the Suneva Lake shoreline approach is on the east side. For both approaches, the Mainline Pipeline would need to be buried from the shoreline out to a depth such that the top of the pipe is sufficiently protected from major hazards (e.g., vessel strikes and formation of stamukhi beach ice). This depth is expected to be from about -35 to -45 feet MLLW.

AGDC's proposed construction method for the shoreline approaches is the open-cut method. Nearshore trenching using terrestrial and amphibious equipment would be used in the intertidal area extending seaward from the shoreline for approximately 600 to 800 feet. The trench in this area would be excavated to a depth sufficient to provide a minimum of 6 feet of cover over the pipeline once installed. The trench would be backfilled using the terrestrial and amphibious equipment as described in section 2.2.2.2. From the end of the nearshore installation area to a water depth of -41 feet MLLW, a trailing suction hopper dredge would be utilized to excavate the trench to a depth sufficient to provide a minimum of 6 feet of cover over the pipeline once installed. The trench in this area would be allowed to naturally in-fill, which AGDC estimates would occur over a period of several days. If the trench does not naturally backfill, then manual backfilling would be required. If so, the trench would be backfilled by reversing the flow of the trailing suction hopper dredger used offshore or mechanically with the use of excavators.

In addition to the open-cut method, AGDC evaluated the use of DMT and HDD for the shoreline approaches. AGDC has stated that neither the HDD nor DMT crossing method would be able to reach the -41 feet MLLW mark transition point utilized in AGDC's analysis and that a dredging vessel and open-cut trenching techniques would be required in addition to the trenchless crossing method. The HDD method is also not considered viable due to the increased risk of large-diameter HDD failure and tie-in complications, the need for an offshore jack-up platform, and recent Cook Inlet shore crossing installations completed for the Osprey and Furie projects, which experienced challenges with conventional HDD installation. We have reviewed the geotechnical investigations at each shoreline approach and agree that the HDD method would be unlikely to succeed. Therefore, we do not consider it further.

Although the use of the DMT method alone to reach -41 feet MLLW may not be feasible, AGDC confirmed that an approach that combines the use of the DMT method to reach a depth of about -20 feet MLLW, along with a hopper dredge to pipelay to a depth of -41 feet MLLW, could be feasible. This combined method for the shoreline approaches has been described as the "DMT continuation methodology." Evaluation of the DMT continuation methodology (based on AGDC's *Geotechnical Based Feasibility Assessment of Trenchless Methodologies at the Cook Inlet Crossings* [Geotechnical Report]) has been conducted.[44] Based on the information provided, AGDC has not incorporated the DMT continuation methodology for several reasons, including limitations of the DMT method to a maximum of 5,000 feet in length; potential of failure due to underlying substrate, specifically the presence of boulders, especially along the Suneva Lake side of Cook Inlet (east side); and concerns over construction schedule and cost due to potential delayed or failed crossings. Stakeholder comments received also suggest that there is an abundance of large boulders along the Suneva Lake shore approach. This information notwithstanding, AGDC's Geotechnical Report does not rule out the DMT continuation method. A preliminary feasibility assessment of the DMT continuation method concluded that the Beluga Landing approach has a 90-percent probability of success, while the Suneva Lake approach has a 75-percent probability of success.

The Geotechnical Report also identifies risks associated with the open-cut methodology. The risks associated with open-cut crossings include fine-grained soils and the presence of perched groundwater within the bluff and nearshore reaches, which could affect slope stability to cuts and bore stability in open-hole drilling; heaving sand conditions noted in boring logs at Beluga Landing and Suneva Lake; and the presence of boulders. The Geotechnical Report states that both the DMT and open-cut excavation would require mitigation plans to address these issues. The report also states that, from a geotechnical perspective, "…it would be prudent for the DMT method to be brought forward as a viable option and that further assessment of DMT and open-cut crossings is warranted during design engineering."

Table 4.3.3-3 provides the estimated excavation/trenching disturbance to offshore waters associated with the open-cut and DMT shoreline approach construction methods for each location. In this table, the shoreline approach refers to the waters from 0 feet MHHW to -41 feet MLLW, which is the current seaward end of trenching and burial for the top of the pipe to always be out of range of ice keels and vessels.

Use of the DMT continuation methodology would reduce the amount of excavation needed and related disturbance. Of particular concern for open-cut crossings is the potential difficulties in stabilizing the shores following construction. Given the projected success rates provided in the Geotechnical Report for the DMT crossing continuation method, the risk factors for the open-cut crossing method, and the fact that the Geotechnical Report states that the DMT method should be considered a viable option, prior to construction, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP:

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[44] AGDC's *Geotechnical Based Feasibility Assessment of Trenchless Methodologies at the Cook Inlet Crossings* geotechnical report was provided in response to information request No. 50 dated June 11, 2018 (Accession No. 20180611-5159), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180611-5159 in the "Numbers: Accession Number" field.

- revised construction plans, including site-specific shoreline crossings plans, that incorporate the use of the DMT continuation methodology for the shoreline crossings at Beluga Landing and Suneva Lake; or

- site-specific justifications, supported by additional site-specific geotechnical investigations conducted during detailed engineering design, demonstrating that the methodology is not feasible at the shoreline crossings.

TABLE 4.3.3-3

Estimated Excavation/Trenching Extent and Volume for Shore Approaches [a] by Shoreline Crossing Method

Shore Approach Location	Construction Methodology [b]	Estimated Excavation/Trenching Extent and Volume	Basis of Estimation
Beluga Landing South	Open-cut	Extent: 29 acres Volume: 274,940 yd^3	A total of 8,754 feet of trenching from 0 feet MHHW to -41 feet MLLW, and a 143-foot-wide trench with a 6H:1V slope
	DMT	Extent: 15 acres Volume: 138,475 yd^3	A micro-tunnel length of 5,000 feet seaward from the onshore battery limit; offshore disturbance is remaining to reach -41 feet MLLW
Suneva Lake			
	Open-cut	Extent: 22 acres Volume: 207,605 yd^3	A total of 6,610 feet of trenching from 0 feet MHHW to -41 feet MLLW, and a 143-foot-wide trench with a 6H:1V slope
	DMT	Extent: 7 acres olume: 71,140 yd^3	A micro-tunnel length of 5,000 feet seaward from the onshore battery limit; offshore disturbance is remaining to reach -41 feet MLLW

yd^3 = cubic yards

[a] Shoreline approach would be from 0 MHHW to -41 feet MLLW, which is the current seaward end of trenching and burial for the top of pipe to always be out of range of ice keels and vessels.

[b] Advanced engineering has not been completed on these alternatives. Data provided for the DMT is based on information considered during early Mainline Pipeline design.

In terms of construction discharges associated with the Mainline Pipeline crossing Cook Inlet, trench dewatering is unnecessary as the trench would be allowed to fill with water in the tidal and sub-tidal areas of the shore crossing. Therefore, no other mitigation measures specific to nearshore trenching are proposed.

NMFS (2017f) reviewed estimates of impacts due to turbidity from dredging and disposal of dredged material. According to this review, the average TSS as a measure of turbidity varies for different types of dredge equipment used, and ranges from 11.5 to 475 mg/L depending on sediment type and proximity to the source. Distances from the dredge site where plumes are still detectable vary due to sediment type, the type of dredge equipment used, and current velocity, but fall with the maximum range of 1,000 to 3,300 feet (NMFS, 2017f). TSS and turbidity levels in the near-surface plume usually decrease exponentially with increasing time and distance from the active dredge due to settling and dispersion, quickly reaching ambient concentrations and turbidities. In almost all cases, the majority of re-suspended sediments resettle close to the dredge area within 1 hour, although very fine particles could settle during slack tides only to be re-suspended by ensuing peak ebb or flood currents (Anchor Environmental, 2003). Therefore, since most of the sediment grab samples at the two Mainline Pipeline shoreline approaches consisted of rock, rock fragments, and coarse sand (see section 4.2.3), disturbed sediments would become suspended in the water column and subsequently settle to the seafloor close to the dredge (dependent on particle size and the velocity of near-bottom currents).

Sediments mobilized by trenching operations during ice-free periods would be rapidly redistributed by strong currents and tides and then settle, and turbidity would be expected to return to normal within a few days after construction (MMS, 1996c). Therefore, increased turbidity and sedimentation due to shore approach trenching in Cook Inlet would be anticipated to be temporary and localized.

During the operational phase of the Project, the buried shoreline approach portions of the pipeline would require pipeline integrity maintenance, inspection, and repair activities. These activities would include minimal site preparation (e.g., excavation), hydrostatic testing, and disturbance of the overlaid sediments, but they would result in a much smaller volume of disturbed sediments than the original installation. Maintenance of the pipeline right-of-way would be conducted according to the measures outlined in the Project Plan and Procedures. Due to the volume of disturbed sediment, the impacts from excess water column concentrations of TSS and bottom deposition would be less than the construction phase. While these impacts would repeat over the lifetime of the pipeline, each time they occur, the impacts would be less than during construction due to the type of work being completed.

For the offshore portion of the Mainline Pipeline within Cook Inlet, the pipeline would be laid on the seafloor via conventional pipelay for the majority of the crossing. The pipeline would be laid between the Beluga Landing South shoreline approach on the western shore of Upper Cook Inlet and the Suneva Lake shoreline approach on the eastern side of the inlet. The offshore portion below -41 feet MLLW would not be buried, but would be laid on the seafloor across Cook Inlet on submerged lands.

In general, Cook Inlet poses potential challenges for oil and gas infrastructure and responses to any pipeline leaks that occur due to strong currents and tides. According to PHMSA (2017b), the strength of the inlet's currents can cause a vortex of water to build around a pipeline if the pipeline is not secured to the seafloor, which can cause the pipeline to snap. It is thought that vortex-induced vibrations are one of the driving forces responsible for the relative movement between pipelines and rocks contacting pipelines in areas where pipelines are unsupported by the seabed (PHMSA, 2017b). Rocks can deteriorate the steel pipe wall of pipelines through abrasion. There have been a series of leaks (involving releases of oil and gas) from Hilcorp pipelines within Cook Inlet due to contact between rocks or boulders and the pipelines. During the latest leak in April 2017, a 3- by 3-foot boulder appeared to have rolled over a pipeline, causing the pipeline to bend. At the base of the bend, there was a small crack in the pipeline (roughly 0.2 by 0.4 inch) from which the leak occurred.

In a letter to AGDC dated March 22, 2017, PHMSA confirmed that Section 192.327(f)(2) would apply to the work in Cook Inlet (PHMSA, 2017a). This regulation requires that pipe installed offshore "…under water not more than 200 feet deep…must be installed so that the top of the pipe is below natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means." As discussed in section 2.2.2, AGDC would coat the offshore pipeline with 3.5 inches of concrete coating for on-bottom stability as well as protection from impacts on the pipeline. AGDC notes that the concrete coating would protect the pipeline from shipping related impacts (e.g., potential anchor or container drops) and natural features (e.g., boulder strikes) and would be in compliance with the cover requirement in CFR 192.327(f)(2). Further, AGDC conducted an evaluation of the potential for ice to affect the unburied pipeline and determined that the pipeline would withstand a direct ice contact under unburied condition provided that the driving forces would be wind and current only. Based on the studies conducted, AGDC asserts that no external damage to the Mainline Pipeline from anchor drop/drag, container drop, trawl gear, ship sinking/grounding, boulders, or ice is expected with the concrete weighted coating, and that the pipeline is safe without burial. In addition, AGDC stated in responses to comments that vortex suppressors such as strakes could be used to minimize vortices where these conditions are present.

In discussions with Commission staff, PHMSA requested additional information regarding locations across the bottom lay portion of the Cook Inlet crossing that could result in free spans, or segments of pipe that would not lay directly on the bottom, due to elevation changes in the seabed contours of Cook Inlet over short distances. Questions were also raised regarding how AGDC would identify free spans that could result in pipeline integrity concerns, such as buckling. AGDC responded that preconstruction surveys would be completed during the detailed design phase of the Project. If free spans that exceed the maximum allowable length or height for the pipeline are identified, AGDC would make localized adjustments to the pipeline route to avoid these areas. If avoidance of a free span area is not possible, AGDC would implement other measures such as sweeping the seabed, placing support under the pipeline, adding grout bags or sand bags, or placing vortex suppressors on the pipe, to mitigate impacts on pipeline integrity. During operation, AGDC would conduct geophysical surveys along the pipeline route across Cook Inlet every 1 to 2 years to assess conditions on the seabed and mitigate any new free spans that develop under the pipeline. The frequency of the surveys could be modified based on the survey results during the initial years of pipeline operation.

PHMSA has reviewed the technical information and responses provided by AGDC. With regard to 49 CFR 192.327(f)(2), PHMSA is satisfied that AGDC would mitigate any future pipeline safety conditions due to subsea bottom free spans. Should mitigation of free spans be required after detailed design is completed, or determined to be necessary during Project construction or operation, additional environmental analysis by FERC and other permitting agencies may be required depending on the proposed scope and anticipated impacts of implementing the mitigation measures.

Offshore construction would disturb about 5,070 acres during construction and about 14 acres during operation. Most of the construction impact would come from anchor cable sweeps. With the surface area of Cook Inlet at 4.7 million acres at MLLW (Zimmerman and Prescott, 2014), the temporary impacts of 5,070 acres and permanent impacts of about 14 acres of open-water marine habitat would be equivalent to 0.1 percent and less than 0.003 percent of the total environment of Cook Inlet, respectively. This would be an insignificant effect with respect to the total water environment of Cook Inlet. The subtidal impact would consist of about 5,035 acres for cable anchor sweep, 19 acres for anchor drag, 12 acres for offshore pipelay, and 4 acres for cable anchor drop, which likewise would be an insignificant effect on the total water environment of Cook Inlet.

Liquefaction Facilities

Construction of the Liquefaction Facilities would include the LNG Plant, which would take place primarily on shore in adjacent upland areas. Construction activities would also extend into marine waters for the Marine Terminal, which would involve construction of the PLF and temporary Marine Terminal MOF. About 30 acres would be used for the temporary Marine Terminal MOF and construction areas, and about 51 acres within Cook Inlet would be dredged to allow for vessel docking and unloading at the Marine Terminal MOF. The Marine Terminal MOF would consist of berths and laydown areas to be constructed of local fill materials with site-specific erosion and shoreline protection measures based on final design. For the PLF, berths would be in natural water depths greater than -53 feet MLLW and 1,600 feet apart, parameters sufficient to receive ships; therefore, no dredging would be required.

Construction and use of the Marine Terminal MOF would require both initial and maintenance dredging to accommodate the drafts of the vessels bringing in modules and materials for construction of the LNG Plant and Marine Terminal. Dredging would not be required for operation of the LNG Plant. The estimated dredge volume for the Marine Terminal totals 800,000 cubic yards over the first two seasons of marine construction (see section 2.1.5). Additionally, about 140,000 cubic yards of maintenance dredging would be necessary at the Marine Terminal MOF berths and approach during Years 3 and 7. The dredged material is anticipated to be a heterogeneous mix of sandy silt and sand with hard-packed clay.

AGDC estimates that the Marine Terminal MOF would require about 6,000 feet of sheet piling and 136 piles installed by a vibratory hammer or pile driving to build a dock and two berths at the Marine Terminal MOF. The dock would require about 600 feet of sheet piling in Cook Inlet. The Marine Terminal MOF would be constructed during Years 1 and 2, and pile driving would occur intermittently during this time; a vibratory hammer would be operated for about 40 percent of a 12-hour workday, and an impact hammer would be operated for about 25 percent of a 12-hour workday. The Marine Terminal MOF would be designed with a nominal design life of 10 years. The sheet piling and other structures would then be removed when the Marine Terminal MOF is no longer required. Therefore, impacts from the use of sheet piling and pile-driving would be short term and localized to the area of the temporary Marine Terminal MOF. Removal of the Marine Terminal MOF after 10 years would require that AGDC remove all sheet piling and gravel backfill; AGDC is not proposing in-water disposal of any of the Marine Terminal MOF materials.

A summary of the acreage affected during construction and operation of the Marine Terminal MOF is provided in table 4.3.3-4, with the duration of dredging during construction activities provided in table 4.3.3-5. As shown in these tables, dredging would be carried out with a combination of a mechanical clamshell dredger and a hydraulic cutterhead dredge plant. Alternative dredging methods fall into two general categories: mechanical dredging (e.g., conventional clamshell, clamshell enclosed bucket, and articulated bucket) and hydraulic dredging (e.g., conventional cutterhead, swinging ladder cutterhead, and horizontal auger) (COE, 2008). Advantages of mechanical dredging include the ability to maneuver around nearshore obstructions and in-water structures, and the ability to remove densely packed or rocky substrate. Mechanical dredging typically causes more resuspension of sediment as the bucket is pulled through the water column, but could be necessary where more precise extraction of materials is required or if rocky or densely packed substrate is present (COE, 2008, 2013a). Advantages of hydraulic dredging include increased production rates in sandy or unconsolidated sediment. Hydraulic dredging is typically best suited for dredging in open areas away from shoreline structures. Hydraulic dredging generates less resuspension of sediment during extraction, but entrainment of large volumes of water in the dredge slurry requires that the dredged material is dewatered, which results in discharge of significant volumes of turbid water from the hopper or barge (COE, 2013a). This can be avoided by using a pipeline to transport the dredged material to a disposal site, the feasibility of which can be limited by distance and in-water hydrodynamics, such as waves and currents (COE, 2013a).

The dredged material is anticipated to be a combination of sandy silt and sand with hard packed clay. Disposal of the Marine Terminal MOF dredged material would be spread over about 1,200 acres over 2 years (about 600 acres per year during construction). AGDC is proposing to dispose of dredged material at two potential open water disposal locations. The proposed open water disposal locations have been submitted in AGDC's COE application and applicable ADNR DMLW application. Two open water disposal sites in Cook Inlet have been identified for dredged materials (DP1 or DP2; figure 2.1.5-7). AGDC's preferred location for DP1 is an open-water site in state waters about 4 miles from the proposed dredge area at water depths between -60 and -110 feet MLLW with dispersive currents. AGDC's alternative open-water disposal location (DP2) would be in deeper water, between -85 to -110 feet MLLW. Sediment dispersion and deposition modeling conducted for these sites demonstrated that both would be sufficient to accommodate the anticipated volume of dredged material (as discussed further below).[45] The shallower DP1 location is the proposed primary disposal site.

[45] AGDC and CH2M's Sediment Transport Modeling – Dredging Infill Studies were included in the response to information request No. 82 for Resource Report 2 dated November 2, 2011 (Accession No. 20171102-5031), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20171102-5031 in the "Numbers: Accession Number" field.

TABLE 4.3.3-4 **Summary of Marine Terminal MOF Construction Dredging Activities**					
Year	Description	Method	Quantity (yd^3)	Production Rate (yd^3/day)	Disposal Method
1	Initial dredging for Marine Terminal MOF coffer cell install	Mechanical clamshell or small hydraulic cutterhead	50,000	3,000	Two 5,000-yd^3 dump scows [b]
2	Dredging to -30 to -32 MLLW	Hydraulic cutterhead with support from mechanical clamshell	750,000	16,000	Three 5,000-yd^3 dump scows [b] OR pipeline disposal
3	Maintenance dredging	Mechanical clamshell or small hydraulic cutterhead	70,000 [a]	3,000	Two 5,000-yd^3 dump scows [b]
7	Maintenance dredging	Mechanical clamshell or small hydraulic cutterhead	70,000 [a]	3,000	Two 5,000-yd^3 dump scow [b]

yd^3 = cubic yards
[a] Based on total volume of 140,000 cubic yards over two seasons of maintenance dredging.
[b] The dump scows' effective capacity is 4,000 cubic yards.

TABLE 4.3.3-5 **Duration of Dredging During Construction Activities at the Marine Terminal**				
	Product Loading Facility		Material Offloading Facility	
Dredging [a]	Performance Period (days)	Construction Hours	Performance Period (days)	Construction Hours
Year 1: Clamshell or excavator for sheet pile foundation preparation	No dredging at this location		10	240
Year 2: Hydraulic cutterhead or clamshell for approach and berth areas	No dredging at this location		64	1,536

[a] Dredging days are based on 24-hour days at 7 days per week.

During the first season, mechanical dredge equipment would remove sediment that would be loaded into 5,000-cubic yard-capacity (4,000-cubic yard-effective capacity) split hull or scow/hopper barges that would transport the material to be dumped in the designated disposal area, either DP1 or DP2. During the second season, hydraulic or mechanical dredging would be conducted. For hydraulic dredging, the dredge slurry would either be pumped to the disposal site via pipeline (within about 4 miles) or pumped into split-hull barges for decanting and transport to the disposal site. Dredging operations would be conducted during the ice-free season, about 6 months out of the year. Therefore, sea ice would not cause an impact on dredging operations in Cook Inlet. Potential impacts on recreational and commercial fishing from dredging are discussed in section 4.11. AGDC would provide mitigation measures that it would implement during dredging and dredged material disposal activities in a Project Dredging Plan. AGDC would file this plan with the Secretary, for the review and written approval of the Director of the OEP, prior to construction.

Based on a two-dimensional sediment transport model developed to simulate sediment transport infill rates at the dredged areas of the Project site near Nikiski, preliminary annual sediment infill rates were estimated to be between 1.1 to 1.6 feet per year (at offshore and nearshore locations, respectively). This model was calibrated by comparing measured suspended load measurements made at two offshore locations near Nikiski, and calibration results showed that suspended sediment load transport rate (i.e., the dominant sediment transport regime in the model) could be accurately predicted at the Project site. Additionally, the annual longshore sediment transport rate was estimated to be about 7,000 to 25,000 cubic yards per year along the Nikiski shoreline.

In addition to the two-dimensional sediment transport modeling conducted by Alaska LNG and CH2M, AGDC and their contractor, Integral Consulting Inc., evaluated the impacts of the Marine Terminal MOF construction dredging and disposal over four seasons (as outlined in table 4.3.3-4) on sedimentation and water quality using both near-field and far-field sediment transport modeling.[46] Modeling was conducted for two scenarios analyzing a combination of dredging and disposal activities involving 70,000 and 750,000 cubic yards of material and disposal at DP1 and DP2. The first scenario models the mechanical clamshell dredging utilizing the maximum design scenario of 70,000 cubic yards of material anticipated from maintenance dredging that would occur in Years 3 and 7, and also serves as a comparative model to the lesser impact of 50,000 cubic yards anticipated during the first year of construction of the Marine Terminal MOF. The second scenario models the hydraulic dredging planned during the second year of construction of the Marine Terminal MOF, when 750,000 cubic yards of material is expected to be dredged and disposed of at DP1 or DP2.

The hydrodynamic and sediment transport models were evaluated and verified by comparison with observed data inputs, such as water level measurements from NOAA station 9455760 (Nikiski, Alaska) and Open Water Project Data current measurements from the Project's 2015–2016 ASL Metocean and Ice Data Measurement Program for current magnitude, current direction, and turbidity time series near Nikiski. The modeling results indicated sedimentation is largely dependent on the total mass of sediment introduced into the water column. Thus, sedimentation for the scenario with 750,000 cubic yards of dredged material was more significant than sedimentation for the scenario with 70,000 cubic yards of dredged material, in which sedimentation was confined to the disposal area. In the model, tidal forcing strongly drove the pattern of sedimentation originating from the disposal area.

For the scenario simulating the dredging of 70,000 cubic yards of material, sedimentation of less than 0.4-inch thickness occurred near the shoreline from Marine Terminal MOF dredging and in the disposal area. For the scenario simulating the dredging of 750,000 cubic yards of material, the total area of sedimentation greater than or equal to 0.4 inch was about 0.2 and 0.1 square mile for the cases with disposal at DP1 and DP2, respectively. As a reference, the area at each disposal site (DP1 and DP2) prior to dumping was about 0.4 square mile. Based on all cases simulated, the maximum modeled sedimentation thickness was about 3.3 inches for the dredging of 750,000 cubic yards of material with disposal at the shallower of the two disposal locations (DP1). The maximum modeled sediment thickness at the Marine Terminal MOF area was 0.3 inch for the dredging of 70,000 cubic yards of material, with disposal at both disposal locations (DP1 and DP2). In all these cases, the strong tidal currents of Cook Inlet would naturally disperse the sediment from the disposal site.

The cumulative sedimentation impact was also calculated by summing the total sedimentation predicted for each construction season. The estimation of cumulative sedimentation likely overestimated the total sedimentation rate because the method of calculation did not account for any potential resuspension or erosion over the construction and maintenance dredging period from Year 1 to 7. The methodology also assumed that dumping occurred in the exact same location within the disposal area over the entire period, which would lead to overestimating the maximum sedimentation thickness reported. Therefore, based on this conservative approach, which was used for all cases simulated, the maximum modeled cumulative sedimentation thickness was about 3.7 inches for disposal at the shallower of the two disposal locations (DP1). The maximum modeled cumulative sedimentation thickness for the MOF area was about 1.1 inches

[46] AGDC's *Sediment Modeling Study Material – Offloading Facility Construction* was included in the response to information request No. 89 dated October 22, 2018 (Accession No. 20181022-5218), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20181022-5281 in the "Numbers: Accession Number" field.

for the deeper of the two disposal locations (DP2). Regardless of dredging method (i.e., mechanical or hydraulic), the disposal of dredged sediments would cause a localized, short-term increase in turbidity and sedimentation near the disposal site for the duration of disposal activities. Currents would then be expected to rapidly disperse any sediments deposited.

The impact of dredging and disposal on water quality within Cook Inlet was also evaluated using model-simulated turbidity relative to measured background turbidity. The simulated sediment concentration was converted to turbidity (NTU) using measured relationships of TSS and turbidity as derived from the Alaska LNG Project's 2015 and 2016 ASL Metocean and Ice Data Measurement Program. The simulated turbidity was normalized by background turbidity from Project monitoring. Therefore, normalized turbidity values less than one (representing higher than background turbidity of 61 NTU) indicated turbidity concentrations less than the measured reference turbidity. The analysis compared turbidity against the lowest mean background measurement of 61 NTU collected at nearby mooring locations off Nikiski during open-water seasons (June through October) in 2014 and 2015. The maximum NTU measurements at these three Nikiski monitoring stations collected between the two sampling seasons ranged from 420 to 983 NTU.

Modeled depth-averaged turbidity impacts exceeded the mean background measurements of 61 NTU for a maximum duration of 80 to 100 minutes and out to 3.7 and 3.9 miles from the source at the DP1 and DP2 disposal sites, respectively. The maximum distance from the Marine Terminal MOF source area at which the depth-averaged normalized turbidity exceeded one (indicating higher than background turbidity of 61 NTU) was about 0.1 mile. The highest maximum depth-averaged turbidity of any model location or scenario was 841 NTU, which was lower than the maximum measurement at nearby monitoring stations, indicating that increases in turbidity due to dredging could fall within the natural fluctuations that occur in the area.

As discussed in section 4.3.3.2, there is a seasonal influence to suspended sediment concentrations within Cook Inlet, with lower rates of discharge during winter months. However, dredging in the winter is not proposed. Additional mobilization of sediment during ice-free periods is not anticipated to have significant impacts. Therefore, dredging operations during construction of the temporary Marine Terminal MOF, using either mechanical or hydraulic methods, would cause a temporary and localized increase in turbidity and sedimentation (within 100 minutes and 3.9 miles from the dredge site) in the marine waters of Cook Inlet.

Based on sediment samples from other Cook Inlet sites, dredged sediments would not be anticipated to contain significant levels of contaminants. Suspended and bottom sediments from Cook Inlet previously sampled have been shown to contain low levels of anthropogenic hydrocarbon contaminants. At the temporary Marine Terminal MOF dredge site, sediments are relatively high density and contain hard clay, suggesting that they are not recent deposits that could contain anthropogenic contaminants. The sediments would be suitable for unconfined, open-water disposal. To mitigate for water quality degradation associated with dredging at the Marine Terminal MOF, the following measures would be implemented:

- construction would follow the techniques as outlined in the Project Dredging Plan that AGDC would file with the Secretary prior to construction;
- construction activities would comply with ADEC water quality regulations pertinent to the required permits;
- construction activities would follow measures in the Project SWPPP; and

- the Project Unanticipated Contamination Discovery Plan would be followed in the event that contaminated sediments are found.

Installation of structural supports on the seafloor would disturb loose sediments, introducing them into the water column, thereby increasing the turbidity of the marine water at the work site. The plumes of elevated suspended sediment concentrations would not be anticipated to extend significant distances from the work sites relative to the existing background conditions within Cook Inlet. The marine waters at the Marine Terminal site are naturally very turbid, and the temporary, localized increase in turbidity from dock installation is not anticipated to have significant impacts on marine waters.

As the Marine Facilities MOF is a temporary structure, it would not be active after construction is completed. Therefore, no additional impacts specific to dredging would be anticipated during the operational phase of the Project. The removal of sheet piling and other structures following the MOF construction, however, would cause a temporary and localized disturbance of the seafloor and turbidity within the water column similar in nature to the impacts caused during installation of the structures.

In addition to impacts from construction of the Marine Terminal MOF, maintenance and repair activities at the LNG Plant (to the west and adjacent to the Marine Terminal MOF) would be anticipated to require minimal site disturbance that could affect marine waters. Potential impacts on Cook Inlet from maintenance and repair activities would be anticipated to be similar but of a lower magnitude than those described for construction because of the smaller-disturbance footprint and infrequent need for maintenance and repair. It is anticipated that impacts on Cook Inlet from maintenance and repair would occur throughout the life of the Project, but the impacts would be intermittent, short term, and minor.

Water Discharges

Section 301(a) of the CWA prohibits the discharge of pollutants to surface waters of the United States except in accordance with a NPDES permit. Section 402 of the CWA establishes the NPDES permit program, which provides the EPA and authorized states the authority to control and limit the discharge of pollutants into waters of the United States. On October 31, 2008, the EPA approved the State of Alaska's application for primacy of the NPDES program for discharges to state waters. ADEC assumed authority to administer the APDES program for certain sectors on October 31, 2012. The EPA has oversight authority of the states' APDES program and maintains the NPDES permitting authority for facilities discharging to federal waters, facilities in the DNPP, facilities with 301(h) waivers, and all facilities in Indian Country (Metlakatla Indian Community, Annette Island Reserve). AGDC would obtain the required permits for all wastewater discharges (e.g., industrial and stormwater) associated with Project construction and operation. The specific sources, volumes, types, frequencies, rates, treatments, and disposal mechanisms for wastewater discharges, as well as the locations of potential outfalls and discharge points, would be determined by AGDC during preparation of the applicable permit applications for the discharges.

Section 403(c) of the CWA requires that NPDES permits authorizing discharges into the territorial seas, the contiguous zones, and the oceans, including the outer continental shelf, comply with EPA's Ocean Discharge Criteria (40 CFR Part 125, Subpart M). The purpose of the Ocean Discharge Criteria Evaluation is to assess the discharges authorized under the NPDES permit and to evaluate the potential for unreasonable degradation of the marine environment based on the consideration of 10 specific criteria (40 CFR 125.122). Unreasonable degradation is defined as "significant adverse changes to the ecosystem diversity, productivity, and stability of the biological community within the area of discharge and surrounding biological communities; threat to human health through direct exposure to pollutants or through consumption of exposed aquatic organisms; or loss of aesthetic, recreational, scientific, or economic values, which is unreasonable in relation to the benefit derived from the discharge." The potential effects of water discharges associated with the Project pertaining to Prudhoe Bay and the Beaufort Sea are discussed by facility below.

Gas Treatment Facilities

Vessel traffic at the West Dock Causeway would be tugs and barges only. Discharges to marine waters associated with vessel traffic during construction of Dock Head 4 and expansion of the West Dock Causeway are subject to a VGP. The VGP covers 27 different types of discharge that are common to the operation of marine vessels. The discharges most likely to occur associated with barges and tugs at the West Dock Causeway include, but are not limited to, bilgewater/oily water separator effluent, ballast water, controllable pitch propeller and thruster hydraulic fluid and other oil sea interfaces, gas turbine washwater, gray water, non-oily machinery wastewater, seawater cooling discharge, and boat engine wet exhaust. These discharges would occur in the open water season between Years 2 and 7 of construction, and would be minor and have minimal impact.

Mainline Facilities

Vessel traffic at the Mainline MOF would be tugs and barges only. A variety of vessels would be used for construction of the Mainline Pipeline across Cook Inlet (e.g., derrick barges, work boats, survey boats, tractor tugs, and ocean going tugs). Vessel discharges from these vessels would be subject to the VGP, and discharges associated with construction stormwater runoff would be subject to applicable APDES permits. The most likely discharges to occur associated with barges and tugs at the Mainline MOF and within Cook Inlet during Mainline Pipeline construction include, but are not limited to, deck washdown and runoff, bilgewater/oily water separator effluent, ballast water, chain locker effluent, controllable pitch propeller and thruster hydraulic fluid and other oil sea interfaces, gas turbine washwater, gray water, non-oily machinery wastewater, seawater cooling discharge, and boat engine wet exhaust. These discharges would occur during construction Years 1 to 4, during Mainline MOF construction and use, and during the Mainline Pipeline construction crossing of Cook Inlet. The discharges to marine waters associated with vessel traffic during construction of the Mainline MOF and the Mainline Pipeline across Cook Inlet would be minor and have minimal impact.

Liquefaction Facilities

Oceangoing vessels that deliver materials for constructing the Liquefaction Facilities could use ballast water and cooling water. The impacts associated with operation are addressed by the protocol for ballast and cooling water discharge and applicable permitting requirements under the VGP. During construction, with all applicable mitigation measures applied, ballast and cooling water discharge from vessels would result in brief periods of discharge during the short-term construction of the Liquefaction Facilities.

Ballast Water

A study for the Cook Inlet Regional Citizen's Advisory Council analyzed the total ballast water discharge in Cook Inlet waters from marine vessels trading at various ports in Cook Inlet over the course of 5 years (1997 to 2001) (Robertson and Crews, 2003). The study estimated the total discharge to be 14.3 million tons (13.0 million metric tons, or approximately 3.3 billion gallons) over 5 years or 2.9 million tons (2.6 million metric tons, or approximately 677 million gallons) per year.

LNG carriers would dock and load at the PLF. These oceangoing vessels generally use ballast water (seawater) that would be exchanged in international waters no less than 200 nautical miles from shore prior to discharge in U.S. waters. Ballast water exchange and discharge would be conducted in accordance with international convention and the requirements of the EPA's NPDES VGP program to discharge ballast water and other pollutants incidental to the normal operation of certain commercial vessels into navigable waters. On December 4, 2018, the Vessel Incidental Discharge Act was signed into law, which requires the EPA to develop new national standards of performance for commercial vessel incidental discharges and the Coast Guard to develop corresponding implementing regulations. The Vessel Incidental Discharge Act legislation has extended the effective date of the 2013 VGP until the EPA finalizes new regulations.

As LNG is loaded onto the LNG carriers at the PLF, the LNG carriers would release the ballast water, thereby replacing the seawater with LNG product as ballast to maintain stability of the LNG carrier in the water. Ballast water is stored below the water line in the hull of the LNG carrier, where water temperatures could slightly deviate from ambient temperatures of the PLF berth. Ballast water discharge would occur near the bottom of the berth, where the dissolved oxygen levels are already inhibited. Cook Inlet tidal exchange is anticipated to dilute the ballast water discharge to temperature, pH, dissolved oxygen, and salinity levels that typically occur near the PLF.

Ballast water discharged from LNG carriers would consist of open-ocean water collected during ballast water exchange performed during transoceanic shipping. Based on the double-hulled LNG carrier design, a significant difference in temperature between ballast water and ambient waters of Cook Inlet is not anticipated. LNG carriers are constructed with double hulls, which increase the structural integrity of the hull system and provide protection for the cargo tanks in case of an incident. The space between the inner and outer hulls is used for water ballast. Because ballast water is stored in the ship's outer hull below the waterline, discharged water temperatures would not be expected to deviate significantly from ambient water temperatures; rather, it is anticipated that the ballast water would be equilibrated to the surrounding water temperature before being discharged. Therefore, thermal impacts in Cook Inlet from LNG carrier ballast water discharge would not be anticipated.

About 2.9 billion to 3.2 billion gallons of ballast water would be discharged per year from LNG carriers during LNG loading operations at the PLF. The range in annual discharge volume would be due to varying LNG carrier sizes and the number of LNG carriers that could call at the PLF (estimated at 204 to 360 LNG carriers annually). This discharge volume can be compared to the strong Cook Inlet tidal exchange. Cook Inlet is larger than other partially enclosed marine waterbodies, such as the Chesapeake Bay and Puget Sound, which have been examined for ballast discharge in previous FERC applications. As described in section 4.3.3.2, the total water volume of Cook Inlet at MHW is about 270.5 trillion gallons, while at MLLW, the volume is 244.1 trillion gallons of water (Zimmermann and Prescott, 2014) with the difference between MHW and MLLW at 26.4 trillion gallons or 9.7 percent of the total volume. The average daily semidiurnal tidal flushing is about 52.8 trillion gallons of water. The estimated ballast water discharge from an LNG carrier is about 12.9 million gallons per port call spread over about 18 to 24 hours while loading. As a result, the daily maximum discharge (12.9 million gallons) of ballast water for LNG carriers contributes less than 0.1 percent (0.00002 percent as a precise value) of the semidiurnal tidal exchange within Cook Inlet. Therefore, the potential variation of salinity, dissolved oxygen, water temperature, and pH between LNG carrier ballast water and the Cook Inlet marine environment would have local, temporary, and minor impacts on water quality.

AGDC does not have the authority or control over independent vessels that would be used for construction and operation of the Project. However, the LNG carriers and marine barges to be utilized would be commercial maritime vessels obligated to meet the requirements of the Coast Guard and EPA VGP regulations.

Coast Guard regulations (33 CFR 151, subpart D and 46 CFR 162.060 on "Standards for Living Organisms in Ships' Ballast Water Discharged in U.S. Waters; Final Rule" [77 FR 17254 (Mar. 23, 2012)] and Navigation and Vessel Inspection Circular 01-18) provide guidance to the maritime industry and Coast

Guard personnel relative to the implementation of Ballast Water Management (BWM) system requirements. Coast Guard regulations (46 CFR 162.060) were enacted in June 2012 in an effort to phase out ballast water exchange practices. The ballast water discharge standard (33 CFR 151.2030(a)) requires vessels calling at all U.S. ports to be equipped with a Coast Guard-approved BWM system. This applies to all new ships constructed on or after December 2013. All vessels over 300 gross tons or that have the capacity to discharge 2,113 gallons of ballast water must submit a notice of intent to the EPA requesting authorization under the VGP. These governing regulations apply to all vessels that enter or operate within U.S. waters and are equipped with a ballast water system that has been approved by the Coast Guard and meets the applicable ballast water discharge standards. The Coast Guard requires that vessels equipped with ballast tanks and bound for ports or places in the United States (except for the Great Lakes), regardless of whether the vessel operated outside the EEZ, submit the ships' BWM information to the Coast Guard no later than 6 hours after arrival at the port or place of destination, or prior to departure from that port or place of destination, whichever is earlier.

Discharges of a pollutant into the navigable waters of the United States requires authorization under the CWA. In 2013, the EPA issued a NPDES permit, the VGP, which sets numeric effluent limits for ballast water discharges from certain large commercial vessels under a staggered implementation schedule. The standard is expressed as the maximum concentrations of living organisms in ballast water. The permit also includes maximum discharge limitations for biocides and residues. The VGP has additional requirements for periodic sampling, including calibration of sensors, sampling of biological indicators, and sampling of residual biocides.

Under the EPA VGP, there are numerous mandatory ballast water management practices applicable to the marine waters resource that would be carried out by masters, owners, operators, or persons-in-charge of Project vessels equipped with ballast water tanks operating in U.S. waters. Examples include, but are not limited to, the following:

- discharge only the minimal amount of ballast water essential for vessel operations;
- minimize or avoid uptake of ballast water in the following areas or situations:
    - areas near sewage outfalls;
    - areas near dredging operations;
    - areas where tidal flushing is known to be poor or times when a tidal stream is known to be turbid; and
    - where propellers may stir up the sediment;
- clean ballast tanks regularly to remove sediments in mid-ocean (when not otherwise prohibited by applicable law) or under controlled arrangements in port or at a dry dock; and
- avoid the discharge of sediment following cleaning of ballast tanks.

In addition to these federal requirements, vessels calling on Alaska ports must also comply with state ballast water exchange rules and laws. Ballast water discharges are regulated under AS 46.03.750(a)(b), which states: "Except as provided in (b) of this section, a person may not cause or permit the discharge of ballast water from a cargo tank of a tank vessel into the waters of the state. A tank vessel may not take on petroleum or a petroleum product or by-product as cargo unless it arrives in ports in the state without having discharged ballast from cargo tanks into the waters of the state and the master of the vessel certifies that fact on forms provided by the department. (b) The master of a tank vessel may discharge ballast water from a cargo tank of a tank vessel if it is necessary for the safety of the tank vessel and no alternative action is feasible to ensure the safety of the tank vessel." Adherence to these rules and regulations would minimize the likelihood of water quality impacts due to discharges of ballast water during Project operation.

AGDC would comply with the conditions set forth in the EPA VGP and the Coast Guard's Ballast Water Discharge Standards, which require vessels calling at U.S. ports to be equipped with a BWM system. All vessels brought into the State of Alaska or federal waters are required to install and operate a ballast water management system approved by the Coast Guard under 40 CFR 162 and subject to Coast Guard 33 CFR 151 regulations, which are intended to reduce the transfer of aquatic invasive organisms. Approved ballast water management systems involve a filtration step and a biological disinfection step. Best practices include using a ballast water management system that limits the number of micro- and macro-organisms per cubic meter of discharge, rinsing anchors upon retrieval, and removing fouling organisms from the hull and tanks regularly.

AGDC has developed a BWM Plan that outlines the applicable regulations and standards to protect against water quality degradation in Cook Inlet and Prudhoe Bay during Project construction and operation. In the Project BWM Plan, AGDC stated that there would be no discharge of untreated ballast water by construction vessels or LNG carriers into the waters of Cook Inlet or Prudhoe Bay unless that ballast water has been subject to a mid-ocean water exchange (at least 200 nautical miles offshore, and in 200 meters of depth). Additionally, AGDC would require that visiting vessels possess documentation to demonstrate compliance with ballast water regulations prior to allowing any ballast water to be discharged into the Project's berthing areas. AGDC's compliance with the regulations outlined above, including implementation of regulations and standards outlined in AGDC's BWM Plan, would adequately minimize the potential to introduce invasive species to, or have a negative impact on, water quality within Cook Inlet.

Cooling Water

LNG carriers that dock at the Marine Terminal would require engine cooling water, the discharge of which is subject to the VGP. Seawater for cooling is a function of vessel size and type of propulsion unit. The source of cooling water would be Cook Inlet. Typical cooling water circulation ranges from 343,421 gallons per hour (5,724 gallons per minute) to 554,761 gallons per hour (9,246 gallons per minute). Assuming a 554,761 gallon per hour flow rate, about 13.3 million gallons would circulate through the heat exchanger while the vessel is alongside the berth over a 24-hour period. As an estimate, assuming there would be 204 to 360 LNG carriers per year, and also assuming that each carrier would be at berth for approximately 24 hours, there could be 2.7 billion to 4.8 billion gallons of cooling water withdrawn and discharged by LNG carriers per year.

The cooling water discharge is not expected to reach the seafloor as the cooling water intakes can range from about 6.6 and 39.4 feet below the surface, while the greatest depth at the berth would be 53 feet. Regardless, the water would undergo minimal filtration upon intake and a heat exchange process to provide cool water needed for the LNG carrier integrated cooling systems for equipment onboard, such as main engines and diesel generators. Modern cooling water systems are designed as non-contact systems to avoid contact with fuels, oils, or other potential contaminants.

AGDC estimates that the cooling water discharge velocity would be about 0.3 foot per second, and the water discharged could be about 1°F warmer than ambient water temperature in Cook Inlet. Impacts would only last while the LNG carrier is at berth, about 24 hours. As was the case for assessing ballast water impacts, the discharge of cooling water can be compared to the strong Cook Inlet tidal exchange. While the estimated cooling water circulated over a 24-hour period is 13.3 million gallons, the thermal impacts of the warmed cooling water would be resolved by natural mixing in the high flushing regimes of Cook Inlet and the rapid assimilation with the turbulent flow past the LNG carriers. The discharge of cooling water would be a long-term impact based on the lifespan of the Project, but seawater intake or cooling water discharge is not anticipated to adversely affect Cook Inlet water quality.

Facility Operational Wastewater

Operation of the LNG Plant would result in multiple operational discharges to Cook Inlet. The plant would draw in water for use as boiler blowdown, reverse osmosis, hydrostatic test water, and water treatment backwashes. For measurable discharges from the LNG Plant, see section 4.3.4 for more details regarding volumes. The LNG Plant would discharge treated wastewater, boiler blowdown waters, reverse osmosis reject water, and site stormwater runoff.

Surface drainage and oily water from process areas at the LNG Plant would be collected for treatment. AGDC would design a wastewater treatment system to treat stormwater and process black and gray water. The wastewater treatment system would include the following subsystems: contaminated stormwater collection, process oily water treatment, and hydrostatic test water disposal. Oil and water would be separated by means of an equalization tank skimmer and a corrugated plate interceptor, which would remove free oil droplets from processed wastewater. The remaining skimmed oil would be trucked off site for proper disposal or recycling. Sanitary wastewater would be treated through a sanitary treatment package plant. The treated effluent would be discharged to Cook Inlet, with residual sludge removed by truck for off-site disposal. Surface water runoff and oily water from collector sumps would be sent to an equalization tank separator system and treated water sent to one of three on-site receiving ponds for further settling prior to discharge to Cook Inlet. In every case, water discharged to Cook Inlet would be required to comply with APDES permits and/or AWQS. The APDES permitting process requires disclosure of all wastewater, a review by ADEC, and a permit that requires discharges to be monitored and limited to specific parameters, including a 5-day biochemical oxygen demand, TSS, fecal coliform, total ammonia, total recoverable copper, total recoverable zinc, whole effluent toxicity, *Enterococci*, total residual chlorine (if applicable), dissolved oxygen, oil and grease, pH, and flow.

Impacts on water quality would be permanent for the lifespan of the facility, but because wastewater would be treated before discharge to Cook Inlet in compliance with the ADEC APDES discharge permit and associated AWQS, these impacts would be minor.

Navigation and Vessel Traffic

Gas Treatment Facilities

The planned construction activities, including screeding and delivery of construction materials for the Gas Treatment Facilities, would increase vessel traffic in the Project area. Table 2.2.1-1 provides a summary of the estimated number of barges and modules per sealift season to be delivered to Dock Head 4.

Peak vessel calls would be expected in Year 4, with the activities concentrated during the July and August summer sealift season, due to the presence of sea ice (as described in section 4.3.3.1). While there would be a vessel traffic increase, it would not be expected to contribute materially to ambient turbidity or to shoreline erosion due to the low vessel speeds mandated for operational safety in and near Prudhoe Bay.

Routine vessel activity is not anticipated during the operation of the Gas Treatment Facilities. Most materials, supplies, and personnel would use ground or air transportation. Therefore, there would be no vessel activity impacts for marine water resources associated with the operation of the Gas Treatment Facilities.

Mainline Facilities

A new Mainline MOF would be constructed adjacent to the existing Beluga Landing facility and far enough away from the current Beluga Landing to avoid interference with existing operations. Both a pier and roll-on/roll-off ramp, consisting of anchored sheet pile walls backed by granular fill, would be constructed at the Mainline MOF. The Mainline MOF would be used to receive barges transporting onshore pipeline construction materials and equipment. AGDC would then truck these materials to the southernmost spreads (north of Cook Inlet) for the Mainline Pipeline.

While there would be an increase of vessel traffic around the Beluga Landing facility due to construction of and use of the Mainline MOF, it would not be expected to contribute materially to ambient turbidity or to shoreline erosion due to the low vessel speeds mandated for operational safety of barges that would be using the Mainline MOF.

Liquefaction Facilities

The marine vessel construction equipment would include derrick and crane barges, deck barges, service and towing tugs, and ice mitigation vessels. During the construction period, vessel traffic to and from as well as near the Marine Terminal would include:

- marine deliveries of bulk granular materials and rock;
- delivery and installation of structural steel, sheet piling, and pipe piling;
- delivery and installation of steel-jacketed (quadropod) structures;
- vessel/barge transport of dredged material to deep water disposal areas; and
- delivery and installation of modules for the PLF decks, pipe racks, and roadways.

About 50 barge shipments of steel products, 45 marine shipments of quadropods and PLF modules, and 100 barge shipments of bulk materials would be required during construction of the Marine Terminal. Shipments would be made during the summer shipping season with as many as three shipments arriving during a 7-day period. Vessel movements during construction at the Liquefaction Facilities would not be expected to contribute to ambient turbidity or to shoreline erosion due to the low vessel speeds mandated for operational safety.

Vessels associated with operation would include LNG carriers and four to five assist tugs used for docking and undocking, vessel escorts, ice management, and firefighting. LNG carriers would call at the Liquefaction Facilities 204 to 360 times per year, depending on capacity. Similar to construction activities, vessel movements during operations at the Liquefaction Facilities would not be expected to contribute to ambient turbidity or to shoreline erosion due to the low vessel speeds mandated for operational safety.

Specific to Cook Inlet, table 4.3.3-6 provides the historic incidence of vessel groundings. The number of incidents per vessel type and resulting spills occurring between 1995 and 2010 had a historical spill rate (percent of incidents resulting in spills) of 48.2 percent (The Glosten Associates and ERC, 2012).

Using the incident data in table 4.3.3-6 and vessel traffic data from the Automatic Identification Systems, The Glosten Associates and ERC (2012) calculated near-term (2010 to 2014) incident and spill rates in Cook Inlet. The near-term incident and spill rates were calculated to be 3.4 percent per year (with the highest spill rate being from workboats at 1.0 percent per year) with an estimate of 3.9 percent per year (with the highest spill rate from non-tank vessels at 1.3 percent per year) when forecasted out from 2015 to 2020.

TABLE 4.3.3-6

Incidents and Spills in Cook Inlet by Vessel Type from 1995 to 2010

Vessel Type [a]	Number of Incidents [b]	Number of Spills [b]	Percent of Incidents Resulting in Spills (%)
Tank ship	24	12	50.0
Tank barge	31	24	77.4
Non-tank vessel	27	5	18.5
Workboat	32	14	43.8
Total	**114**	**55**	**48.2**

Source: The Glosten Associates and ERC, 2012

[a] Some vessel types were combined into broader categories to summarize the data.

[b] Spill and incident data from the ADEC Cook Inlet Database; database contained a total of 121 incidents (The Glosten Associates and ERC, 2012).

The Glosten Associates and ERC (2012) assessed the relative risks associated with vessel traffic scenarios in Cook Inlet. Scenarios were defined for 2,112 unique combinations of vessel types and spill factor subcategories. A relative probability level and consequence level was determined for each scenario. Tank ships were found to have the lowest baseline spill rate but presented the most risk from an oil spill in Cook Inlet. The CIRA concluded that the overall probability of a tank ship grounding in Cook Inlet is very low. While the consequence of a spill by an LNG carrier and an oil tanker are different, both vessel categories are considered high risk. CIRA data (Nuka and Pearson, 2015), however, demonstrates that operators of both of these high-risk vessel categories operate to a higher standard with a significantly lower number of grounding incidents as a result. In the 15-year history studied in the CIRA (Nuka and Pearson, 2015), one oil tanker suffered a grounding incident that resulted in a 200-gallon spill. There are no records of an LNG carrier grounding in these waters since LNG exports commenced out of Cook Inlet over 40 years ago.

In comments on the draft EIS, the USFWS said that its trust resources could be affected by oil spills occurring in difficult sea ice conditions. Overall, the probability of an oil spill to marine waters in difficult sea ice conditions due to Project construction or operation is low. The Project would transport natural gas, not oil. Oil needed for Project operations at onshore facilities near the coast, such as the Liquefaction Facilities, would be stored and managed in compliance with applicable ADEC and EPA requirements, including those for petroleum storage tanks regulated by ADEC under AS 46.04.030 and secondary containment for regulated petroleum storage tanks under 18 AAC 75 Article 1 (see section 2.5.3.1). The potential for an oil spill to the marine environment largely would be limited to Project vessels transiting through or working in the Beaufort Sea or Cook Inlet. Construction activities in these areas would be limited to ice-free months, which would minimize the potential for oil spills from vessels in difficult sea ice conditions. No marine vessel traffic in Prudhoe Bay for Project operation is anticipated. Marine vessel traffic for Project operations in Cook Inlet would be limited to LNG carriers and assist tugs transiting to and from the marine terminal (an average of 21 round trips per month). While difficult sea ice conditions in Cook Inlet are possible from December through March, ice conditions in lower Cook Inlet where the marine terminal would be constructed are not typically severe, as discussed in section 4.3.3.2.

If any oil spills should occur in Cook Inlet due to Project operation, vessel operators would implement the applicable spill response plans, as discussed above. Both federal and state regulations (33 CFR 155 and 18 AAC 75 Article 4, respectively) establish that operators must evaluate and plan for unique regional conditions such as presence of sea ice and other similar unique regional conditions, and must address these in their ODPCPs (e.g., Area Contingency Plans developed according to the National Contingency Plan and Part 3 – Supplemental Information addressed in "Oil discharge prevention and contingency plan content" according to state regulations). For these reasons, we conclude that adverse impacts on USFWS trust resources due to oil spills in difficult sea conditions would be unlikely.

The potential for impacts on marine waters within Cook Inlet due to a spill of fuel or other potential hazardous materials would exist for the lifespan of the Marine Terminal. Due to the incident rates of spills outlined above, and with proper training of vessel pilots, the potential risks of a spill would be adequately minimized.

4.3.4 Water Use

4.3.4.1 Existing Water Use

Groundwater in Alaska is used for agricultural, commercial, industrial (mineral extraction), and domestic purposes (ADEC, 2017a). About 90 percent of Alaska's rural population, and 50 percent of the overall state population, utilizes groundwater as their primary drinking water source (ADEC, 2008). Table 4.3.4-1 provides known groundwater uses and volumes near or within the Project area by borough or census area (Maupin et al., 2014). Of the 177.5 million gallons of groundwater withdrawn per day in 2010, about 19 percent was freshwater and 81 percent was saline groundwater. Of the freshwater withdrawn, about 57 percent was used for domestic and public water supplies for major population centers, such as Fairbanks and Anchorage. The remaining 43 percent was used for irrigation, livestock, mining, industrial, and thermoelectric purposes (Maupin et al., 2014).

TABLE 4.3.4-1

Groundwater Uses for Areas Crossed by the Project [a]
(million gallons per day)

Type of Groundwater Withdrawals (fresh and saline)	North Slope Borough	Yukon-Koyukuk Census Area	Denali Borough	Fairbanks North Star Borough	Matanuska-Susitna Borough	Kenai Peninsula Borough	Total Withdrawal by Use
Public supply	<0.1	0.2	<0.1	7.5	1.6	0.8	10.1
Domestic self-supply	0.0	<0.1	0.1	2.6	4.2	2.0	8.9
Irrigation	0.0	0.0	0.1	0.2	0.5	0.1	0.9
Livestock	0.0	0.0	0.0	<0.1	<0.1	<0.1	<0.1
Aquaculture (hatcheries)	0.0	0.3	<0.1	<0.1	5.1	5.3	10.7
Mining - fresh	0.0	0.0	0.0	0.0	<0.1	0.0	<0.1
Mining - saline	144.4	0.0	0.0	0.0	0.0	<0.1	144.4
Industrial self-supply	<0.1	0.0	0.0	0.5	0.2	0.0	0.7
Thermoelectric	0.0	0.0	0.6	0.7	0.0	0.5	1.8
Total Fresh Groundwater Withdrawal	**<0.1**	**0.5**	**0.8**	**11.5**	**11.6**	**8.7**	**33.1**
Total Saline Groundwater Withdrawal	**144.4**	**0.0**	**0.0**	**0.0**	**0.0**	**<0.1**	**144.4**
Total Groundwater Withdrawals	**144.4**	**0.5**	**0.8**	**11.5**	**11.6**	**8.7**	**177.5**

Source: Maupin et al., 2014
[a] The totals shown in this table may not equal the sum due to rounding.

Surface waters, which can be either freshwater or saline or brackish water, are used for a variety of purposes in Alaska, including commercial shipping traffic, subsistence and recreational fishing, commercial fishing, transportation, drinking water / domestic uses, industrial uses, and support of plant and animal life. Table 4.3.4-2 provides known surface water uses and volumes near or within the Project area, which vary by borough or census area (Maupin et al., 2014).

In terms of commercial shipping, access to the Prudhoe Bay area by marine vessels is limited to the summer open-water season, which is estimated to be August and September (60 days).[47] Cook Inlet is used for shipping year-round, with ready access to several ports, including Kenai and Nikiski. Subsistence and recreational fishing occurs on waterbodies that support fisheries throughout the Project area, and commercial fishing occurs in Cook Inlet. Rivers and streams that are deep enough are used by hunters, fishers, rafters, and others during the open-water period. In winter, frozen waterbodies are used as snow machine, dog sled, and other transportation corridors and provide year-round access to remote communities. Larger waterbodies, such as the Yukon and Tanana Rivers, are used for shipping via barge for various communities along the rivers. Sixteen existing oil and gas platforms are within Cook Inlet (ADNR, 2013a). Municipal wastewater is discharged either directly or indirectly into Cook Inlet from communities within the drainage basin.

TABLE 4.3.4-2

Surface Water Uses for Areas Crossed by the Project [a]
(million gallons per day)

Type of Surface Water Withdrawals	North Slope Borough	Yukon-Koyukuk Census Area	Denali Borough	Fairbanks North Star Borough	Matanuska-Susitna Borough	Kenai Peninsula Borough	Total Withdrawal by Use
Public supply	0.5	<0.1	0.0	0.0	0.0	2.7	3.2
Domestic self-supply	<0.1	0.0	0.0	0.0	0.0	0.0	<0.1
Irrigation	0.0	0.0	0.0	0.0	<0.1	0.0	<0.1
Livestock	0.0	0.0	0.0	<0.1	<0.1	<0.1	<0.1
Aquaculture (hatcheries)	0.0	0.9	<0.1	<0.1	20.4	15.8	37.2
Mining - fresh	0.7	0.4	0.1	10.4	1.6	<0.1	13.3
Mining - saline	75.6	0.0	0.0	0.0	0.0	0.8	76.4
Thermoelectric	0.0	0.0	23.2	31.7	0.0	0.0	55.0
Total fresh surface water withdrawal	**1.2**	**1.3**	**23.4**	**42.2**	**22.1**	**18.6**	**108.7**
Total saline surface water withdrawal	**75.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**76.4**
Total surface water withdrawals	**76.7**	**1.3**	**23.4**	**42.2**	**22.1**	**19.4**	**185.1**

Source: Maupin et al., 2014
[a] The totals shown in this table may not equal the sum due to rounding.

As depicted in tables 4.3.4-1 and 4.3.4-2, a combined total of about 221.1 million gallons per day (gpd) of surface water and groundwater are used in the North Slope Borough. About 99 percent of this total is saline water used for mining. The Yukon Koyukuk census area has minimal water use (totaling 1.8 million gpd) in comparison with the other borough/census areas crossed by the Project, which reflects the small population present in this area. The Denali and Fairbanks North Star Boroughs total 24.2 million and 53.7 million gpd of water use, respectively. The largest water use for both boroughs is thermoelectric,

[47] AGDC's 2014 *Marine Sampling Program: Evaluation of Test Trench Dredging and Disposal Reuse* was included as appendix R2 of Resource Report 2 (Accession No. 20170417-5357), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

comprising 98 percent and 60 percent of water use in each borough, respectively. This is reflective of the energy being produced to support the larger population centers in these boroughs. The MSB and Kenai Peninsula Borough total 33.7 million and 28.1 million gpd of water use, respectively. The largest water use for both boroughs is aquaculture, comprising 76 percent and 75 percent of water use in each borough, respectively. This is reflective of the large fishing industries present in these boroughs.

4.3.4.2 Surface Water and Groundwater Withdrawal and Discharge Permits

Project construction would require the use of surface water and groundwater for hydrostatic testing, DMT activities, ice road construction, potable water, and activities such as dust control (see section 4.15.4). PHMSA requires hydrostatic testing to be completed on pipeline segments before they are placed in service (see section 2.2.2). Operating the Project would require water for a variety of activities, including hydrostatic testing, emergency repairs, and potable water. The water needed for the construction and operational activities would be primarily sourced from surface waters, but substantial groundwater withdrawals would also be required.

The State of Alaska administers programs that regulate the withdrawal and discharge of water used for hydrostatic testing and specifies measures to ensure consistency with AWQS and the antidegradation policy.[48] The state also administers programs to avoid conflicts in water uses. The ADNR administers a program for Alaskan water rights, which are legal rights to use surface and groundwater under the Alaska Water Use Act. AGDC would acquire appropriate water rights permits prior to Project construction and operation. Water withdrawals from fish bearing waterbodies additionally would require an authorization from the ADF&G in accordance with its AS Title 16 authority.

ADEC developed an APDES general permit that authorizes the discharge of seven waste streams, including hydrostatic test water, from the construction, operation, and maintenance of oil and gas pipelines. AGDC would obtain the required permits for all wastewater discharges (e.g., industrial and stormwater) associated with Project construction and operation. The specific sources, volumes, types, frequencies, rates, treatments, and disposal mechanisms for wastewater discharges, as well as the locations of potential outfalls and discharge points, would be determined by AGDC as construction plans are finalized and through the acquisition of the required permits from ADEC (or the EPA for discharges within the DNPP). See table 1.6-1 for a list of permits and authorizations applicable to the Project.

4.3.4.3 General Impacts and Mitigation

Impacts associated with water use for the Project include surface water withdrawals, groundwater withdrawals from new wells, and wastewater discharges (e.g., hydrostatic test water, black/gray water, industrial water, truck wash water, fire water, and stormwater runoff). Water withdrawals from surface waters would temporarily and permanently reduce water availability for other uses. Withdrawals could also temporarily affect biological and recreational uses of surface water sources if a large percentage of the source water flow is withdrawn. Similar to pipeline waterbody crossings, withdrawals could impair water quality and affect aquatic habitats for wildlife. With the exception of hydrostatic test water discharges into Cook Inlet, the impacts and mitigation discussed in this section focus on withdrawals of surface waters and groundwater, and discharges into non-marine waters. See section 4.3.3.3 for a discussion regarding the Project's impact on marine waters, including barge and tug discharges, ballast water, and cooling water. See sections 4.3.2.5 and 4.7.1 for additional discussion regarding the Project's impacts on water resources and aquatic habitats.

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[48] Antidegradation is a tool used to protect the water quality in Alaska, and the state's antidegradation policy was adopted in 1997. Implementation methods can be found in 18 AAC 70 – Water Quality Standards.

Project-related surface water withdrawals would be subject to state permitting requirements such as volume restrictions and reporting to ensure that adequate volumes of water remain in the waterbodies to support aquatic life. AGDC would monitor water withdrawal rates and keep intake hoses off the waterbody bottom to avoid sediment uptake. Implementation of the Project Procedures and SWPPP would also reduce impacts during construction and operation. These plans are discussed in section 2.2, with additional information on the measures outlined in the SWPPP provided in section 4.3.2.4. A list of potential water sources for the Gas Treatment Facilities and Mainline Facilities is included in appendix J. These water sources are less than 5 miles from the Project area, with designated primary water sources less than 2 miles from the Project. In addition to the specific water volumes discussed in the sections below, water would also be required to compact granular work pads used during construction of Project facilities.

For lakes that have been identified as potential sources of ice chips (as discussed below), snow would be stockpiled and a loader-mounted rotary trimmer would be used to make ice chips from surface ice. Ice chips and snow would be transported to the Project area using dump trucks.

At other approved surface water sources, a submersible pump would be placed at the waterbody edge and connected to an intake line to provide a filling station for water tanker trucks to transport water to the Project area or to serve as a temporary transport line to the Project area. In locations where adequate depth is not naturally provided, and where approved by the permitting agency, AGDC would dig a small sump to allow the pump intake to be fully submerged in the waterbody. The fill pump engine would be placed within a plastic-lined bermed or metal containment area to prevent spills and/or leaks from reaching the waterbody. All fill pumps would be continuously monitored during operation. To reduce the uptake water approach velocity, thereby minimizing impingement or entrainment of small fish, larvae, and eggs, intakes would be constructed to provide an adequate surface area of fine-meshed screen.

In addition to surface water withdrawals, new groundwater wells would be installed to access water for construction and operation of Project facilities. These wells could potentially cause localized groundwater drawdown and affect water yields in nearby wells.

To account for the necessary water withdrawals, potential impacts associated with water withdrawals and discharges, and assurance of water rights and maintaining water volumes for existing users, AGDC prepared a draft Water Use Plan that specifies the anticipated water uses and volumes for construction and operation of Project facilities. Prior to construction, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, an updated and finalized Water Use Plan that identifies final water volumes, source locations (including aquifers for all known groundwater wells), discharge locations, and proposed water treatments required for Project construction and operation. The plan would include water use volumes and sources for all construction camps and aboveground facility camps and would also identify estimated operational water use volumes and sources. The plan would evaluate the potential for reuse of hydrostatic test water and demonstrate that the reuse of water (e.g., for hydrostatic testing) has been applied where practicable.

The Project would require the construction of ice roads for the Gas Treatment and Mainline Facilities. Ice roads would utilize freshwater, snow, and ice chips from nearby lakes, rivers, and flooded gravel mines, potentially affecting the water level of these sources depending on the season of uptake. If required for the protection of sensitive waterbodies as part of ADF&G's Anadromous Waters Catalog (AWC), AGDC would identify protection measures based on the timing of water withdrawals. These measures could include limiting water for ice road construction to ice chips and snow to ensure adequate under-ice water flow and volumes. Construction of ice roads and ice pads on top of lakes and ponds would create thicker ice, which could melt later in the season than adjacent areas of the waterbody. Additionally, ice bridges could potentially affect stream flow at spring breakup. Through implementation of the Project Winter and Permafrost Construction Plan and the Project Plan and Procedures, impacts from ice roads would be temporary and minor because the surface water volumes would be replenished each year during spring breakup. To further minimize impacts during spring breakup, AGDC would cut slots in the ice to direct melt and minimize the potential for flooding.

As described in AGDC's Fugitive Dust Plan, to minimize fugitive dust, water would be applied, as needed, to unpaved haul/access roads and staging areas. Watering rates would be controlled by EIs to reduce the amount of water needed and to minimize the chance of sediment runoff. Erosion and sediment controls would be installed in accordance with AGDC's Plan and Procedures to avoid or reduce impacts from potential sediment runoff.

As discussed in section 2.2, hydrostatic testing of various Project facilities (including the Mainline Pipeline and various components at the Gas Treatment and Liquefaction Facilities) would be required during construction. Hydrostatic testing involves the use of water that is pressurized within pipeline segments to determine if the installed pipeline is free from leaks and possesses the strength to safely operate at the proposed MAOP. Except as discussed below, hydrostatic testing is planned to occur in the summer using water from surface waters without additives. AGDC would discharge test water into the same basin as the water source withdrawal, so inter-basin transfer of water would not occur.

During construction, EIs would supervise hydrostatic test water discharges and dewatering. Generally, the discharge water would be of similar water quality as the source waterbody, but after long pipeline segments are tested, the test water could contain particulate mill scale (rust). The rust during dewatering would settle out in the dewatering structure, avoiding the potential for transportation into adjacent surface waters. Where discharged into uplands and wetlands, the test water would pass through energy dissipation devices to minimize the potential for scour, erosion, and sedimentation into nearby surface waters. ADEC identifies multiple pollutants of concern that are commonly present in hydrostatic test water, which would be identified and handled through the APDES permitting process. During initial hydrostatic testing of the new pipe, the primary pollutant of concern is sediment debris (i.e., welding slag left behind during construction).

AGDC has stated that hydrostatic testing of the PTTL would occur in the summer; however, hydrostatic testing of other Project facilities on the North Slope could occur year-round and would require additives to prevent the test water from freezing. If hydrostatic testing in winter becomes necessary, any chemical additives (e.g., biocides or antifreeze chemicals) would need to be identified during the permitting process. Discharges of the test water would be conducted in accordance with permit requirements.

Hydrostatic test water would have an average residence time of about 48 hours; therefore, the water temperature would be within a few degrees of the surrounding ground temperature at the time of discharge. Test water would be discharged at the ground surface, separated from the frozen subgrade, thereby reducing heat transfer. Dewatering devices are designed to limit erosion and scour and to filter contaminants from discharged water. It is not expected that the test water would have sufficient excess heat to cause thermal erosion or thermokarsting.

Water used for Mainline Pipeline hydrostatic testing would primarily be discharged into uplands and wetlands in accordance with applicable federal and state permit requirements (see table 1.6-1). For more information on hydrostatic testing and potential impacts on wetlands and avian resources, see sections 4.4.2 and 4.6.2.3, respectively.

Effects from hydrostatic testing would be temporary and minor through adherence to permit requirements and the Project Plan and Procedures. The Temporary Water Use Authorization issued by the ADNR would dictate permissible withdrawal amounts for the Project. Water withdrawal rates and volumes would comply with applicable permit requirements to reduce impacts on stream flow and downstream effects. As discussed in section 4.7.1, AGDC would limit water withdrawals to no more than 20 percent of a waterbody's flow rate. Flow rates may be adjusted during the permitting process by agencies based on site-specific conditions, timing of withdrawal, and total withdrawal volumes. To ensure sufficient volume and dissolved oxygen concentrations, lake withdrawals would be limited to a percentage of the total seasonal lake volume. In some instances, longer withdrawal periods would be required to fill hydrostatic test sections based on approved rates. Where required, AGDC would reuse test water from one section to another to reduce its water needs. The ADF&G requires a Fish Habitat Permit for water withdrawal from fish-bearing waterbodies; requirements for these permits are discussed in section 4.7.1.

The anticipated uses and volumes of groundwater and surface water resources, construction and operational wastewater discharges, and facility specific procedures, impacts, and mitigation measures are described in the following sections.

4.3.4.4 Facility-Specific Impacts and Mitigation

Gas Treatment Facilities

Due to the lack of freshwater aquifers on the North Slope, groundwater would not be used during construction or operation of the Gas Treatment Facilities. To construct these facilities, water would be trucked in and stored on site until the new water reservoir and pumping stations are completed (see section 2.1.3). Potential temporary water sources include nearby lakes and rivers (see appendix J) as well as the North Slope Borough's water system.

Construction of the GTP and PBTL would require about 77.9 million gallons of water per year, including:

- 3.7 million gallons from the North Slope Borough's water system (estimated 10,000 gpd), if available;
- 20.8 million gallons per year at the peak of construction for potable water and general construction uses; and
- 53.4 million gallons per year during integrated construction and operation at the camp.

Additionally, 188.2 million gallons of water would be needed for ice road construction. This water use would be spread out over 4 years, with the majority of water needed in Year 3 for construction of the right-of-way / ice road for the water line extending from the reservoir to the GTP pad.

In addition to yearly water use during construction, prior to in-service, the GTP and PBTL would require a one-time total of 14.2 million gallons of water for hydrostatic testing.

The North Slope Borough has indicated that 10,000 gpd would be available for use during Project construction. If the North Slope Borough should determine that the water would not be available for AGDC's use, other sources, such as lakes and the Putuligayuk River, would be used. Natural surface water levels within lakes, rivers, and ponds on the North Slope generally recharge during spring breakup to their original water levels.

AGDC has estimated that about 62.1 million gallons of wastewater would be produced each year during construction of the GTP, as noted in the Project Waste Management Plan. This total includes black water/gray water, hydrostatic test water discharges, industrial water, truck wash water, and other sources. The water from hydrostatic testing and other wastewater streams associated with the Gas Treatment Facilities with the exception of the PTTL would be discharged into two UIC Class I wells, which would be installed during facility construction within the GTP pad footprint. The UIC wells would be designed and constructed to prevent the movement of injected wastewaters outside of the injection zone. These wells would be properly cased with steel or fiberglass-reinforced plastic for the full depth of the well in accordance with EPA permit requirements. The anticipated injection depth would be about 6,000 to 7,000 feet below ground surface in the Sagavanirktok formation.

The UIC wells would be operated so that injection pressures would not expand existing fractures or create new fractures. Operators would monitor the characteristics of the injected wastewater, annular pressures, and containment of wastewater within the injection zone. The pioneer camp associated with the Gas Treatment Facilities would be self-sustaining with water treatment and sewage treatment capabilities and wastewater being discharged into the UIC wells. Disposal of Project wastewater into permitted UIC wells would avoid impacts on surface waters.

Construction of the PTTL would require an estimated 246.5 million gallons of water, including:

- 194.6 million gallons for ice pads and roads;
- 31.5 million gallons for construction;
- 14.2 million gallons for hydrostatic testing, including 1.3 million gallons for the PTTL meter station; and
- 6.2 million gallons for the construction camp.

Hydrostatic testing of the PTTL would occur in the summer when tundra travel is not allowed. An existing work pad at PTTL MP (PTMP) 35.4 and new helipad at PTMP 35.0 would provide summer access to the Kadleroshilik River. No existing or new road access to the Shaviovik River would be available during the summer; therefore, this waterbody would not be used as a water source for hydrostatic testing of the PTTL. Source and discharge locations of the hydrostatic test water for the PTTL are provided in table 4.3.4-3.

TABLE 4.3.4-3

PTTL Hydrostatic Test Water Source and Discharge Locations

Test Section [a]	Water Source	Water Source PTTL Milepost	Discharge PTTL Milepost	Test Section Volume (gallons)	Discharge Area
PT 1-A-01	Badami Reservoir	18.8	18.9	3,912,500	Wetlands
PT 1-A-02	Kadleroshilik River	35.4	35.0	3,332,900	Uplands
PT 2-A-03	Kadleroshilik River	35.4	35.0	3,457,100	Uplands
PT 2-B-04	Sag Mine Site C	52.5	51.7	2,236,900	Wetlands

[a] Table does not include the 1.3 million gallons of water required for the hydrostatic testing of the PTTL meter station.

The Gas Treatment Facilities would require water during operation for process water, firewater, gray water/black water, dust abatement, and hydrostatic testing of GTP pipelines for maintenance and emergency repairs. Water would be withdrawn from the GTP water reservoir, avoiding impacts on other surface waters. The reservoir would require annual water withdrawals from the Putuligayuk River to maintain the required volume of water needed to test and operate the Gas Treatment Facilities, as discussed below. Water would be transported from the Putuligayuk River to the GTP water reservoir by an aboveground pipeline constructed on VSMs (section 2.1.3). Fuel gas, gray water, and raw water pipelines would also be constructed aboveground between the GTP pad and the operations camp pad.

Wastewater from operational hydrostatic testing activities and gray water/black water would be discharged into permitted UIC wells at the Gas Treatment Facilities, thereby avoiding impacts on surface waters. During operation, an estimated 22 million gallons of wastewater would be produced, excluding hydrostatic test water discharges, where the volume is currently unknown and would be determined post-construction. As discussed in section 2.5.1.2, the 22 million gallons include black and gray wastewater, industrial wastewater, truck wash water, and other wastewater. Estimated quantities of process wastewater associated with natural gas production at the GTP would be determined after construction of the facility.

To maintain the reservoir during operation, water would be withdrawn from the Putuligayuk River annually over the course of about 20 days. Water would only be withdrawn from the Putuligayuk River during the high water levels of spring breakup, for a short period of time, resulting in temporary and minor effects on the water level and quality of the river. This timing would also ensure that effects on fish and aquatic resources would be minimized and that there would be no effects on existing water rights. Water withdrawals from the Putuligayuk River would not draw more than 20 percent of the water's flow in accordance with permit restrictions. The water withdrawal intakes at the Putuligayuk River would be screened to prevent entrainment of fish and biota as well as remove silt and sand. The proposed water withdrawal from the Putuligayuk River would be permitted through the ADNR and ADF&G.

Mainline Facilities

Construction of the Mainline Facilities would require a combination of groundwater and surface water. Table 4.3.4-4 identifies water requirements by Mainline Pipeline spread for various construction needs. A total of about 1.6 billion gallons of water would be required for construction of the Mainline Facilities, including:

- 1.1 billion gallons for ice roads, ice pads, dust suppression, and road maintenance;
- 297.6 million gallons for hydrostatic testing;
- 186.9 million gallons for civil, pipelay, and aboveground facility construction camps; and
- 67.0 million gallons for remaining construction camps

TABLE 4.3.4-4

Anticipated Water Needs for Construction of the Mainline Facilities (gallons)

Spread [a]	Milepost Start	Milepost End	Ice Roads/Ice Pads/Road Maintenance/Dust Suppression	Construction Camps [b]	Hydrostatic Testing [c]	Total
Spread 1	0	208.9	682,950,000 [d]	41,161,745	74,340,000	798,451,745
Spread 2	208.9	400.7	126,030,000	54,465,516	68,290,000	248,785,516
Spread 3	400.7	607.4	126,030,000	82,952,595	73,580,000	282,562,595
Spread 4	607.4	806.6	126,030,000	52,618,242	70,910,000 [e]	249,558,242
Aboveground facilities	N/A	N/A	8,680,000	22,690,000	10,460,000	41,830,000
Total			**1,069,720,000**	**253,888,098**	**297,580,000**	**1,621,188,098**

N/A = Not applicable

[a] Each spread includes construction activity at civil and pipelay construction camps from the summer before winter construction starts to the third summer o construction.

[b] Includes AGDC's estimated volumes to support civil and pipelay construction camp numbers.

[c] Includes between 16 million and 26 million gallons required for the DMT activities at Middle Fork Koyukuk, Yukon, Tanana, Chulitna, and Deshka Rivers.

[d] Includes 556.9 million gallons or ice roads / ice pads (combination of ice chips, water, and snow) and 126.0 million gallons for road maintenance.

[e] Includes 9.7 million gallons for offshore pipeline hydrostatic testing.

As shown in appendix J, construction water for Mainline Facilities would be sourced from a wide variety of waterbodies. While open water volumes are only available for lakes identified in appendix J, there is a minimum of 16.1 billion gallons of water available from lakes with an additional 3.6 billion gallons of under ice volume available.

AGDC currently anticipates that water wells would be installed to withdraw groundwater for use at pipelay camp locations. For civil, pioneer, and facility camps, no new groundwater wells would be installed. Water would be sourced from nearby surface water and hauled by tankers to camps, but AGDC has stated that they are still evaluating the feasibility of using groundwater wells at other locations. As shown in table 2.1.4-5, there are 46 locations where construction camps would be built for the Project. Camps would vary in size, with the number of workers housed at the camps ranging from about 120 people at pioneer camps to 1,200 people at Mainline Pipeline camps. As shown in table 4.3.4-4, about 253.9 million gallons of water would be used at these camps over the course of the Project's construction. Of these 253.9 million gallons, 78.8 million gallons would be required at pipelay camps and are proposed to be sourced from groundwater wells. The use of these 78.8 million gallons would span across the four construction spreads over 2.5 years for construction of the Mainline Facilities. These numbers are based on the estimated use of 75 gpd per person. Therefore, at a single construction camp site, daily water uses would range from about 9,000 to 90,000 gpd depending on the camp type. The construction water needs presented in table 4.3.4-4 would be spread over multiple years at each location.

AGDC would conduct groundwater withdrawals in accordance with its ADNR authorization of groundwater allocation permits. To minimize any potential impacts on local drinking water sources, water supply wells for the construction camps would be sited outside of DWPAs for active PWS sources, and the supply wells would be monitored for groundwater quality and yield to detect potential groundwater drawdown in accordance with the Project Water Well Monitoring Plan, Groundwater Monitoring Plan, and agency requirements. AGDC identified wells in the Project area using the ADNR Well Log Tracking System. No registered water supply wells were identified within 500 feet of construction camps.

A temporary wastewater treatment plant would be installed at each construction camp. The temporary wastewater treatment facility would discharge treated gray water and black water in accordance with ADEC requirements, and would meet applicable effluent requirements. At this time, the treatment technology to be implemented and the anticipated discharge volumes, rates, and frequencies are unknown. AGDC would work with ADEC through the state permitting process to ensure requirements are met. Wastewater generated during operation of the Mainline Facilities would be collected and disposed of at an approved disposal facility (industrial wastewater), treated onsite and discharged to the ground (gray water), or treated using disinfectants (black water). The wastewater discharges would be subject to the appropriate APDES and EPA permitting (see section 1.6). Where practicable given the remoteness of a facility, AGDC proposes to use fully contained wastewater treatment facilities that would not discharge into the environment. For facilities that would not be accessible by road and where hauling wastewater offsite would not be feasible, AGDC would establish small packaged wastewater treatment systems. These systems would be placed on level ground, in areas disturbed for permitting discharge, and proximate to the right-of-way. Project discharge permits would include mitigation controls to minimize erosion, sedimentation, and the creation of thermokarst.

AGDC has estimated that between about 6,000 and 75,000 gallons of wastewater (black water and gray water) per construction spread would be produced each day during construction of the Mainline Facilities. The upper range of this estimate is based on an average annual peak workforce of about 1,400 workers for each individual spread, which would equal a little more than 50 gallons of water used per person per day. Because construction of the Mainline Pipeline would occur simultaneously on multiple spreads, AGDC estimates that the total daily production of wastewater per day would range between about

11,500 and 149,500 gallons.[49] At this time, the estimated volume of wastewater created during operation of the Mainline Facilities is unknown and would be calculated after construction based on finalized operating and maintenance planning.

The Mainline Pipeline would be hydrostatically tested in sections up to 20 miles long over three summer seasons. Mainline Pipeline hydrostatic test water source and discharge locations are included in table 4.3.4-5. As shown in the table, water used for hydrostatic testing along the Mainline Pipeline would be discharged into uplands, wetlands, the GTP water reservoir, and Cook Inlet.

As discussed in section 2.2.2, hydrostatic testing of the Mainline Pipeline offshore portion would be conducted shortly after the pipeline is installed on the seabed. It is estimated that about 9.7 million gallons of marine waters would be required for hydrostatic testing of this pipe segment. Marine water would be evacuated during the running of a gauging pig prior to filling the pipeline for hydrostatic testing. AGDC has stated that it currently has no plans to use biocide during hydrostatic testing. If the use of biocides becomes necessary due to the timing of the test, the biocide use would be disclosed during the APDES permit process.

AGDC has estimated that the rate of hydrostatic test water withdrawal in Cook Inlet would be about 3,000 gpm. The location of the intake has not been determined. The hydrostatic test waters would be discharged via outfalls to Cook Inlet in accordance with applicable federal and state permit requirements. Potential impacts on fisheries and plankton associated with marine water hydrostatic testing can be found in sections 4.7.1 and 4.7.3 respectively.

South of the Brooks Range, Mainline Facilities operation would require water sourced from nearby surface waters, trucked in and stored on site, or acquired from onsite groundwater wells. AGDC anticipates that 15,000 gallons would be required annually for these sites, which would be spread out over the year. AGDC has not indicated that any operational water use would be needed north of the Brooks Range for the Mainline Pipeline. If needed, however, that water would either be trucked in or sourced from nearby surface waters.

Liquefaction Facilities

Construction of the Liquefaction Facilities, excluding hydrostatic testing, would require about 420,000 gallons of water per day, including:

- 360,000 gpd for potable water and construction uses at the construction camp;
- 50,000 gpd for the onsite batch concrete plant; and
- 10,000 gpd for dust control during the summer.

In addition to daily construction water use, the LNG Plant would require a one-time total of about 88.2 million gallons of water prior to in-service, including about:

- 2.3 million gallons to flush piping for the freshwater system;
- 0.5 million gallons to fill the freshwater system;
- 1.4 million gallons for two freshwater tanks for commissioning of the LNG Plant (690,000 gallons per tank); and
- 84 million gallons for the two LNG tanks (42 million gallons per tank).

[49] Since filing the Project Waste Management Plan on October 2, 2018, AGDC updated its estimate of the volume of black and gray wastewater that would be produced during Mainline Pipeline construction; see AGDC's response [Accession No. 20191204-5163] to question 30 of our information request dated November 22, 2019 (available on the FERC website at http://www.ferc.gov; using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20191204-5163 in the "Numbers: Accession Number" field). The final EIS has been revised to incorporate the updated estimate. AGDC would file a final Project Waste Management Plan prior to construction.

TABLE 4.3.4-5

Onshore Mainline Pipeline Hydrostatic Test Water Source and Discharge Locations

Test Section	Water Source	Nearest Water Source Milepost	Discharge Milepost	Test Section Volume (gallons) [a]	Discharge Area
ML 1-A-01	Putuligayuk River	1.0	0.0	7,117,600	UIC Wells
ML 1-A-02	Sagavanirktok River	36.0	36.7	5,957,400	Wetlands
ML 1-A-03	Sagavanirktok River	36.0	36.7	7,078,400	Wetlands
ML 1-B-04	Sagavanirktok River	56.6	56.6	2,847,100	Wetlands
ML 1-B-05	Sagavanirktok River	84.0	84.0	6,893,400	Wetlands
ML 1-B-06	Sagavanirktok River	84.0	95.0	3,914,700	Uplands
ML 1-B-07	Sagavanirktok River	95.0	114.7	7,025,100	Uplands
ML 1-C-08	Kuparuk River	131.0	131.0	5,786,600	Uplands
ML 1-C-09	Kuparuk River	131.0	131.0	1,957,400	Uplands
ML 1-C-10	Roche Moutonnee Creek/Intermittent Stream	151.0/152.0	152.0	5,516,100	Uplands
ML 1-C-11	Atigun River and Tributaries	163.0	152.0	3,914,700	Uplands
ML 1-C-12	Atigun River and Tributaries	163.0	163.0	2,021,400	Uplands
ML 1-E-13	Chandalar River	171.0	171.9	1,181,600	Uplands
ML 1-F-14	Chandalar River	171.0	171.9	2,491,200	Uplands
ML 1-G-15	Dietrich River	188.0	189.0	3,558,800	Uplands
ML 1-H-16	Dietrich River	188.0	208.9	7,074,900	Uplands
ML 2-A-17	Middle Fork Koyukuk River	229.0	228.9	7,110,400	Uplands
ML 2-B-18	Middle Fork Koyukuk River	229.0	248.6	7,096,200	Uplands
ML 2-C-19	Jim River	248.8	248.6	7,117,600	Uplands
ML 2-D-20	Prospect Creek	282.0	281.4	4,498,300	Uplands
ML 2-E-21	Prospect Creek	282.0	286.0	1,640,700	Uplands
ML 2-E-22	South Fork Bonanza	286.0	293.9	2,686,900	Uplands
ML 2-E-23	Fish Creek	299.0	298.7	1,921,800	Uplands
ML 2-E-24	Fish Creek	299.0	298.7	2,847,100	Uplands
ML 2-E-25	Kanuti River	307.0	307.9	4,484,100	Uplands
ML 2-F-26	Tributaries to the West Fork of the Dall River	320.0	329.5	3,523,200	Uplands
ML 2-G-27	James Creek	348.0	347.9	6,533,900	Uplands
ML 2-I-28	James Creek	348.0	355.7	2,847,100	Uplands
ML 2-J-29	Yukon River	357.0	355.7	2,185,100	Uplands
ML 2-J-30	ML-2-J-31 (Cascade from Hess Creek)	372.4 (cascade, 382.0)	372.5	3,701,200	Uplands
ML 2-J-31	Hess Creek	382.0	381.9	3,416,500	Uplands
ML 2-K-32	Hess Creek	382.0	381.9	2,491,200	Uplands
ML 2-L-33	Erickson Creek	389.0	389.0	2,491,200	Uplands
ML 2-L-34	ML-2-J-33 (Cascade from Erickson Creek)	396.0 (cascade, 389.0)	389.0	1,067,700	Uplands
ML 2-L-35	Tolovana and West Fork Tolovana Rivers	403.0	400.8	622,800	Uplands
ML 3-A-36	Tolovana and West Fork Tolovana Rivers	403.0	400.8	2,882,600	Uplands
ML 3-B-37	ML-3-B-38 (Cascade from Tatalina River)	421.6	408.8	4,523,200	Uplands
ML 3-B-38	Tatalina River	431.0	429.9	3,146,000	Uplands
ML 3-C-39	Tatalina River	431.0	439.0	3,060,600	Uplands

TABLE 4.3.4-5 (cont'd)					
Onshore Mainline Pipeline Hydrostatic Test Water Source and Discharge Locations					
Test Section	Water Source	Nearest Water Source Milepost	Discharge Milepost	Test Section Volume (gallons) [a]	Discharge Area
ML 3-C-40	Chatanika River	439.0	454.9	5,694,100	Uplands
ML 3-C-41	Nenana and Tanana Rivers	473.0	473.3	6,512,600	Uplands
ML 3-D-42	Nenana and Tanana Rivers	473.0	473.3	6,996,600	Uplands
ML 3-F-43	Bear Creek	505.0	493.0	4,996,500	Uplands
ML 3-G-44	Panguingue Creek	521.0	507.1	4,925,400	Uplands
ML 3-H-45	Panguingue Creek	521.0	520.8	3,960,900	Uplands
ML 3-I-46	Nenana River	533.0	536.0	1,430,700	Uplands
ML 3-J-47	ML-3-I-46 (Cascade from Nenana River)	536.0	536.5	178,000	Uplands
ML 3-J-48	Nenana River	543.0	543.1	2,345,300	Uplands
ML 3-L-49	Nenana River	543.0	543.1	6,377,300	Uplands
ML 3-L-50	Jack and Nenana Rivers w/ tributaries	561.0	561.1	2,135,300	Uplands
ML 3-M-51	Middle Fork Chulitna River	586.0	587.0	7,117,600	Uplands
ML 3-M-52	Middle Fork Chulitna River	586.0	607.5	7,295,500	Uplands
ML 4-A-53	ML-4-A-54 (Cascade from Chulitna River)	612.0 (647.0)	612.0	1,601,500	Uplands
ML 4-A-54	ML-4-A-55 (Cascade from Chulitna River)	625.8 (647.0)	625.8	4,921,800	Uplands
ML 4-A-55	Chulitna River	647.0	648.2	7,946,700	Uplands
ML 4-A-56	Susitna River	675.0	675.2	9,637,200	Uplands
ML 4-B-57	Susitna River	675.0	704.0	10,235,000	Uplands
ML 4-C-58	Deshka River	704.0	725.9	7,804,400	Uplands
ML 4-C-59	Susitna River	725.0	725.9	5,363,100	Uplands
ML 4-D-60	Lewis River	744.0	741.0	9,003,700	Uplands

[a] Volumes presented in this table were provided by AGDC in response to information requests. The totals do not sum to the values presented in table 4.3.4-4 above, but the magnitude of impacts are similar.

Due to the elevated contaminant concentrations that were identified in underlying aquifers during the 2016 hydrogeological survey of the LNG Plant, AGDC would not withdraw groundwater for use during construction or operation of the Liquefaction Facilities. Rather, AGDC has proposed to extend the City of Kenai public drinking water system to the LNG Plant to provide the freshwater volumes described above. The City of Kenai would supply water by an extension from the northwestern section of the city near mile 14 of the Kenai Spur Highway to the Liquefaction Facilities near highway mile 20. This expansion would be completed in time to provide water for the facility construction camps. A discussion of this expansion and the potential impacts on the aquifer is included in section 4.19.

After the LNG tanks and piping are installed, they would be hydrostatically tested with freshwater obtained from the City of Kenai or saline water from Cook Inlet. In advance of filling each tank, the hydrostatic test water source would be tested to ensure that the water would meet all applicable permit requirements. If Cook Inlet saline water would be used for hydrostatic testing, one or more pumps would be temporarily located on the Marine Terminal causeway. Hydrostatic testing of the LNG tanks would occur over a 14- to 21-day period, with an average fill rate of 1,400 to 2,000 gpm. Hydrostatic testing of each of the approximately 8.5 million-cubic-foot tanks would require about 42 million gallons of water. AGDC is planning to sequence the tests so that the test water from the first tank could then be used for the second tank. An estimated 50,000 gallons of water from hydrostatic testing of the tanks would be recycled and used for hydrostatic testing of non-cryogenic plant piping over a multi-year period during construction. The test water would be discharged to Cook Inlet via an outfall.

AGDC has estimated in their draft Project Waste Management Plan that about 57.5 million gallons of stormwater runoff would be produced each month during both construction and operation of the Liquefaction Facilities. Additionally, during operation of the Liquefaction Facilities, an estimated 160,000 gallons per month would be created from firewater testing runoff. AGDC would dispose of all wastes as required by federal, state, and local environmental regulations. The Liquefaction Facilities would have permitted outfalls to Cook Inlet for the removal of stormwater runoff and firewater runoff. Prior to disposal, wastewater would undergo treatment by a sedimentation pond and an oily water separator as needed.

Impacts on groundwater and Cook Inlet are discussed in sections 4.3.1 and 4.3.3, respectively. During LNG Plant operation, liquid waste (including stormwater runoff, firewater testing runoff, gray water, and black water) would be treated at on-site treatment facilities and sedimentation ponds prior to discharge to Cook Inlet according to the effluent requirements described in the APDES individual permit. By adhering to the appropriate permit requirements, no freshwater (groundwater or surface water) impacts would be anticipated due to wastewater disposal.

4.3.5 Conclusion

Project construction and operation would result in minor impacts on groundwater resource inventories. The Project would cause permanent alterations to surface and groundwater hydrology due to impacts on permafrost. Impacts on groundwater would be adequately minimized through implementation of the mitigation measures described above, AGDC's commitments, construction monitoring, and compliance with federal, state, and local regulatory approvals and requirements. Groundwater uses for the Project would be primarily focused on the Mainline Facilities. AGDC has stated that no groundwater would be used during construction or operation of the Gas Treatment or Liquefaction Facilities. For the Mainline Facilities, given the remoteness of the construction camps and the monitoring that would take place at wells, and since groundwater volumes would be recharged each year during spring thaw, the potential groundwater drawdown impacts caused by water use at construction camps would likely be minor and temporary. Based on AGDC's commitments to follow measures identified in Project plans, construction and operational groundwater impacts would be temporary and short-term.

Project construction and operation would result in minor and temporary impacts on surface water quality and streamflow. Impacts on freshwater resources would be adequately minimized through implementation of the mitigation measures described above, AGDC's commitments, our recommendation, and compliance with federal, state, and local regulatory approvals and requirements. Therefore, we conclude that Project construction and operation would not significantly affect freshwater resources.

Construction activities within marine waters, such as dredging and construction of in-water structures, would result in short-term and localized turbidity and sedimentation that would dissipate, resulting in less than significant impacts. For these reasons, we conclude that Project construction would not significantly affect the quality of marine waters.

The most notable potential impact during operation would be the possibility of spills from a vessel within marine waters. The risk potential for spills during operation would be adequately minimized through adherence to the Project Emergency Response Vessel Assurance Execution Plan, a site-specific SPCC Plan for the Liquefaction Facilities, and the implementation of ODPCPs and/or SOPEPs for vessels.

Offshore construction of the Mainline Pipeline via the bottom lay method would result in turbidity in the immediate vicinity of the pipe and associated anchoring activities for construction vessels. The increases in turbidity and sediment dispersal would be minimal and short term in nature. Beyond the shoreline crossings, the Mainline Pipeline would remain as a permanent feature on the bottom of Cook Inlet, which would be a permanent impact.

Surface water would be used during construction and operation of all Project facilities. With implementation of the mitigation measures described above, AGDC's commitments, and compliance with applicable permits, impacts from surface water withdrawal, use, and discharge would be minor and short term. Project plans and permit regulations would require timing of water withdrawals during high flows, supervising the withdrawal and discharge of hydrostatic test water by EIs, installing new wells in accordance with ADNR authorizations, disposing of wastewater at approved facilities, and mitigating potential fishery impacts.

4.4 WETLANDS

Wetlands are areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions (Environmental Laboratory, 1987). Wetlands serve several functions, including, but not limited to, flood control, groundwater recharge, biodiversity maintenance, wildlife habitat, and water quality maintenance. More than 43 percent of Alaska's surface area is composed of wetlands (Hall et al., 1994). This amounts to greater than 175 million acres of land.

Most of the wetlands affected by the Project (see appendix K) are federally regulated by the COE under Section 404 of the CWA. The EPA has the authority to review, elevate, and/or object to permits issued by the COE under Section 404 (see sections 1.2.3 and 1.2.4). Permits issued under Section 404 require water quality certification under Section 401 of the CWA to certify that the regulated activity complies with applicable provisions of the act, including state water quality standards. The Project would require certifications from ADEC for areas outside the DNPP, and the EPA for areas inside the DNPP. Per NPS requirements, the segment of the Mainline Pipeline within the DNPP would need to follow and comply with NPS Director's Order 77-1 regarding protection of wetlands. The CWA is described in more detail in section 1.6.8.

4.4.1 Existing Wetland Resources

4.4.1.1 Regional Wetland Resources

The wetlands crossed by the Project encompass a range of land resource areas within three regions in Alaska: the Arctic and Western Region, the Interior Region, and the Southern Region. Hall et al. (1994) sub-classified these regions into physical subdivisions (subdivisions), which are comparable to watershed drainage basins, by modifying land resource areas previously identified by Rieger et al. (1979) based on topography, climate, vegetation, and soils. The Project crosses three subdivisions in the Arctic and Western Region (the Arctic Coastal Plain, Arctic Foothills, and Brooks Range); four subdivisions in the Interior Region (the Interior Alaska Highlands, Kanuti Flats, Tanana-Kuskokwim Lowlands, and Alaska Range); and one subdivision in the Southern Region (the Cook Inlet-Susitna Lowlands). Hall et al. (1994) characterized and quantified wetland resources within the subdivisions using the classification system by Cowardin et al. (1979) (Cowardin classification system). Hall et al. (1994) additionally quantified the amount of wetlands within each subdivision.

Arctic and Western Region

Sixty-one percent of the Arctic and Western Region is comprised of wetlands (Hall et al., 1994). Within this region, the Arctic Coastal Plain, Arctic Foothills, and Brooks Range Subdivisions consist of about 17 million acres (83 percent), 30 million acres (83 percent), and 7 million acres (22 percent) of wetlands, respectively. The Arctic Coastal Plain and Arctic Foothills Subdivisions are underlain by continuous permafrost that prevents drainage and causes waterlogged soils that lead to the establishment of wetland vegetation. The Arctic Coastal Plain Subdivision supports extensive lowland tundra plant communities often dominated by sedges (e.g., water sedge and Bigelow's sedge [*Carex aquatilis* and *C. bigelowii*]) and small shrubs (e.g., willows [*Salix reticulata* and *S. arctica]*). The Arctic Foothills Subdivision supports tussock tundra (e.g., tussock cottongrass [*Eriophorum vaginatum*]), shrub tundra (e.g., dwarf birch [*Betula nana*], and the tealeaf willow [*Salix pulchra*]), and mixed tundra communities (Berner et al., 2018). The Brooks Range Subdivision acts as a divide between the Arctic Foothills and the Interior Alaska Highlands Subdivisions. Within the Brooks Range Subdivision, wetlands occur in valleys and lower sloped areas. The predominant vegetation types include sedge tussocks and mixed shrub-sedge tussocks (e.g., tussock cottongrass, Bigelow's sedge, dwarf birch, and mountain cranberry [*Vaccinium vitis-idaea*]) (Alaska Geobotany Center, 2012).

Participants in the traditional knowledge workshops on the North Slope indicated that there were more wetlands in the past and wetlands were abundant (more observable) during breakup and summer. Participants observed that wetlands are getting drier within the area (Braund, 2016).

Interior Region

Forty-four percent of the Interior Region is wetlands (Hall et al., 1994). Within this region, the Interior Alaska Highlands, Kanuti Flats, Tanana-Kuskokwim Lowlands, and Alaska Range Subdivisions consist of about 22 million acres (39 percent), 1 million acres (77 percent), 8 million acres (61 percent), and 1 million acres (7 percent) of wetlands, respectively. The Interior Region's northern portion has thicker, more continuous permafrost compared to the region's southern portion, where permafrost occurs sporadically. Black spruce and tamarack (*Larix laricina*) are common in bogs and other areas where soils are poorly drained. Sparse, low-growing vegetation is found at the highest elevations of mountain ranges, with wetlands being more common at lower elevations. Spruce and hardwood forests are the dominant vegetation, but black spruce, ericaceous shrubs (e.g., black crowberry [*Empetrum nigrum*] and bog blueberry [*Vaccinium uliginosum*]) occur in lowlands and bogs.

Participants in the traditional knowledge workshops in the Yukon River area noted that lakes and wetlands in the Yukon River Region have been drier in recent years with lower water levels. The lower water levels were attributed to factors such as increased vegetation, silt accumulation, beaver dams blocking flow, and climate change. At traditional knowledge workshops in the Tanana River area, participants noted drier wetlands and decreased water levels as a result of human activities, less precipitation, silt accumulation, and climate change. Participants in the traditional knowledge workshops in the Tanana and Susitna River area also noted that wetlands in the Tanana River region and area of Cantwell take a long time to recover from impacts made by human activities, such as damage caused by off-road vehicles. A participant in the traditional knowledge workshops in the Nenana River area noted that gas (methane) bubbling has increased in wetlands as permafrost thaw has increased, and other participants noted the depth to permafrost has increased over time (Braund, 2016).

Southern Region

The Project would cross one subdivision in the Southern Region, the Cook Inlet-Susitna Lowlands Subdivision. The Cook Inlet-Susitna Lowlands Subdivision consists of about 3 million acres (28 percent) of wetlands. Wetlands in this subdivision include scrub bogs and marshes dominated by grasses such as bluejoint reedgrass (*Calamagrostis canadensis*) and sedges (*Carex* spp.) (Gallant et al., 1995). Tidally influenced mud flats, which are defined by the COE as a special aquatic site, would be crossed in the Cook Inlet-Lowlands Subdivision by the Mainline Pipeline along the upper portion of the Cook Inlet waterway.

Traditional knowledge workshop participants in the Susitna River area noted that there are abundant wetlands in the area, which contain sinkholes and depressional features. Participants also observed that wetlands have been affected by fluctuations in water levels between the rainy and dry seasons or annually based on precipitation (Braund, 2016).

4.4.1.2 Wetland Determinations

AGDC conducted wetland determinations in the Project area with a multi-year desktop and field analysis that used the field target sampling method, which is a uniquely modified approach approved by the COE's Alaska District (COE, 2015d). The COE's Alaska District accepted the field target sampling method for AGDC's preliminary jurisdictional determination identifying potential jurisdictional waters of the United States within the Project area.[50]

The field target sampling method protocols used a three-step approach, including: 1) wetland mapping relying primarily on aerial photo interpretation; 2) ground reference data collection at predetermined field targets to verify the photo interpretation and areas of uncertainty; and 3) revision of wetland pre-mapping based on the results of the field surveys. AGDC generated wetland maps based on this three-step approach, as described below.

AGDC created initial wetland maps with a GIS platform using an office method commonly referred to as "heads-up" digitizing. This method applies aerial image interpretation to delineate vector polygons for ground features. Wetland polygons were mapped within a 2,000-foot-wide corridor along the Mainline Pipeline. AGDC then conducted field target surveys at select locations within a 300-foot-wide field verification corridor centered on the Mainline Pipeline. Within the field verification corridor, field target sampling sites were used to confirm areas where wetland mappers had high confidence in their aerial interpretation and to confirm or adjust wetland boundaries. Field target samplings were also placed in low-confidence areas to provide field data where the photo signatures or landscape features were not indicative of wetland or upland.

AGDC assessed each field target sampling site using the *Corps of Engineers Wetlands Delineation Manual* (Environmental Laboratory, 1987) and the *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Alaska Region (Version 2.0)* (COE, 2007) to collect pertinent field data, which was classified using Cowardin and Hydrogeomorphic (HGM) classes within the Project mapping corridor, as described in detail below.[51] AGDC refined its wetland maps based on the results of the field target surveys, as presented in the Project's field target sampling study reports.[52] AGDC estimated that about 11 percent (about 1,247 acres) of construction impacts on wetlands was determined in the field. The remaining 89 percent (about 10,513 acres) of construction impacts on wetlands was determined using aerial photo interpretation (NWI data and other digital sources).[53]

Section VI.A.1 of FERC's Procedures requires applicants to "conduct a wetland delineation using the current federal methodology." The main difference between the field target sampling method and the federal methodology (i.e., the routine determination/transect method) is that the latter involves field verification of all wetland boundaries crossed by the Project route, whereas the field target sampling method

[50] Preliminary jurisdictional determinations are indications issued by the COE that there may be waters of the United States on a parcel or indications of the approximate location(s) of waters of the United States on a parcel (33 CFR 331.2).

[51] The Hydrogeomorphic classification system was developed by Brinson (1993).

[52] The field target sampling study reports were included as part of AGDC's Resource Report No. 2, appendix G (Accession No. 20170417-5357). They can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

[53] Digital NWI data is only available for 80 percent of the route (USFWS, n.d.[b]).

focuses only on high confidence and/or low confidence areas (FERC, 2017).[54,55] Observations along transects identify wetland–non-wetland boundaries within the sampling area. Because AGDC completed wetlands mapping using a methodology that is a modification of the federal methodology, AGDC conducted a wetland validation study to determine if the modified methodology provided similar results.

In November 2016, AGDC filed its *2016 Wetlands Methodology Validation Study Report* that analyzed 354 wetland/upland boundaries by comparing the methods. We provided comments on the report and requested approaches to standardize the regions analyzed, as well as to maintain the scientific and statistical integrity (FERC, 2017). Since a revised wetland validation study with the requested information was not included in AGDC's application in April 2017, we issued an information request in November 2017. AGDC provided a revised wetland validation study in December 2017; however, the revised study did not adequately address our concerns and we issued another information request in February 2018. In May 2018, AGDC provided an updated analysis to address our concerns.

The revised wetland validation study found that the field target sampling method provided a reasonable estimation of wetlands affected by the Project. Within the study area, the field target sampling method identified about 1,677 acres and the routine determination/transect method identified about 1,533 acres. When comparing the outcome of the two methods in the wetland validation study, the field target sampling method excluded more wetlands in mountainous regions (e.g., 36 percent in the Alaska Range and 32 percent in the Brooks Range). Additionally, wetland locations and their boundaries were not accurately mapped by the field target sampling method. For example, of the 354 boundaries analyzed by both methods within all ecoregions, 115 boundaries matched within a range of 5 feet or less, which is 32 percent of the total boundaries analyzed. Because the field target sampling method does not confidently map wetland boundaries, minimization measures required by FERC and the COE to protect wetlands could not be accurately applied during construction. Therefore, AGDC would complete field-verified wetland delineations (i.e., using the routine determination/transect method) prior to construction once the final pipeline centerline has been surveyed and access can be obtained.

During active construction, AGDC would file final wetland delineation reports that document the results of all field delineations completed during the previous growing season with the Secretary on an annual basis. The reports would identify the type, location, and acreage for each wetland and provide impact summaries, indicating if permanent fill (including granular fill and cut fill material) was placed in the wetland and if the final elevation was contoured to match the pre-construction elevation.

As previously indicated, construction of portions of the Project would take place during the winter season when wetland boundaries could be difficult or impossible to distinguish. We conclude that the wetland boundaries must be identified and marked during the growing season as defined in the *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Alaska Region (Version 2.0)* (COE, 2007). AGDC would field-delineate wetland areas during the growing season immediately prior to planned winter construction segments of the Mainline Pipeline. AGDC would identify field-delineated boundaries with markers in the field and on revised construction alignment sheets that would be filed with the Secretary prior to construction through these areas. The results of these field surveys would also be included in the final wetland delineation reports filed with the Secretary, as described above.

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[54] The field target sampling method requires surveying predetermined field target locations. Field target locations are selected to verify areas mapped as wetlands to ascertain the wetland status of uncertain or unknown sites, or to confirm or revise wetland boundaries.

[55] The routine determination/transect method requires surveying transects at intervals of no more than 0.5 mile. Once the wetland boundary is determined along a survey transect, a representative wetland delineation data point is used to characterize the wetland and adjacent upland sites (Environmental Laboratory, 1987; COE, 2007).

4.4.1.3 Wetland Classifications

AGDC's wetland determinations identified wetland classes crossed by the Project. These classes can be grouped into major classifications using the Cowardin classification system and Brinson (1993) HGM classification system.

Following the Cowardin classification system, wetlands are first grouped by systems (e.g., landscape position) as coastal (tidal or estuarine) or inland (non-tidal, freshwater, or palustrine). They are then classified by class (cover-type) (e.g., emergent wetlands, scrub-shrub wetlands, and forested wetlands) and by water regime (temporarily or permanently flooded, saturated) (EPA, 2002).

Although riverine, lacustrine, and marine systems are described by Cowardin classification, those resources and impacts are discussed in detail in sections 4.3.2 (riverine and lacustrine) and 4.3.3 (marine). A description of Cowardin classification wetland types found within the Project area is provided below.

- Palustrine emergent (PEM): These wetlands are characterized by erect, rooted, herbaceous hydrophytes, excluding mosses and lichens, that provide at least 30-percent areal cover. Vegetation is present for most of the growing season in most years. In order to normalize AGDC's data for our analysis, Cowardin classifications of palustrine ponds (e.g., palustrine aquatic bed and palustrine unconsolidated bottom classes) have been reassigned to PEM based on the vegetation type shown on aerial imagery.

- Palustrine scrub-shrub (PSS): These wetlands are dominated by woody vegetation less than 20 feet tall that provides at least 30-percent areal coverage. Vegetation includes broadleaf, needle-leaf, and mixed shrub plant communities in Alaska. According to wetland data provided by AGDC, PSS wetlands would be the most prevalent wetland type in the Project area.

- Palustrine forested (PFO): These wetlands are dominated by woody vegetation 20 feet tall or taller with trunk diameter at breast height of 3 or more inches providing at least 30-percent areal coverage.

- Estuarine: These wetlands consist of deepwater tidal habitats and adjacent tidal wetlands that are usually semi-enclosed by land but have open, partly obstructed, or sporadic access to the open ocean. The ocean water is at least occasionally diluted by freshwater runoff from the land. Estuarine wetlands consist of two subsystems, including where the substrate is continuously submerged (subtidal) or is exposed and flooded by tides (intertidal).

Wetlands crossed by the Project were also classified into seven HGM classes. The HGM Approach is a method to assess the functional condition of a specific wetland referenced to data collected from wetlands across a range of physical conditions (Smith et al., 1995). The HGM classification system divides wetlands into classes and subclasses based on geomorphic setting, the water source for the wetland, and hydrodynamics of flow. A description of the HGM classifications for wetlands crossed by the Project is provided below, as defined by Brinson (1993).

- Mineral soil flats: These wetlands do not receive groundwater discharge; rather, they receive water from precipitation and overland flow. Flat wetlands lose water by evapotranspiration and overland flow from precipitation during saturated conditions. Flat wetlands are very common in permafrost soils but can also form from an accumulation of organic material. The wetlands primarily function to store surface water and provide wildlife habitat, notably for waterfowl.

- Depressional: These wetlands occur in topographic depressions. The water source is precipitation, groundwater discharge, and both interflow and overland flow from adjacent wetlands. These wetlands store surface water and provide groundwater recharge and wildlife habitat.

- Slope: These wetlands occur where groundwater discharges to sloping surfaces. They are normally found along elevation gradients ranging from slight to steep slopes. They do not store surface water or recharge groundwater. Instead, they mediate surface flow to other wetlands and waterbodies.

- Riverine: These wetlands occur in floodplains and riparian corridors. Their water source is primarily overbank flow supplemented by overland flow and precipitation. Riverine wetlands can moderate stream flow, store floodwaters, and facilitate nutrient export.

- Lacustrine fringe: These wetlands occur adjacent to ponds and lakes where the water elevation of the pond or lake maintains the water table in the wetland. They function to store floodwater and detritus (organic material) and provide habitat for wading birds and juvenile fish.

- Organic soil flats, or extensive peatlands: These wetlands are created by the vertical accretion of organic matter. The water source for extensive peatlands is typically precipitation with water loss due to saturation and seepage to groundwater. Bogs or muskegs are common examples. According to wetland data provided by AGDC, organic soil flat wetlands would be the most prevalent HGM wetland type in the Project area.

- Estuarine fringe: These wetlands occur along coasts and estuaries influenced by sea level. They intergrade with riverine wetlands where tidal current declines and river flow is the dominant source. These wetlands frequently flood from tidal exchange. Organic matter accumulates in higher elevated marsh areas. Salt marshes are an example of an estuarine fringe wetland.

4.4.1.4 Wetland Resources in the Project Area

Gas Treatment Facilities

The Gas Treatment Facilities are entirely within the Arctic Coastal Plain Subdivision. The majority of the Gas Treatment Facilities are within PEM wetlands except for some of the West Dock Causeway expansion and the PTTL. Grasses and sedges found in PEM wetlands, such as water sedge and cottongrass (*Eriophorum angustifolium*), are the dominant vegetation types. Wetlands containing pendant grass (*Arctophila fulva*) provide important waterfowl and shorebird habitat (see section 4.6.2.1). The area is underlain by continuous permafrost soils that are poorly drained and impervious to water infiltration.

The majority of the West Dock Causeway expansion would occur within estuarine wetlands along the unconsolidated shores of Prudhoe Bay, including intertidal and subtidal wetlands that contain less than 5-percent vegetative areal cover. Beaufort Sea estuarine wetlands generally have sedge species such as Ramensk's sedge (*Carex ramenskii*) or Hoppner's sedge (*C. subspathacea*).

Work for the PTTL and associated aboveground facilities would occur in limited PSS wetlands. The PSS wetlands are typically dominated by dwarf willow species, dwarf birch, mixed shrub-tussock tundra, and ericaceous plants (e.g., bog rosemary [*Andromeda polifolia*]). PSS wetlands occur along stream banks such as the Kadleroshilik and Shaviovik Rivers and in the Point Thomson area. Like the PEM wetlands, the PSS wetlands are underlain by continuous permafrost soils that are poorly drained and impervious to water infiltration.

Mainline Facilities

The Mainline Facilities would cross eight subdivisions, including the Arctic Coastal Plain, Arctic Foothills, Brooks Range, Interior Alaska Highlands, Kanuti Flats, Tanana-Kuskokwim Lowland, Alaska Range, and Cook Inlet-Susitna Lowlands. The abundance and types of wetlands across these subdivisions vary. Throughout the state, the Mainline Pipeline would cross PEM, PSS, PFO, and estuarine wetlands (intertidal). PEM wetlands are vegetated by mostly sedges and grasses. PSS wetlands are usually dominated by willow, alder (*Alnus* spp.), or dwarf birch; mixed shrub-tussock species; and ericaceous species. These wetlands are abundant in the valleys and basins associated with large perennial systems. PFO wetlands typically contain black spruce with a shrub (e.g., alder or willow) and/or a moss-covered understory. Balsam poplar (*Populus balsamifera ssp. balsamifera*) is a tree commonly found in riparian areas associated with PFO wetlands. The Mainline MOF and additional work areas (ATWS and an access road) would be within Cook Inlet intertidal estuarine wetlands. Typical vegetation found in these wetlands include salt-tolerant vegetation such as hairgrass (*Deschampsia* spp.), creeping alkali grass (*Puccinellia* spp.), or sedges (e.g., Lyngbye's or manyflower sedge [*Carex lyngbyaei* or *C. pluriflora*]). These wetlands are subject to extreme tidal ranges that mix large amounts of freshwater from glacial sediments with saltwater, affecting water salinity.

Liquefaction Facilities

The Liquefaction Facilities would be within the Cook Inlet-Susitna Lowlands Subdivision where wetlands are not as abundant as in other subdivisions. The facilities would primarily be constructed in uplands, but a small portion of the footprint would occur within PEM, PSS, and estuarine wetlands. The PEM wetlands at the LNG Plant are vegetated by grasses and sedges. PSS wetlands in the area of the LNG Plant typically include balsam poplar, sweet gale (*Myrica gale*), and willow. The Marine Terminal and a portion of the LNG Plant would be in estuarine wetlands within Cook Inlet, which are dominated by salt-tolerant species, such as hairgrass, creeping alkali grass, or sedges.

4.4.2 General Impacts and Mitigation

Of the total area affected by Project construction (35,474 acres), about 33 percent (11,760 acres) would be wetlands temporarily and/or permanently affected. Temporary impacts on wetlands are typically related to construction activities and would be restored to pre-construction conditions over time with durations that are temporary, short term, or long term, as defined in section 4.0. About 3,535 acres of wetlands would be temporarily affected by the Project. Permanent impacts on wetlands would occur during construction where wetlands would not be restored within the life of the Project (30 years), affecting about 8,225 acres of wetlands. About 195 acres of PFO wetlands would be converted to PEM and/or PSS wetlands as a result of clearing and operational vegetative maintenance. About 1,809 acres of wetlands would be permanently affected by material sites, disposal sites, a water reservoir, and a stormwater pond. Fill placed in wetlands during construction would remain in perpetuity, resulting in about 6,220 acres of wetlands converted to uplands. In addition to the wetlands affected by Project construction (11,760 acres total and 8,225 acres permanent), about 29 acres of PSS wetlands would be permanently converted to PEM wetlands for operational vegetative maintenance for the Mainline Pipeline.

In comments on the draft EIS, the COE said that AGDC identified about 10,000 acres of permanent impacts on waters of the United States in its DA permit application, whereas we estimate about 8,225 acres of permanent impacts on wetlands based on wetland data filed by AGDC. Two factors contribute to this discrepancy. First, our permanent impact acreage is limited to wetlands; other waters of the United States (i.e., riverine, lacustrine, and marine) have been assessed in our analysis but are discussed separately in sections 4.3.2 or 4.3.3. In the DA permit application, all waters of the United States are quantified together. Second, the wetland impact data that AGDC filed with FERC was based on their field and desktop wetland studies; the wetland data in the DA permit application is based on the COE-approved preliminary jurisdictional determination. While there are discrepancies between these data, we have reviewed them and concluded that they do not change any of our conclusions regarding impact significance. As such, the analysis presented here will satisfy the COE's CWA responsibilities. Further, we expect that the field delineation surveys to be completed during the growing season prior to construction would provide acreages that differ from the ones presented here, but would also not change our conclusions. The results of the field delineation surveys would be filed with the Secretary on a yearly basis, as discussed above.

The Project wetland impacts would lead to fragmentation of wetlands and the loss of wetland functions such as water storage, groundwater recharge, fish and wildlife habitat, shoreline stabilization, and nutrient production. Additionally, the Project would affect special wetland complexes and wetlands not previously affected by development. The large area of wetland conversion to upland, loss of wetland function, and long timeframe for restoration would result in a significant adverse impact. The COE has the responsibility under the CWA to determine whether the proposed wetland impacts can be permitted (as explained in sections 1.2.4 and 1.6.8).

AGDC provided wetland impact data for the Mainline Pipeline, which we updated to be consistent with the mile-by-mile identification of construction modes in the Project Winter and Permafrost Construction Plan (e.g., impacts associated with Mode 1 would only apply to MPs 0.0 to 56.6, and impacts associated with Mode 5B would only apply to uplands). AGDC concurred that our analysis of the wetland impact data with respect to construction mode by milepost is correct.

Wetlands affected by Project activities are summarized in table 4.4.2-1, according to both classification systems described in section 4.4.1.3. Acreages of affected wetlands by sub-watershed (HUC8) are summarized in table 4.4.2-2. Individual wetland crossings by Project facility, approximate milepost, sub-watershed (HUC8), unique identification number, Cowardin classification, HGM classification, length crossed, impact acreage, and Mainline Pipeline construction mode are listed in appendix K.

Project construction and operation would temporarily and permanently affect wetlands. During construction and operation, wetlands would be permanently affected by granular fill (e.g., creating uplands), material site development (e.g., unreclaimed after construction), and some of the clearing (e.g., in areas where it takes 30 years or more to revegetate). During construction and operation, turbidity and sedimentation, fugitive dust, fueling, use of hazardous materials, and invasive species could affect wetlands. During construction, wetlands would be temporarily affected by discharging hydrostatic test water, by granular roads and work pads modifying natural drainage patterns and hydrology, and by blasting. Construction and operational impacts on estuarine wetlands (e.g., at the West Dock Causeway and Marine Terminal) are discussed in detail in section 4.3.3.

Construction of granular fill pads for infrastructure would occur across the Project area and result in the permanent loss of wetlands, which would extend beyond the nominal design life of the Project. The conversion of wetlands to uplands through granular fill placement would affect adjacent wetlands by fragmenting them into smaller sections and changing natural drainage patterns. Granular fill placement would change the surface elevation and hydrology of existing wetlands. In addition, it would cover and compact wetland substrates, decreasing the wetland's ability to provide water storage and groundwater recharge. Biogeochemical cycling functions, such as the decomposition of soil organic matter and carbon sequestration, are diminished when wetlands are covered with granular fill (Berkowitz et al., 2017). Wetlands in the Arctic Coastal Plain and Arctic Foothills Subdivisions are known to store large quantities of carbon, which provide carbon sequestration on a massive scale (Mack et al., 2004). Wetland loss from granular fill placement would reduce the capacity to sequester and transform carbon. Adjacent wetlands could also experience increased turbidity and sedimentation because fine particles would be transported from granular fill to adjacent wetlands by stormwater runoff during construction and operation.

TABLE 4.4.2-1

Summary of Wetland Impacts

Classification Type	Temporary, Short-Term, and Long-Term Impacts [a] (acres)	Permanent Impacts [a] (acres)
Cowardin classification [b]		
PEM	2,939	2,589
PSS	528	4,451
PFO	N/A	1,132
Estuarine	68	53
Total	**3,535**	**8,225 [c]**
HGM classification [d]		
Mineral soil flats	3	185
Depressional	416	478
Slope	98	1,431
Riverine	79	232
Lacustrine fringe	21	N/A
Organic soil flats	2,850	5,846
Estuarine fringe	68	54
Total	**3,535**	**8,225 [c, e]**

N/A = Not applicable

Note: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

a See section 4.0 for definitions of temporary, short-term, long-term, and permanent impacts.

b Wetland classification according to Cowardin et al. (1979).

c Does not include operational impacts for vegetative maintenance in PSS wetlands (see wetland vegetation conversion discussion in section 4.4.3.2).

d Wetland classification according to Brinson (1993).

e The sum of the addends may not equal the total in all cases due to rounding.

Construction of material sites would affect wetlands through excavation. Material sites that are not reclaimed to wetlands would result in a permanent adverse effect on wetland area and function. Material sites are proposed in wetlands that support fish, provide wildlife habitat, retain flood water, stabilize shorelines, produce and export food and nutrients for plants and aquatic organisms, and support groundwater recharge. AGDC has not provided reclamation plans to determine whether wetlands would be changed to open water or permanently lost. As noted in section 4.1.2, AGDC would file an updated Gravel Sourcing Plan and Reclamation Measures prior to construction.

Clearing activities and disturbing wetland vegetation and soils (construction and operation) would affect the wetlands capacity to buffer floods and/or control erosion. Disturbance of the organic soil horizons would affect nutrient availability for plants and aquatic organisms. Where wetland revegetation would take longer than 30 years, clearing would result in a permanent impact. Disturbing soils and removing vegetation lessens a wetland's capacity to store rainfall and snowmelt and accelerates runoff. Stormwater runoff could transport sediment from construction and operational areas into adjacent wetlands, which would affect water quality. Turbidity and sedimentation could occur throughout the life of the Project, but would be localized and adequately minimized by implementing the mitigation measures in the Project Plan, Procedures, and SWPPP, such as the use of temporary erosion and sediment control measures. AGDC would provide a Project-wide SWPPP that would cover all facilities and activities during construction and operation. AGDC would obtain coverage for construction and operational activities from ADEC under the APDES program or from EPA under the NPDES program.

TABLE 4.4.2-2

Affected Wetlands by HUC8 Sub-watershed [a]

Sub-watershed (HUC8)	Ecoregion Subregion [b]	Project Facilities	Temporary, Short-Term, and Long-Term Impacts [c] (acres)	Permanent Impacts [c] (acres)
Kuparuk River (19060401)	Beaufort Coastal Plain Brooks Foothills	Gas Treatment Facilities Mainline Facilities	741	1,035
Canning River (19060501)	Beaufort Coastal Plain	Gas Treatment Facilities	71	<1
Mikkelsen Bay (19060403)	Beaufort Coastal Plain	Gas Treatment Facilities	901	34
Sagavanirktok River (19060402)	Beaufort Coastal Plain Brooks Foothills Brooks Range	Gas Treatment Facilities Mainline Facilities	1,260	2,022
Lower Colville River (19060304)	Brooks Foothills	Mainline Facilities	N/A	15
Middle Fork-North Fork Chandalar Rivers (19040301)	Brooks Range	Mainline Facilities	2	89
Upper Koyukuk River (19040601)	Brooks Range Kobuk Ridges and Valleys Ray Mountains	Mainline Facilities	31	1,178
South Fork Koyukuk River (19040602)	Ray Mountains	Mainline Facilities	1	830
Kanuti River (19040604)	Ray Mountains	Mainline Facilities	<1	120
Yukon Flats-Yukon River (19040403)	Ray Mountains	Mainline Facilities	<1	116
Ramparts-Yukon River (19040404)	Ray Mountains	Mainline Facilities	<1	386
Tolovana River (19040509)	Ray Mountains Tanana-Kuskokwim Lowlands Yukon-Tanana Uplands	Mainline Facilities	118	610
Lower Tanana River (19040511)	Tanana-Kuskokwim Lowlands	Mainline Facilities	28	30
Nenana River (19040508)	Tanana-Kuskokwim Lowlands Alaska Range	Mainline Facilities	215	837
Chena River (19040506)	Yukon-Tanana Uplands	Mainline Facilities	N/A	43
Chulitna River (19020502)	Alaska Range Cook Inlet Basin	Mainline Facilities	5	238
Lower Susitna River (19020505)	Cook Inlet Basin	Mainline Facilities	97	475
Yentna River (19020504)	Cook Inlet Basin	Mainline Facilities	N/A	35
Anchorage (19020401)	Cook Inlet Basin	Mainline Facilities	N/A	N/A
Redoubt–Trading Bay (19020601)	Cook Inlet Basin	Mainline Facilities	1	95
Upper Kenai Peninsula (19020302)	Cook Inlet Basin	Mainline Facilities Liquefaction Facilities	65	37
Total [d]			**3,535**	**8,225**

N/A = Not applicable

Note: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

[a] Sub-watershed (HUC8) drainages are further defined in section 4.3.2.

[b] Subregions are based on the Unified Ecoregions of Alaska classification system delineated by Nowacki et al. (2001c), as described by the ADF&G (2015a).

[c] See section 4.0 for definitions of temporary, short-term, long-term, and permanent impacts.

[d] The sum of the addends may not equal the totals in all cases due to rounding.

Equipment and vehicle traffic could permanently affect adjacent wetlands by creating fugitive dust. Dust deposition could permanently affect water quality and vegetation in wetlands. Fugitive dust is a greater concern in wetlands underlain by permafrost because dust deposition can cause thermokarst (see section 4.2.4). Thermokarst would cause soil subsidence and ponding that expands in an unnatural manner, resulting in an anthropogenic perturbation of wetlands (e.g., human-caused disturbance of wetlands). As ponding expands, it can drain or flood adjacent wetlands, continuing the cycle of permafrost thaw. Impacts of thermokarst on wetlands would be permanent, but the likelihood of this occurring would be reduced with implementation of the dust control measures in the Project Fugitive Dust Control Plan.

The storage and use of fuel and hazardous materials are construction and operational activities that could incidentally release these materials into wetlands. Spills have the potential to permanently contaminate wetlands, vegetation, and soils, and to decrease water quality. Adherence to the fueling, storage, containment, and cleanup measures discussed in the Project Procedures, SPCC Plan, and Waste Management Plan, along with specific requirements from land management and regulatory agencies, would decrease the potential for an incidental release into wetlands and reduce the impacts if a release should occur. AGDC would develop facility/work site-specific SPCC plans prior to construction, as discussed in section 4.2.6. Hazardous materials would be handled in accordance with the Project Procedures as well as the Project Waste Management Plan (see sections 4.9.6 and 4.11.6.3). Although releases of fuels or hazardous materials could result in permanent impacts on wetlands, commitment to the practices and procedures described in the plans and requirements above would adequately minimize the likelihood of impacts on wetlands from potential contamination.

NNIS could increase as a result of Project construction and maintenance, affecting revegetation and plant biodiversity within wetlands. The potential introduction and spread of NNIS would be reduced by implementation of the Project Invasives Plan, ISPMP, and Revegetation Plan, as discussed in section 4.5.8.

During construction, three DMT crossings of major waterbodies would require entry and exit points within wetlands. The entry and exit points for the Middle Fork Koyukuk River, exit point for the Yukon River, and exit point for the Deshka River crossings would be within PEM, PSS, and PFO wetlands. As discussed in section 2.2.2, the use of DMT could result in an inadvertent release of drilling fluid, which could occur in these wetlands. Releases of drilling fluids could act as fill and coat wetland vegetation, reducing productivity and changing hydrology due to modified circulation. As discussed in section 4.1.5, impacts on wetlands would be mitigated by installing containment structures at exit and entry points and implementation of FERC-approved DMT Plans. Although the extent of impacts would vary depending on the volume of fluid released, area affected, and time of year, impacts on wetlands would be temporary with prompt response and restoration mitigation. AGDC requested approval to place the entry and exit points within wetlands as part of its request for modifications to the FERC Procedures to allow for ATWS within 50 feet of waterbodies and wetlands. Our evaluation of this request is discussed in section 4.4.3.2.

Discharges of hydrostatic test water would result in temporary impacts on wetlands. Hydrostatic test water discharges would be conducted in accordance with the Project Procedures and any permit requirements. Implementing the Project Procedures and permit requirements, which include installation of sediment barriers and energy dissipation devices, would minimize wetland impacts. AGDC would not use additives in test water except where hydrostatic testing would occur year-round on the North Slope. Test water containing additives would be discharged into UIC-permitted wells, thus avoiding the introduction of chemicals into wetlands. The discharged water temperature would be within a few degrees of the surrounding ground temperature, thus minimizing thermal impacts on the wetland discharge locations. Additional detail on hydrostatic test water discharges is provided in section 4.3.4.

Linear granular fill features (e.g., access roads and granular work pads within the construction right-of-way) left in place after construction could permanently modify natural drainage patterns within wetlands. Federal regulatory agencies have noted a concern that the Project's new permanent granular fill roads could block natural drainage patterns in large wetland areas. These granular fill linear features would intercept natural drainage, causing ponding on the up-gradient side of the road, and prevent water flow into the down-gradient side, which could adversely reduce wetland hydrology (e.g., cause drying of the wetland). Increased surface water or ponding can cause thermokarst and affect the accumulation and decomposition of soil organic matter in wetlands, which would affect the physical features to which native plants have adapted, potentially modifying plant communities (Berkowitz et al., 2017). AGDC would install appropriately sized culverts within access roads to allow surface water flow and maintain the hydrologic characteristics of adjacent wetlands. AGDC would contour the granular fill work pads within the construction right-of-way following construction to allow natural drainage and hydrologic connectivity. In some cases where multiple natural drainage features intersect the granular fill, AGDC would divert drainage into one drainage feature to facilitate hydrologic connectivity. Implementation of these mitigation measures would reduce the potential effects on wetlands.

Blasting activities required for material site development and Mainline Pipeline trenching could affect adjacent wetlands, soils, and vegetation. Flyrock from blasting deposited outside the disturbance area could accumulate and create a layer of fill on top of wetlands, crush vegetation, cover existing soils, and diminish water storage capacity. The effect of flyrock would be minimized to a minor impact on wetlands through the use of blasting mats and other measures identified in the Project Blasting Plan.

The outcome of construction activities would extend into the operational phase, resulting in temporary and permanent impacts on wetlands. The loss of wetlands and their functions from Project construction (e.g., placement of granular fill, material site development, and clearing) would be permanent. With the implementation of mitigation measures described above, permanent impacts on adjacent wetlands from turbidity and sedimentation, fugitive dust, fueling, use of hazardous materials, and invasive species would be reduced and localized. Impacts on wetlands from hydrostatic test water discharges and modifications to natural drainage patterns (e.g., linear granular features) would be minor. Blasting would result in a minor impact on wetlands due to minimization measures.

As discussed in section 2.2, AGDC's Project Procedures include some modifications to FERC's Procedures. These modifications, which we have reviewed and accepted with some revisions, are summarized in appendix D.

4.4.3 Facility-Specific Impacts and Mitigation

Wetland impacts from construction and operation of each facility would be dependent on the activities required for each facility. The Mainline Facilities would have the largest impact on wetlands, and the Liquefaction Facilities would have the least impact on wetlands (see table 4.4.3-1). Facility-specific wetland impact and mitigation discussions are provided below.

TABLE 4.4.3-1 **Summary of Wetland Impacts by Project Facility**		
Facility	Temporary, Short-Term, and Long-Term Impacts [a] (acres)	Permanent Impacts [a] (acres)
Gas Treatment Facilities	1,710	771
Mainline Facilities	1,763	7,419 [b]
Liquefaction Facilities	63	35
Total [c]	**3,535**	**8,225 [b]**

Note: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

[a] See section 4.0 for definitions of temporary, short-term, long-term, and permanent impacts.

[b] Does not include operational impacts for vegetative maintenance in PSS wetlands (see wetland vegetation conversion discussion in section 4.4.3.2).

[c] The sum of the addends may not equal the totals in all cases due to rounding.

4.4.3.1 Gas Treatment Facilities

Construction and operation of the Gas Treatment Facilities would temporarily and permanently affect wetlands (see table 4.4.3-2). Construction activities would permanently affect wetlands and permanently alter functional characteristics through placement of fill, conversion of wetlands to open water for the gravel mine and water reservoir, and installation of VSMs for pipelines. Wetlands that would be affected by the Gas Treatment Facilities provide habitat for threatened and endangered species, water storage capacity, surface water flow, sediment and shoreline stabilization, and nutrient cycling. Wetlands would be temporarily affected by ice road and ice pad construction. Estuarine wetlands at the West Dock Causeway expansion would be temporarily affected by the barge bridge and permanently affected from the placement of permanent fill.

Of the 771 acres of wetlands permanently affected by the Gas Treatment Facilities, about 596 acres would be permanently lost by the placement of granular fill for infrastructure, such as the GTP pad, operations center, camp pads, PTTL aboveground facilities, and access roads. About 641 acres of PEM wetlands would be permanently affected by the GTP, of which 466 acres would be the result of the placement of granular fill. All of the 110 acres of PEM wetlands permanently affected by the PTTL would be the result of placement of granular fill. Less than 1 acre of PSS wetlands would be permanently lost for construction of the Point Thomson Meter Station associated with the PTTL. About 20 acres of estuarine wetlands would be permanently lost by expansion of the West Dock Causeway. The placement of permanent granular fill would affect many wetland functions as described in section 4.4.2, including habitat for threatened and endangered species, water storage capacity, surface water flow, nutrient cycling, sediment and shoreline stabilization, and soil organic matter accumulation and decomposition (Berkowitz et al., 2017). Turbidity and sedimentation could also occur in adjacent wetlands as a result of stormwater runoff; however, implementation of AGDC's Plan and Procedures and SWPPP would reduce these impacts.

The seasonal use of ice roads and ice pads in the winter for construction would avoid the use of permanent granular fill and minimize impacts on wetlands. Fresh water, snow, and ice chips would be used to create ice roads and ice pads on top of wetlands with frozen soils that are covered by packed snow, thereby minimizing ground disturbance. During construction, ice roads and ice pads would only result in temporary impacts on wetlands because they would melt during spring breakup. Ice roads and ice pads alter the snowpack structure, physically disturbing vegetation and soils and compacting soils if the snowpack is thin. Ice road and ice pad construction would be conducted in accordance with permitting requirements from the ADNR-DMLW that impose specific standards to minimize impacts on wetlands and the tundra. The state regulatory requirements for ice road and ice pad construction were developed to avoid impacts such as soil compression. Because packed snow and ice might not melt until spring breakup, vegetation and soils could remain covered for a longer period into the summer, possibly delaying vegetation growth. As discussed in section 4.5, however, vegetation impacts would be minor, resulting in minor and temporary impacts on wetlands.

TABLE 4.4.3-2

Wetland Impacts Associated with the Gas Treatment Facilities

Wetland Type (Cowardin Class) [a]	Temporary Impacts [b] (acres)	Permanent Impacts [b] (acres)
GTP [c]		
PEM	122	641
Estuarine	3	20
PTTL [d]		
PEM	1,533	110
PSS	44	<1
PBTL		
PEM	7	<1
Total [e]	**1,710**	**771**

Note: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

[a] Wetland classification according to Cowardin et al. (1979).

[b] See section 4.0 for definitions of temporary and permanent impacts; there are no short-term or long-term impacts associated with the Gas Treatment Facilities.

[c] These facilities include the GTP pads, access roads, associated transfer pipelines, additional work areas, West Dock Causeway, gravel mine, and water reservoir.

[d] These facilities include the PTTL pipeline, aboveground facilities, construction camps, ice roads and ice pads, pipe storage yards, and a helipad.

[e] The sum of the addends may not equal the totals in all cases due to rounding.

Of the 641 acres of PEM wetlands permanently affected by the GTP, development of the gravel mine and water reservoir at the GTP would result in the permanent conversion of 175 acres of PEM wetlands to open water. This conversion would result in the loss of PEM wetlands, but the conversion could create open water habitat that provides different functions and values than unaltered PEM wetlands. Conversion to open water would be dependent on the availability of water from external sources (e.g., seasonal precipitation for the gravel mine and mechanical pumping for the water reservoir) and could take multiple seasons. Construction activities for the gravel mine and water reservoir would affect adjacent wetlands from blasting activity flyrock and overburden stockpiling. Ice roads would be constructed around the gravel mine perimeter to provide a surface where flyrock material within the ice road could be removed at the end of each winter season; however, flyrock might not be removed beyond the ice road. Frozen water within the surface of the overburden stockpiles around the gravel mine perimeter could thaw during the summer, resulting in drainage to adjacent wetlands. The drainage water volume would be minor and unlikely to generate concentrated runoff or erosion and sedimentation within adjacent wetlands. Overburden stockpiles would be removed from the gravel mine perimeter as part of reclamation activities in accordance with final approved reclamation plans, as discussed in section 4.2.5.

Pipelines associated with the Gas Treatment Facilities would be constructed entirely within wetlands, but construction impacts would be minor. The PTTL, PBTL, and GTP associated transfer pipelines would be constructed aboveground on VSMs in the winter using ice roads and ice pads. This construction method would minimize permanent wetland impacts to a small footprint at the base of about 6,644 VSMs (up to about 13 square feet per VSM) for a total impact of less than 1 acre. Aboveground pipelines avoid subsidence issues attributed to heat loss from soil disturbance that can affect permafrost in wetlands (North Slope Borough, 2014). Use of ice roads and ice pads minimizes impacts on wetlands from construction, as discussed above. In the spring and summer following installation, sediments disturbed during construction would result in temporary wetland turbidity at the base of each VSM, resulting in a minor temporary water quality impact on wetlands.

Expansion of the West Dock Causeway would temporarily and permanently affect estuarine wetlands. About 3 acres of subtidal estuarine wetlands would be temporarily affected by the barge bridge. About 20 acres of estuarine wetlands would be permanently affected by the placement of granular fill for the causeway (16 acres of subtidal and 4 acres of intertidal). The West Dock Causeway is discussed in more detail in section 4.3.3.

Operational and maintenance activities of the Gas Treatment Facilities would require construction of ice roads or ice pads. Impacts from these activities would be similar in nature to those resulting from construction. The Gas Treatment Facilities could also be accessed via the tundra by low ground-pressure equipment approved by state regulatory agencies. Tundra travel could alter the types and distribution of plants, cause thermokarst, and create waterbodies in wetlands (North Slope Borough, 2014). The ADNR-DMLW approves and monitors tundra travel activities to avoid damage to the tundra and wetlands. Impacts on wetlands would be minor when operation and maintenance activities would be conducted in accordance with state regulatory requirements.

Granular fill infrastructure and VSM installation for the Gas Treatment Facilities would result in the permanent loss of wetlands and their associated functions. Gravel mine and water reservoir construction would permanently change PEM wetlands to open water. With the implementation of mitigation measures, including adherence to AGDC's Project Plan and Procedures, SWPPP, Blasting Plan, Revegetation Plan, and Winter and Permafrost Construction Plan, as well as the permitting requirements described above, temporary impacts from construction on wetlands associated with the Gas Treatment Facilities would be adequately minimized. Long-term maintenance of the Gas Treatment Facilities would use ice roads, ice pads, and tundra travel; therefore, operational impacts would be minor.

4.4.3.2 Mainline Facilities

Constructing and operating the Mainline Facilities would result in temporary, short-term, long-term, and permanent effects on wetlands (see table 4.4.3-3). Construction activities would permanently affect wetland vegetation and permanently alter functional characteristics through conversion of PFO to PSS or PEM wetlands and placement of fill. Granular fill placement in the construction right-of-way and for permanent infrastructure associated with the Mainline Facilities (e.g., aboveground facilities and access roads) would also result in the permanent loss of wetlands and wetland functions, as discussed below. Wetlands affected by the Mainline Facilities provide water storage, wildlife habitat, groundwater recharge, shoreline stabilization, and nutrient cycling, among other functions. The Mainline Facilities would affect wetlands that are unlikely to be restored to pre-construction conditions (i.e., PFO wetlands and string bogs). Some wetlands would be affected by construction activities but restored within the life of the Project, resulting in temporary, short-term, or long-term impacts. Mainline Facilities would temporarily and permanently affect intertidal estuarine wetlands. Vegetation maintenance during operation would permanently convert PSS wetlands to PEM wetlands.

TABLE 4.4.3-3 **Wetland Impacts Associated with the Mainline Facilities**		
Wetland Type (Cowardin Class) [a]	Temporary, Short-Term, and Long-Term Impacts [b] (acres)	Permanent Impacts [b] (acres)
Pipeline right-of-way [c]		
PEM	929	1,063
PSS	434	2,659 [d]
PFO	N/A	597
Estuarine	1	N/A
Pipeline Right-of-Way Subtotal [e]	**1,365**	**4,319** [d]
Aboveground facilities [f]		
PEM	N/A	26
PSS	N/A	79
PFO	N/A	8
Estuarine	N/A	5
Aboveground Facilities Subtotal	**N/A**	**118**
Additional work areas [g]		
PEM	347	742
PSS	50	1,712
PFO	N/A	528
Estuarine	1	<1
Additional Work Areas Subtotal [e]	**398**	**2,982**
Total [e]	**1,763**	**7,419** [d]

N/A = Not applicable

Note: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

[a] Wetland classification according to Cowardin et al. (1979).

[b] See section 4.0 for definitions of temporary, short-term, long-term, and permanent impacts.

[c] Pipeline right-of-way permanent impacts include granular fill work pads in the construction right-of-way and cut and fill construction areas where fill would not be removed after construction, as well as where wetlands would be converted from PFO to PSS or PEM. Impacts from the Cook Inlet crossing are discussed in section 4.3.3.

[d] Does not include operational impacts for vegetative maintenance in PSS wetlands (see wetland vegetation conversion discussion in section 4.4.3.2).

[e] The sum of the addends may not equal the totals in all cases due to rounding.

[f] Mainline aboveground facilities include compressor stations, meter stations, launchers/receivers, cathodic protection system, MLVs, the Mainline MOF, and a heater station.

[g] Mainline additional work areas include ATWS; access roads; helipads and airstrips; construction camps; contractor, pipe, and double joining yards; railroad spurs and work pads; disposal sites; and material sites.

Mainline Pipeline

Mainline Pipeline onshore construction would result in 1,364 acres of temporary and 4,319 acres of permanent impacts on PEM, PSS, and PFO wetlands. An additional 29 acres of PSS wetlands would be permanently affected for vegetative maintenance during operation. Mainline Pipeline offshore construction would result in temporary and permanent impacts on about 1 acre of intertidal estuarine wetlands.

Construction impacts on PEM, PSS, and PFO wetlands can be grouped into three categories depending on the wetland type affected, construction method used, length of the growing season, and restoration method. As listed in table 4.4.3-4, these three categories are:

- restored to pre-construction conditions (e.g., topography and hydrology);
- wetland vegetation conversion (e.g., PFO to PEM); and
- permanent loss of wetland from placement of granular fill.

These impact categories are described below for each construction mode.

AGDC would use a minimum construction right-of-way width of 110 feet over 920 wetland crossings along the Mainline Pipeline (see appendix K). AGDC would also use additional space as needed for travel lanes, bypass lanes, cut and fill slope areas, and site-specific conditions (e.g., wider trench for blasting and safety concerns on steep terrain). Section II.A.2 of FERC's Procedures require site-specific justifications for the use of a construction right-of-way width greater than 75 feet in wetlands. We have reviewed AGDC's site-specific justifications and confirmed that the wider right-of-way is necessary to safely install the pipeline within the physical settings and conditions common along the route.

Restored to Pre-construction Conditions

Construction activities within the Mainline Pipeline right-of-way would affect wetlands even though they would be restored to pre-construction conditions following construction. As shown in table 4.4.3-4, about 1,364 acres of wetlands affected within the Mainline Pipeline construction right-of-way (Modes 1, 2, and 3) would be restored, which includes 27 acres of wetlands associated with waterbody and fault crossings. As described in section 2.2.2, construction Mode 1 (ice work pad over permafrost in flat terrain), Mode 2 (winter frost packed in non-permafrost or thaw-stable permafrost), and Mode 3 (matted summer wetlands) would result in the least amount of wetland disturbance. The disturbed trench area and construction right-of-way would be restored, but the time needed for PEM and PSS wetlands to recover to pre-existing vegetative conditions would vary depending on the length of the growing season (Hagg, 1974; Billings, 1987). Wetland revegetation would be considered successful when vegetative cover standards are met, as described in the Project Revegetation Plan. AGDC would file an updated Revegetation Plan prior to construction (see section 4.5.8.3).

Mode 1 would be used for about 56.6 miles of Mainline Pipeline construction entirely within the Arctic Coastal Plain Subdivision. About 894 acres of PEM and PSS wetlands would be affected by Mode 1 construction. The primary impact on wetlands within Mode 1 areas would occur during trenching because the soil and vegetative structure would be removed. Water storage capacity and surface water flow would be modified. The trenchline would be treated with seed and fertilizer to initiate revegetation. Generally, most of the construction right-of-way would be temporarily affected and recover the following growing season, but revegetation of the trench area would be affected for the long term because AGDC estimates that vegetation recovery (70 percent of pre-construction cover) would not occur for about 10 years.

Mode 2 would be used for about 69.4 miles of Mainline Pipeline construction across all subdivisions in Alaska except the Arctic Coastal Plain Subdivision. About 437 acres of PEM and PSS wetlands would be affected by Mode 2 construction. Vegetation would be cleared within the construction right-of-way in addition to the trench area. The vegetative root structure and soils would be maintained within the right-of-way but outside the trenchline to promote restoration, resulting in shorter temporal impacts than in the trench area. AGDC estimates that PEM and PSS wetlands within the northern portion (e.g., Arctic Foothills and Brooks Range Subdivisions) would establish 70-percent cover in about 10 years. Within the southern portion (e.g., Interior Alaska Highlands Subdivision and south), AGDC estimates that

PEM and PSS wetlands would require about 5 years to achieve 70 percent of pre-construction cover. Therefore, impacts on PEM and PSS wetlands would be short term to long term.

TABLE 4.4.3-4

Wetland Impacts Associated with the Mainline Pipeline Right-of-Way

Wetland Type (Cowardin class) [a]	Restored to Pre-construction Conditions (acres)	Conversion of Vegetation (acres)	Permanent Loss from Placement of Fill (acres)
PEM	929 [b]	N/A	1,063
PSS	434 [b]	29 [c]	2,659
PFO	N/A	186	410
Total [d]	**1,364**	**215**	**4,133**

N/A = Not applicable

Notes: The wetland impact data in this table was provided by AGDC and reviewed for consistency with other information provided by AGDC.

[a] Wetland classification according to Cowardin et al. (1979).

[b] Includes 1 acre of PEM wetlands and 26 acres of PSS wetlands associated with waterbody and fault crossings, which would be restored.

[c] AGDC would conduct vegetative maintenance of a 10-foot-wide strip centered over the Mainline Pipeline. The calculated acreage is based on PSS wetland crossing length multiplied by mowed width (10 feet).

[d] The sum of the addends may not equal the totals in all cases due to rounding.

Mode 3 would be used for less than 1 mile of Mainline Pipeline construction. This mode would use construction mats in saturated wetlands in summer to reduce ground disturbance along the working side of the right-of-way, but would result in damage to vegetation through cutting of trees and brush, which would delay plant development. About 6 acres of PEM and PSS wetlands would be affected by Mode 3 construction. The pipeline would be floated into the excavated trench using “push-pull” methods and then the trench backfilled, resulting in the redistribution of soils and vegetation in the trench area. Mode 3 would involve restoration of the hydrologic regime. PEM and PSS wetlands within the right-of-way and disturbed trench area would not be permanently affected because the vegetative and soil structure would remain intact and available to facilitate restoration. Mode 3 would be used within the Tanana-Kuskokwim Lowlands and Alaska Range Subdivisions where the growing season would be relatively longer. Because AGDC estimates that hydrologic regime restoration would occur within about 1 to 2 years, and the disturbed areas restored within 3 years in most cases, the impacts would be short term.

Wetland Vegetation Conversion

Construction clearing and maintenance of the right-of-way following construction would affect PFO and PSS wetland vegetation but not PEM wetland vegetation. Construction within PFO wetlands would require clearing forested areas, which would permanently affect the vegetative species within the wetlands and adjacent wetlands. Given the slow growth of trees that dominate the PFO wetlands, regeneration to pre-construction conditions could take several decades. Through natural recruitment, boreal forests take 25 to 45 years to reestablish on intact soils in non-permafrost areas; 30 to 55 years on intact soils in permafrost areas; and 30 to 100 years following scouring of soils to bare rock, gravel, silt, or sand (ADF&G, 2001b). About 186 acres of PFO wetlands would be converted to PEM or PSS wetlands (see table 4.4.3-4). PFO wetlands cleared for construction would be allowed to revegetate, but we have considered this a permanent impact because it would take longer than 30 years to return to pre-construction conditions.

During operation of the Mainline Pipeline, AGDC would conduct vegetative maintenance of a 10-foot-wide strip centered over the pipeline no more than every 3 years, but PEM vegetation would not generally be mowed or otherwise maintained, and therefore would not be permanently affected. PSS vegetation would be allowed to regenerate, but would be affected by maintenance of the 10-foot-wide strip. About 29 acres of PSS wetlands would be permanently converted to PEM wetlands due to vegetative maintenance. Most of the permanent impacts on wetland vegetation would be in PFO wetlands where trees within 15 feet of the pipeline centerline could compromise the integrity of the pipeline. Such trees would be selectively cut and removed. Since these trees would be cleared for construction and not reestablish within the life of the Project, the vegetative maintenance impact acreage is included in the acres of converted PFO wetlands provided in table 4.4.3-4. Therefore, by maintaining the right-of-way and limiting revegetation of a portion of PSS and PFO wetlands, functions (primarily habitat) of these wetlands would be permanently altered by conversion to PSS and/or PEM wetlands.

Clearing of PFO wetlands for construction and operational vegetative maintenance would affect adjacent forested wetland vegetation communities leading to fragmentation, the introduction and spread of NNIS, riparian vegetation loss, and microclimate changes associated with gaps in the canopy. Impacts on the adjacent vegetative communities could include changes in vegetation density, type, and biodiversity. Given the temporal loss of mature forested communities, impacts would be permanent.

AGDC stated that PFO wetlands affected by Mode 5A would result in vegetative conversion, but this construction mode would involve placing cut fill material across the width of the construction right-of-way, which would permanently convert the areas to uplands instead of a different wetland type (e.g., PEM or PSS wetlands). These impacts are discussed below.

Permanent Loss from Placement of Fill

Modes 4 and 5A for the onshore portion of the Mainline Pipeline would result in significant permanent impacts on wetlands. Collectively, these modes would be used to construct about 639.9 miles (about 82 percent) of the onshore Mainline Pipeline. Permanent impacts on wetlands would result from the permanent placement of granular fill for construction work pads within the right-of-way (Mode 4—granular work pad) and placement of cut fill material within the right-of-way to create level working surfaces (Mode 5A—graded). Mode 4 would be used for about 290.9 miles of Mainline Pipeline construction and would affect about 3,134 acres of wetlands within the right-of-way. Mode 5A would be used for about 349.0 miles of Mainline Pipeline construction and would affect about 999 acres of wetlands. Fill used for these construction modes would neither be removed nor the areas restored to wetlands within the life of the Project, thereby resulting in the permanent loss of about 4,133 acres of wetlands (see table 4.4.3-4).

As discussed in section 4.4.2, filling a wetland would result in localized and broad ecosystem impacts by fragmenting wetlands, reducing nutrient cycling, affecting groundwater discharge and recharge, modifying natural drainage patterns, reducing flood storage, and causing turbidity and sedimentation. In addition, permafrost wetlands are highly susceptible to anthropogenic impacts. For example, granular fill would increase soil thermal conductivity that, when coupled with increased solar radiation, would lead to permafrost thaw, causing thermokarst and ponding as the granular fill settles. Adjacent to granular fill areas, related construction activities (e.g., clearing, grading, and fugitive dust from vehicles) could further degrade permafrost wetlands.

AGDC's rationale for using granular fill is to protect permafrost and to provide a stable and safe construction work surface (see section 4.2.4). Based on past construction issues in permafrost in Alaska, and our own review of scientific research, we cannot conclude with certainty that granular fill would protect permafrost or minimize impacts on wetlands, and have therefore recommended in section 4.2.4 that AGDC review areas proposed for Mode 4 construction in the summer (179.2 miles), reassess whether winter construction would be feasible in low slope (0 to 2 percent) areas, and, if so, complete the work in the winter.

To attempt to further minimize impacts associated with permanent placement of granular fill, we reviewed information provided by AGDC on alternative construction methods, including the use of wood chips, corduroy roads, timber mats, and conventional grading without granular fill. Both wood chips and timber for corduroy roads could be used as a biodegradable alternative to granular fill. Given that nearly 12,000 acres of forest are proposed to be cleared for this Project, we asked AGDC if timber could be used to make a level work surface. However, AGDC stated that there is not a sufficient supply of suitable timber (e.g., hardwood species) proximate to the right-of-way; therefore, transportation costs to haul it from distant sources (ranging from about 10 to 200 miles) would be high. In contrast, granular fill haul distances would be shorter (about 9 miles). AGDC also cited literature indicating that piles of wood chips could potentially leach into wet areas and adversely affect water quality and aquatic organisms (Taylor and Carmichael, 2009; Rex et al., 2016).

AGDC stated that hardwood timber and (non-timber) composite mats would be cost prohibitive because they are not readily available in Alaska. Both types of mats would need to be shipped in by rail or barge. AGDC stated that mats in relatively flat terrain would require grading or filling to create a stable work surface where terrain is irregular (e.g., from tussocks). AGDC noted that the mats could compress the active layer in permafrost wetlands, potentially causing thermokarst. Additionally, AGDC stated that equipment needed for pipeline construction would exceed the weight load restrictions of composite mats. Multiple layers of composite mats could support the equipment weight and provide a stable work surface, but would increase the quantity of mats required.

AGDC also provided a summary of effects from not using granular fill (Mode 4) and instead relying on conventional grading (Mode 5A). In comparing the advantages and disadvantages of these modes, we conclude that disturbance to the organic layer by both modes (via covering by Mode 4 and grading by Mode 5A) would ultimately lead to thermokarst and potentially a sunken right-of-way within several decades after construction. The primary advantage of importing granular fill is that it provides a predictable material to create a safe working surface.

While we acknowledge that AGDC could need granular fill on sloped wetlands (i.e., greater than 2 percent) for safety reasons, we evaluated AGDC's proposed use of granular fill on flat wetlands (i.e., 0 to 2 percent) to minimize and avoid the loss of wetlands. AGDC stated that switching construction modes for numerous and relatively short flat wetland segments that are within larger wetland crossing areas proposed for Mode 4 would not be feasible or practicable because of increased costs and potential for schedule execution delays. AGDC also stated that grading or fill would be required even if mats are used, but AGDC's use of clearing equipment (e.g., hydro-ax and brush hog) would adequately level irregular surfaces, avoiding the need for granular fill and retaining organic material for restoration. Because granular fill may not be necessary in flat wetlands to create a safe workspace, and given the magnitude of wetland impacts, we have determined that mats should be used in these areas to minimize impacts on wetlands from granular fill. After construction is complete, mats would be removed, allowing wetland restoration, including hydrologic connectivity between remaining granular work pads. Therefore, we recommend that AGDC file revised construction alignment sheets showing the use of timber/composite mats in place of granular fill in wetlands on slopes of 0 to 2 percent in areas where Mode 4 construction would occur (see section 4.2.4).

Although implementation of this recommendation would reduce impacts, the construction impact on PEM, PSS, and PFO wetlands from the Mainline Pipeline (e.g., clearing, trenching, and granular fill placement) would still be significant and permanent. The conversion of about 4,133 acres of wetlands to upland by permanent granular fill and the conversion of about 186 acres of PFO wetlands to PSS and/or PEM wetlands would permanently modify the functions of those wetlands and result in a significant impact given the magnitude of the affected acreage.

In comments on the draft EIS, AGDC stated that the determination that the impact on wetlands would be significant failed to put the wetland impacts into context. AGDC pointed out that the Project would affect only a small percentage of the wetland inventory within each affected watershed. A significance determination must consider both the context and the intensity of the impact. Intensity refers to the severity of the impact, in whatever context it occurs. To determine intensity, we consider the severity of the impact using both the quantity of acres affected and the duration of the impacts. Because the permanent impacts for construction of the Mainline Facilities—many of which would involve the permanent conversion of aquatic habitats to upland—would total about 7,419 acres, we conclude that the impact would be significant.

Ultimately, the placement of granular fill in wetlands would be approved or denied by the COE. If the COE approves the use of granular fill in wetlands, then the impacts described above would occur. If they do not approve it, then we would require AGDC to develop an alternative construction plan. The COE permitting process also identifies unavoidable adverse impacts on wetlands and appropriate and practicable measures to offset the loss of wetlands and wetland functions through compensatory mitigation (see section 4.4.4).

Offshore

Mainline Pipeline offshore construction would result in temporary impacts on intertidal estuarine wetlands. About 1 acre of intertidal estuarine wetlands would be temporarily affected by trenching required to install the pipeline across the shores of Cook Inlet. To reduce these impacts, AGDC would incorporate the use of the DMT continuation methodology for the shoreline crossings, or provide a site-specific justification demonstrating that this methodology is not feasible.[56] See section 4.3.3 for a discussion of impacts on Cook Inlet from Mainline Pipeline construction.

Mainline Aboveground Facilities

Mainline aboveground facilities would permanently affect about 118 acres of wetlands. Granular fill placement for Mainline aboveground facilities, including compressor stations, the heater station, meter stations, launchers/receivers, the cathodic protection system, and MLVs would result in the loss of about 26 acres of PEM wetlands, 79 acres of PSS wetlands, and 8 acres of PFO wetlands. The Mainline MOF would result in the permanent loss of 5 acres of intertidal estuarine wetlands.

AGDC stated that the compressor and heater station locations avoid wetlands to the extent practicable to minimize permanent wetland impacts, but not all wetlands could be avoided due to their prevalence in the Project area. In addition to the permanent loss of wetland functions at aboveground facilities, granular pad and road construction would affect adjacent wetlands. There is also the possibility of the introduction of NNIS, as discussed above in section 4.4.2. Operational impacts from Mainline aboveground facilities include turbidity and sedimentation from surface runoff and fugitive dust. The operational impacts would be similar to the construction impacts discussed in section 4.4.2; the impacts would be minor but occur for the life of the facility. A 130-foot-wide area would be cleared and maintained on three sides of the compressor and heater stations for a fire buffer zone. Vegetation mowing and clearing in wetlands for the fire buffer zone would convert PFO and PSS wetlands to PEM wetlands for the life of the Project, resulting in permanent operational impacts on wetlands that are the same as discussed for the Mainline Pipeline.

[56] A preliminary feasibility assessment of the DMT continuation methodology concluded that the Beluga Landing approach has a 90-percent probability of success, while the Suneva Lake approach has a 75-percent probability of success.

The Mainline MOF within Cook Inlet would temporarily and permanently affect estuarine wetlands. Increased turbidity and sedimentation would temporarily affect water quality and vegetation productivity in adjacent estuarine wetlands during construction when fine particles from the granular fill would be transported by stormwater runoff. The placement of granular fill for the low tide offloading area would result in the permanent loss of about 5 acres of intertidal estuarine wetlands and shoreline stabilization functionality. Effects on marine waters for the Mainline MOF are discussed in section 4.3.3.

Mainline Additional Work Areas

Mainline additional work areas would result in about 398 acres of temporary and 2,982 acres of permanent impacts on wetlands. The construction and temporary use of ice roads and ice pads would result in temporary and minor impacts on wetlands, as discussed in section 4.4.3.1. ATWS in PEM and PSS wetlands that would be cleared but not filled with granular material would be restored (e.g., buried trenchless waterbody crossings). About 342 acres of PEM wetlands and 55 acres of PSS wetlands would be restored. ATWS that would require clearing trees would lead to the permanent conversion of about 9 acres of PFO wetlands. Granular fill left in place for other work areas (i.e., ATWS; access roads; helipads and airstrips; construction camps; contractor, pipe, and double joining yards; and railroad spurs and work pads) would result in the permanent loss of about 392 acres of PEM, 738 acres of PSS, 215 acres of PFO, and less than 1 acre of intertidal estuarine wetlands. One ATWS would also temporarily affect 1 acre of intertidal estuarine wetlands. Disposal sites and material sites would permanently affect about 350 acres of PEM, 974 acres of PSS, and 304 acres of PFO wetlands.

AGDC would implement wetland crossing procedures and mitigation measures that are based on our Procedures, but has requested a modification to allow ATWS within 50 feet of certain wetlands, as listed in appendix I-6. The most prevalent justifications include the need for ATWS for horizontal bends, spoil storage, and road crossings where sufficient space from wetlands is not available. Construction of ATWS within wetlands would temporarily affect water quality and vegetation and result in the permanent loss of wetlands and associated functions, as discussed in section 4.4.2. Implementation of mitigation measures would minimize potential turbidity and sedimentation and vegetative loss. Based on our review of the ATWS, we have determined that the modifications are justified because wetlands are ubiquitous across the Project area and cannot be avoided during construction.

Special Wetland Complexes

The Project would affect two areas of regionally unique or expansive wetland complexes. The Project would cross multiple wetland areas as it crosses in and out of the Minto Flats SGR between MPs 430.9 and 468.6. String bogs would be affected by the Project between MPs 591.0 and 684.9.

In response to scoping comments from the EPA, local governmental agencies, and other stakeholders, wetland areas within Minto Flats SGR were evaluated as a special wetland complex. The Minto Flats is a large wetland complex lying along a northerly loop of the middle Tanana River in the Tanana-Kuskokwim Lowland Subdivision. The wetland complex contains a mosaic of ponds, oxbows, stream channels, and wetlands that provide habitat for waterfowl, wildlife, and fish. The Minto Flats SGR has traditionally been and remains an important area for harvesting fish, wildlife, and other resources for Athabaskans living in Minto and Nenana. Fairbanks area residents also use the area for fish and wildlife harvest (ADF&G, 2018f). Therefore, the Minto Flats SGR provides the important functions of fish and wildlife support, production and export of food and nutrients for terrestrial and aquatic organisms, and recreation. Mainline Facilities, including about 14 miles of the Mainline Pipeline and additional work areas, would affect about 350 acres of wetlands within the Minto Flats SGR. The Mainline Pipeline would be installed using Modes 2, 4, and 5A, resulting in short-term, long-term, and permanent impacts, as discussed above. Mainline additional work areas (e.g., access roads, material sites, an MLV, and a helipad) would remain in place during operation, resulting in permanent impacts.

In section 3.6.3, we considered an alternative that would avoid the Minto Flats SGR (Fairbanks Alternative). While the Fairbanks Alternative would avoid the sensitive Minto Flats SGR, this would be offset by the impacts on land, water, and other resources that would result from the much longer Fairbanks Alternative. For these reasons, we concluded that the Fairbanks Alternative does not provide a significant environmental advantage over the proposed route.

String bogs are unique features where sloped areas and ridges alternate with flat wetland areas containing depressions or open water. The ridges are oriented perpendicular to the direction of drainage creating an atypical hydrogeomorphologic feature. The origin of string bogs with regard to permafrost in Alaska is undetermined (Péwé, 1975). String bogs have the capacity to store precipitation and provide wildlife support, but little scientific research has been conducted on these uncommon features, including their formation and functions. The Mainline Pipeline would cross less than 1 mile of string bogs in 19 separate locations, disturbing less than 3 acres. In these areas, the Mainline Pipeline would be installed using Modes 2, 3, 4, and 5A. Short crossings of saturated and deep string bogs could be treated as wet-ditch open-cut crossings. Given that string bogs form over centuries, restoration would not be feasible. Although the disturbed string bogs affected by Modes 2 and 3 could retain wetland characteristics, the unique hydrogeomorphologic features would be permanently lost, resulting in a permanent alteration. String bogs affected by Modes 4 and 5A would be permanently filled, resulting in a wetland loss, as discussed above.

AGDC stated that the Mainline Facilities have been routed or sited to avoid crossing the Minto Flats and string bogs where possible. Where wetlands and string bogs could not be avoided, construction would occur in the winter where feasible (e.g., Minto Flats SGR and MPs 667.6 to 739.0) using ice bridges for some crossings. Construction in the Minto Flats SGR would result in short-term, long-term, and permanent effects on a diverse mosaic of wetlands that provide fish and wildlife support and recreational opportunities. String bogs are a unique wetland feature, and the loss of these wetlands through construction would permanently affect water storage capacity because they do not have the potential to be restored.

4.4.3.3 Liquefaction Facilities

Liquefaction Facilities construction would permanently and temporarily affect PEM, PSS, and estuarine wetlands. Construction activities for the LNG Plant would permanently affect 6 acres of PEM wetlands, less than 1 acre of PSS wetlands, and 10 acres of intertidal estuarine wetlands. The Marine Terminal would temporarily affect 31 acres of subtidal estuarine wetlands and 32 acres of intertidal estuarine wetlands during construction (MOF with shoreline protection and MOF dredging) and the PLF would permanently affect 18 acres of subtidal estuarine wetlands and 1 acre of intertidal estuarine wetlands.

The LNG Plant would permanently affect PEM, PSS, and estuarine wetlands. Grading and clearing activities for the LNG Plant would strip the wetland vegetation and soils, place fill, and grade the surface, resulting in the loss of the PEM and PSS wetlands that provide wildlife support, sediment and nutrient retention and removal, surface water storage, and groundwater recharge functions. Stormwater runoff could transport fine sediments, causing turbidity and sedimentation in adjacent estuarine wetlands, but the stormwater would be captured in sediment basins and then discharged to Cook Inlet in compliance with APDES permit requirements. Hydrostatic test water and domestic wastewater would also be discharged to one of three on-site ponds and not directly into wetlands. Use of sediment basins and adherence to the Project SWPPP would minimize turbidity and sedimentation from clearing and grading, resulting in temporary and minor impacts on estuarine wetlands. The LNG Plant footprint would result in the loss of estuarine wetlands along the shoreline connecting the LNG Plant to the Marine Terminal.

The Marine Terminal would affect estuarine wetlands through permanent fill for the PLF. Turbidity and sedimentation could be increased in estuarine wetlands from shoreline erosion during ground-disturbing construction activities, installation of structural supports on the seafloor, and dredging at the Marine Terminal MOF. Wetland vegetation productivity and water quality would be degraded, but impacts from turbidity and sedimentation would be short term and localized, as discussed in section 4.3.3. Turbidity and sedimentation would occur during the period of construction and use, but would not result in a significant increase above ambient conditions in Cook Inlet.

4.4.4 Compensatory Mitigation

In accordance with the CWA Section 404(b)(1) Guidelines, 33 CFR 332, and the 1990 Memorandum of Agreement Between the DA and the EPA, compensatory mitigation would be required to replace (offset) the loss of wetland and aquatic resource functions for any unavoidable impacts on wetlands or aquatic resources. Methods of providing compensatory mitigation include restoration, establishment, enhancement, or preservation as authorized through the issuance of DA permits pursuant to CWA Section 404 and/or RHA Section 10. Per NPS requirements, wetland compensatory mitigation for impacts under NPS regulatory authority (e.g., the DNPP) would be consistent with the NPS Director's Order 77-1.[57] AGDC provided a Project Wetland Mitigation Plan to the COE for review. AGDC is consulting with the COE and other resource management agencies to determine the appropriate form of mitigation offsets for unavoidable impacts on waters of the United States, including wetlands (33 CFR 328).

4.4.5 Conclusion

With implementation of the measures discussed above, AGDC's commitments, and our recommendations, wetland impacts would be minimized. We additionally note that AGDC agreed to implement two of our recommendations from section 4.4 of the draft EIS (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

About 8,225 acres of wetlands would be permanently affected by the Project, which includes about 6,220 acres of permanent granular fill and about 195 acres of PFO wetlands converted to PEM and/or PSS wetlands. The remaining 1,809 acres of wetlands would be permanently affected by material sites, disposal sites, a water reservoir, and a stormwater pond. Although AGDC proposes to restore some of the affected wetlands, the length of time for the wetlands to return to pre-construction conditions would range from short term to permanent (i.e., beyond the 30-year life of the Project) depending on the construction mode and growing conditions. The permanent loss and conversion of wetland function and long timeframe for restoration across a large area of wetlands would result in a significant adverse impact. The COE (as explained in sections 1.2.3, 1.2.4, and 1.6.8) must determine whether the proposed wetland impacts can be permitted.

4.5 VEGETATION

The Project crosses plant communities within two climate groups, three ecoregions, and nine subregions, as identified in the section 4.0 introduction and on figure 4-1. Plant communities in the Project area were mapped along a 2,000-foot-wide corridor based on a desktop analysis supplemented by field surveys, as described in section 4.4.1 and the Project's *Vegetation Mapping and Field Study Report*.[58] The desktop assessment involved delineating vegetation classes primarily using aerial imagery and LiDAR

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[57] NPS Director's Order 77-1 establishes the policies, requirements, and standards for implementing EO 11990 "Protection of Wetlands" related to permitting activities under NPS authority.

[58] AGDC's *Vegetation Mapping and Field Study Report* were included as appendices B (Accession No. 20170417-5354) and Q (Accession No. 20170417-5356), respectively, in Resource Report 3, available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5354 or 20170417-5356 in the "Numbers: Accession Number" field.

data, supplemented by other available resources. AGDC conducted field surveys to characterize representative vegetation as well as improve vegetation maps where photo signatures or landscape features were not readily discernible for reliable classification of vegetation. Field targets for upland vegetation were the same as those used for the wetland survey. As stated in section 4.4.1, field survey comprised about 11 percent of the Project area. Vegetation was classified based on the Alaska Vegetation Classification system (Viereck et al., 1992) and the Cowardin (1979) wetland classification system.

This section describes the vegetation, including biological soil crusts (BSC), aquatic vegetation, pollinator habitat, rare plants, and NNIS, that could be affected by the Project. Wetland vegetation, forest products, and subsistence use plants are discussed in sections 4.4, 4.9, and 4.14, respectively.

4.5.1 Existing Vegetation Resources

Plant communities generally transition from herbaceous, to scrub, to forest-dominated plant communities moving south along the Project area from Prudhoe Bay. Along the North Slope, as well as in alpine regions in interior Alaska, scrub and herbaceous plant communities consist of tundra, a plant community absent of trees due to climate conditions (Viereck et al., 1992). Forests can be found from the Brooks Range Subregion and south to Cook Inlet and are the dominant plant communities in this portion of the Project area, with the exception of the following: alpine areas; areas with newly exposed alluvium such as floodplains, streambanks, drainageways, and lake margins; burned or otherwise disturbed areas; and some wetlands and north-facing slopes. In these areas, scrub and herbaceous communities dominate.

Growing conditions can vary dramatically with changes in elevation and latitude, with more extreme conditions in the north and at higher elevations. The climate varies from a polar climate in the northern Arctic Tundra Ecoregion to a temperate continental climate in the more southern Beringia Boreal and Coast Mountains Boreal Ecoregions. The more northern portion of the Project area (the Arctic Tundra Ecoregion) has a growing season of about 56 days (NRCS, 2016), with annual precipitation ranging from 4 to 22 inches, and the average annual temperature ranging from 6 to 20°F (ADF&G, 2015a). The central portion of the Project area has a growing season of about 121 days, with annual precipitation ranging from about 12 to 22 inches, and the average annual temperature ranging from 22 to 29°F. The most southern portion of the Project area has a growing season of about 135 days, with annual precipitation ranging from 12 to 30 inches, and the average annual temperature ranging from 27 to 32°F.

In accordance with the more extreme growing conditions in the north, vegetative cover tends to increase moving from north to south, with naturally occurring mean total live vascular cover (TLVC)[59] estimated at 74 percent in the Arctic Tundra Ecoregion and 111 percent in the Alaska Range Transition and Intermontane Boreal Ecoregions based on AGDC's review of available literature on vegetative cover in Alaska.[60] In addition, the landscape ranges from level terrain in low-elevation floodplains to alpine areas across a number of mountain ranges, including the Brooks Range, the Ray Mountains, and the Alaska Range with elevations as high as 20,000 feet amsl.

Many of the forest, scrub, and herbaceous plant communities described below include wetland communities, which make up a large portion of the Project area. In addition, permafrost plays an important role in the composition of the plant communities, particularly in the more northern portions of the Project area. See sections 4.2 and 4.4 for an analysis of impacts on permafrost and wetland resources, respectively.

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59 Total live vascular cover is the additive percent cover of all plants in a sampling plot, such that overlapping stems and leaves can result in a percent cover greater than 100 percent.

60 AGDC reviewed data from multiple studies for baseline TLVC estimates in the Project area, as presented in the August 15, 2018 response to information request No. 150, dated February 15, 2018 (Accession No. 20180713-5057). The data and sources can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180713-5057 in the "Numbers: Accession Number" field.

4.5.1.1 Herbaceous Plant Communities

Herbaceous plant communities dominate the vegetation in the Gas Treatment Facilities and northern portion of the Mainline Facilities in the Arctic Tundra Ecoregion, particularly the Beaufort Coastal Plain and Brooks Foothills Subregions, where they make up 98 and 51 percent of the vegetation, respectively, primarily as wetlands. Herbaceous communities are less abundant in the more southern ecoregions at no more than 9 percent of the vegetative cover. Overall, they make up just 21 percent of the total vegetative cover in the Project area. The herbaceous community types that occur in the Project area include graminoid herbaceous (dominated by grasses and sedges, such as tussock tundra and sedge meadow), forb herbaceous (dominated by forbs such as fireweed (*Chamerion angustifolium*) and large umbel species), and bryoid herbaceous (dominated by lichens and mosses) (Viereck et al., 1992; Nowacki et al., 2001a). Graminoid herbaceous communities are the dominant herbaceous community throughout the Project area. Examples along the North Slope include wet sedge tundra dominated by water sedge and cottongrass, and *Arctophila* wetlands, which are dominated by pendant grass (Spetzman 1959, Bergman et al. 1977, Derksen et al. 1981).

Moving south into the more forested subregions of the Alaska interior, herbaceous vegetation is found in the forest understory and in alpine tundra. In mixed forest stands on floodplains, horsetails (*Equisetum* spp.) are a major ground cover, with feathermosses and foliose lichens prominent in moist habitats (Nowacki et al., 2001a). Herbaceous alpine tundra is typically found in wetter areas and may include sedges, mosses, and cottongrass. In the Ray Mountains Subregion, summer forest fires occasionally occur and are considered an important part of the ecosystem (Nowacki et al., 2001a). Recently burned areas may be dominated by herbaceous vegetation and include species such as fireweed and bluejoint reedgrass. In the more southern portions of the Project, graminoid species such as alpine holygrass (*Anthoxanthum monicola*), Bigelow's sedge, Canadian single-spike sedge (*Carex scirpoidea*), large flowered wintergreen (*Pyrola grandiflora*), and polar grass (*Arctagrostis latifolia*) may co-dominate with shrubs, and dry fescue communities may occur on glacial outwash.

4.5.1.2 Scrub Plant Communities

Scrub is the second most abundant plant community in the Project area, making up about 31 percent of the total vegetative cover. Scrub communities are found along the PTTL and PBTL and in the footprint of the Mainline and Liquefaction Facilities. They are the dominant plant community at 62 and 91 percent of the vegetation in the Brooks Range and the Kobuk Ridges and Valleys Subregions, respectively. In the Ray Mountains Subregion, the proportion of scrub communities (46 percent) is similar to that of forest communities (49 percent). Scrub communities are grouped by shrub height and include:

- dwarf tree scrub (10 percent or more of cover in trees less than 10 feet high at maturity);
- tall scrub (vegetation 5 feet high or greater with 25-percent cover by tall shrubs);
- low scrub (vegetation 8 inches to 5 feet in height with 25-percent cover by low shrubs); and
- dwarf scrub (vegetation less than 8 inches in height with 25-percent cover by dwarf shrubs).

The northern portions of the Project area cross dwarf and low scrub communities such as dwarf scrub sedge–mountain avens (*Geum peckii*) tundra, *Vaccinium* tundra (e.g., bog blueberry and other shrubs in the heath family), and low willow communities (e.g., diamondleaf willow [*Salix plainfolia*] (Viereck et al., 1992; Nowacki et al., 2001a). Moving south, discontinuous stands of dwarf tree scrub communities dominated by dwarf black spruce and mixed tall scrub communities consisting of species such as willow, dwarf birch, and narrow-leaf Labrador tea (*Ledum decumbens*) become common in subalpine areas. As forests become more dominant farther south, shrubs can be found in the forest understory. Common understory shrubs found in white spruce (*Picea glauca*) forests and black spruce woodlands include green alder (*Alnus crispa*), narrow-leaf Labrador tea, blueberry (*Vaccinium* spp.), and mountain cranberry. Low and tall scrub become the most common scrub communities in the most southern part of the Project area, with relatively small amounts of dwarf tree scrub. Low scrub communities are dominated by birch (*Betula* spp.) and willows. Other shrubs commonly found in these communities include red-fruit bearberry (*Arctostaphylos rubra*), bog blueberry, and mountain avens. Tall scrub communities occur at treeline and along streambanks, drainages, and on floodplains. These communities are dominated by willow, alder, and birch, with understory species such as Beauverd spirea (*Spirea beauverdiana*), narrow-leaf Labrador tea, and bog blueberry. Approaching Cook Inlet, tall scrub communities form thickets on floodplains, along streambanks, and in drainageways. The wettest areas are colonized by tall scrub swamp and low scrub bog (Gallant et al., 1995).

4.5.1.3 Forest Communities

Overall, 48 percent of the vegetation in the Project area is forest. Boreal forests are found in the Mainline and Liquefaction Facilities portions of the Project and are the dominant plant community from the Mainline Facilities in the Ray Mountains Subregion to the Liquefaction Facilities in the Cook Inlet Basin Subregion, comprising between about 49 and 86 percent of the vegetation in each of the subregions crossed. The dominant tree species are fairly consistent across ecoregions, particularly spruce species. At their northern-most limit in the Brooks Range, forest communities include coniferous and mixed forests, such as white spruce and white spruce–alder forests, respectively (Viereck et al., 1992; Nowacki et al., 2001a). Moving south, forests are dominated by black spruce and white spruce, while mixed and deciduous forests occur on well-drained uplands, south-facing slopes, and along rivers, and contain species such as balsam poplar, Alaska paper birch (*Betula neoalaskana*), quaking aspen (*Populus tremuloides*), and resin birch (*Betula glandulosa*). Tall stands of alders and willows occur in active floodplains and river bars, while the Project area in Cook Inlet includes forests with white spruce, black spruce, Sitka spruce (*Picea sitchensis*), quaking aspen, balsam poplar, black cottonwood (*Populus balsamifera trichocarpa*), and Kenai birch (*Betula kenaica*).

4.5.2 General Impacts and Mitigation

Project construction and operation would have temporary to permanent effects on vegetation. Impacts associated with all Project facilities would include the permanent loss of vegetation due to the placement of granular fill, installation of aboveground facilities, excavation for material sites, and construction of disposal sites. Short-term to permanent impacts could also occur due to vegetation disturbance from temporary or intermittent construction and operational activities. Short-term to permanent impacts on vegetation would occur along the Mainline Pipeline right-of-way from clearing, granular fill, and aboveground facilities, which would similarly affect vegetation in the Liquefaction Facilities.

Constructing the Project would affect about 26,054 acres of vegetation, including 12,440 acres of forest, 8,080 acres of scrub, and 5,534 acres of herbaceous vegetation (see table 4.5.2-1). These values encompass the smaller operational area that would affect about 7,596 acres, including 3,282 acres of forest, 2,214 acres of scrub, and 2,101 acres of herbaceous vegetation. For context, the Project would affect less than 1 percent of the estimated 2.1 million acres of forest, 1.7 million acres of scrub, and 0.7 million acres of herbaceous vegetation in the HUC12 watersheds crossed by the Project based on the USGS Gap Analysis Project (GAP)/LANDFIRE National Terrestrial Ecosystems land cover data (2018f).

4.5.2.1 Permanent Loss or Conversion

Constructing and operating the Project would result in the permanent loss or conversion of vegetation at all Project facilities. Specifically, construction activities would involve the placement of granular fill, excavation of material sites, and development of disposal sites that would have lasting impacts on all plant community types. The placement of granular fill would significantly reduce revegetation potential. The rocky substrate would lack sufficient water-holding capacity as well as an organic component that would provide plant nutrients, and would result in the permanent loss of affected vegetation with little to no plant development following construction without significant modification of the substrate. Although AGDC would apply restoration measures to granular fill areas according to the Project Revegetation Plan (appendix B of the Project Restoration Plan) described in section 4.5.2.3, the planned measures are limited and we do not anticipate that they would produce plant communities similar to the pre-construction plant communities during the life of the Project, particularly in forest and tundra communities.

Where soils are scoured to bare rock, gravel, silt, or sand, boreal forests would not be expected to reestablish for 30 to 100 years (ADF&G, 2001b). Pioneer herbaceous plants could establish within 10 years, and shrubs within 10 to 30 years. In tundra communities on the North Slope, research has indicated that natural revegetation on thick granular fill would only be able to reach up to about 10-percent plant cover after 50 years (Bishop and Max, 2002). Revegetation on gravel and rocky soil could be enhanced with a higher proportion of fines or small particles in the granular fill (Bishop and Max, 2002; Czapla and Wright, 2012), which correlates with increased water-holding capacity (Bishop and Max, 2002) (see additional discussion in section 4.2.4). Therefore, we have included a recommendation that AGDC use granular fill with at least 20-percent fines for the surface course used on construction workspace and temporary access roads (see section 4.2.4).

Operational impacts would result in the permanent replacement of pre-construction plant communities by non-vegetated surfaces or a different type of plant community. Aboveground facilities (including fire buffers) and additional work areas would permanently remove forest, scrub, and herbaceous vegetation. Forest in the permanent right-of-way would be converted to scrub or herbaceous vegetation (operational maintenance in the permanent right-of-way would allow herbaceous and scrub communities to persist and is not counted as a permanent loss or conversion). Combined, construction and operational impacts would result in the permanent loss or conversion of 8,512, 4,293, and 2,199 acres of forest, scrub, and herbaceous communities, respectively (see table 4.5.2-1).

To reduce the permanent loss of vegetation at material sites, AGDC would segregate and replace the organic layer. This measure would improve revegetation at material sites, although the excavated area would not likely be fully covered by the topsoil since excavation would increase the surface area at the site. In addition, material sites could fill with water and prevent plant establishment. At material sites hydrologically connected to sensitive fish habitat, AGDC would develop measures in consultation with the USFWS and ADF&G, which could include the establishment of aquatic and riparian revegetation, to minimize long-term impacts (see section 4.7.1).

The effect of the proportionally small losses of vegetation compared to the overall vegetation in the HUC12 watersheds crossed by the Project (see above) would be further minimized because the majority of impacts would be spread out along the Mainline Pipeline. Given the relatively small amount and linear distribution of impacts, along with the implementation of the Project Revegetation Plan (see section 4.5.2.3) and our recommendation regarding the proportion of fines in granular fill, we find that the permanent losses of native scrub and herbaceous plant communities in the Project area would not be significant. Impacts on forest communities would be significant given the quantity of additional forest vegetation that would be removed through construction clearing for the Mainline Facilities (see section 4.5.3.2 for forest acreages affected by construction clearing).

TABLE 4.5.2-1

Vegetation Affected by Project Construction and Operation (acres) [a]

	Forest			Scrub			Herbaceous			Total		
Facilities	Construction	Operation	Permanent Loss/ Conv [b]	Construction	Operation	Permanent Loss/ Conv	Construction	Operation	Permanent Loss/ Conv	Construction	Operation	Permanent Loss/ Conv [b]
Gas Treatment Facilities												
GTP	0	0	0	0	0	0	268	268	268	268	268	268
Infrastructure [c]	0	0	0	0	0	0	357	294	357	357	294	357
GTP Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**625**	**562**	**625**	**625**	**562**	**625**
PBTL Pipeline	0	0	0	0	0	0	6	6	0	6	6	0
PTTL Pipeline	0	0	0	22	7	0	1,465	539	0	1,487	546	0
Aboveground facilities [d]	0	0	0	<1	<1	<1	<1	<1	<1	<1	<1	<1
Additional work areas [e, f]	0	0	0	11	0	11	109	0	109	120	0	120
PBTL and PTTL Subtotal	**0**	**0**	**0**	**33**	**7**	**11**	**1,580**	**545**	**109**	**1,613**	**552**	**120**
Gas Treatment Facilities Subtotal	**0**	**0**	**0**	**33**	**7**	**11**	**2,205**	**1,107**	**734**	**2,238**	**1,114**	**745**
Mainline Facilities												
Pipeline right-of-way [g]	5,526	2,217	2,796	4,552	1,860	1,417	2,378	931	630	12,456	5,008	4,843
Aboveground facilities [h]	111	111	111	132	132	132	22	22	22	265	265	265
Additional work areas [I, j]	6,168	382	4,970	3,274	139	2,646	913	25	797	10,355	546	8,413
Mainline Facilities Subtotal	**11,805**	**2,710**	**7,877**	**7,958**	**2,131**	**4,195**	**3,313**	**978**	**1,449**	**23,076**	**5,818**	**13,521**
Liquefaction Facilities												
LNG Plant	572	572	572	76	76	76	16	16	16	664	664	664
Marine Terminal [k]	0	0	0	2	0	<1	0	0	0	2	0	<1
Construction camp	63	0	63	11	0	11	0	0	0	74	0	74
Liquefaction Facility Subtotal	**635**	**572**	**635**	**89**	**76**	**87**	**16**	**16**	**16**	**740**	**664**	**738**
Total	**12,440**	**3,282**	**8,512**	**8,080**	**2,214**	**4,293**	**5,534**	**2,101**	**2,199**	**26,054**	**7,596**	**15,004**

TABLE 4.5.2-1 (cont'd)												
Vegetation Affected by Project Construction and Operation (acres) [a]												
	Forest			Scrub			Herbaceous			Total		
Facilities	Construction	Operation	Permanent Loss/ Conv [b]	Construction	Operation	Permanent Loss/ Conv	Construction	Operation	Permanent Loss/ Conv	Construction	Operation	Permanent Loss/ Conv [b]

Source: Affected acreages are based on Project vegetation mapping, supplemented by the Vegetation Map for Northern, Western, and Interior Alaska (Alaska Center for Conservation Science [ACCS], 2017c).

Conv = Conversion

Note: Totals may not equal the sum of all addends due to rounding.

[a] Construction acreage includes operational areas.

[b] Permanent impacts include permanent vegetation conversion or loss both in and outside the operational footprint due to right-of-way maintenance, permanent infrastructure, permanent granular fill, and material and disposal sites. See section 2.0 for descriptions of construction and operational areas. Permanent loss/conversion acreages do not include the acreage of forest communities that could be permanently affected by construction clearing in temporary non-granular fill workspace outside the permanent operational footprint based on recovery times; see section 4.5.3.2 for further discussion.

[c] GTP infrastructure includes a GTP module staging area; West Dock Causeway modifications; access roads; mine site; water reservoir and pump facilities; and GTP associated transfer pipelines.

[d] PTTL aboveground facilities include three MLVs.

[e] PTTL additional work areas include a granular fill construction camp, helipad, and pipe storage yard; the remaining associated infrastructure would be constructed from ice and is not included in this table.

[f] Permanent impacts from the PTTL additional work areas are due to granular fill outside the operational footprint (see section 4.5.2.1).

[g] The Mainline Pipeline construction right-of-way width would be between 65 and 185 feet, and the permanent maintained right-of-way width would be between 10 feet (certain wetland areas) and 30 feet (all other areas).

[h] Mainline aboveground facilities include compressor stations, meter stations, MLVs, and a heater station.

[i] Additional work areas include ATWS, construction camps, pipe storage yards, disposal sites, double joining yards, material sites, railroad spurs, railroad work pads, helipads, and selected access roads that would be retained during operation. Acreages exclude ice roads and ice pads.

[j] Permanent impacts from Mainline additional work areas include granular fill and material and disposal sites outside the operational footprint (see section 4.5.2.1).

[k] The Marine Terminal includes the area needed for the Marine Terminal MOF dock and shoreline protection.

4.5.2.2 Disturbance

Vegetation damage could occur both in and adjacent to construction areas where vegetation would not be permanently lost or converted (see section 4.5.2.1) or cleared (see section 4.5.3.2), but would be affected by other types of disturbance during construction and operation. Examples include stormwater runoff from exposed soil, road dust, salt from tidewaters, temporary placement of cleared snow and trench spoils, temporary ice roads and ice pads, timber mats, and right-of-way and facility maintenance of scrub and herbaceous vegetation. Impacts would affect vegetation both in and adjacent to the Project area.

Sedimentation and erosion caused by stormwater runoff from exposed soils could smother or wash away soils and vegetation, although erosion and sediment controls established in the Project Plan, Procedures, and SWPPP would avoid or minimize these impacts. Access roads could also affect adjacent plant communities by creating roadside impoundments that could result in changes to snowdrift patterns and thermokarst (see section 4.2). These changes could result in long-term or permanent subsidence and ponding and consequently drown out adjacent vegetation.

Salt and road dust could be deposited on adjacent vegetation and adversely affect plant growth. A traditional knowledge workshop participant noted that plants appeared to be dead from salt on an ice road near the coast as a result of water run-up during high tides (Braund, 2016). Impacts from salt on vegetation would be minor because the potential movement of tidewaters up ice roads would be temporary, and potential effects on vegetation would be limited to roadsides.

Dust from access roads in the Prudhoe Bay area has been found to eliminate vegetation within about 16 feet of heavily traveled roads (National Research Council, 2003). AGDC would implement measures in the Project Fugitive Dust Control Plan to reduce fugitive dust associated with construction areas and access roads, such as reduced road speeds (see section 4.15). Along with fugitive dust, chemical air pollution from the GTP and LNG Plant could have a detrimental effect on vegetation. A participant in a traditional knowledge workshop from the North Slope observed that smog affects grass, noting that grass does not seem as green and dies from the smog; conclusive evidence for this effect on vascular plants was not found. A study that measured nitrogen oxides (NO_x) and sulfur dioxide (SO_2) in the North Slope from 1989 to 1994 did not detect any effects on vascular plants attributable to these pollutants (Kohut et al., 1994). A discussion of the potential effects of air pollution on BSCs is provided in section 4.5.4.

The use of temporary ice roads and ice pads, frost packed snow, and wetland mats for constructing the Gas Treatment and Mainline Facilities (Modes 1, 2, and 3, respectively) could damage underlying vegetation and delay plant development during the next one or two growing seasons, resulting in reduced vascular plant cover (e.g., see Noel and Pollard, 1996), although construction on frozen ground would minimize any damage to dormant plant root mats. Temporary damage to tussocks and shrubs from scraping and compression would likely occur, but the organic layer would remain intact. The North Slope Borough (2014) noted that ice roads can damage tussock tundra vegetation when the roads are constructed in low snow areas on dry upland sites. A participant of the North Slope traditional knowledge workshop noted that ice roads damage plants, with the vegetation previously covered by the ice road staying brown, possibly due to the ice road persisting longer into the spring season and suppressing plant growth; participants did not note how long this effect lasts (Braund, 2016).

Where ice road damage does occur, tussock tundra plant communities in the Beaufort Coastal Plain Subregion are noted to recover naturally without rehabilitation within 10 years (North Slope Borough, 2014), although the USFWS noted during scoping that recovery could take longer depending on the methods used for ice road and ice pad construction. As discussed in section 4.4.3, ice roads would be constructed in accordance with ADNR-DMLW permitting requirements to minimize impacts on tundra vegetation. Because the organic layer, along with scrub and herbaceous vegetation, would remain largely intact, and any vegetation damaged by ice roads would be expected to fully recover within about 10 years following construction, impacts would be temporary to long term and minor.

Potential snow accumulation against the VSMs of the PTTL and PBTL and along new access roads could alter the underlying plant community. Increased snowpack would delay snowmelt in spring, which could shorten the growing season and delay plant development, thereby reducing plant growth for certain species (Semenchuk, 2013). Conversely, other plant species could benefit from snowpack melt increasing soil moisture, which would also increase nutrient availability.

Inadvertent spills of oil, lubricants, and other hazardous materials during Project construction and operation could damage, kill, and suppress vegetation, either temporarily or for the long term, depending on the contaminant, its volume, and site conditions (National Research Council, 2003). Similarly, inappropriate handling of waste produced during Project construction and operation, including various chemicals, wastewater, and sewage, could contaminate plant communities (see sections 4.9.6 and 4.11.6). A template for the Project SPCC Plan describing general practices and procedures to protect resources from a potential release of fuel or hazardous materials through avoidance, minimization, and mitigation was included in AGDC's application. AGDC would develop facility/work site-specific SPCC plans prior to construction, as discussed in section 4.2.6. AGDC would also implement its Project Waste Management Plan to safely manage and dispose of wastes generated by Project activities to prevent or minimize the release of contaminants to the environment.

Plant pests such as insects, fungi, and pathogens could be introduced as a result of the Project, which could have a detrimental effect on the adjacent plant community. In riparian areas, plant pests could be spread through the importation or movement of infected live plant materials for revegetation, which is the primary pathway for the introduction of plant pathogens (Liebhold et al., 2012; Graham and Heutte, 2014; and Klapwijk et al., 2016). Reduced health and productivity due to physical damage, altered hydrology, and road dust could make plants more susceptible to infestation or infection. In particular, vegetation clearing and construction activities could exacerbate forest pests (Costello et al., 1995; Ferrell, 1996; Gast et al., 1991). In Alaska, spruce beetles (*Dendroctonus rufipennis*) have been a major concern for forest health (Moan, 2017). Forest vegetation could become more susceptible to pests due to damage and increased stress on trees through limbing, surface wounds, root damage from vehicles, and changes in microclimate adjacent to the cleared pipeline right-of-way (Costello et al., 1995; Ferrell, 1996; Gast et al., 1991). Pests could infest brush piles from vegetation clearing and spread from the harvest area with the transport of logs and on equipment.

Participants in the traditional knowledge workshops in the Kenai Peninsula, Tanana River, and Yukon River regions mentioned spruce beetles as having affected trees in the area, although they were not described as currently presenting large problems (Braund, 2016). Because construction would be temporary and right-of-way maintenance would occur infrequently (about every 3 years), tree stress and other vectors for pests and pathogens would be minimal. In addition, the Project Invasives Plan and ISPMP contain measures to address pests and pathogens, including a USFWS Hazard Analysis and Critical Control Point planning process that helps preemptively identify risks from non-native, invasive pests and pathogens and includes methods for control (USFWS, 2011b). Furthermore, to address the potential for spreading spruce beetles in forested areas, AGDC would comply with the Alaska Forest Resources and Practices Act, which requires mitigation when clearing spruce trees (AS 41.17.082; 11 AAC 95.195). AGDC would follow requirements for tree removal during construction, which includes using methods for processing spruce trees and limbs that minimize the risk of spruce beetle infestation.

During operation, the permanent Mainline Pipeline right-of-way and fire buffers around aboveground facilities would be mowed and cleared periodically to maintain herbaceous and low scrub plant communities. Vegetation would be maintained free of trees within a 30-foot-wide corridor centered on the pipeline in the permanent Mainline Pipeline right-of-way in upland areas, and a 10- to 30-foot-wide corridor in wetlands (a 10-foot-wide corridor would be maintained in an herbaceous state in wetlands, where only trees growing within 15 feet of the centerline that threaten pipeline integrity would be removed). This maintenance could favor herbaceous and low shrub species more tolerant of disturbance, although it would not occur more frequently than every 3 years.

Damage to vegetation from disturbances that do not involve permanent loss or conversion or vegetation removal would generally be short term and/or reduced to less than significant levels with the implementation of the mitigation measures described above. Vegetation maintenance during operation would have minor permanent impacts on scrub and herbaceous vegetation (see section 4.5.3.2 for a discussion of impacts from right-of-way maintenance on forest communities). Potential disturbance from operation (e.g., dust and air pollutants) would be permanent, although impacts would be localized and adequately reduced through the implementation of mitigation measures (also see section 4.5.3 for further assessment of impacts by facility).

4.5.2.3 Restoration

AGDC would facilitate the restoration of native plant communities in temporary construction areas and in the permanent pipeline right-of-way. As described in the Project Revegetation Plan, revegetation of areas affected by granular fill placement, material site excavation, disposal sites, and clearing of the Mainline Pipeline right-of-way would initially rely on natural plant recruitment from adjacent areas, with the exception of the Mainline Pipeline trenchline for Modes 1 and 5B (steep slopes) and sensitive areas including streambanks and areas with NNIS infestations (see section 4.5.8). For these areas, AGDC would seed and fertilize exposed ground within the first growing season following construction or via dormant seeding by the subsequent fall. According to the Revegetation Plan, AGDC would incorporate a variety of revegetation methods for streambank restoration, including salvaging and transplanting native plants at or near the site before construction. In addition, revegetation in the DNPP would be done in consultation with the NPS, following NPS guidelines and specifications detailed in the NPS's *Management Policies* (2006c) and *Native Plant Revegetation Manual for Denali National Park and Preserve* (Densmore et al., 2000).

AGDC would monitor revegetation success for the first 3 years following construction. The Mainline Pipeline trench and associated right-of-way would be monitored at Representative Monitoring Evaluation Sites (RMES) every 10 to 20 miles and at sensitive river crossings and steep slopes. AGDC would also monitor other sites used for temporary construction support purposes for the PTTL, PBTL, and Mainline and Liquefaction Facilities, including construction camps, access roads, pipe storage yards, double joining yards, material sites, waste disposal areas, and any other temporary construction areas that would experience vegetation loss. With the exception of sites used for temporary construction support, AGDC does not plan to monitor the PTTL and PBTL rights-of-way because these pipelines would be installed aboveground from ice roads and ice pads, which would minimize impacts on vegetation.

Based on revegetation achieved for similar projects in Alaska (Project Restoration Plan; AGDC's 2017 *Comparative Belowground Designs and Revegetation Efforts in Northern and Interior Alaska* [AGDC's Revegetation White Paper];[61] Czapla and Wright, 2012), AGDC would consider revegetation successful when at least 70 percent of the pre-disturbance vascular canopy cover (i.e., the percentage of ground obscured by vegetation) is restored based on the canopy cover in undisturbed reference sites adjacent to the Project area. Where the Project would cross BLM property, successful revegetation along streambanks would need to achieve 70-percent cover with native plants. As described previously,

[61] AGDC's 2017 *Comparative Belowground Designs and Revegetation Efforts in Northern and Interior Alaska* was filed with the December 29, 2017 response to granular fill FERC information request No. 5 (Accession No. 20180102-5212). The document can be viewed on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20180102-5212 in the "Numbers: Accession Number" field.

successful revegetation could require a substantial amount of time. AGDC estimates that the final restoration standard (i.e., 70 percent of pre-disturbance canopy cover) would occur within 10 years north of the Brooks Range and 5 years south of the Brooks Range, although evidence from restoration of similar projects in these areas indicates longer timeframes (e.g., about 30- and 70-percent cover within 10 years north and south of the Brooks Range, respectively) (Project Restoration Plan; AGDC's Revegetation White Paper; Czapla and Wright, 2012). AGDC has developed interim performance standards to use as indicators that the final restoration standard would eventually be met. These interim standards are based on revegetation rates for performance standards found on other Alaska projects and include:

- 40 percent of pre-disturbance canopy cover within 3 years for steep slopes (Mode 5B); and
- 30 percent of pre-disturbance canopy cover within 3 years for all other areas.

Interim performance standards could be reduced at specific locations where reference site canopy cover percentages, indicating natural conditions, are less than the standard. Steep slopes would have a higher percentage canopy cover than other areas due to the need to stabilize the sites more quickly. As described in the Project Revegetation Plan, AGDC would visit monitoring sites annually starting the second year following construction until the end of the interim performance period or once the interim performance standards have been met, at which point AGDC plans to request closure of the RMES. If interim performance standards have not been met at the end of the performance period, AGDC would assess site performance and determine where additional monitoring or revegetation efforts would be required. Once the interim performance standards are met, AGDC would conduct canopy cover surveys at RMES in all construction workspaces every 3 years until the final performance standards are met. Following each monitoring season, AGDC would file the corresponding survey reports with the Secretary.

Along with the canopy cover standard, AGDC recommended that restored plant communities in the three northernmost subregions should contain at least five native or seeded species that contribute greater than 0.2 percent to the TLVC at the interim performance period, or greater than a total of 1 percent of the TLVC, as an indication of the potential for successful establishment over the long term. Other guidance for plant establishment in Alaska recommends higher cover targets for native plants, ranging from live vascular cover of 5 to 10 percent depending on seed mix composition (BP Exploration [Alaska], Inc. et al., 2014).

In seeded areas, achieving the short-term native species diversity described above would be facilitated by the Project seed mixes, which consist of seven native grass cultivars. AGDC would apply these seed mixes to about 9 percent of the Mainline Pipeline construction right-of-way based on immediate reseeding of the trenchline for streambanks and Modes 1 and 5B, along with additional areas that should fail to meet the interim performance standards within 3 years of construction. While seeding could help reestablish plant communities by stabilizing soils, improving soil moisture, and contributing to soil development (Jorgenson and Joyce, 1994), a grass seed mix could permanently reduce both species and functional group diversity (e.g., forb and shrub diversity) by suppressing the natural recruitment of other species and functional groups, and/or by a single grass cultivar out-competing the other species (McKendrick, 2002; Jorgenson and Joyce, 1994).

AGDC would use grass seed because they assert it would be the only commercially available native seed abundant enough for use on the Project. Four of the species in the Project seed mixes are bunchgrasses, which can be more conducive to natural recruitment than sod-forming grasses (Czapla and Wright, 2012). Three of the species are sod-forming grasses, including red fescue (*Festuca rubra*). Red fescue in particular has been known to form homogenous stands in restored areas in Alaska and is noted for being an aggressive plant that can prevent alder and willow establishment (McKendrick, 2002; Czapla and Wright, 2012). McKendrick (2002) advises against the use of red fescue in restoration seed mixes in Alaska, and the North Slope Plant Establishment Guidelines (BP Exploration [Alaska], Inc., et al., 2014) do not include the species in its recommended seed mixes. To minimize the creation of homogenous grass stands in the restored Project area and better ensure that post-construction plant communities reflect the pre-construction plant communities as closely as possible, prior to construction, AGDC would file an updated Revegetation Plan with the Secretary, for the review and written approval of the Director of the OEP, that includes:

- an updated interim performance standard that includes at least 5-percent live-canopy cover of native non-seeded plant species in all subregions of the Project; and
- updated seed mixes that exclude red fescue except for reseeding steep slopes or other areas with a high erosion risk when no other effective species are available to help stabilize soils.

In comments on the draft EIS, the NPS said that commercially available red fescue seed should not be used in the DNPP, that revegetation in the DNPP should follow the guidelines of Densmore et al. (2000), and that AGDC should use locally collected native seeds with some use of sterile annual rye (*Lolium multiflorum*) to quickly establish cover in steep sites where needed. The native seed used in the DNPP would need to be collected within a 3.7-mile (6 km) radius of the restoration area for conservation of the local gene pools.

4.5.3 Facility-Specific Impacts and Mitigation

4.5.3.1 Gas Treatment Facilities

GTP construction, the West Dock Causeway expansion, and GTP-associated infrastructure construction, including five new permanent gravel access roads, a gravel mine, and a water reservoir, would result in the loss of about 625 acres of herbaceous communities in the Beaufort Coastal Plain Subregion (see table 4.5.2-1), including graminoid herbaceous communities and a small amount of freshwater aquatic (non-emergent) herbaceous communities (also see section 4.5.5). These impacts would involve permanent vegetation loss because any or most temporary construction workspace would involve the placement of permanent granular fill (e.g., facility pads and the West Dock Causeway) or permanent excavation (e.g., gravel mine and water reservoir). Aboveground transfer pipelines would result in less than 0.1 acre of vegetation lost due to a small footprint at the base of about 348 VSMs (up to about 13 square feet per VSM), along with reduced productivity on surrounding vegetation from limited shading by the pipeline. About 110 acres of vegetation would experience temporary to long-term damage from temporary ice roads during construction (see table 2.1.3-2). Temporary to permanent disturbance of adjacent plant communities, including damage to vegetation from stormwater runoff, roadside impoundments, saltwater intrusion along Project roads, fugitive dust, chemical air pollution, and hazardous waste spills, could also occur but would be localized in extent and minimized with the mitigation measures discussed in section 4.5.2.2.

Construction of the PTTL and PBTL would affect about 33 acres of scrub communities and 1,580 acres of herbaceous communities in the Beaufort Coastal Plain Subregion (see table 4.5.2-1). In addition, ice pads and ice roads would have temporary to long-term impacts on about 216 acres of herbaceous and scrub vegetation for pipeline construction (see tables 2.1.2-1 and 2.1.3-2). The affected scrub communities would include low and dwarf scrub, while the affected herbaceous communities would include graminoid herbaceous and freshwater aquatic (non-emergent) herbaceous communities (also see section 4.5.5). Impacts would primarily be from minor vegetation clearing and disturbance because the PTTL and PBTL would be placed aboveground on VSMs, construction and maintenance would primarily occur in winter on ice pads and ice roads, and operation would not require vegetation maintenance in the permanent rights-of-way. The use of an aboveground pipeline would minimize permanent vegetation loss of less than 1 acre, and cause reduced productivity on surrounding vegetation from limited shading by the pipeline. Most permanent losses of vegetation would occur as a result of granular fill needed for three MLVs and PTTL construction (additional work areas), which would affect about 11 acres of scrub communities and 109 acres of herbaceous communities (see table 4.5.2-1). The additional work areas would include a construction camp, helipad, and pipe storage yard, as well as the potential addition of granular fill to amend year-round roads and roads to MLVs or hydrostatic testing locations. While these temporary construction areas would be restored following construction, the original plant communities would not be expected to reestablish due to the permanently altered substrate (see section 4.5.2.1).

For context, Gas Treatment Facilities construction and operation would affect less than 1 percent each of the scrub and herbaceous native vegetation in the affected HUC12 watersheds, which includes about 63,899 acres of scrub and 695,268 acres of herbaceous communities based on USGS land cover data (2018f). With the installation of aboveground pipelines, the use of ice roads and ice pads for both construction and maintenance, adherence to the mitigation measures described for disturbed areas in section 4.5.2.2, and implementation of the Project Revegetation Plan for restoration of temporary work areas (see section 4.5.2.3), construction and operation of the Gas Treatment Facilities would not significantly affect vegetation.

4.5.3.2 Mainline Facilities

Construction of the Mainline Pipeline and aboveground facilities would result in the most impacts on vegetation. Impacts would include construction clearing, permanent loss or conversion (see section 4.5.2.1), forest fragmentation and edge effects, and other types of disturbance described in section 4.5.2.2). All plant community types discussed in section 4.5.1 would be affected across the nine subregions crossed by the Mainline Facilities, with the majority of impacts on evergreen and mixed forest, followed by low scrub communities and graminoid herbaceous communities (see section 4.5.5 for a discussion of aquatic vegetation impacts).

Construction Clearing

Construction clearing would involve vegetation removal and grading for the Mainline Pipeline construction right-of-way and additional work areas, along with trenching for the Mainline Pipeline right-of-way, which would affect about 11,805 acres of forest communities, 7,958 acres of scrub communities, and 3,313 acres of herbaceous communities (see table 4.5.2-1). Much of this activity would occur in temporary workspaces outside the permanent operational footprint and granular fill areas, including about 6,522 acres of vegetation consisting of 3,891 acres of forest, 1,723 acres of scrub, and 908 acres of herbaceous plant communities (see table 4.5.3-1). After construction, vegetation in these areas would be allowed to reestablish and would not be affected by Project operation. The remaining acreage would be affected by maintenance of the permanent right-of-way and facility fire buffers, permanent granular fill, or aboveground facilities.

The effects of clearing on vegetation would vary depending on the ability of plant communities to reestablish and the length of time needed for recovery. These factors would in turn depend on the type of plant community affected, the subregion in which impacts would occur, soil quality, the effects on the substrate, and restoration methods.

TABLE 4.5.3-1

Vegetation Affected by Construction Clearing in Temporary Workspaces for the Mainline Facilities (acres) [a]

Facilities	Forest	Scrub	Herbaceous	Total
Pipeline construction right-of-way	2,718	1,252	817	4,787
Additional work areas [b]	1,173	471	91	1,735
Total	**3,891**	**1,723**	**908**	**6,522**

Source: Affected acreages are based on Project vegetation mapping, supplemented by the Vegetation Map for Northern, Western, and Interior Alaska (ACCS, 2017c).

[a] Acreages are estimated for temporary workspaces outside the operational footprint and granular fill areas based on values provided in table 4.5.2-1.

[b] See table 4.5.2-1 for a listing of all components included in additional work areas.

The type of plant community affected and the subregion would influence vegetation recovery time. Reestablishment could take longer due to the mixing of subsoils and other soil impacts during trenching that affect plant productivity and establishment (see below). Through natural recruitment, boreal forests take 25 to 45 years to reestablish on intact soils in non-permafrost areas and 30 to 55 years on intact soils in permafrost areas (ADF&G, 2001b). Furthermore, it should be noted that forest recovery includes both the overstory trees and the understory shrub and herbaceous plant communities, which include shade-tolerant plant species such as devilsclub that are important for wildlife forage and subsistence use (Healy, 2002; Burton and Burton, 2012). While some understory plants like devilsclub could persist or regrow following disturbance, population density and individual plant vigor would be reduced until the overstory recovers and recreates the necessary microclimate for the understory plant community to thrive (Healy, 2002; Burton and Burton, 2012).

Construction clearing would have relatively shorter-term impacts on scrub and herbaceous plant communities in both temporary workspaces and the permanent right-of-way based on general timeframes for forest succession in Alaska, although impacts could still be permanent for scrub communities. Where topsoil can be retained in non-tundra areas, reestablishment of scrub communities could occur within 3 to 25 years in non-permafrost areas and 5 to 30 years in permafrost areas, while herbaceous communities could reestablish within 1 to 3 years in non-permafrost areas and 5 years in permafrost areas (ADF&G, 2001b). Since topsoil or the organic layer would not be salvaged along the majority of the Project area (see section 4.2.5.2), recovery for both herbaceous and scrub communities in these areas would generally take longer than these standard projections.

Recovery in tundra communities would also take more time. Based on studies of oil and gas and mineral exploration trails in the North Slope, damage to herbaceous and scrub tundra involving varying degrees of disturbance, including the destruction of the vegetative mat and exposure of the underlying soil, resulted in visible changes in vegetation for at least 14 years (National Research Council, 2003). Monitoring of similar projects along the North Slope have reported the reestablishment of only about 30-percent vegetative cover in 10 years on restored sites with topsoil or overburden applications (see Project Restoration Plan and AGDC's Revegetation White Paper), while Bishop and Max (2002) predicted that about 22-percent cover could be achieved in 10 years in disturbed land in the Kuparuk Oil Field on the North Slope.

A majority of soils in the Project area are considered to have revegetation concerns due to high rock content or other variables, making revegetation challenging (see section 4.2). Adding to the poor soil quality, Project effects on the substrate would further restrict or slow plant establishment and growth and could alter species composition. Trenching, grading, and vehicle compaction in the pipeline rights-of-way would damage soil structure and mix less fertile subsoil and subsoil rocks with surface soils (see section 4.2), reducing plant health and productivity. AGDC does not plan to segregate the organic layer along most of the pipeline right-of-way; therefore, soil fertility, the native seed bank, and BSCs (see section 4.5.4) associated with the organic layer would be lost or diminished. Erosion of exposed soils could cause soil instability (gullying) and further loss of topsoil. Subsidence from subsurface flow along the underground pipe could alter soil hydrology and cause ponding, which could alter the post-construction plant community to favor plants more tolerant of hydric conditions. Any of these factors would adversely affect vegetation establishment following construction, and an altered substrate could change the mix of species that make up the post-construction plant community. Images of buried sections of TAPS in AGDC's Revegetation White Paper appear to show altered vegetation in the TAPS right-of-way compared to adjacent plant communities several decades after the pipeline was installed.

Temporary placement of trench spoils, fill using native soil (e.g., cut and fill on side slopes), and waste disposal areas (for excess trench spoil) would directly affect vegetation by smothering plants, but trench spoil would be removed following construction and vegetation could reestablish on native fill and excess trench spoil. Other impacts from pipeline installation could include subsidence from subsurface flow along the underground pipe, which could alter soil hydrology and cause ponding, subsequently altering the post-construction plant community to favor plants more tolerant of hydric conditions.

The use of Modes 1 through 3, where ground disturbance would primarily occur in the trenched area, would reduce impacts on vegetation. For all construction modes, AGDC would install trench breakers or ditch plugs in the pipeline trench to prevent subsurface water flow and apply crowning over the trenched area. Crowning would be used to make up for soil subsidence in order to achieve a stable surface that would return the site to pre-construction condition and avoid both ponding and disruption of sheet flow. As summarized in AGDC's Revegetation White Paper, these measures were found to be important for successful plant community establishment in previous studies in Alaska. AGDC would also segregate and redistribute the organic layer across portions of the construction right-of-way for Mode 5A summer construction (see section 4.2.5). Organic layer segregation would help preserve the native seed bank and soil nutrients available to help reestablish the plant community in these areas. Restoration of the Mainline Pipeline right-of-way plant communities affected by construction clearing would follow the Project Revegetation Plan, as summarized in section 4.5.2.3.

Although thousands of acres of native plant communities would be temporarily cleared for construction of the Mainline Facilities, only a small proportion of these communities in each Project HUC12 watershed would be affected (see section 4.5.2). The linear distribution of the Mainline Pipeline would result in minimal impacts on any single plant community or sub-watershed. AGDC's commitments to monitoring, applying native seed mixes and other amendments (where needed and according to specific performance standards), and implementing measures to control erosion and subsidence, along with our recommendations, would reduce the potential for revegetation failure and the degree to which native plant communities would be altered. With the proposed mitigation and the expected reestablishment of scrub and herbaceous plant communities within about 1 to 30 years, the loss and alteration of native scrub and herbaceous plant communities from vegetation clearing for Project construction would be reduced to less than significant levels. Impacts on forest communities would be significant, however, given that forests can take up to 100 years to reestablish following removal, along with the quantity of forest communities affected (11,805 acres; see table 4.5.2-1) through both construction clearing in temporary workspaces and permanent loss and conversion (see below).

Permanent Loss or Conversion

Operational vegetative maintenance of the permanent 10- to 30-foot-wide right-of-way, aboveground facilities, and additional work areas would permanently remove forest vegetation, while aboveground facilities and additional operational work areas would permanently remove scrub and herbaceous communities (see section 4.5.2.1). In addition, all plant community types would experience permanent loss due to granular fill placement, material site excavation, and disposal site development outside the operational footprint. Impacts from Mainline Facilities construction would involve the placement of permanent granular fill along about 37 percent of the Mainline Pipeline right-of-way for Mode 4; the placement of granular fill for access roads, ATWS, construction camps, double joining yards, pipe storage yards, railroad spurs, work pads, and the Mainline MOF; and the development of new material and disposal sites. Outside these areas, the remaining vegetation in temporary workspaces would reestablish over time (see construction clearing discussion below). Combined, impacts from operation, granular fill, and material and disposal sites would permanently remove about 7,877 acres of forest; 4,195 acres of scrub; and 1,449 acres of herbaceous communities (see table 4.5.2-1).

AGDC's rationale for using granular fill along the Mainline Pipeline right-of-way is to protect permafrost and provide a stable and safe construction work surface (see section 4.2.4). Based on past construction issues in permafrost in Alaska, and our own review of scientific research (see section 4.2.4), we cannot conclude with certainty that granular fill would protect permafrost. Therefore, we have recommended in section 4.2.4 that AGDC review areas proposed for Mode 4 construction in the summer (179.8 miles), reassess whether winter construction would be feasible in low slope (0 to 2 percent) areas as an alternative to the use of granular fill, and, if so, complete the work in winter. Restoration of granular fill used along the right-of-way and in the additional work areas would follow the Project Revegetation Plan (see sections 4.5.2.1 and 4.5.2.3).

The permanent loss or conversion of scrub and herbaceous plant communities would not be significant based on the relatively small proportion of vegetation affected in the Project HUC12 watersheds. Impacts on forest communities would be significant based on the quantity and duration of these impacts along with additional impacts from construction clearing (see below).

Forest Fragmentation and Edge Effect

Forest fragmentation and edge effects would occur along portions of the Mainline Pipeline corridor and new Mainline access road corridors. Fragmentation is the splitting of larger habitat blocks into smaller less continuous habitat (fragments), which can affect diversity and species composition in the resulting fragments. Although the Mainline Pipeline corridor is within 100 feet of existing corridors (cleared) for only about 20 percent of its length, it is generally sited along existing corridors for most of its length. Specifically, the Mainline Pipeline route generally follows the existing TAPS crude oil pipeline and adjacent highways south to Livengood, Alaska. From Livengood, the Mainline Pipeline would generally head south–southwest to Trapper Creek following the Parks and Beluga Highways, and then turn south–southeast around Viapan Lake. Consequently, the fragmentation of large continuous forested areas would generally not occur.

However, the southern portion of the Mainline Pipeline could further fragment forests already affected by human development around Cook Inlet. Impacts would be minor because forests in this area have already been altered from previous disturbance. Forest fragmentation caused by the Mainline Pipeline and access roads could have a greater impact in areas where forest stands are naturally small, such as in the forest–wetland complexes between MPs 677 and 693. Sharp declines in species richness have been found to occur in forest stands less than about 5 to 7 acres (2 to 3 hectares), including late successional spruce forests in forest–wetland complexes (Berglund, 2004) and subtropical woodlands (Drinnan, 2005). Development of the Mainline Pipeline corridor could create fragments of this size in these smaller forests. Impacts on vegetation would be variable depending on species, forest age, and baseline conditions. The understory plant communities present in forest stands less than about 5 acres before construction would likely already be suited to the conditions of a smaller forest (i.e., greater exposure to forest edges and lower diversity), such that a further size reduction may not significantly alter baseline conditions.

In addition to forest fragmentation, clearings can have an edge effect on adjacent forest communities. Edge effects include changes in the forest understory microclimate through increased solar radiation, decreased humidity, increased temperature variability, and increased wind exposure that can affect tree health and stability as well as the understory plant community (Bruna et al., 2009; Jules, 1998; Murcia, 1995). An increase in tree mortality can occur due to microclimate changes and from being damaged or felled by increased wind (Laurance, 1997). Microclimate changes can also reduce understory plant seed germination and seedling development as far as about 213 feet (65 meters) into the forest interior, resulting in the eventual decline of understory plant populations along this edge (Jules, 1998). Other research shows effects on vegetation ranging from 82 to over 328 feet (25 to over 100 meters) from the forest edge (Kremsater and Bunnell, 1999). While edge effects decline over time due to secondary growth, the forest edge remains more susceptible to wind and climatic changes (e.g., drought), a permanent change in composition due to the presence of short-lived pioneer species, and could become more susceptible to forest pests and pathogens, as well as NNIS invasion through increased disturbance (see section 4.5.8) (Laurance, 1997). As with forest fragmentation, edge effects caused by the Project would likely have a greater adverse effect in the more highly developed Cook Inlet area and along portions of the Mainline Pipeline that cross smaller forest stands (see discussion above).

Given that edge effects would not necessarily result in the loss of adjacent forest communities, the impacts from edge effects themselves would not be significant. However, they would result in the long-term to permanent alteration of forest habitat adjacent to the right-of-way and access roads, contributing to the overall significant impacts on forest communities (see section 4.5.2.1 and the construction clearing discussion in section 4.5.3.2). Conversely, the creation of herbaceous and scrub plant communities in the Mainline Pipeline permanent right-of-way would benefit plant species that rely on open and edge habitats and increase overall plant diversity, which would somewhat offset overall impacts on herbaceous and scrub vegetation.

4.5.3.3 Liquefaction Facilities

Construction of the Liquefaction Facilities would result in impacts on 635 acres of forest communities, 89 acres of scrub communities, and 16 acres of herbaceous communities through permanent loss of vegetation, construction clearing, and disturbance (see table 4.5.2-1). Plant communities in the Cook Inlet Basin Subregion would be affected, including deciduous and mixed forest; dwarf tree scrub and low scrub; and graminoid, forb, and freshwater aquatic (non-emergent) herbaceous communities. The primary impact for all plant communities would be permanent vegetation loss (see table 4.5.2-1), although AGDC would apply restoration measures based on the Project Revegetation Plan to the temporary workspace cleared of vegetation for most of the onshore access trestle to the Marine Terminal MOF (a little over 1 acre).

Forests around Cook Inlet occur in a transition zone between coastal rain forest and the interior boreal forests (ADF&G, 2015a). As such, and given their proximity to the coast, the type of forest communities that would be affected by the Liquefaction Facilities are less abundant than the interior boreal forests along the Mainline Pipeline. Nonetheless, about 15,522 acres of these transitional forest communities are in the affected HUC12 watershed, along with about 3,489 and 1,147 acres of associated scrub and herbaceous communities, respectively (USGS, 2018f). Given that the Project would remove only about 3 and 1 percent of the scrub and herbaceous communities, respectively, in this watershed, along with the presence of similar plant communities in adjacent coastal areas surrounding Cook Inlet, impacts from the Liquefaction Facilities on scrub and herbaceous vegetation would not be significant.

4.5.4 Biological Soil Crusts

BSCs are a dominant feature of bryoid herbaceous communities as well as an important component of the organic layer in other herbaceous and scrub plant communities. BSCs are a conglomerate of organisms covering the soil surface in deserts and arid areas throughout the world, including the high Arctic and alpine areas. Major components of BSCs include crustose lichens, algae, liverworts, and moss (Walker et al., 2012). BSCs play an important role in the Arctic; they improve seed germination and seedling growth by enhancing soil temperatures, retain moisture, fix atmospheric nitrogen for improved soil fertility, contribute to soil development, improve soil stability, and reduce erosion (Bliss and Gold, 1999; Dickson, 2000; Gold, 1998; Gold and Bliss, 1995). BSCs contribute to carbon storage and make up a large portion of the biomass in the high Arctic tundra. In addition to occurring in herbaceous and scrub plant communities, they occur in many areas mapped as barren in the high Arctic, which includes about 1,340 acres or 14 percent of the Project area in the Arctic Tundra Ecoregion.

Fugitive dust and chemical air pollution, particularly air pollutants associated with the GTP (see section 4.15), could have a detrimental effect on BSCs. Mosses, a component of BSCs, have been eliminated out to about 66 feet from access roads by fugitive dust deposits in the Prudhoe Bay area (National Research Council, 2003). A study in the North Slope from 1989 to 1994 found SO_2 was present at levels known to suppress photosynthesis in several lichen species (Kohut et al., 1994), suggesting that oil and gas facility emissions on the North Slope could detrimentally affect the BSC, particularly the lichen component. Excavation, rutting, and compaction could also damage BSCs in the long term or permanently. Research on lichens has provided evidence that lichen recovery from overgrazing and fire in Siberian and Alaskan tundra could take between 20 to 80 years (Andreev, 1954; Ektova and Morozova, 2015; Jandt and Meyers, 2000; Palmer and Rouse, 1945). The impacts on BSCs from construction and operation would be permanent, and the loss of BSCs in temporary workspace could adversely affect plant reestablishment, resulting in increased erosion on disturbed soils in the Project area over the long term. Since there are about 81,125 acres of suitable BSC habitat in the HUC12 watershed surrounding the GTP and in tundra communities throughout the Beaufort Coastal Plain Subregion (USGS, 2018f), and with implementation of the Project Fugitive Dust Control Plan for fugitive dust control and the Project SWPPP, Plan and Procedures, and Revegetation Plan for erosion control and plant reestablishment, impacts would not be significant.

4.5.5 Aquatic Vegetation

Aquatic herbaceous plants that could occur in the Project area include both vascular plants and algae found in freshwater ponds and streams, brackish ponds within coastal marshes adjacent to Prudhoe Bay and the Beaufort Sea coast, and marine habitats in Prudhoe Bay and Cook Inlet. They include floating or submerged algae and plants, such as:

- pondlily (e.g., *Nuphar polysepalum*) and aquatic buttercup (*Ranunculus trichophyllus*) in freshwater (Viereck et al., 1992);
- marine macroalgae and filamentous algae, such as rockweed (*Fuscus gardneri* and *F. distichus*) and annual green algae (e.g., *Ulva* spp.), in Cook Inlet (Houghton et al., 2005; Lees et al., 2013; NMFS, 2017a); and
- brown and red algae, such as common sea oak (*Phycodrys fimbriata*), and sea brush (*Phycodris rubens*) in Prudhoe Bay (Houghton, 2012; NMFS, 2017a).

No large beds of marine submerged aquatic vegetation (SAV) are known to occur in the Project area. The closest documented substantial beds of SAV are east of the West Dock Causeway in Stefansson

Sound, where sporadic boulders and cobbles support arctic kelp (*Alaria esculenta*) beds referred to as the "Boulder Patch" (Barnes and Reimnitz, 1974; Dunton and Schonberg, 2000). Similar small boulder patches supporting macroalgae could also occur in Prudhoe Bay in or near construction areas. In Cook Inlet, a considerable amount of macroalgae has been found in benthic samples in proposed Project disposal and reference areas (Houghton, 2012). Otherwise, the nearest documented occurrences of SAV are rockweed beds more than 10 miles away, and beds of green and red algae and rockweed about 20 miles away, based on NOAA ShoreZone Mapping (NMFS, 2017a).

Of the herbaceous communities affected by the Project, about 4 acres would be freshwater aquatic vegetation, of which about 1 acre would be permanently lost due to construction and operation of the LNG Plant, GTP, and Mainline aboveground facilities. The remaining 3 acres would be expected to recover naturally following temporary construction impacts. Impacts would include aquatic plant removal and increased turbidity and sedimentation from trenching activities and potential erosion from disturbed uplands. In addition, incidental spills, such as fuel from construction and operation equipment, could reduce water quality, as could inadvertent releases of drilling mud from DMT procedures (see sections 4.3.2 and 4.7.1 for further discussion). Reduced water quality resulting from these effects could detrimentally affect aquatic plant growth in the short term. To reduce impacts, mitigation measures in the Project Procedures would be implemented to restore affected waterbodies, including installing erosion controls and restoring the bed and banks following construction. The Project SPCC Plan would reduce the risk and potential effects of contaminant spills and releases, while the DMT Plans would reduce the risk of drilling fluid releases. Because the Project would result in the loss of less than 1 percent of the estimated 1,257 acres of aquatic vegetation in the HUC12 watersheds surrounding the Project area (USGS, 2018f), and with implementation of mitigation measures in the Project plans described above, the Project would have minor impacts on freshwater aquatic vegetation.

Aquatic NNIS occur in Alaska and could be encountered during Project construction and operation during in-water work for pipeline waterbody crossings. Although none are currently known to occur in the Project area, there are occurrences upstream of the Alexander Creek crossing. As discussed in more detail in section 4.5.8.3, AGDC would file an updated Invasives Plan that includes a measure to clean construction equipment prior to entering and leaving Alexander Creek. With the mitigation measures described in section 4.5.8.3 and AGDC's commitment regarding Alexander Creek, and because no known aquatic NNIS occur directly in the Project area, the Project would have no to minor impacts on aquatic vegetation due to aquatic NNIS.

4.5.6 Pollinator Habitat

On June 20, 2014, President Obama signed a Presidential Memorandum, *Creating a Federal Strategy to Promote the Health of Honey Bees and Other Pollinators* (79 CFR 35901). According to the memorandum, "there has been a significant loss of pollinators, including honey bees, native bees, birds, bats, and butterflies from the environment." The memorandum also states that "given the breadth, severity, and persistence of pollinator losses, it is critical to expand Federal efforts and take new steps to reverse pollinator losses and help restore populations to healthy levels." In response to the President's memorandum, the federal Pollinator Health Task Force published a *National Strategy to Promote the Health of Honey Bees and Other Pollinators* in May 2015. This strategy established a process to increase and improve pollinator habitat.

Constructing and operating the Project would temporarily affect about 26,054 acres of potential pollinator habitat (vegetation) and permanently remove or convert about 15,004 acres (see table 4.5.2-1). The loss of this habitat could increase the rates of stress, injury, and mortality experienced by honeybees and other pollinators. Notably, participants in traditional knowledge workshops in the Tanana River Region expressed concern over a recent perceived decline in bee populations (Braund, 2016). Once revegetated, affected lands could provide pollinator habitat if pollinator plant species, including native forbs and shrubs (USFWS, 2012b), reestablish in the post-construction plant community. AGDC would rely on natural recruitment for restoration of disturbed areas for a majority of the Project area, which should result in the eventual establishment of native pollinator species from adjacent habitat. Where NNIS occur, ground disturbance could facilitate the spread of NNIS, which would likely outcompete native pollinator species where they occurred previously.

To help minimize the spread of NNIS, AGDC would immediately reseed disturbed areas with native seed where NNIS infestations occur (see section 4.5.8.3). Based on this commitment, and because pollinator habitat would likely remain in the abundant habitat adjacent to the Project area (see section 4.5.2), we conclude that impacts on pollinator species would not be significant.

4.5.7 Rare Plant Species and Plant Communities

The AKNHP maintains a list of plant species considered rare based on distribution, number of occurrences, population size, population trends, habitat specificity, and other information (AKNHP, 2018c). In addition, the Alaska Center for Conservation Science (ACCS) recognizes rare plant communities in Alaska (ACCS, 2017a; Boggs et al., 2016a). No federal, state, or local laws protect these rare plant species and communities, except as they occur on BLM lands (see section 4.8).

4.5.7.1 Rare Plant Species

No rare plant species or rare plant communities were observed during Project field surveys, although targeted surveys for rare plant species were not conducted. Twenty plant species on the AKNHP rare plant list are documented to occur within 1.0 mile of the Project area, although none are known to occur within the Project footprint (see table 4.5.7-1) (AKNHP, 2014b,c; ACCS, 2017b; Nawrocki et al., 2013; NRCS, 2014). The majority of these rare plants are associated with forb herbaceous communities, followed by graminoid herbaceous, aquatic herbaceous, and low scrub communities. Most of the rare plant occurrences are in the Arctic Tundra and Coast Mountains Boreal Ecoregions. Nine of the species are on the BLM Sensitive Plant List or Watch List (see table 4.5.7-1). The BLM (2019) also noted that Bostock's miner's lettuce (*Montia bostockii*) is known to occur in the Toolik Lake Research Natural Area (RNA) in the Brooks Foothills Subregion, which would be crossed by the Project (see section 4.6.1) (Carroll et al., 2003). The BLM could require rare plant surveys and other potential mitigation measures in appropriate habitat where the Project would cross BLM land (see section 4.8.2).

None of the species have documented occurrences within the Project footprint. Muir's fleabane and windmill fringed gentian occur nearby at about 100 feet from the Project footprint, coontail occurs within about 150 feet of the Project footprint, and field locoweed occurs within 317 feet of the Project footprint (see table 4.5.7-1). Windmill fringed gentian, coontail, and field locoweed also have more than one documented occurrence within 1.0 mile of the Project area. Given their proximity and/or number of occurrences, Muir's fleabane, windmill fringed gentian, coontail, and field locoweed would be more likely to occur in the Project area and be affected by ground disturbance.

TABLE 4.5.7-1

Rare Plants and Rare Plant Communities in the Project Vicinity [a]

Common Name	Scientific Name	Associated Ecoregion	Conservation Rankings [b]	BLM Lists	Nearest Documented Occurrence (miles)
Gas Treatment Facilities					
Arctic tidal marsh	N/A	Arctic Tundra	S3	—	0
Bluegrass [d]	*Poa sublanata*	Arctic Tundra	GNR	Sensitive	0.7
Vahl's alkaligrass [c]	*Puccinellia vahliana*	Arctic Tundra	S3, G4	Watch	0.1
Mainline Facilities					
Bluegrass	*Poa sublanata*	Arctic Tundra	SU, GNR	Sensitive	0.5
Bristleleaf sedge [e]	*Carex eburnea*	Arctic Tundra	S3, G5	—	0.2
Coontail [e]	*Ceratophyllum demersum*	Coast Mountains Boreal	S3S4, G5	—	0.03
Field locoweed	*Oxytropis tananensis*	Coast Mountains Boreal	S3S4Q, GNR	—	0.06
Fragile rockbreak	*Cryptogramma stelleri*	Arctic Tundra	S3S4, G5	—	0.3
Lapland sedge [e]	*Carex lapponica*	Coast Mountains Boreal	S3S4, G4G5Q	—	0.3
Longstem sandwort [e]	*Arenaria longipedunculata*	Arctic Tundra	S3S4, G4G5Q	Watch [f]	0.2
Macoun's draba [e]	*Draba macounii*	Arctic Tundra	S3, G3G4	Watch [f]	0.6
Muir's fleabane [e]	*Erigeron muirii*	Arctic Tundra	S2S3, G2G3	Sensitive [f]	0.02
Northern fescue [e]	*Festuca viviparoidea ssp. viviparoidea*	Arctic Tundra	SU, G4G5		0.2
Robbins' pondweed [e]	*Potamogeton robbinsii*	Coast Mountains Boreal	S2, G5	—	0.1
Rock stitchwort [e]	*Minuartia dawsonensis*	Coast Mountains Boreal	S3S4, G5	—	0.6
Selkirk's violet	*Viola selkirkii*	Coast Mountains Boreal	S3S4, G5?	—	0.7
Spreading dogbane	*Apocynum androsaemifolium*	Beringia Boreal	S3, G5	—	0.6
Williams milkvetch [e]	*Astragalus williamsii*	Beringia Boreal	S3, G4	—	0.4
Windmill fringed gentian [e]	*Gentianopsis barbata ssp. barbata*	Beringia Boreal	S3Q, GNR	Watch	0.02
Yellow mountain saxifrage	*Saxifraga aizoides*	Arctic Tundra	S1, G5	—	0.8
Yenisei River pondweed	*Potamogeton subsibiricus*	Coast Mountains Boreal	S3S4, G3G4	Watch	0.8
Yukon aster	*Symphyotrichum yukonense*	Arctic Tundra	S3, G3	Sensitive [f]	0.9
Geothermal springs	N/A	Coast Mountains Boreal	S4	—	4.8
Liquefaction Facilities					
—	—	—	—	—	—

Sources: AKNHP, 2014b, 2014c; BLM, 2019a; Boggs et al., 2014; NRCS, 2014; Nawrocki et al., 2013

N/A = Not applicable

"—" indicates species are not on the BLM Sensitive Plant or Watch Lists.

[a] Based on documented occurrences within 1.0 mile of the Project area with the exception of geothermal springs, found within 4.8 miles.

[b] NatureServe Conservation Rankings: G = global; S = state; 1 = critically imperiled; 2 = imperiled; 3 = vulnerable to extirpation or extinction; 4 = apparently secure; 5 = demonstrably secure; NR = global rank not yet assessed; Q = questionable taxonomy; U = unrankable (due to lack of information or substantially conflicting information about status or trends); ? = Inexact numeric rank (NatureServe, 2018a).

[c] Occurrences found within 1.0 mile of the PBTL and PTTL.

[d] Occurrences found within 1.0 mile of the PTTL.

[e] Species with more than one occurrence or population found within 1.0 mile of the Mainline Pipeline centerline.

[f] Project area occurrences are on BLM land.

In general, the types of impacts on rare plant species would be the same as for other vegetation (see sections 4.5.2 and 4.5.3), although the level of impacts would be greater given that rare species are more susceptible to declines in population and habitat, particularly when species are locally rare (i.e., have small populations sizes) and more at risk of local extinction events. Rare plant species dependent on forest communities would lose the most suitable habitat due to aboveground facilities construction in forest and the conversion of the Mainline Pipeline permanent right-of-way to herbaceous or scrub habitat. Depending on the species' tolerance for disturbance, vegetation maintenance in the permanent right-of-way during operation could reduce the ability of the species to persist or reestablish, with impacts ranging from intermittent and short term for more tolerant species to permanent for less tolerant species. In addition, the introduction and spread of NNIS could outcompete and displace rare plant populations (Carlson and Shephard, 2005) (see section 4.5.8). These potential effects on rare plant populations could range from minor to significant depending on the proportion of the plant populations affected, their ability to recover from disturbance, adjacent suitable habitat, and the species' conservation status.

Muir's fleabane, with one of the least secure conservation rankings of the species documented within 1.0 mile of the Project (i.e., S2S3) based on NatureServe conservation rankings (2018a), is found in mountain avens tundra plant communities (Nawrocki et al., 2013), which is abundant in the Arctic Tundra Ecoregion (see section 4.5.1.2). In addition, 16 documented populations of the species are widely distributed across Alaska's North Slope, from the western coast to the border with Canada (Nawrocki et al., 2013). At least two of the populations are considered locally common, with 500 to 1,000 individuals. Given the abundant suitable habitat, number of documented occurrences, and widespread distribution in Alaska, impacts would not likely be significant for this species. For other species, impacts would likely be none to moderate given their lower likelihood of occurring in the Project area based on the proximity of known occurrences, their conservation status, and/or the abundance of undisturbed potential habitat in adjacent areas and greater Alaska.

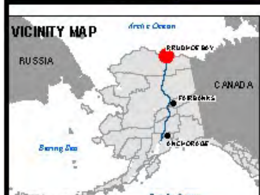
4.5.7.2 Rare Plant Communities

The ACCS identified two rare plant communities that could occur in the Project area: arctic tidal marsh and geothermal springs (Boggs et al., 2016a). An arctic tidal marsh rare plant community would be in the West Dock Causeway Expansion footprint based on a delineation of arctic tidal marshes (ACCS, 2017a) (see figure 4.5.7-1a and b), which occur along the Arctic Ocean coastline and form a narrow fringe on salt-killed tundra and along tidal river channels, inlets, and lagoons (Boggs et al., 2014). Arctic tidal marshes are of conservation concern due to:

- the restricted area in which they occur along the Arctic Ocean coastline;
- coastal erosion from global sea level rise;
- permafrost degradation;
- an increase in ice-free days due to climate change; and
- a relatively low level of protection due to land ownership (i.e., abundant private versus public lands) (Boggs et al., 2014, 2016a).

Modifications to the West Dock Causeway to help movement of modules to the GTP would permanently remove less than 1 acre of vegetated arctic tidal marsh. The West Dock Causeway would only be used for the Project during construction, but the improvements (causeway expansion and Dock Head 4 construction) would be permanent.

Figure 4.5.7-1a
Alaska LNG Project
Arctic Tidal Marsh in the Gas Treatment Facilities Project Area



- Mainline Milepost
- PTTL Milepost
- Mainline RevC2 Alignment
- PTTL Alignment
- Project Footprint
- PBU MGS Non-Jurisdictional Facility Project Footprint
- Arctic Tidal Marsh
- Arctic Tidal Marsh Within 0.5 Miles of Project Footprint

0 0.25 0.5 1 Miles

SCALE: 1:42,000

DATE: 2018-10-12

Figure 4.5.7-1b
Alaska LNG Project
Arctic Tidal Marsh in the Gas Treatment Facilities Project Area

Nine plant species of conservation concern and 10 plant associations of conservation concern are known to occur in arctic tidal marshes (Boggs et al., 2016a). The state conservation status for the plant species includes critically imperiled (two species), imperiled to vulnerable (two species), vulnerable (three species), and two species that are unranked, while the global conservation statuses includes vulnerable (one species), apparently secure (one species), apparently secure to secure (three species), secure (three species), and unranked (one species) (NatureServe, 2018b). The state conservation status for the plant associations is vulnerable at both the state and global levels (Boggs et al., 2014). None of the species of concern or plant associations of concern associated with arctic tidal marsh are known to occur in the Project area.

Because arctic tidal marsh is a wetland, mitigation to offset these impacts could be required under Section 404 of the CWA as determined by the COE with input from other resource management agencies (see section 4.4). The removal of arctic tidal marsh and any associated rare plant species or plant associations of conservation concern would be less than significant since the affected area would be small relative to the total acreage of arctic tidal marsh in Alaska (estimated at about 208,557 acres [Boggs et al., 2016a]).

The Mainline Pipeline passes through the eastern end of a long string of documented geothermal spring biophysical settings that occur along the Aleutian volcanic arc (Boggs et al., 2014), although the closest documented geothermal spring is about 4.8 miles northwest of the Mainline Pipeline on the west side of Cook Inlet. Geothermal springs also occur in areas with historic and current volcanic activity throughout Alaska. Geothermal springs are of conservation concern due to their limited area and number (fewer than 150 geothermal springs are known in Alaska), threats from development, and potential geothermal energy development (Boggs et al., 2014). Geothermal springs support rare and distinct populations of halophytic plants and thermophilic algae and microbes. Boggs et al. (2016a) reports that 15 plant species of conservation concern are found in geothermal springs in Alaska. Given the distance of the nearest known geothermal spring from the Project area, no impacts on this biophysical setting would be anticipated.

4.5.8 Non-native Invasive Species

4.5.8.1 Regulations

NNIS are plant species introduced to an ecosystem through human activities likely to cause economic or environmental harm to human health (USDA, 2016). The federal Plant Protection Act designates certain NNIS as noxious weeds due to their potential to harm agriculture, natural resources, public health, and/or the environment (7 USC 7701). The State of Alaska has a similar designation for noxious weeds, and has developed a state noxious weed list (11 AAC 34.400, 34.020), as well as a prohibited aquatic invasive weed list (ADNR, 2014b) (see section 4.5.5). Under 11 AAC 34, the State of Alaska establishes quarantines on noxious and prohibited plants and sets limits on the presence of noxious weed seeds in commercial seed mixes.

The federal Noxious Weed Act requires federal agencies to develop an undesirable plants management program on federal lands if a similar program is implemented on state or private lands in the same area, where undesirable plants are defined as “undesirable, noxious, harmful, exotic, injurious, or poisonous, pursuant to State or Federal law” (7 USC 2814). Executive Order 13112, issued in 1999 and amended in 2016, directs federal agencies to identify actions that may cause the introduction, spread, or establishment of invasive species; take action to control and monitor invasive species; provide for the restoration of native systems; and refrain from authorizing any actions likely to result in an increase in invasive species, unless the benefits of the action outweigh the potential harm, and feasible and prudent measures are undertaken to minimize the risk of harm. The federal Noxious Weed Act and Executive Order 13112 would apply to Project activities on BLM and NPS lands. The Carlson-Foley Act of 1968

(43 USC 1241–1243) further authorizes the BLM and the NPS to manage noxious weeds and coordinate with other federal and state agencies in managing noxious weeds on federal lands.

The BLM and NPS are in the process of finalizing invasive species stipulations that would apply to AGDC's application for a right-of-way grant on their respective federal lands, of which BLM lands make up a substantial portion of the Project area (see section 4.9.2). The BLM anticipates developing stipulations based on those in *Best Management Practices: Controlling the Spread of Invasive Plants During Road Maintenance* (BLM, 2018b; Graziano et al., 2017). AGDC has prepared an ISPMP to be implemented on BLM and state lands. The NPS uses guidelines in Densmore et al. (2000) and the *Alaska Region Invasive Plant Management Plan* (NPS, 2009) for invasive species control and would require coordination with DNPP managers regarding a park-specific invasives plan for the Project (also see section 4.5.8.3). Plans regarding invasive species management would be finalized with the BLM right-of-way grant, NPS right-of-way permit, and state right-of-way lease.

4.5.8.2 Potential Introduction and Dispersal

Terrestrial NNIS could be introduced and spread by Project implementation based on a number of factors: existing sources of NNIS in the Project area, disturbance and dispersal mechanisms associated with the Project, and climate change, as discussed below. Aquatic NNIS are not documented to occur in the Project area based on AKNHP data (2018a), but they do occur upstream from Project waterbody crossings and, as such, have potential to occur in the Project area and be spread by construction activities.

Existing Sources of Non-native Invasive Species

<u>Terrestrial Non-native Invasive Species</u>

Twenty-one terrestrial NNIS are documented in the Project area, as listed in table 4.5.8-1 and described in the Project Invasives Plan and ISPMP. None of these species are on the federal noxious weed list; two species are on the state noxious weed list. The majority of documented occurrences are in the Mainline Pipeline right-of-way where it crosses the Ray Mountains Subregion (117 documented occurrences), followed by the Brooks Range Subregion (21 documented occurrences). Fourteen, seven, and three documented occurrences of NNIS are also in the Alaska Range, Cook Inlet (in both the Mainline Pipeline and Liquefaction Facilities footprints), and Yukon-Tanana Uplands Subregions, respectively.

Many of the NNIS occur where the Project is collocated with existing industrial or transportation corridors with known NNIS infestations, such as the Dalton Highway. Previously disturbed areas likely to contain NNIS that are closely associated with the Project include the Alaska Railroad Corporation railroad, TAPS, Dalton Highway, and other road and pipeline crossings (see table C-2 in appendix C for collocated and abutting utility corridors).

The NNIS in the Project area are ranked according to the threat they pose to the environment. Nawrocki et al. (2011) assigned these rankings to NNIS occurring in Alaska based on a species' ecological impacts, biological attributes, distribution, and ability to be controlled, with 0 representing the lowest threat to native ecosystems and 100 representing the highest threat (see category rankings in table 4.5.8-1). Highly or extremely invasive species (ranked 70 and higher) have been determined to pose serious threats to natural ecosystems in Alaska, while modestly or moderately invasive species (ranked 50 to 69) pose a threat but are less likely to invade or cause major impacts. Weakly or very weakly invasive species (ranked 0 to 49) are unlikely to invade and significantly alter ecosystems (Nawrocki et al., 2011). The University of Alaska Fairbanks Cooperative Extension Service recommended that management action be focused on NNIS with rankings of 60 or higher (high-risk NNIS) (University of Alaska Fairbanks Cooperative Extension Service, 2018). Where the Project crosses BLM land, the BLM could require AGDC to apply control treatments to NNIS ranked 50 and higher.

TABLE 4.5.8-1

Non-native Invasive Plant Species Documented in the Project Area [a]

Common Name	Scientific Name	Associated Subregions (Number of Documented Occurrences)	Invasiveness Ranking [b]
Gas Treatment Facilities			
None	—	—	N/A
Mainline Facilities			
White sweetclover [c]	*Melilotus alba medikus*	Brooks Range (1); Ray Mountains (27); Alaska Range (29) (Total = 57)	81
Bird vetch	*Vicia cracca* ssp. *cracca*	Ray Mountains (1); Alaska Range (1) (Total = 2)	73
Yellow sweetclover	*Melilotus officinalis*	Cook Inlet Basin (2); Alaska Range (2) (Total = 4)	69
Foxtail barley	*Hordeum jubatum*	Brooks Range (10); Ray Mountains (18); Yukon-Tanana Upland (1); Alaska Range (9) (Total = 38)	63
Smooth brome	*Bromus inermis*	Ray Mountains (2)	62
Oxeye daisy	*Leucanthemum vulgare*	Brooks Range (1)	61
White clover	*Trifolium repens*	Cook Inlet (1)	59
Common dandelion [c]	*Taraxacum officinale*	Brooks Range (2); Ray Mountains (11); Yukon-Tanana Upland (1); Alaska Range (6) (Total = 20)	58
Alsike clover	*Trifolium hybridum*	Ray Mountains (4)	57
Narrowleaf hawksbeard	*Crepis tectorum*	Brooks Range (1); Ray Mountains (15); Alaska Range (9) (Total = 25)	56
Kentucky bluegrass	*Poa pratensis*	Ray Mountains (1)	52
Narrowleaf hawkweed	*Hieracium umbellatum*	Ray Mountains (2)	51
Annual bluegrass [d]	*Poa annua*	Alaska Range (1)	46
Prostrate knotweed	*Polygonum aviculare*	Brooks Range (1); Ray Mountains (6); Alaska Range (1) (Total = 8)	45
Common plantain	*Plantago major*	Brooks Range (4); Ray Mountains (9) (Total = 13)	44
Herb Sophia	*Descurainia sophia*	Ray Mountains (1); Alaska Range (1) (Total = 2)	41
Lambsquarters	*Chenopodium album*	Ray Mountains (4)	37
Pineappleweed	*Matricaria discoidea*	Brooks Range (1); Ray Mountains (9); Alaska Range (1) (Total = 11)	32
Common pepperweed	*Lepidium densiflorum*	Ray Mountains (7); Yukon-Tanana Upland (1) (Total = 8)	25
Liquefaction Facilities			
Reed canarygrass	*Phalaris arundinacea*	Cook Inlet Basin (1)	83
Yellow toadflax [d]	*Linaria vulgaris*	Cook Inlet Basin (1)	69
Common dandelion [c]	*Taraxacum officinale*	Cook Inlet Basin (2)	58

Sources: AKNHP, 2014a; Nawrocki et al., 2011

N/A = Not applicable

"—" indicates no species are known to occur in the footprint of the Project facility.

[a] The NNIS list and rankings presented here are subject to change; the NNIS that occur in Alaska, and their respective invasiveness rankings, are updated regularly by the ACCS at the Alaska Exotic Plants Information Clearinghouse at https://accs.uaa.alaska.edu/invasive-species/non-native-plants/.

[b] Invasiveness ranks are scaled from 0 to 100 according to the following categories:

- 0 to 39 = very weakly invasive;
- 40 to 49 = weakly invasive;
- 50 to 59 = modestly invasive;
- 60 to 69 = moderately invasive;
- 70 to 79 = highly invasive; and
- 80 and higher = extremely invasive.

[c] Noted as invasive weeds by participants of the traditional knowledge workshops (Braund, 2016).

[d] Species on the state noxious weed list, as codified in 11 AAC 34.020.

Eight NNIS in the Project area are high-risk NNIS, six of which are associated with the Mainline Facilities and two with the Liquefaction Facilities (see table 4.5.8-1). Of these, white sweetclover and reed canarygrass are considered extremely invasive, while bird vetch is considered highly invasive. The most widespread NNIS in the Project area, of which two (foxtail barley and white sweetclover) are high-risk NNIS, include:

- foxtail barley;
- white sweetclover;
- narrowleaf hawksbeard;
- common dandelion;
- pineappleweed; and
- common plantain.

In addition, the NPS expressed concern with bird vetch, which is a species of greatest management concern to the NPS. The NPS noted that bird vetch has increased dramatically in disturbed areas around Fairbanks and other areas in the Alaska interior over the last 15 years.

Participants from all five of the traditional knowledge workshops (as summarized by Braund [2016]; see section 4.14) noted concerns with NNIS, including observations that invasive plants are taking over the natural vegetation in yards, along roadways, in pipeline corridors, and in construction workspaces. For example, a participant observed that bank stabilization plants choke out native willows that are important for moose. Other participants mentioned seeing a number of potential NNIS in the area replacing native plants, including two listed in table 4.5.8-1, common dandelion and white sweetclover, as well as orange hawkweed (likely *Hieracium aurantiacum*), vetch (possibly *Astragalus*, *Securigera*, and/or *Vicia* spp.), a purple iris (likely *Iris* spp.), and *Elodea* spp. (also see below).

Aquatic Non-native Invasive Species

In freshwater and marine aquatic systems, invasive, non-native SAV (e.g., dead man's fingers [*Codium fragile*] and Canadian waterweed [*Elodea canadensis*]) can be transmitted in ballast or bilge water, on ship hulls, and on construction equipment (e.g., anchors, stream crossing equipment, etc.) (Alaska Committee for Noxious and Invasive Plant Management, 2016). Aquatic non-native invasive SAV can have negative impacts on aquatic resources. For example, *Elodea* spp. can displace native aquatic vegetation and form dense growth that restricts water movement, increases sedimentation of waterbodies, and blocks the passage of juvenile salmon (Washington Invasive Species Council, 2009).

Comments were received from the USFWS regarding concerns about potential significant impacts from aquatic invasive species, which are not yet widespread in Alaska (USFWS, 2018d). The USFWS Region 7 has developed an aquatic invasive species watch list of species that have the potential to occur in Alaska (USFWS, 2018d). Of those that can occur in lakes and rivers, two *Elodea* species, Canadian waterweed and western waterweed (*E. nuttallii)*, are known to occur in Alaska (Alaska Natural Heritage Program [AKNHP], 2018a; USFWS 2018b). A number of riparian species [e.g., reed canarygrass] also occur in Alaska, as discussed above. Canadian waterweed has an invasiveness ranking of 79 based on Nawrocki et al. (2011). Although western waterweed was not separately evaluated, it was assigned the same rank because it is of close taxonomic relation, it readily hybridizes with Canadian waterweed, and it has the same behavior in the ecosystem. Participants in the traditional knowledge workshops noted seeing *Elodea* in lakes in the Kenai Peninsula Region (Braund, 2016). The nearest documented occurrences of *Elodea* populations are about 15 miles upstream from the Mainline Pipeline crossing of Alexander Creek north of Cook Inlet, and about 40 miles upstream of the Nenana River No. 3 crossing southwest of Fairbanks (AKNHP, 2018a).

Disturbance and Dispersal Mechanisms

NNIS can quickly become established where plant communities or the soil surface have been disturbed. The ground disturbance resulting from construction and maintenance activities along pipeline corridors and access roads and adjacent to aboveground facilities could facilitate the establishment of NNIS in the Project area, which could prevent or suppress native plant reestablishment. As noted by the ADNR, disturbed ground from the Mainline Pipeline right-of-way would create a new 806.9-mile distribution pathway for NNIS to spread (ADNR, 2015b). Disturbed ground and degraded growing conditions resulting from compaction, reduced fertility, degraded soil structure through mixing of subsoil with the topsoil, and introduced granular fill could favor NNIS over native plants and prevent or suppress the reestablishment of the pre-construction plant community, particularly because the organic layer along the majority of the pipeline right-of-way would not be segregated and replaced. The granular fill placed on the working side of the Mainline Pipeline right-of-way under Mode 4, on access roads, and in ATWS would be highly susceptible to NNIS establishment and dominance because the poor substrate would significantly restrict the number of native plant species that could establish or thrive. In addition, changes in the microclimate due to an edge effect could create openings for NNIS in forests adjacent to the Mainline Pipeline right-of-way and the Liquefaction Facilities.

Fire, both natural and human-caused, could also create a disturbance suitable for NNIS establishment, particularly fire-tolerant species, such as white sweetclover (AKNHP, 2008). Fire-tolerant NNIS introductions have been widespread in the semi-arid perennial grasslands and shrublands of the Intermountain West, where cheatgrass (*Bromus tectorum*) and medusahead (*Taeniatherum caput-medusae*), among other NNIS, have infested large swaths of rangeland, resulting in increased fire frequencies, permanently altered plant communities, and rangeland degradation (Rottler et al., 2015).

There is little evidence that NNIS have been widely distributed by wildfires in Alaska to date. Nawrocki et al. (2011) reported that only 0.1 percent (98 of 97,828 records) of known Alaska infestations was due to disturbance associated with forest fires (anthropogenic or natural) based on the 2011 Alaska Exotic Plants Information Clearinghouse database. A review by Anzinger and Radosevich (2008) determined that fire has done little to contribute to the invasion of non-native species into coastal hemlock–spruce forest, interior boreal forest, and tundra plant communities in Alaska. However, a number of studies found that fire has spread non-native plants where there is a viable seed source and dispersal vector, such as along the Dalton Highway where narrowleaf hawksbeard, Canadian hawkweed (*Hieracium canadense*), and white sweetclover have moved into adjacent areas affected by the 2005 North Bonanza Burn (Villano and Mulder, 2008; Walker et al., 2017).

Therefore, although NNIS do not appear to have been spread over large areas by wildfire in Alaska to date, evidence shows that fires can exacerbate the spread of NNIS in Alaska. In particular, the portion of the Mainline Facilities that crosses the Ray Mountains Subregion could be at higher risk for spreading NNIS because the subregion is known to experience more frequent wildfires (Nowacki et al., 2001a) and has the second highest number of occurrences of the fire-tolerant white sweetclover (27) of the subregions crossed by the Project. Furthermore, there is evidence that a warming climate (see discussion below and section 4.19.4) is decreasing the fire return interval and increasing the number of extreme fire events in boreal forests in Alaska (Kasischke et al., 2010). These conditions raise the potential for increased interactions between wildfires and NNIS. Increased traffic and outdoor work due to Project construction and maintenance would also increase the risk of human-caused fires, although the Project Fire Prevention and Suppression Plan would reduce this risk (see below).

Along with disturbance, the use of a new utility corridor could affect the dispersal of NNIS. Historically, Alaska has been less susceptible to NNIS because most areas burned by forest fires are distant from anthropogenic disturbance and consequently have few vectors or seed sources that could start an NNIS infestation (Greenstein and Heitz, 2013). Correspondingly, most NNIS infestations found to date in Alaska are relatively small in area (less than 0.01 acre), and there are no known infestations in certain remote subregions, such as in interior Alaska in the Kobuk Ridges and Valleys and Tanana-Kuskokwim Lowlands Subregions, as well as the North Slope (see further discussion below). However, a growing interest in resource extraction, settlement, and tourism make the Arctic region (and other remote areas) particularly vulnerable to future biological invasion (CAFF and PAME, 2017; Carlson and Shepard, 2007). Accordingly, the creation of new roads and a new utility corridor for the Project, along with the associated movement of vehicles and equipment from place to place, would create new opportunities for terrestrial and aquatic NNIS to enter the more remote portions of the Project area.

NNIS and NNIS propagules (e.g., seeds, rhizomes, etc.) could be carried into the Project area on vehicles, machinery, tools, shoes, erosion control materials, revegetation seed mixes, and imported fill (including granular fill) associated with construction and operation. The AKNHP has documented that 70 percent of recorded infestations of NNIS have been due to imported fill projects such as new roads and railroads (Nawrocki et al., 2011). Participants of the traditional knowledge workshops also noted that NNIS have probably been spread by people’s shoes, vehicle tires, hay, horseback riders, dog mushing, and seed mixes for roadways (Braund, 2016). In addition to human-caused dispersion, wind and animals can carry seed into nearby disturbed areas, while streams can provide a pathway for spreading aquatic and riparian NNIS by transporting plants and plant propagules downstream (AKNHP, 2006; USFWS, 2015c).

Climate Change

Alaska, and in particular, the North Slope, has been largely spared from ecological issues caused by NNIS. Along with limited human development, as discussed above, cold temperatures, permafrost, and a short growing season have likely also played a role in limiting or slowing the establishment and spread of NNIS in Alaska (Carlson and Shepard, 2007). As noted in comments from the USFWS, BLM, and other sources (see CAFF and PAME, 2017 and Carlson and Shepard, 2007), a warming climate, along with increased disturbance, may accelerate the spread of NNIS throughout the state, including into the North Slope and higher elevations. During traditional knowledge workshops, participants noted that overall, plant communities in the area have recently seemed more productive, with earlier fruiting times for berries and the treeline occurring further north and higher in elevation (Braund, 2016). Improved growing conditions (e.g., a longer growing season) that may be associated with these observations could contribute to increased NNIS establishment and productivity. An existing dormant NNIS seed bank may already exist along northern travel corridors, which could result in an abrupt increase in NNIS occurrences with a shift in climate and more favorable growing conditions. Nawrocki et al. (2011) estimated that out of 164 NNIS, 126 could eventually spread into a region that includes the Brooks Range, Brooks Foothills, and Beaufort Coastal Plain Subregions. About 40 of these species are high-risk NNIS. In addition, a warming climate could increase the frequency and extent of wildfires, which can help create openings for NNIS dispersal, as discussed above.

4.5.8.3 Impacts and Mitigation

NNIS are highly competitive and prolific and can often tolerate a wide range of environmental conditions. These traits allow them to outcompete and displace native plants and subsequently alter the plant community, reduce biodiversity, and degrade both terrestrial and aquatic habitat and ecosystem function. For example, white sweetclover, a NNIS reported in the Arctic, interior, and coastal areas of Alaska, degrades natural grasslands and riparian areas, is fire tolerant, and alters soil characteristics

(AKNHP, 2014a; USFWS, 2015c). The plant is highly prolific, with each plant capable of producing up to 350,000 seeds that may remain viable for up to 81 years (AKNHP, 2014a).

Given the Project disturbance and dispersal mechanisms described above, along with potential climate change and existing NNIS infestations in the Project area, NNIS could increase as a result of Project construction and maintenance. The NPS noted that based on their experience and as evidenced by NNIS infestations along the TAPS right-of-way (Cold Regions Research and Engineering Laboratory, 1981), there is a high probability that the area occupied by NNIS would expand substantially if the Project is built, and that this increase would include species of management concern, such as white sweetclover and bird vetch. NNIS establishment could cause revegetation to fail, particularly on granular fill and at existing NNIS infestations where revegetation would rely on natural recruitment (see discussion regarding restoration below). Affected vegetation could include rare plant species, pollinator habitat, and vegetation important for subsistence (see section 4.14).

While most impacts from NNIS would be localized, NNIS could disperse into adjacent vegetation, particularly in areas with a high frequency of natural disturbance like wildfires, or along river corridors and steep slopes, as noted in comments by the NPS (Carlson and Shephard, 2007). Because NNIS have a relatively limited distribution in Alaska, particularly in northern latitudes and higher altitudes, an increase in the distribution of NNIS could have a significant impact on vegetation (Carlson and Shephard, 2007) in and near the Project area.

To mitigate the potential introduction and spread of NNIS, AGDC has developed an Invasives Plan along with an ISPMP to be implemented in conjunction with the Project Revegetation Plan during construction and operation. The Invasives Plan would be implemented in all portions of the Project area, including the North Slope, whereas the ISPMP would be implemented on BLM and state lands. Measures include conducting a survey to identify the locations and extent of existing NNIS populations the year before construction, mapping and flagging NNIS populations, treating NNIS infestations prior to construction, and cleaning and inspecting vehicles and equipment at established wash stations before entering a Project area and before leaving a Project area with NNIS populations. AGDC defined a NNIS infestation as one or more high-risk NNIS plants found in the construction zone based on guidance from the University of Alaska Fairbanks Cooperative Extension Service (2018). According to the Invasives Plan and ISPMP, high-risk NNIS would be prioritized for suppression and removal, although some mitigation measures, such as segregation of infested topsoil, signage around infested areas, and other measures, would target lower ranking NNIS as well. The appropriate treatment methods for NNIS would be based on the specific invasive plant, the infestation extent, and site-specific conditions.

According to the Project ISPMP, treatment goals on BLM and state lands would range from eradication to suppression of high-risk NNIS, where eradication would involve complete removal within 2 years and suppression would involve a 50-percent reduction within 2 years. All other NNIS would be monitored to watch for any unanticipated increases in population that could pose a threat, at which point treatment could be implemented. Staff would be trained on NNIS identification, known infestations, and general protection measures. Training would include resources from the University of Alaska Fairbanks Cooperative Extension Service. Treatment methods would include manual or mechanical removal or herbicide applications, as allowed under land use permits and state policies. During the restoration period, AGDC would monitor NNIS infestations and employ control measures where needed.

Where the Project crosses the DNPP, the NPS has said that the Project Invasives Plan would need to be consistent with the guidelines in Densmore et al. (2000) and the *Alaska Region Invasive Plant Management Plan* (NPS, 2009). The NPS also said that AGDC would need to coordinate with park managers to develop a long-term plan to prevent establishment of new NNIS populations in the park. NPS management guidelines (NPS, 2006c) specifically require that all exotic species must be managed, up to and including eradication, for the life of the Project. New exotic species may not be introduced into national parks. The conservation purposes outlined in the NPS Organic Act require a stringent standard for the management of nonnative and invasive species on NPS lands, so that these lands will be unimpaired and in their natural condition for use by future generations of Americans. NNIS management and preventative measures in the DNPP would be established by the NPS as conditions in their right-of-way permit.

To better track the effectiveness of NNIS management given the concerns expressed by other federal agencies, and given the likelihood of NNIS introductions and spread from Project activities, prior to construction, AGDC would file an updated Revegetation Plan, Invasives Plan, and ISPMP with the Secretary, for the review and written approval of the Director of the OEP, that incorporates a 0-percent increase in high-risk NNIS canopy cover in the Project area as part of the final performance standards for construction and operational activities. In addition, once the interim performance standards from the Project Revegetation Plan have been met, AGDC would conduct annual canopy cover surveys at RMES in all construction and operational workspaces with NNIS infestations until the final performance standards are met. Following each monitoring season, AGDC would file the corresponding survey reports with the Secretary.

In aquatic systems, while there are no known aquatic NNIS in the Project area, *Elodea* populations occur upstream of the Alexander Creek and Nenana River No. 3 crossings. These occurrences elevate the potential that unknown populations could occur or that populations could establish in the Project area at the time of construction or operation. If present, propagules could become attached to construction equipment during waterbody crossing activities and be spread into new areas at subsequent waterbody crossings. The Alexander Creek crossing would be a dry-ditch crossing, which should minimize the risk of *Elodea* propagules becoming attached to Project equipment (see section 4.3.2). The Nenana River No. 3 crossing would use an aerial span; therefore, construction activities in the water and potential exposure to *Elodea* propagules would be avoided. In addition, AGDC would clean construction equipment, aircraft, and watercraft to remove weeds before being allowed onto Project sites, as described in the Project Invasives Plan and ISPMP. EIs would inspect equipment and vehicles for weeds upon delivery to the contractor yard, staging areas, or the right-of-way. Given the concerns expressed by the USFWS and the potential presence of *Elodea* in Alexander Creek, since reliable detection of aquatic NNIS could be challenging, and to avoid spreading *Elodea* into new freshwater systems, prior to construction, AGDC would file an updated Invasives Plan with the Secretary, for the review and written approval of the Director of the OEP, that includes a measure to clean construction equipment prior to entering and leaving Alexander Creek.

In marine systems, measures in the Project Invasives Plan and ISPMP would be implemented to reduce the potential introduction of invasive marine plants and algae through ballast water and fouled ship hulls and equipment into Cook Inlet in accordance with 33 CFR 151.2026, 46 CFR 162.060 (as revised in 2012), 33 CFR 151.2035(a)(6), the Coast Guard's Navigation and Vessel Inspection Circular 01-18, and the EPA's NPDES VGP program (see section 4.3.3). The standards, cleaning, and reporting requirements regarding the presence of organisms in ballast water in these regulations would help minimize the risk of introducing invasive marine SAV into Cook Inlet and Prudhoe Bay. Measures would include the use of a Coast Guard-approved BWM system (see section 4.3.3), the use of cargo and minimal amounts of freshwater for ballast rather than seawater, and regular cleaning of ship hulls. In addition, vessels would be subject to VGP requirements under the CWA, which would limit and manage ballast water discharges.

To further reduce the potential of introducing NNIS from outside the Project area, the Project would adhere to allowable tolerances (proportions) of state-designated noxious weed seeds contained in revegetation seed mixes, as stipulated under state law (11 AAC 34.020). Imported fill areas would be surveyed and treated for NNIS, as needed, and only certified weed-free hay and straw would be used for sediment barriers and mulch. AGDC would also use granular fill sources certified as weed-free through the Weed Free Gravel Certification Program of the ADNR Plant Materials Center, or would adopt the weed-free gravel inspection standards for new granular fill sources if certified sources are not available (ADNR, 2012). In addition, the Project Fire Prevention and Suppression Plan would reduce the risk of fire during construction and operation, minimizing the potential for NNIS seed to spread into adjacent areas through fire disturbance.

Following construction, temporary workspaces would be restored (see section 4.5.2.3). As previously discussed, some areas would not be seeded for at least 3 years following construction to promote natural recruitment. In areas with NNIS infestations, reliance on natural recruitment could be problematic because NNIS would most likely establish and spread before native species could establish. To reduce this risk, AGDC would seed areas with NNIS infestations within the first growing season following construction, but this measure has not been incorporated into the Project Revegetation and Invasives Plan or ISPMP. To ensure areas with NNIS infested areas are reseeded based on the measure above, and so we have the opportunity to review the locations of NNIS prior to construction and better assess restoration success, AGDC would file the following documents with the Secretary prior to construction, for the review and written approval of the Director of the OEP, and provide them to the appropriate land management agencies:

- the results of pre-construction NNIS surveys, including species-specific maps of NNIS locations and up-to-date invasiveness rankings for each NNIS found in the Project area; and
- an updated Revegetation Plan, Invasives Plan, and ISPMP that include a measure to reseed areas with NNIS infestations within the first growing season following ground-disturbing activities.

Based on AGDC's adherence to its Project Invasive Plan, ISPMP, Revegetation Plan, and other commitments, and with implementation of our recommendations, we conclude that the potential introduction and spread of NNIS has been sufficiently reduced.

4.5.9 Conclusion

Project construction and operation would result in the permanent loss, conversion, and disturbance of thousands of acres of vegetation. Impacts on scrub and herbaceous plant communities would be less than significant based in part on the small areas affected relative to the larger watersheds and their shorter recovery time relative to forest communities (however, see section 4.4 for a discussion of potentially significant wetland impacts). Impacts on other vegetation resources, including rare plants and rare plant communities, BSCs, aquatic vegetation, and pollinator plant species, would likely not be significant due to a number of factors, including the small areas affected relative to the larger watersheds or the total distribution of the plant community type or species. Implementation of the mitigation measures described above, along with AGDC's commitments, would contribute to reduced impacts on scrub and herbaceous plant communities, rare plants and rare plant communities, BSCs, aquatic vegetation, and pollinator plant species. We additionally note that AGDC has agreed to implement five of our recommendations from section 4.5 of the draft EIS (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

Impacts on forest communities would be significant given the greater acreages affected and the longer recovery period for areas that would be allowed to revegetate. In addition, the potential introduction and dispersal of NNIS into a relatively pristine environment, particularly along the 806.9-mile-long Mainline Pipeline right-of-way, could have a significant impact on native plant communities. We find AGDC's measures to minimize potential impacts from NNIS—including implementation of the Project Invasive Plan, ISPMP, and Revegetation Plan during both construction and operation, along with AGDC's commitment to incorporate a final cover standard for high-risk NNIS into the final performance standard and reseed areas with high-risk NNIS infestations—to be acceptable.