U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Final Environmental Assessment
and
Finding of No Significant Impact

Strain Based Design Special Permit Application

Special Permit Information:

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Requested By:	Alaska Gasline Development Corporation
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Strain Based Design - Special Permit Application

Final Environmental Assessment

This Final Environmental Assessment (FEA) analyzes the Alaska LNG Pipeline for a special permit request from the Alaska Gasline Development Corporation (AGDC or Applicant) to waive the requirements of 49 Code of Federal Regulations (CFR) 192.103 in specified regions of discontinuous permafrost.[1] The special permit request described herein is related to, but distinct from, the Federal Energy Regulatory Commission (FERC) decision making process for siting and permitting Alaska LNG Pipeline's 42-inch pipeline to transport natural gas from a facility on Alaska's North Slope. The United States Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA) does not have pipeline siting or construction approval authority, but PHMSA's Pipeline Safety Regulations impose certain safety requirements that would apply to the Alaska LNG pipeline. The requirements for special permit applications to PHMSA to request waiver from one or more safety regulations are described in 49 CFR 190.341. This FEA references the Alaska LNG Pipeline's FERC Resource Reports (RR) to avoid duplication. The FEA accompanies Alaska LNG Pipeline's special permit request for the use of strain-based design (SBD). This information can also be found in Appendix D, *Environmental Information for Strain-Based Design Special Permit* of the Alaska LNG Pipeline FERC Resource Report 11, *Reliability and Safety* found on the FERC docket CP17-178, Accession Number 20170417-5342 which can be accessed through https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14562356.

I. Purpose and Need

AGDC is proposing to build a 42-inch pipeline (the pipeline, the Mainline, or Alaska LNG Pipeline) to transport natural gas to a Liquefied Natural Gas (LNG) facility from a gas treatment plant located on Alaska's North Slope. The FERC is the lead Federal agency. PHMSA has authority over the design and operation of natural gas transmission pipelines under 49 CFR Part 192. 49 CFR Part 192 includes specific regulatory requirements for the design, construction,

[1] Section 192.103 requires a pipeline to be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipeline after installation. Sections 192.105, 192.317, and 192.620 give additional requirements on how to provide adequate design, protections, and alternative MAOPs for operating a gas transmission pipeline to protect from hazards. The special permit conditions were developed to maintain these requirements through alternative materials, design, construction, and operating procedures. Implementation of the special permit conditions by AGDC on the Alaska LNG Pipeline will maintain the 49 CFR 192.53 requirements of maintaining the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated.

operation, and maintenance of natural gas pipelines to maintain safety. If required, special permits can be granted under 49 CFR 190.341 for proposed deviations from established pipeline standards. PHMSA imposes conditions on the grant of special permits to assure safety and environmental protection in accordance with 49 CFR 190.341. PHMSA is required to comply with the National Environmental Policy Act (NEPA) in deciding whether to issue the special permit.

The AGDC special permit will waive the requirements of 49 CFR 192.103 in regions of discontinuous permafrost. Time dependent ground movement exists in this region, which would require the pipe be built with heavy walled pipe with sufficient thickness to withstand the external forces of ground freezing and thawing, otherwise known as frost heave and thaw settlement, respectively. While pipelines transporting warm oil (e.g. Trans Alaska Pipeline System (TAPS)) can mitigate these forces through an aboveground pipeline, a high-pressure gas transmission pipeline built above ground would require prohibitively expensive steel metallurgy to ensure pipeline integrity commensurate to fulfill the requirements of 49 CFR 192.53 at temperatures as low as negative 50 degrees Fahrenheit (-50˚F).

The AGDC special permit will allow SBD of the segments of the pipeline, which would be buried in permafrost or potentially permafrost soils, shown in the following Table 1 (the "Summary SBD Segments").

Table 1: Summary of SBD Segments

SBD Segment	Start Milepost	End Milepost	Strain Demand Mitigation
1	194	196	Frost Heave
2	227	230	Frost Heave
3	257	262	Potential Frost Heave
4	270	276	Potential Frost Heave
5	429	440	Potential Thaw Settlement
6	541	544	Frost Heave
7	559	563	Frost Heave

SBD involves enhanced metallurgy and engineering to allow the pipe to deform in the longitudinal direction while maintaining its integrity and safety. SBD is a technology that enables compliance with 49 CFR 192.53, which requires that materials are “able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated.”

The special permit will allow AGDC to design and construct the Alaska LNG Pipeline using SBD for discrete pipeline segments. The special permit will include conditions to ensure the pipeline has equal or greater safety than a pipeline constructed in accordance with 49 CFR Part 192.

II. Background and Site Description

Figure 1 shows the Mainline route from the proposed gas treatment plant located at Prudhoe Bay to the proposed LNG Plant site located on the Kenai Peninsula. The Mainline will be a 42-inch-diameter natural gas pipeline, approximately 807 miles in length, extending from the Alaska LNG’s Gas Treatment Plant (GTP) on the North Slope to the Liquefaction Facility on the shore of Cook Inlet near Nikiski, including an offshore pipeline section crossing Cook Inlet. The onshore pipeline would be a buried pipeline with the exception of short aboveground special design segments, such as aerial water crossings and aboveground fault crossings.

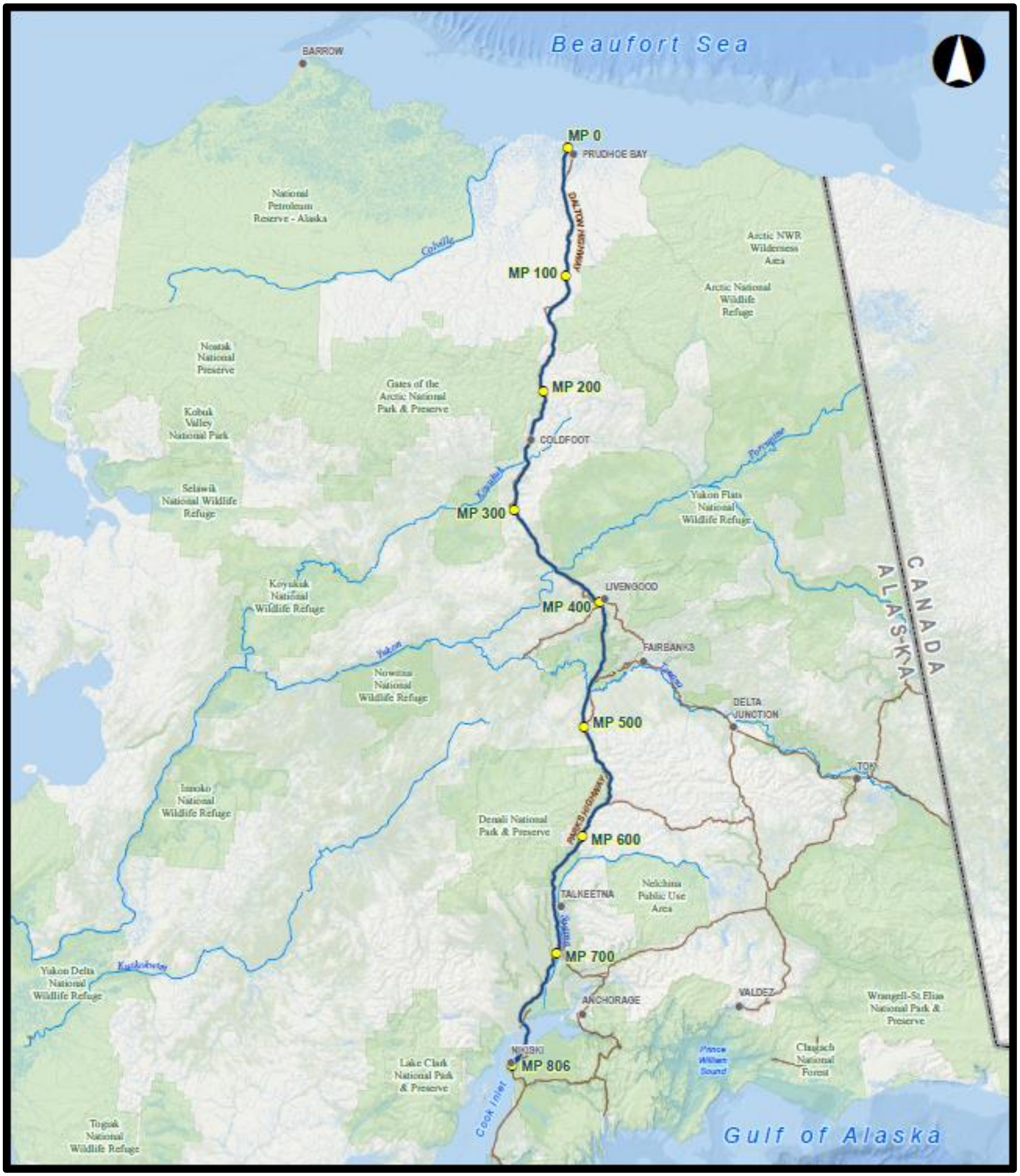

Figure 1: Alaska LNG Pipeline Route Map

As presented in Table 1.3.2-1 of FERC Resource Report 1, *General Project Description,* (inserted below), the Mainline would originate in the North Slope Borough, traverse the Yukon-Koyukuk Census Area, the Fairbanks North Star Borough, the Denali Borough, the Matanuska-Susitna Borough, and the Kenai Peninsula Borough, and terminate at the Liquefaction Facility. The Alaska LNG Pipeline's design has a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The range of gas temperatures during operations is shown in FERC Resource Report 1, General *Project Description*, Figure 1.3.2-2, as shown below.

TABLE 1.3.2-1 (From FERC Resource Report 1)
Alaska LNG Pipeline Route Summary for a 42-inch Pipeline

Segment or Facility Name	Boroughs or Census Areas	Approximate Length (miles)
Alaska LNG Pipeline	North Slope Borough	184.4
	Yukon-Koyukuk Census Areas	303.8
	Fairbanks North Star Borough	2.4
	Denali Borough	86.8
	Matanuska-Susitna Borough	179.9
	Kenai Peninsula Borough	51.3
	Total	**806.6**

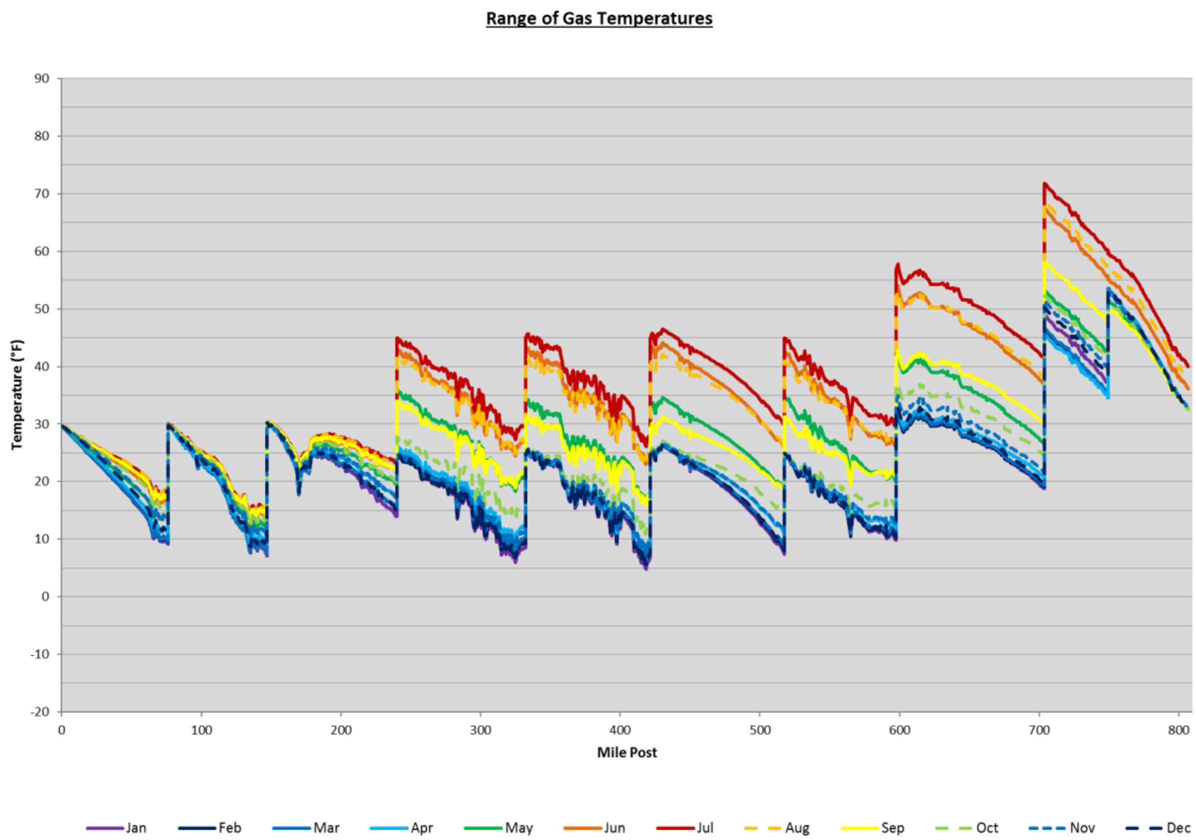

Figure 1.3.2-2 (from FERC Resource Report 1)

The Mainline would include several types of aboveground pipeline facilities. The design includes eight (8) compressor stations, four (4) meter stations, multiple pig launching/receiving stations, multiple mainline block valves (MLBV), and five (5) potential gas interconnection points. A list of compressor stations, heater station, and meter stations is provided in Table 1.3.2-6 of FERC Resource Report 1, *General Project Description* (inserted below).

TABLE 1.3.2-6 (From FERC Resource Report No. 1)
Preliminary Locations of Pipeline Aboveground Facility Stations

Station	Type	Location (Pipeline MP)
GTP/Mainline Meter Station	Meter Station	0.0
Sagwon Compressor Station	Compressor Station with Cooling	76.0
Galbraith Lake Compressor Station	Compressor Station with Cooling	148.5
Coldfoot Compressor Station	Compressor Station with Cooling	240.1
Ray River Compressor Station	Compressor Station with Cooling	332.6
Minto Compressor Station	Compressor Station with Cooling	421.6
Healy Compressor Station	Compressor Station with Cooling	517.6
Honolulu Creek Compressor Station	Compressor Station without Cooling	597.4
Rabideux Creek Compressor Station	Compressor Station with Heating and without Cooling	675.2
Theodore River Heater Station	Heater Station	749.1
Nikiski Meter Station	Meter Station	806.6

Approximately 36 percent of the Alaska LNG Pipeline route is collocated within 500 feet of an existing right of way (ROW), to include Trans-Alaska Pipeline System (TAPS) and other pipelines, highways or major roads, utilities, and railroads. Table 1.3.2-2 of FERC Resource Report 1, *General Project Description,* (inserted below) summarizes collocation of the Mainline route that are within 500 feet of highways, major roads, TAPS, other pipeline ROWs, utilities, and railroads. The Mainline crosses TAPS 12 times, the TAPS Fuel Gas Line five (5) times, and has four (4) railroad crossings. Design of the road and railroad crossings would be validated for applicability of the minimum wall thickness requirements for service loads on crossings in accordance with American Petroleum Institute, Recommended Practice for Steel Pipelines Crossing Railroads and Highways (API RP 1102), using the appropriate design factor for the design class location, and comply with 49 CFR 192.111. The minimum depth of cover would be four (4) feet for road crossings as specified by the Alaska Administrative Code 17.AAC 15.211 “Underground Facilities” and 10 feet for railroad crossings, as specified in Alaska Railroad Corporation (ARRC) standards below travel surface (this exceeds the 49 CFR 192.327(a) requirement that requires a minimum of three (3) feet at drainage ditches of public roads and railroads). Specific designs for major highway and railroad crossings are provided in Appendix H of the FERC Resource Report 1, *General Project Description*. Additional details on roads, railroads, pipelines, utilities, and power lines crossings can be found in FERC Resource Report 8, *Land Use, Recreation and Aesthetics*.

TABLE 1.3.2-2 (From FERC Resource Report No. 1)
Collocated ROWs with the Alaska LNG Pipeline (within 500 feet)

Borough/Census Area Category	Length (Miles)	Length (Feet)
North Slope Borough		
Trans-Alaska Pipeline System (TAPS)	24.39	128,768
Other Pipelines[a]	34.83	183,904
Highways or Major Roads[b]	59.97	316,630
Utilities	108.65	573,692
Railroads	–	–
Yukon-Koyukuk Census Area		
TAPS	64.14	338,653
Other Pipelines[a]	–	–
Highways or Major Roads[b]	94.13	496.985
Utilities	106.42	561.898
Railroads	0.83	4,405
Denali Borough		
TAPS	–	–
Other Pipelines[a]	0.09	453
Highways or Major Roads[b]	13.25	69,984
Utilities	46.21	243,983
Railroads	1.00	5,283
Matanuska-Susitna Borough		
TAPS	–	–
Other Pipelines[a]	2.31	12,206
Highways or Major Roads[b]	26.76	141,289
Utilities	29.76	157,157
Railroads	2.30	12,123
Kenai Peninsula Borough[c]		
TAPS	–	–
Other Pipelines[a]	3.37	17,810
Highways or Major Roads[b]	1.58	8,342
Utilities	0.02	130
Railroads	–	–
Total Collocation Opportunities	**289.58**	**1,528,971**

a Other Pipelines – any pipeline other than the Trans-Alaska Pipeline System

b	Highways or Major Roads – includes public roads only
c	Kenai Peninsula Borough – includes offshore portions of the Alaska LNG Pipeline

Aerial crossings on pipeline specific bridges (i.e. bridges that carry only a pipeline) are located at Nenana River at Moody and Lynx Creek. The design factor for the pipeline at aerial crossings will comply with 49 CFR 192.111.

Pipeline design standards in 49 CFR 192.5 are based on "class location units," which classify locations based on population density in the vicinity of an existing or proposed pipeline system. The higher the class location (1-4), the lower the design factor used to find the minimum required wall thickness for pressure containment (i.e., the required minimum thickness of the pipe increases as the Class location increases). Ninety-nine percent of the Alaska LNG Pipeline route is in a Class 1 location, which is defined as having 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of pipeline. On the Kenai Peninsula, near Nikiski, there is a Class 2 location that is about 2.6 miles long. Also on the Kenai Peninsula there is a potential Class 3 location as the Alaska LNG Pipeline nears the LNG Plant. In the Nenana Canyon region of Denali National Park (~milepost [MP] 536) there is approximately a 0.5-mile of Class 3 location. Additional details on class locations for the Alaska LNG Pipeline can be found in FERC Resource Report No. 11, *Reliability and Safety*, Section 11.7. Resource Report No. 11 Table 11.7.2-1 that outlines Class Locations for the Mainline of Alaska LNG, Route Revision C2, is reproduced below.

TABLE 11.7.2-1 (From FERC Resource Report No. 11)
Class Locations for the Alaska LNG Pipeline

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

There are 10 potential high consequence areas (HCA) along the Mainline as defined under 49 CFR 192.903. Details of HCA locations can be found in FERC Resource Report 11, *Reliability and Safety*, Section 11.7. Table 11.7.4-1 from this FERC Resource Report is repeated below. A comparison with the SBD Segments shows there are no HCA in the SBD Segments.

TABLE 11.7.4-1 (from FERC Resource Report 11)
Potential HCA Takeoff Mainline Route Revision C2

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

In addition, the SBD Segments will be incorporated into the integrity management program (IMP), and treated as covered segments in HCA in accordance with 49 CFR Part 192, Subpart O, and the special permit conditions.

The construction ROW width will vary depending on the type of terrain, the season of construction, and the ease of access from nearby roads. The permanent ROW width would be 50 feet plus the diameter of the pipeline, i.e. 53-1/2 feet. Greater details on construction ROW can be found in FERC Resource Report 1, *General Project Description*. The Mainline would be sited on land composed of more than 85 percent federal, State of Alaska, and borough land of various holdings, with the remainder on privately owned land (see Resource Report 8, *Land Use, Recreation and Aesthetics*).

The gas pipeline corridor spans nine physiographic regions including the Beaufort Coastal Plain, Brooks Foothills, Brooks Range, Kobuk Ridges and Valleys, Ray Mountains, Yukon-Tanana Upland, Tanana-Kuskokwim Lowland, Alaska Range, and Cook Inlet Basin. These regions host a variety of ecosystems including muskeg bogs, spruce upland forest, alpine and Arctic tundra, high brush, and bottomland spruce and poplar forests. The associated ecosystems support a variety of species which include grizzly and black bears, arctic foxes, seals, caribou, moose, small terrestrial mammals, birds, and anadromous fish. A variety of marine mammals inhabit the coastal waters in the Project area, including the bowhead whale, polar bear, beluga whale, ringed seal, bearded seal, Stellar sea lion, harbor seal, ribbon seal and spotted seal. Some of these species are critical subsistence resources for Alaska Native peoples. For additional information see FERC Resource Report 3, *Fish, Wildlife and Vegetation Resources*.

A detailed description of the Mainline ROW is included in Section 1.3.2.1 of FERC Resource Report 1, *General Project Description*. Supporting facilities are described in Section 1.3.2.1.3 and temporary construction infrastructure is described in Section 1.3.2.4 of FERC Resource Report 1. Baseline environmental conditions and the analysis of environmental effects resulting from construction and operation of the Mainline are addressed by individual resources in the individual FERC Resource Reports can be accessed by entering the FERC Docket Number "CP17-178" and then opening the Accession Number of the FERC filing for that Resource Report as follows below. A direct link to the Accession File is also given for each Resource Report below:

- Resource Report 1 (General Project Description) 20170417-5337.
  https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561634

- Resource Report 2 (Water Use and Quality) 20170417-5341. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561641
- Resource Report 3 (Fish, Wildlife and Vegetation) 20170417-5351. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561657
- Resource Report 4 (Cultural Resources) 20170417-5336. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561631
- Resource Report 5 (Socioeconomics) 20170417-5338. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635
- Resource Report 6 (Geological Resources) 201704167-5338. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635
- Resource Report 7 (Soils) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report 8 (Land Use, Recreation and Aesthetics) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report 9 (Air and Noise Quality) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report 10 (Alternatives) 20170417-5340 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561638
- Resource Report 11, (Reliability and Safety) 20170417-5342. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561642

Description of Special Permit Needs

The pipeline will traverse areas potentially subject to geotechnical hazards (geohazards). Broadly defined, a geohazard is a geological and/or environmental condition with the potential to cause distress or damage to civil works. Geohazards of interest for the Alaska LNG pipeline are time dependent, such as thaw settlement and frost heave. The geohazard from fault displacement, which is time independent, is not expected to be of concern for strain based design due to the design/construction approach; that is, the active faults on the alignment will be crossed via an aboveground mode designed to allow for fault displacement without exceeding the 0.5 percent axial strain criteria for strain based design.

Thaw settlement may occur when frozen ground temperatures rise as a result of the disturbance of the surface vegetative mat and/or an elevated temperature of the pipeline (see Figure 1.3.2-2), causing ground subsidence as the soil melts. The melting of previously permanently frozen (permafrost) soils results in soil consolidation or settlement, the magnitude of which is dependent on the type of soil. The amount of settlement divided by the initial thickness of the frozen soil layer is denoted as “thaw strain.”

Frost heave occurs as a result of ice lens formation from freezing of the previously unfrozen or recently thawed soil beneath the pipe. As the chilled pipe extracts heat from the unfrozen soil, a frost bulb develops around the pipe. The interface between the unfrozen soil and the frost bulb is the frost front. Capillary action between the ice and water at the soil pore-scale causes water to be drawn to the frost front during the freezing process, forming discrete ice-lenses within the frost bulb around the pipe. The volumetric expansion of the soil within the frost bulb from the discrete ice lenses causes an upward displacement of the frost bulb and the pipe itself. Frost heave can occur when a cold pipe (i.e. operating below 32°F) runs through unfrozen or previously thawed "frost-susceptible soil.”

Frost-susceptible soils include fine-grained silt and clay soils, while granular soils are non -frost-susceptible. Granular sand and gravel soils are not frost heave susceptible because these soils develop only minimal suction at the frost front due to relatively large pore size (see FERC Resource Report 7, *Soils* for additional route soils description). Permafrost soils that remain frozen after construction are not considered frost susceptible for pipeline design because water migration in frozen soils is negligible. However, for purposes of evaluating heave potential, all soils in the discontinuous zone are conservatively assumed to be unfrozen.

Pipe integrity concerns arise when the displacement from the soil movement is not uniform along the pipeline, such as when a heaving segment of pipe is adjacent to a non-heaving segment, and the pipe has to bend to conform to this differential displacement. Differing amounts of settlement/heave displacement along the alignment may then cause longitudinal bending in the pipe resulting in strains in excess of 0.5% (the pipe material's yield strength, which is defined at 0.5% strain). The potential displacement caused by these conditions can be addressed through the use of the use of SBD, heavier walled pipe, an above-ground pipeline, route avoidance, soil remediation or other mitigative mode as appropriate for the route segment and local conditions. Soils that are only seasonally frozen (the near surface soil layers freeze during winter along the entire pipeline alignment) will not cause displacement of the bottom of the pipe ditch and thus will not affect pipe longitudinal bending.

AGDC has confirmed that the presence of discontinuous permafrost for the seven (7) SBD segments could potentially result in thaw settlement or frost heave (settlement/heave) causing longitudinal pipe strains in excess of 0.5%. 49 CFR Part 192 requires that "pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation." Because buried pipe would need to be exceptionally thick-walled to withstand the forces and strains due to the settlement/heave, AGDC is proposing to design, install and operate the pipeline shown in Table 1 using a SBD approach. The SBD approach would account for these strains from soil settlement/heave using alternative strategies, mitigation, and conditions in lieu of a heavy-walled pipe. Regulatory requirements do not presently exist for the use of SBD. A special permit would be required because the pipe wall thickness will not meet the standard in 49 CFR 192.105. SBD includes factors and conditions to ensure the design and safety considerations described under 49 CFR 192.103, 192.105, 192.317, and 192.620.

AGDC further recognizes additional areas of permafrost that could potentially result in settlement/heave causing longitudinal pipe strains in excess of 0.5% may be identified at any point in the discontinuous permafrost zone as project engineering advances. If such areas are identified and cannot be addressed using the alternative engineering and construction techniques described above then, utilizing the design change process established in the special permit conditions, the pipeline will be designed, installed, and operated in these additional areas using a SBD approach.

III. Alternatives

For PHMSA's environmental assessment pursuant to NEPA, the "No Action" alternative reflects a pipeline design that would be fully compliant with 49 CFR Part 192. The Proposed Action alternative reflects AGDC's utilization of SBD for which a special permit with conditions would be issued for the Alaska LNG Pipeline.

An applicant requesting a special permit from PHMSA has the option of building a pipeline that adheres to the design, construction, and operation in full compliance with 49 CFR in Part 192. Thicker-walled pipe or above ground construction would be required under Part 192 to prevent longitudinal bending that result in pipe longitudinal strains above 0.5%. Therefore, PHMSA's NEPA assessment is slightly different from other agencies in that the No Action alternative is not a "no build" alternative. Rather, the No Action alternative reflects a pipeline design that would not require issuance of a special permit. The Proposed Action alternative describes AGDC's utilization of SBD for which a special permit with conditions would be issued. The two (2) alternatives are described below.

a. No Action Alternative – Construct the pipeline using engineering and construction techniques to mitigate thaw settlement if fully compliant with 49 CFR Part 192. In lieu of SBD, one or a combination of two or more of the following techniques would be employed to mitigate the thaw settlement or frost heave geohazard:

   i. Removal and replacement of unstable material – This technique (over excavation) would be employed only if the proposed action were rejected and in areas where very high thaw strains in near surface soils are evident, such as massive ice directly under the ditch. The unstable soils would be removed and replaced with imported stable materials. This would require deeper and wider trenches than would be necessary with a SBD pipeline; it would also require the mining and importation of additional select fill material to backfill the trench below the pipe and disposal of the removed material. This technique is not favored by the applicant given the cost of displacement required to prevent high pipe strains would require a removal depth in normal soils of over ten feet below ditch bottom.

   ii. Installation of extra heavy wall pipe (~1.000-inch in thickness) – Heavy wall pipe allows the pipe to resist soil movement and conform more gradually to differential displacement of the ditch bottom. This technique could be employed in areas where the heavy wall pipe can be demonstrated to withstand strains resulting from permafrost related geohazards. This technique is not favored by the applicant given the cost of heavy walled pipe.

iii. Trenchless technologies (horizontal directional drilling, horizontal boring, etc.) – This technique might be employed in areas where the lateral extent of unstable soils is limited, the strata thickness is relatively thin and well mapped, and favorable subsurface conditions for drilling exist to bore under the problematic soil strata. Although this technique could be envisioned for use in some site-specific conditions, it is not a practical technique for the entire route alignment due to the expense, duration, and complexity of drilling, and the fact that not all ground conditions are amenable to drilling.

iv. Installation of thermosyphons – In some areas, free-standing vertical pipes that extract heat from the subsurface could be employed to stabilize in situ frozen segments or create new frozen segments dependent on the site-specific requirements. These "thermosyphons" are passive heat exchangers that employ natural convection to chill the subsurface soils, and have been successfully used on TAPS to stabilize the frozen soil in potential thaw settlement areas. Although thermosyphons are inactive during the summer, they can act to cool the ground during the winter enough to where, in the summer, the ground remains frozen. They can also be employed to "pre-freeze" soils of potential frost heave segments, thus avoiding potential deleterious effects of an operating chilled pipeline. Similar to aboveground pipeline installation, the installation of thermosyphons is not generally favored because of visual impacts, potential disruption of animal migration and movement, safety and security concerns associated with exposed aboveground section of the thermosyphon, and the increased cost of installation.

v. Aboveground installation – This technique requires installation of support structures to elevate the pipeline a sufficient height above the ground surface to limit thermal interaction between the pipe and the soil. This technique was successfully used on TAPS. The cost of this alternative is such that it would only be employed if the proposed action were rejected and in areas where heavy wall pipe is not sufficient to reduce the longitudinal bending of the pipe to acceptable levels and the depth to a stable soil strata is greater than practical for complete removal and replacement of the unstable soils or in other areas considered practical. Aboveground pipeline installation is not favored because of: (1) cost, which will be substantially higher due to the need for support structures and advanced line-pipe steel technology to obtain suitable mechanical properties at –50°F; (2) environmental issues, such as visual impacts, potential disruption of animal migration and movement; and (3) operational concerns, primarily increased safety and security associated with exposed pipe, and challenges handling larger volumes of liquid drop-out caused by lower operating temperatures.

For purposes of the impact analysis, it is assumed the No Action alternative would utilize Aboveground Installation with other methods implemented as practical/necessary.

b. Proposed Action Alternative – Design, construct, operate, and maintain the pipeline in compliance with the special permit conditions, which will ensure that the pipeline will continue to function effectively and safely, even if thaw settlement or frost heave, and longitudinal bending occur. The SBD special permit conditions will require specific materials, engineering, construction and operations and maintenance (O&M) procedures for mitigation where thaw settlement or frost heave and consequent longitudinal bending strains exceed allowed limits (0.5%) in the specified SBD Segments

i. *Explain what the special permit application asks for.*

PHMSA's current pipeline regulations (see ii below) do not address strain based design, and the proposed alternative is to install pipe that would not meet the thickness requirements in 49 CFR 192.53, 192.103, 192.105, and 192.317. Therefore, additional special permit conditions are warranted to address anticipated external loads, and/or route hazards, that could cause a pipe to move or sustain longitudinal loads that require consideration of high strains. Such additional conditions are contemplated under 49 CFR 192.103 and 49 CFR 192.317. AGDC requests that PHMSA issue a special permit to waive the requirement to comply with 49 CFR 192.53, 192.103, 192.105, and 192.317.

The special permit application covers the use of strain based design and assessment (SBD) to address longitudinal bending of the pipe due to permanent ground deformations. For the proposed action, the time dependent geohazards that require the use of SBD are thaw settlement and frost heave. The pipeline would be constructed of 42-inch diameter, API 5L Grade X-70 pipe[2] with a minimum wall thickness of 0.862-inch used in all segments identified as requiring SBD. For an MAOP of 2,075 psig, the wall thickness corresponds to a design factor of 0.72.

ii. *Cite regulation(s) for which special permit is sought in accordance with 49 CFR 190.341:*

AGDC's application for a special permit also addresses the following regulations:

49 CFR 192.53, 192.103, 192.105, and 192.317

iii. *Explain/summarize how the design/operation/maintenance of the pipeline operating under the SP would differ from the pipeline in the no action alternative.*

Compliance with the thickness requirements of 49 CFR 192.53, 192.103, 192.105, and 192.317 requiring thicker pipe or other mitigative means would be waived. In addition to applicable requirements under 49 CFR Part 192, a pipeline utilizing SBD would be subject to more rigorous materials testing, construction, and O&M monitoring requirements defined in the SBD special permit conditions and specifications and procedures developed by AGDC. As part of the design phase, AGDC would develop, with PHMSA's review and "no objection," Material Specifications as defined in Appendix A of the special permit conditions that address the requirements of high strain behavior and perform material testing, including full-scale tests, to establish tensile and compressive strain capacities for the pipeline material procured as per the developed Material Specifications.

During the construction phase, AGDC would complete comprehensive construction and weld procedure qualifications and non-destructive testing of all welds and an extensive Quality Assurance and Quality Control program for pipe installation, with emphasis on girth welds, 100% nondestructive examination (NDE) of all girth welds, and records of all field welding.

[2] API 5L is American Petroleum Institute, Specification for Line Pipe.

During the operation phase, AGDC will implement comprehensive monitoring to identify potential high strain conditions and implement appropriate corrective action, as required, to ensure the safe operation of the pipeline. Additional detail on the requirements for design, construction, and operation is provided in Section VII of this document and the special permit conditions.

During the operation phase, AGDC must have operational controls and furnish compressor station discharge temperature records to confirm compliance with the monthly average limits presented in Table 2: Operational Constraints.

Table 2: Operational Constraints

Description	Pressure	Station Discharge Temperature[1, 2]
Gas Treatment Plant Outlet	2025 psig	30 degree Fahrenheit (°F)
Compressor Station Discharge		
Continuous Permafrost	2050 psig	30°F maximum
Discontinuous Permafrost	2050 psig	45°F maximum
Non-Permafrost	2050 psig	80°F maximum

[1]Station discharge temperature requirements represent temperatures at the point where the mainline enters the ground. Unplanned excursions, due to cooling equipment malfunctions, of up to 10°F above the maximums are permissible for up to 24-hours in a 72-hour interval.

[2] AGDC may propose an alternative temperature excursion limits operational procedure that is supported by project-specific data, operational analysis and environmental impact analysis to PHMSA. This procedure must receive a response of “no objection” from PHMSA’s Western Region Director or Project Designee prior to implementation.

iv. ***Applicant*** *should include the pipeline stationing and mile posts (MP) for the location or locations of the applicable **special permit segment(s)***

The special permit segments for the Alaska LNG Pipeline are shown in the table below, which is in FERC Resource Report 1, *General Project Description*, Section 1.3.2.1.2 *Pipeline Design*. The types of Mainline Segments are defined in the following way:

- Conventional – potential longitudinal strains less than 0.5% during the design life of the pipeline
- Offshore Conventional – same as conventional, but offshore
- Strain-based – potential longitudinal strains 0.5% or greater during the design life of the pipeline

TABLE 1.3.2-4
Pipeline Design - Mainline Segments

Segment	Type	MP From	MP To	Miles
1	Conventional Design	0.0	194.0	194.0
2	Strain Based Design	194.0	196.0	2.0
3	Conventional Design	196.0	227.0	31.0
4	Strain Based Design	227.0	230.0	3.0
5	Conventional Design	230.0	257.0	27.0
6	Strain Based Design	257.0	262.0	5.0
7	Conventional Design	262.0	270.0	8.0
8	Strain Based Design	270.0	276.0	6.0
9	Conventional Design	276.0	429.0	153.0
10	Strain Based Design	429.0	440.0	11.0
11	Conventional Design	440.0	541.0	101.0
12	Strain Based Design	541.0	544.0	3.0
13	Conventional Design	544.0	559.0	15.0
14	Strain Based Design	559.0	563.0	4.0
15	Conventional Design	563.0	766.0	203.0
-	Offshore Conventional Design	766.0	793.3	27.3
16	Conventional Design	793.3	806.6	13.3

v. *Mitigation Measures*

Additional mitigation measures are addressed in Section VII of this document and the special permit conditions.

IV. Environmental Impacts of Proposed Action and Alternatives

a. Describe how a small and large leak/rupture to the pipeline could impact safety and the environment/human health.

i. A small leak from a buried or aboveground pipeline would result in a much slower release of gas when compared with a full-bore rupture, with the total amount of gas being released dependent on the time it takes for the leak to be detected and fixed. Gas from a small leak from a buried pipeline would permeate through the backfill material (soil) before dissipating into the air. In the case of an above ground line, natural gas would dissipate directly into the air. Small gas pipeline leaks result in some impacts or loss of surrounding vegetation. This browning of vegetation can facilitate identification of small underground leaks.

ii. A large rupture would cause the rapid release of a large volume of natural gas resulting in significant damage to the pipeline would create a trench or crater in the immediate vicinity of the rupture. If an ignition source is present, an intense fire or explosion would result.

iii. For a fire resulting from a large rupture; the extent of a fire would depend on the extent of the combustible materials in the vicinity, and local environmental conditions (e.g., rain, snow cover, etc.).

iv. When comparing an aboveground pipe segment to a buried segment, both options have the potential for starting a fire, once a rupture occurs.

b. *Submit an explanation of **delta/difference** in safety and possible effects to the environment between the 49 CFR Part 192 baseline (Code baseline) and usage of the special permit conditions for strain based design mitigation measures.*

i. FERC Resource Report 10, *Alternatives* (Section 10.4.5.1) contains a detailed comparative analysis of aboveground and buried design alternatives. Further detailed information and analysis of the environmental impacts of a buried pipeline are contained in the FERC Resource Reports and are referenced accordingly, where applicable in the following analyses of the difference in environmental impacts between the Project Proposed Action and No-Action alternatives. The basis for the FERC Resource Reports is the Proposed Action alternative.

1. Human Health and Safety

   As discussed above, under the No Action alternative with an aboveground pipeline, leaks may be easier to locate and repair.

   The pipeline route is largely remote, with human use in the SBD segment areas near the ROW consisting primarily of subsistence and recreational hunting and related activities. As such, the potential for people to be impacted by a gas release and potential subsequent explosion and fire is low. The aboveground aspect of the pipeline under the No Action alternative would present a greater physical threat to the safety of subsistence or other cross-country travelers who could potentially contact the pipeline under low-visibility conditions. On the other hand, a buried pipeline is susceptible to excavation damage, which can be a cause of pipeline failure.

2. Air Quality

   There would be no significant difference in emissions between the No Action and Proposed Action alternatives. The majority of heavy equipment required for construction in either alternative will be the same, including equipment such as brushers and bulldozers for the clearing and leveling of the ROW, trucks for transporting pipe, and side booms and welding trucks for pipe placement and welding. More excavation would be required for the Proposed Action. Installation of aboveground components would require the use of additional equipment, such as pile drivers, for portions of the No Action alternative and would be expected to require additional crews and time, although this is not likely to significantly increase overall emissions. O&M activities to maintain the pipeline for the No Action and Proposed Action alternatives would require similar equipment and personnel. However, additional O&M activities related to any aboveground components, including pilings that the pipeline rests on, may add small amounts of emissions. O&M activities involving more integrity-assurance in the No Action alternative might also add small amounts of emissions.

3. Aesthetics

The extensive aboveground pipeline under the No Action alternative would present a substantial visual impact. The pipeline would be seen from numerous points along the Dalton and Parks highways and by recreational and subsistence users of the land in the vicinity of the ROW. Visual effects of the Proposed Action alternative would be limited to the ROW clearance, which would be less obvious with winter snow cover.

The effects of a small leak are expected to be similar under both pipeline scenarios. In the event of a large rupture from a buried pipeline, a crater would be created, while in the event of a rupture from aboveground pipeline damage from the rupture would be more surficial in nature. The resulting damage in either case would occur within the ROW footprint.

4. Biological Resources (including vegetation, wetlands, and wildlife)

FERC Resource Report 1, *General Project Description*, provides a detailed description of pipeline construction methods. FERC Resource Report 2, 3, 6, and 7 discuss impacts to soils (including permafrost), vegetation, wetlands, aquatic resources and wildlife resulting from the pipeline construction. No Endangered Species Act-listed species reside within the pipeline corridor of the SBD Segments.

Construction of extensive aboveground pipeline portions of the No Action alternative would also result in disturbance within the ROW but would require less excavation and hydrology disturbance than the buried pipeline under the proposed action. The buried pipeline under the proposed action would generate more surface disturbance compared to aboveground pipeline under the No Action alternative due to the excavation necessary to bury the line and in developing borrow areas for pipeline bedding. The effects of excavation from pipeline installation and borrow areas could have a large effect in wetland areas, which would impact vegetation and wildlife. There would also be more risk for the introduction of invasive species with more excavation and soil exposure. The ROW would require design and construction measures to reestablish drainage and sub-surface flow patterns. Construction of the aboveground portions of the No Action alternative (installation of the vertical support members) would have less of an adverse effect on wetland hydrology. Under both scenarios the impacts to wetlands would be minimized by the use of construction techniques and routing, then mitigated through revegetation and restoration. Operational temperature constraints, which are intended to reduce the likelihood of integrity risks from of thaw settlement, may also mitigate melting that could negatively affect wetland hydrology. Construction-related wetland impacts are discussed in FERC Resource Report 1, *General Project Description*.

Vegetation clearing would need to occur under both alternatives, but the trench excavation under the proposed action is likely to have a more profound and long-term impact to vegetation. AGDC would conduct mitigative practices for revegetation and to reestablish hydrology patterns.

The difference in the effect of a small leak would be the potential mortality for vegetation in the immediate vicinity of the leak from a buried pipeline that would not occur in an aboveground pipeline. A similar difference could also occur with wetlands. There would be no difference in effect on wildlife species due to such a leak. The difference in effects to vegetation, wetlands, and wildlife between and aboveground and buried pipeline would be small in the event of a large rupture. In the event of a large rupture in a buried segment of pipeline, a crater of approximately 4,356 square feet could be created within the ROW. In the event of a large rupture in an aboveground line, damage would be more surficial, but also constrained to the ROW footprint. Any crater would be regraded with repair of the pipeline. The likelihood of a fire and explosion in the event of rupture is the same in both cases and the extent of adverse effects would depend on site conditions at the time of the incident.

5. Climate Change

There would be limited differences in emissions of greenhouse gases between the No Action and Proposed Action alternatives reflected primarily in the diesel emissions during construction. The No Action and Proposed Action alternatives would both require activity by fossil fuel-burning equipment for ground clearance, transportation of construction materials and employees, and stringing of the pipeline itself. The No Action alternative would require the setting of over three thousand vertical support members (VSMs) (34 miles at an average 60-foot bent spacing with expansion loops, assuming one VSM per bent) while buried portions of the No Action and Proposed Action would require excavation equipment and trenching and backfill over more than 770 miles. This excavation, trenching, and backfill that would primarily occur in the Proposed Action would likely result in the release of more greenhouse gases than the No Action alternative. However, the manufacture of thicker pipe under the No Action alternative using heavy walled pipe would result in the release of more greenhouse gases than the manufacture of SBD pipe.

Permanent melting of permafrost results in the release of methane gas and carbon dioxide. There would be some permanent melting under both alternatives, but greater permanent melting would result from the Proposed Action due to trench excavation and hydrology disruption, causing further loss of insulating vegetation and further permanent melting. Permanent melting will be mitigated to some extent by operational temperature constraints to reduce the gas compressor station discharge temperature in permafrost and discontinuous permafrost areas.

Although the Proposed Action would result in greater release of greenhouse gases than an above-ground pipeline, when considered on a global scale, the difference between emissions for the alternatives would be minimal (FERC Resource Report 9, *Air and Noise Quality* discusses Greenhouse gas emissions for the Proposed Action). The effect on climate change related to permafrost effects from the Proposed Action is discussed in FERC Resource Report 1, Section 1.3.

6. Cultural Resources

FERC Resource Report 4, *Cultural Resources*, addresses the potential effects of the project on cultural resources and the consultations with stakeholders in reasonable proximity to the project. Construction activities have the potential to affect cultural resources. Ground-clearing activities under both cases would be similar. The excavation necessary for a buried pipeline would result in a greater potential for adverse effects to buried cultural resources.

There would be no difference between the two alternatives in the event of either a small or large leak for buried segments. A small gas leak from either a buried or aboveground segment would be unlikely to affect cultural resources.

7. Environmental Justice

Since both pipeline designs would be sited in the same corridor, there would be no difference in effects on environmental justice resulting from construction or operation of the pipeline.

8. Geology, Soils and Mineral Resources

Construction activities, including excavation, have the potential to affect soils in a localized manner with minimal effect on regional geology or mineral resources. Construction activities that could contribute to erosion include clearing and grading, excavation trenching, stockpile management, backfilling, and the development of gravel pads. Most erosion effects are effectively managed through the use of erosion and sediment control measures, including:

1. The use of winter construction in areas of wet and frozen ground conditions;
2. Minimization of areas of compacted vegetation;
3. Salvaging of organic mats and using them in surface reclamation;
4. Use of settlement basins, silt fences, and other Best Management Practices (BMP) for storm water control;

5. Use of engineered flow diversions and slope breakers to control water flow on slopes and around water courses; and
6. Installation of trench breakers to address storm and groundwater flow through the trench backfill or during construction.

A more detailed discussion of impacts to soils and erosion resulting from the pipeline construction and the potential mitigation measures to address those impacts is provided in FERC Resource Report 7, *Soils*. Mitigation measures for erosion and sediment control for both alternatives would be addressed in detail through the Rights-of-Way agreements and Section 404 permitting activities.

The difference in effects to soils would be greater with the proposed alternative because it would result in more physical disturbance to the soil resource. Mineral resources and geology (FERC Resource Report 6, *Geological Resources*) would be affected in the development of material sites; the need for bedding materials for the buried pipeline would result in a more surface disturbance than an above-ground pipeline.

9. Indian Trust Assets

No Indian Trust Assets or Native allotments are located within the SBD special permit segments.

10. Land Use, Subsistence, and Recreation

During construction, land use in the form of subsistence activities and recreation could be altered in the immediate vicinity of activities. The pipeline's route and location, combined with the relatively small width of the ROW, would generally limit the extent of displacement by users to the active construction zones. Construction activities would be timed to avoid potential use conflicts with tourists during high activity times, such as at the Denali Park area in summer.

The difference in effects from construction of an aboveground versus a buried pipeline would be minor. After construction, the ROW would be graded and revegetated to a stable condition. No long term linear access along the pipeline alignment is proposed, however under either alternative PHMSA regulations will require that the pipeline ROW is brushed to prevent the growth of large vegetation over and around the pipeline to maintain a clearly defined ROW. FERC Resource Report 1 includes a detailed description of the pipeline ROW footprint and post construction remediation of the ROW. The presence of an aboveground pipeline could create an additional physical barrier in the landscape that would not occur with a buried pipeline. The barrier would represent an adverse effect for both recreational and subsistence land use activities in summer and winter in the vicinity of the pipeline compared to the effects from a buried pipeline. Under either alternative, the differences in effects of either a small leak or large rupture would be negligible for subsistence and recreational use.

Potential effects to recreational, visual effects are examined in detail in FERC Resource Report 8, *Land Use, Recreation and Aesthetics*.

11. Noise

Noise impacts during construction would be similar for installation of an aboveground or buried pipeline since much of the equipment would be the same. Impacts would generally be limited to the sounds of construction equipment operations; human use of the area is transient and limited resulting in a relatively short duration of effect (transiting the area). Wildlife could also be affected by construction-related noise. Noise related to operation of the pipeline itself would primarily result from the occasional maintenance of the ROW and limited to the duration of the physical activity. Considering it would be years between these activities, the effect would be minimal and no difference in noise levels is expected between the No Action and Proposed Action alternatives. A detailed discussion of noise impacts associated with pipeline construction and operation is provided in FERC Resource Report 9, *Air and Noise Quality*.

12. Water Resources

The trenching required for the buried pipe under the Proposed Action could result in additional impacts to surface and groundwater if appropriate design and construction techniques are not utilized for the trenching and backfill of the trench. Appropriate techniques, including the use of trench plugs as discussed in FERC Resource Report 2, *Water Use and Quality,* will be utilized to prevent the extended flow of groundwater along the trench. The placement of adequate backfill and proper reclamation of the ROW will prevent channeling and obstruction of surface water flows. Flow of groundwater along the trench could threaten pipeline safety by causing the pipeline to move due to floatation. This could also result in further environmental impact to the original ecosystem.

Stabilization techniques, including gravel blankets, riprap, gabions, or geosynthetics, would be used to stabilize the channel bed and stream banks at stream crossings. The majority of rivers and streams along the pipeline route would be crossed by an open-cut method during winter months when flows are lowest and disturbance of the channel and stream bank can be minimized. Burial depths for crossings have been based on site specific evaluations to avoid the potential for scour.

The difference in the effects of a small leak on water resources from an aboveground pipeline and a buried pipeline would be minimal as the gas would pass through any water exposed to a leak underground. A large rupture in an aboveground pipeline would have no effect on water resources; a large rupture in a buried pipeline could introduce natural gas into surface or groundwater although the effect would be both short-lived and localized.

A detailed discussion regarding the management of water during construction and operation of the pipeline and impacts to ground and surface water flow and quality resulting from the construction and operation of the pipeline is presented in FERC Resource Report 2, *Water Use and Quality*

c. Describe safety protections provided by the special permit conditions.

i. What factors were considered to ensure the conditions are adequate to protect against waiving protections, (maximum pipe strength limitations), of the code?

The special permit will require extensive evaluation of the potential for thaw settlement, frost heave and other geohazards over the full operational life of the pipeline. Specific test work requirements for the selection and production of the pipe are specified in the SBD Conditions to ensure the steel is of appropriate quality. This selection process, and the requirements are specified in the special permit conditions.

Specific training, monitoring and testing requirements for welding during construction are addressed in the SBD Conditions. Specific requirements for monitoring through operations are also addressed in the SBD Conditions to ensure that any longitudinal strains that exceed those contemplated in the design are identified and mitigated in a timely manner. These are discussed in more detail in Section VIII below.

ii. What are the safety and environmental risks from usage of strain based design that need to be protected against?

The safety and environmental risks associated with the Proposed Action would result from a change from permafrost to wetland conditions, causing unsustainable external loads leading to a failure of the pipeline. The use of SBD as defined in the special permit will ensure the pipeline is designed, constructed, maintained, and operated in a way that avoids failure by development and adherence to the SBD Plan, as per Special Permit Condition 3. The special permit conditions are discussed in more detail in Section VII. The SBD Plan ensures the pipeline will achieve increased flexibility to safely resist the high longitudinal strains.

d. *Explain the basis for the particular set of alternative mitigation measures used in the special permit conditions. Explain whether the measures will ensure that a level of safety and environmental protection equivalent to compliance with existing regulations is maintained.*

The basis for the mitigation measures is the expectation that some segments of the pipeline may experience thaw settlement or frost heave after construction, resulting in unacceptable longitudinal strain on the pipe. To address this expectation, the mitigation measures require the quantification of the maximum amount of ditch displacement, the selection of an appropriate pipe wall thickness, use of steel of an appropriate quality, ongoing O&M procedures, including operational temperature constraints depending on whether an area is permafrost, discontinuous permafrost, or non-permafrost and more frequent running of certain in line inspection tools to deal with increases of the pipeline longitudinal strain. Additional welding procedure and welder qualification, as well as enhanced welding quality during construction, will be employed to ensure sufficient weld strength to deal with the longitudinal strain. Monitoring requirements during operation are established to ensure that the longitudinal strain does not exceed that contemplated in design, while mitigation requirements are established in the event that does happen.

Additional requirements for inspection of the pipeline welds during construction are imposed to ensure weld strength is sufficient to deal with the longitudinal strain. Monitoring requirements during operation are established to ensure the longitudinal strain does not exceed that contemplated in design, while mitigation requirements are established in the event that does happen. The requirements for monitoring, and the requirements for responses to monitored magnitude levels at specified levels of the strain demand limit is given in Table 3 of Special Permit Condition 17, repeated below in Section VIII. Pipeline remediation requirements are discussed in Special Permit Condition 23.

The use of the above measures ensures that no significant environmental impacts will result from the use of SBD.

e. *Discuss how the special permit would affect the risk or consequences of a pipeline leak, rupture, or failure (positive, negative, or none). This would include how the special permits preventative and mitigation measures (conditions), would affect the consequences and socioeconomic impacts of a pipeline leak, rupture, or failure.*

The special permit will allow for burial of the pipeline in areas that may be susceptible to high magnitudes of thaw settlement or frost heave, which could lead to increased longitudinal strain on the pipeline and ultimately failure if appropriate mitigation is not in place. The conditions imposed by the special permit result in an approved, enforceable SBD Plan, with requirements specific and unique to the Alaska LNG Pipeline, to ensure the pipeline is designed, constructed, and operated to reduce the likelihood of thaw settlement and so that neither thaw settlement nor frost heave will lead to pipeline failure. Under either the Proposed Action or the No Action alternative, the consequences of a pipeline failure would be similar.

f. *Discuss any effects on pipeline longevity and reliability such as life-cycle and periodic maintenance including integrity management. Discuss any technical innovations as well.*

Full implementation of the conditions in the special permit will ensure that there are no overall impacts on pipeline longevity and reliability. Implementation of the conditions will impose additional requirements for pipeline integrity management, monitoring, and periodic maintenance.

Requirements for design include:

- The development of an overall SBD Plan that addresses all aspects of the pipeline's life cycle including design, materials, construction, and O&M;
- Comprehensive material testing of the pipe, and welds, to include both small-scale and full-scale compression and tension tests;
- The development and implementation of written material, design, construction, and O&M specifications and procedures; and
- Engineering critical assessments.

Requirements for construction include:

- Expanded welding procedure and welder qualification requirements;
- Expanded testing requirements for welds;
- Running a high-resolution deformation tool through all SBD segments;
- Expanded grounding and cathodic protection requirements; and
- Development of a ROW monitoring program.

Requirements for O&M include:

- Development of O&M procedures for all operating parameters that have an effect on compliance with the special permit;
- Monitoring and determination of pipeline strain demand and specified timelines for remediation;
- Remedial action for coating disbondment;
- Interference current control;
- Integration and analysis of integrity data; and
- Expanded requirements for the reporting and certification including both technical; and management oversight.

g. *Discuss how the special permit would impact human safety.*

The special permit is designed to ensure an equivalent level of human safety as full compliance with 49 CFR Part 192. This document proposes that the special permit would allow burial of the pipeline in permafrost areas without pipeline failure resulting from thaw settlement or frost heave. Burial of the pipeline reduces the potential for pipeline failure resulting from human actions.

h. *Discuss whether the special permit would affect land use planning.*

By allowing for burial of the pipeline the special permit should provide for increased flexibility in land use planning. Burial will reduce visual impacts associated with the line and reduce the potential for human caused damage to the pipeline. Reduction of these potential impacts reduces the need to consider them in evaluating future land use.

i. *Discuss any pipeline facility, public infrastructure, safety impacts and/or environmental impacts associated with implementing the special permit. Discuss how any environmentally sensitive areas could be impacted.*

Implementation of the special permit will not affect any other pipeline facilities, public infrastructure, or environmentally sensitive areas.

V. Response to Public Comments Placed on Docket PHMSA-2017-0044

PHMSA published a Notice of Availability in the Federal Register on May 28, 2019, for four (4) special permit requests for the line pipe of the Alaska LNG Pipeline. (84 FR 24594, Docket Nos.: PHMSA-2017-0044, Usage of Strain Based Design; PHMSA-2017-0045, Alternative Mainline Block Valve Spacing; PHMSA-2017-0046, Usage of 3LPE Coating; and PHMSA-2017-0047, Usage of Crack Arrestor Spacing at www.Regulations.gov). PHMSA requested comment on the special permit applications, the draft permit conditions, and the draft environmental analyses. The public notice comment period ended on July 29, 2019, with PHMSA reviewing and considering all comments received through July 29, 2019. PHMSA received a public comment concerning usage of fossil fuels, the building of the Alaska LNG Pipeline, and the building of a liquified natural gas (LNG) facility. PHMSA does not have siting authority over pipeline facilities. The public comment received did not submit concerns directed towards the special permit, the environmental assessment, or the special permit conditions, which were the issues within PHMSA's decision making authority and the intent of the public notice.

VI. Finding of No Significant Impact

Although technically distinct, PHMSA considered the combined impacts and safety risks associated with the issuance and implementation of the special permits, including the special permit conditions, for usage of three-layer polyethylene (3LPE) coating, usage of strain based design, alternative spacing of mainline block valves, and alternative spacing of crack arrestors. PHMSA finds that special permits and associated special permit conditions will not impose a significant impact on the human environment. The special permit conditions are designed to be consistent with pipeline safety and to ensure the same or a greater level of safety as would be achieved if the pipeline were designed, constructed, operated, and maintained in full compliance with 49 CFR Part 192.

VII. Consultation and Coordination

a. *Please list the name, title and company of any person involved in the preparation of this document.*

Alaska Gas Development Corporation – Frank Richards (Senior Vice President); Alaska LNG LLC – Rick Noecker (PHMSA Filing Coordinator), Mario Macia (Pipeline Technology Lead), Patrick McAlister (Pipeline Design Lead), Norm Scott (ERL Advisor);
Michael Baker International – Keith Meyer (Senior Pipeline Advisor, Paul Carson (Corporate Pipeline Engineer);
PHMSA – Amelia Samaras (Attorney), Joshua Johnson (Engineer), and Steve Nanney (Engineer).

b. *Please provide names and contact information for any person or entity you know will be impacted by the special permit. PHMSA may perform appropriate public scoping. The applicant's assistance in identifying these parties will speed the process considerably.*

Adjacent landowners/land managers potentially impacted:

Cook Inlet Region, Inc.

Jason Brune
Sr. Director, Land and Resources
PO Box 93330
Anchorage
AK 99509
(907) 263-5104

Bureau of Land Management
Earle Williams
Chief, Branch of realty and Conveyance Services
BLM Alaska State Office222 W. 7th Avenue #13
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Alaska Department of Natural Resources
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State Pipeline Coordinator
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AK 99508
(907) 269-6419

Alaska Dept. of Transportation & Public Facilities
Joe Kemp
Gasline Liaison
2301 Peger Road
Fairbanks
AK 99709
(907) 451-5497

c. *If you have engaged in any stakeholder or public communication regarding this request, please include information regarding this contact.*

AGDC has been active in stakeholder engagement throughout Alaska. As well, Federal, State, and Local agency engagement is ongoing. In 2015 and 2016, AGDC held one-on-one as well as multiagency engagement meetings to cover pipeline design construction and routing. Included in the multiagency meetings were presentations and discussions related to permafrost management from pipeline construction and operation.

PHMSA has participated in scoping and public outreach lead by FERC related to the Alaska LNG FERC Resource Reports. Details of the public outreach, which included both members of tribal entities and the general public, are provided in FERC Resource Report 1, *General Project Description*, Section 1.9 and Appendix D.

VIII. Bibliography

Applicant to document information submitted, if they consulted a book, website, or other document to answer the question, please provide a citation.

Documentation for the environmental evaluation for the project Proposed Alternative relies on the extensive documentation contained in the FERC Resource Reports, which is cross-referenced often throughout this document.

IX. Conditions: Example of what special permit (SP) conditions address

a. *If Applicant plans to use strain based design, detail the use of strain based design and the procedures/conditions to be included in a special permit application to address frost heave, thaw settlement, and other geotechnical issues associated with the arctic or sub-arctic.*

AGDC proposes to use SBD to specifically address thaw settlement and frost heave as discussed in Section II, and applied to PHMSA for a special permit as described in Section III(b)(i). To accommodate AGDC's request, PHMSA identified the series of special permit conditions described below.

b. *The special permit submittal should explain how Applicant will develop and monitor strain based design from a quality assurance standpoint as follows:*

1. **Materials** – specifications for steel strength, pipe dimensions' pipe toughness, steel strength, qualification and manufacturing tests, and steel and pipe mill quality inspections.

a. *What Regulatory Code and industry standards will be used for steel and pipe qualifications?*

The Alaska LNG Pipeline in SBD segments will be constructed of line pipe meeting the requirements of API 5L, Grade X70M, PSL2, and will comply with the additional design requirements for steel pipe using alternative MAOP as given in 49 CFR 192.112. In addition, AGDC will develop a pipe material specification to ensure consistent material properties are used for material testing, strain capacity modeling, welding procedures, and strain demand limits. The Pipe Material Specification for use in SBD segments will include the requirements contained in Appendix A to the special permit conditions.

b. *Will Applicant conduct a small scale and full-scale testing program for steel, pipe, girth welds, and anomalies (such as corrosion anomalies) to determine tensile strain capacity or limits?*

AGDC will conduct tests and analysis to address the full range of material characteristics, including: chemical compositions, microstructures and manufacturing variables, manufacturers, and girth welding procedures. In addition, the tests will address potential girth weld flaws (type, size, and location) and expected types of anomalies (e.g., corrosion defects, mechanical damage, etc.). The tests and analysis will include, as appropriate, finite element analysis, small-scale testing, medium-scale testing, and full-scale testing. The testing will be conducted on pipe material procured using the Pipe Material Specification (Appendix A to the special permit conditions). As required based on the test results, the Material Specifications may be adapted to reflect requirements for change.

c. *What design safety factor will be used for test program results?*

The safety factor for the tensile strain demand limit is 1.667. The tensile strain demand limit is the tensile strain capacity calculated using the procedures, predictive equations and models as outlined in the special permit conditions divided by 1.667.

The safety factor for the compressive strain demand limit is defined as follows: The compressive strain demand limit must be the compressive strain capacity calculated using the procedures, predictive equations and models as outlined in the special permit conditions divided by 1.25 in Class 1, 2, 3, and 4 locations. In Class 1 locations where the pipeline is not in the right-of-way for an aboveground pipeline, is not in the right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway or contains less than two buildings within a potential impact circle, as defined in 49 CFR 192.903, that have human occupancy of less than 50-days in a 12-month period, a 1.11 factor may be used in-lieu of 1.25.

The compressive strain demand limit is the compressive strain capacity calculated using project-specific compressive strain capacity models, which are based on finite element analysis, divided by the compressive strain capacity safety factor. The test program results will be used to validate the compressive strain capacity model. AGDC may propose an alternate safety factor, in which case, the proposed safety factor shall be reviewed by an independent third party and PHMSA. AGDC will implement the alternate safety factor only if no objection is received from PHMSA.

d. *What will be the test sample size?*

The final test sample sizes are not yet established. To date, 10 full-scale tension tests and 10 full-scale bend tests have been performed on NPS 42 sample pipes. Full-scale tension tests consist of two or more pipe pieces welded together pulled in tension. Internal pressure is typically applied to the specimen, and the welds may contain intentionally introduced flaws and high-low misalignment. Similarly, full-scale bend tests are performed on internally pressurized pipe, with or without a girth weld and associated flaws and high-low misalignment. The tests performed to date have been reviewed by DNV GL, acting in the capacity of independent third-party reviewer, and confirm the suitability of the tensile and compressive strain capacity models performed by AGDC. Additional tests may be performed in the future to evaluate repair welds, additional pipe manufacturers, anomalies or an alternate pipe diameter, if the design of the pipeline changes.

Additionally, comprehensive small-scale testing has been performed on NPS 42 pipe samples produced by three manufacturers and on mechanized mainline welds and tie-in welds. Additional testing may be performed to evaluate other pipe manufacturers and welding procedures. In addition, before final production of project line pipe, the selected manufacturer will perform manufacturing procedure qualification tests as required by Appendix A of the special permit conditions and project weld procedures will be subject to full weld qualification testing to the requirements of API 1104 and project specifications.

As required by Condition 3 of the special permit conditions, additional details on test sample size will be submitted to PHMSA and an independent third-party reviewer as part of Element 1 of AGDC's Strain Based Design Plan for the Alaska LNG Pipeline.

e. *What tests will be conducted during manufacturing?*

The tests required during pipe manufacturing are presented in Appendix A, Table A-3 of the special permit conditions (reproduced below).

Special Permit Appendix A, Table A-3: Test and Requirements

Items		**Frequency** NOTE 3	**Number, location and orientation of specimen (See Note 4)**
Pipe Body NOTE 1	Chemical composition product analysis	1/heat	1
	Pipe body transverse tensile	1/lot NOTE 2	1
	Pipe body longitudinal tensile (aged)	1/lot	1 (90°, longitudinal)
	Charpy impact - pipe body transverse	1/lot	1 set of 3 specimens
	DWTT	1/lot	2
Weld	Welded joint tensile	1/lot	1
	Guided root bending	1/lot	1
	Guided face bending	1/lot	1
	Charpy impact - weld	1/lot	1 set of 3 specimens
	Charpy impact - HAZ	1/lot	1 set of 3 specimens
	Macro	1/lot	1
	Vickers hardness	1/lot	Per API 5L
Hydrostatic pressure test		Each pipe	

Visual	Each pipe	
Dimension	Each pipe	
NDT	Each pipe	
NOTE 1: For helical seam pipe the samples must be taken mid-way between the weld seam. NOTE 2: A lot is defined as 100 pipes, or per heat, or as per API 5L, whichever is less. NOTE 3: Testing frequency and test type must meet both Table A-3 and API 5L criteria. NOTE 4: Location and orientation must comply with API 5L, if not specified otherwise.		

f. *How often will tests during manufacturing be conducted – per heat[3]?*

i. Testing frequencies for each test are outlined in Appendix A, Table A-3 of the special permit conditions (see table above).

ii. In addition, manufacturing procedure qualification tests will be conducted on pipe from two heats of steel as follows:

Two pipes per heat will be tested for:

1. Chemical analysis;
2. Longitudinal and hoop tensile tests in the as-received condition;
3. Longitudinal tensile tests of pipe body in the aged condition;
4. Longitudinal compression tests of pipe body in the aged condition;
5. Tensile Test of seam weld in the as-received condition;
6. Charpy impact test (pipe body transverse, weld and HAZ), at the specified temperature;
7. DWTT, at the specified temperature;
8. Vickers Hardness traverse across seam weld;
9. Guided bend test; and

One (1) pipe from each heat will be tested as follows:

1. Metallography of pipe body;
2. Visual inspection and dimensions;
3. Nondestructive inspection;
4. Hydrostatic test at an applied hoop stress corresponding to 100% SMYS;
5. Single Edge Notch Tension (SENT) tests or Crack Tip Opening Displacement (CTOD) tests of pipe body to measure tearing resistance curves;

[3] Typical heat sizes used by steel mills will result in 35-45 Alaska LNG Mainline pipes

6. For information only, Charpy transition curve of the pipe body in the aged condition, as determined via the Charpy V-Notch (CVN) impact test

2. **Material Test Program** – *What types of small scale and full-scale testing, design and material specifications qualifications are needed for the project including girth welds and anomaly effects?*

Small-scale tests of pipe will consist of those listed in Section VIII(1)(e) for production testing and Section VIII(1)(f) for manufacturing procedure qualification testing. Small-scale tests of girth welds will consist of the test required for weld procedure qualification according to American Petroleum Institute (API) Standard 1104, *Welding of Pipelines and Related Facilities*, in addition to the following supplemental tests:

1. All weld metal tensile tests;
2. CTOD;
3. SENT tests.

Full-scale tests to assess compressive strain capacity will consist of pressurized bend tests and will include plain pipe tests, tests of pipes with girth welds with a range of high-low misalignment, and tests of pipes with cold bends (i.e. field bends).

Full-scale tests to assess tensile strain capacity will consist of pressurized tension tests including girth welds with flaws and high-low misalignment.

Project-specific line pipe material and girth weld specifications specify the type and number of small-scale tests required to qualify the pipe manufacturing procedure(s) and girth welding procedures.

The AGDC design approach for strain capacity will be qualified by confirming the applicability of tensile and compressive strain capacity models with full-scale tests on sample materials procured to Alaska LNG Pipeline specifications. Similarly, finite element models addressing the effects of anomalies on strain capacity will be validated with full-scale tests.

a. How will the remaining wall strength calculations be validated?

For the majority of cases where wall loss anomalies are detected and strain is not present, remaining wall strength calculations will be performed according to ASME/ANSI B31G, in compliance with 49 CFR 192.485 and the special permit conditions. In the unlikely event that wall loss anomalies occur in a location with longitudinal strains that exceed 0.5%, the effect of strain on remaining strength will be accounted for using procedures approved by PHMSA in accord with the special permit conditions. O&M procedures for remaining wall strength calculations accounting for strain will be developed based on results of the material testing program, finite element analysis of the anomaly, and available PHMSA research on the effects of anomaly wall loss under combined pipeline loadings. Should PHMSA research indicate additional tests are required for the effects of anomalies, AGDC will provide the required tests, finite element analysis, and O&M procedures for the special permit segments.

b. *How will steel and girth weld strength variability be accounted for in the design?*
   i. AGDC will perform Design calculations for a range of steel and girth weld strengths using the results of the project material testing program;
   ii. During operations, site specific assessments of strain capacity will be based on the best-known information on the pipe and weld strength for the location where strain is occurring. Information sources that will be utilized will include the pipe production data for the specific pipe manufacturer and weld qualification data for the type of weld experiencing strain.

3. Geotechnical Test Program

A project-specific geotechnical test program has been conducted to characterize the subsurface route conditions. Additionally, geotechnical results from other Alaskan geotechnical field programs that share a similar route have also been collated into the project Geographic Information System (GIS). These additional field programs include those conducted by TAPS, the Alaska Natural Gas Transportation System (ANGTS), the Alaska Pipeline Project (APP), and the Alaska Stand Alone Pipeline (ASAP). Collectively, these results have been used to quantify the magnitude and extents of frost heave and thaw settlement geohazards and to estimate the resultant strain demand.

a. *Where and how many geotechnical tests will be conducted?*

Over 9,000 geotechnical investigation locations comprising approximately 38,000 laboratory tests have been conducted.

- TAPS – 7,244 boreholes, 31,992 laboratory tests;
- ASAP – 1,883 boreholes and 4,445 laboratory tests available to AGDC which includes borehole data from the Alaska Department of Transportation and Public Facilities (DOTPF);
- APP – 191 boreholes, 1673 laboratory tests;
- Alaska LNG Pipeline - 70 boreholes, 1099 laboratory tests;
- In addition, the project is utilizing publicly available ANGTS geotechnical alignment sheets that include the soil types and landform types with depth along the alignment based on borehole data, water table depths, and terrain units, among other information.

It is noted that ASAP, TAPS, APP and ANGTS utilized similar routing north of Fairbanks.

Additionally, geotechnical characterization along the route included Light Detection and Ranging (LiDAR), aerial photography, seismic trenching, and terrain unit mapping.

b. *What are engineering parameters for tests?*

The main engineering parameters related to the tests include Unified Soil Classification, dry density, moisture content, and thermal state (during borehole logging).

c. *What are examples of how pipe will be designed: above ground, heavier wall thickness, or maximum strain?*

As described in Section III above – Alternative installation modes to the base case of burial of the X80 grade line-pipe, which follow the Alternative MAOP provisions of 49 CFR Part 192 could include the following installation modes: buried heavier wall thickness pipe, removal and replacement of frost heave/thaw unstable materials, trenchless technologies, soil stabilization using measures such as thermosyphons, or a combination of these methods.

The Proposed Alternative will be designed using strain based design techniques allowing the pipe to experience strains beyond 0.5%, but with strains limited to specified percentages of the material strain capacity established based on actual material testing. The target values of the material strain capacities are based on the engineering assessment of the magnitude of pipe displacements due to ditch heave or thaw settlement along the alignment, using the soil index values from the samples recovered from the field geotechnical investigations.

4. **Design and Construction** – design procedures, specifications, design factors, and inspection including pipe and weld misalignment.

   a. *What are the temperature effects on strain based design loads and tensile strain capacity?*

      i. The temperature differential that the pipeline material experiences, due to the difference between the temperatures of the subsurface at construction tie-in to the operating temperature of the product, causes a mechanical stress (strain) that all pipelines routinely account for in design calculations, and which AGDC includes in all pipeline strain determinations along the route. To illustrate the magnitude of this added strain, an example is: for a tie-in temperature at -10 degrees Fahrenheit and for a maximum operating temperature of 80 degrees Fahrenheit, the temperature difference of 90 degrees Fahrenheit from the tie-in temperature to the operating temperature results in an added strain magnitude of about 0.06%.

      ii. The effects of ground surface disturbance on the ROW, operating pipeline temperature, and climate after construction may cause thaw of permafrost below the pipe, largely due to the increase of heat energy entering the ground from the construction disturbance and destruction of the vegetative mat on the ROW. Consolidation of the thawed soils may in turn cause an overall decrease in soil volume and settlement of the pipe ditch bottom. The magnitude of the thaw depth beneath the pipe, along with the associated settlement of the soil within this thaw depth depends on the geomechanical and geothermal properties of the subsurface, which in turn depend on the properties of the subsurface found from the geotechnical field investigations as discussed in Response #3 above. The Alaska LNG FERC Resource Report 6, *Geological Resources* discusses ditch displacement and notes that the designs and measures, best management practices, and erosion and sediment control measures are expected to reduce permafrost impacts during construction and operation.

iii. The effect of the climate and pipeline operating temperature on the subsurface below the pipe after construction may cause freezing of unfrozen soil beneath the pipe, largely due to the effects of the chilled pipeline. Freezing of the subsurface soils may in turn cause water migration to the frost front and resultant upward displacement of the pipe ditch bottom. The magnitude of associated heave of the soil within the frozen bulb of soil around the pipe depends on the geomechanical and geothermal properties of the subsurface, which in turn depends on the properties of the subsurface found from the geotechnical field investigations as discussed in Response #3 above. The Alaska LNG Report 6, *Geological Resources* discusses ditch displacement and notes that the designs and measures, best management practices, and erosion and sediment control measures are expected to reduce frost heave impacts during construction and operation.

Temperature does not affect the tensile strain capacity based on the predictive equations for tensile strain capacity. The requirement in Condition 7(a)i of the special permit conditions that pipe and welds operate on the upper shelf ensures that the strain capacity is independent of temperature.

b. *What is the effect of longitudinal loads on MAOP (72% SMYS) operational hoop pressures – do strain based longitudinal loads add to hoop stress, if so how much?*

The hoop stress evaluated as per Barlow's equation, which is the basis for the design formula for steel pipe (49 CFR 192.105), is unaffected by longitudinal behavior. Barlow's equation is derived from first principles of equilibrium, and does not rely on principles of compatibility for its derivation. A consequence of the derivation is that actions in the longitudinal direction minimally affect the hoop stress evaluation and MAOP.

c. *What is the effect of steel strength, weld property, and wall loss due to corrosion on the strain capacity of pipe under longitudinal and hoop stresses?*

   i. AGDC intends to utilize critical assessment procedures, predictive equations, and models for calculating tensile and compressive strain capacity in the SBD segments during their life cycle based upon PHMSA research guidance documentation.[4]

   ii. Generally, the approach used by AGDC for the evaluation of wall loss due to corrosion is that the effect of longitudinal strain must be technically considered in the presence of metal wall loss or other anomalies. Metal loss must be maintained below 20% of the pipe wall thickness, (*see* Special Permit Condition 18), and pressure failure ratios maintained in accordance with Special Permit Condition 23, when the longitudinal strain magnitude exceeds 0.5%. Anomalies greater than 20% wall loss, and up to 40% wall loss, may be allowed in SBD segments with longitudinal strains over 0.5% strain. However, these anomalies must be evaluated with O&M Procedures based upon a destructive test program, finite element analysis, or a combination of the two methods. The effects of pipe wall loss or corrosion has been addressed by research sponsored by PHMSA, and AGDC will utilize those results. The results of the PHMSA research will require AGDC to conduct further tests on the effect of pipe wall loss or corrosion on longitudinal strains and to use the results in its integrity management procedures.

d. *What will be the safety factor used for longitudinal stresses – will these stresses be over 100% SMYS? If so what safety factor will be used and what are the expected strain design factors?*

   The intent of the SBD approach is to accommodate longitudinal stresses in excess of 100% SMYS. The safety factors to be applied are discussed in Section VIII(b)(1)(c) above.

e. *What construction inspection procedures and processes will be in-place to ensure geotechnical limits for strain based design are not exceeded during construction?*

[4] Tang, H, Panico, M, Fairchild, DP, Crapps, JM, Cheng, W (2014). "Strain Capacity Prediction of Strain-Based Design Pipelines" Proc. of 10th Int'l Pipeline Conf., Calgary, Alberta, Canada, and Tang, H., Fairchild, D.P., Cheng, W., Kan, W., Cook, M.F., Macia, M.L., 2014, "Development of Surface Flaw Interaction Rules for Strain-based Design Pipelines", Proc. 24th Int'l Soc.Offshore and Polar Eng. Conf., Busan, S. Korea.

Longitudinal stress and strain during construction will be calculated based upon the anticipated pipe ditch installation procedure. AGDC will specify pipe lifting and lowering-in practices, ditch depths, lift heights, number of lift points, and spacing between lift points as part of the construction quality assurance procedures. The intent of the construction specifications is to ensure that the pipe stress during pipeline installation remains below 100% SMYS, and as further defined in 49 CFR Part 192 and the special permit conditions.

f. *How many and what types of geotechnical tests need to be conducted along the right-of-way in areas where strain based design will be implemented?*

Geotechnical testing for ROW has been conducted along the SBD segment(s). For types of geotechnical tests see Section VIII (b)(3)(a) above. As required for further design verification, such as to address route alignment changes resulting from environmental consultation during the FERC Resource Report review, additional geotechnical testing for ROW would be implemented according to the project protocols used for previous testing.

g. *How will the pipeline be cathodically protected during construction to ensure anomalies do not jeopardize strain based design and integrity management?*

The special permit does not require the pipeline to be cathodically protected during construction, but that cathodic protection be provided within one year of backfilling. Prior to installation, the pipe is only subject to atmospheric corrosion mechanisms, which are significantly less pronounced than those experienced in a buried environment. Atmospheric corrosion will be negligible during the time between pipe production and construction due to the application of a high-quality corrosion coating (fusion-bonded epoxy and/or three-layer polyethylene) to the exposed exterior surface. For segments where a permanent sacrificial anode system is not installed at the time of construction, a temporary sacrificial anode system will be installed to protect the pipeline before startup of the permanent CP system.

h. *How will the pipeline be checked before and/or after construction to ensure low strength pipe has not been installed?*

Each pipe joint will undergo hydrostatic pressure testing as part of the Production Testing requirements at the line pipe mill (see Table A-3 above). Additionally, all SBD pipeline segments will be hydrotested, see Section VIII(4)(K) below.

i. *Will all girth welds be non-destructively tested to ensure strain based design is applicable? Due to the pipeline high operating pressures, will all girth welds be non-destructively tested?*

All girth welds along the length of the SBD segment will be non-destructively tested in accordance with 49 CFR Part 192 and the Part 192 referenced edition of API Standard 1104 – *Welding of Pipelines and Related Facilities*.

j. *Due to the high operating pressures of the pipeline, will the pipeline have Charpy impact values that arrest a running fracture, if so, how will the pipe toughness be designed to limit this operating failure effect?*

The pipeline will be designed to self-arrest a running ductile fracture per the requirements of 49 CFR 192.112. The pipeline will be constructed of materials operating on the upper shelf of the brittle-ductile transition as demonstrated by results of drop weight tear testing (DWTT) analysis. Minimum values, as specified by a Charpy V-notch (CVN) impact test will be specified to ensure self-arrest of a running fracture.

k. *What will be the minimum pressure test factors used: for Class 1, 2 and 3 locations, compressor stations, and major river crossings?*

All pressure tests will be conducted in accordance with 49 CFR Part 192, Subpart J and 49 CFR 192.620 for segments that will be operated using Alternative Maximum Allowable Operating Pressure requirements, which includes the SBD segments in accord with the Special Permit Condition 2. Compressor stations, regulator stations, and meter stations would be pressure tested to 1.5 times MAOP in accordance with 49 CFR 192.505(b) and 49 CFR 192.620(a)(2)(ii).

5. **Operations and Maintenance (O&M)** – reducing likelihood of and monitoring for frost heave, thaw settlement, and other atypical earth movement issues associated with the arctic or sub-arctic;

a. *AGDC will control compressor station discharge temperatures and will furnish compressor station discharge temperature records to confirm compliance with the limits presented in Table 2: Operational Constraints.*

Table 2: Operational Constraints

Description	**Pressure**	**Station Discharge Temperature[1, 2]**
Gas Treatment Plant Outlet	2025 psig	30 degree Fahrenheit (°F)
Compressor Station Discharge		
Continuous Permafrost	2050 psig	30°F maximum
Discontinuous Permafrost	2050 psig	45°F maximum
Non-Permafrost	2050 psig	80°F maximum

[1]Station discharge temperature requirements represent temperatures at the point where the mainline enters the ground. Unplanned excursions, due to cooling equipment malfunctions, of up to 10°F above the maximums are permissible for up to 24-hours in a 72-hour interval.

[2] AGDC may propose an alternative temperature excursion limits operational procedure that is supported by project-specific data, operational analysis and environmental impact analysis to PHMSA. This procedure must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

b. *The methodology for determining stress and strain.*

AGDC will develop and implement a strain demand monitoring program that will focus on use of an in-line inspection (ILI) tool to evaluate changes in curvature of the pipeline. The curvature change, from which pipe strain can be directly calculated, is a direct assessment of the longitudinal bending that the pipe is undergoing. By comparing the results from successive ILI runs, the strain growth rate can be calculated to calibrate the required frequency of future ILI runs. Strain Demand prediction tools will be maintained and calibrated during pipeline operating life to support ILI data and strain mitigation planning. Additional details on the reporting and remediation requirements are specified in Special Permit Condition 17, which is reproduced below in Table 3, *Pipeline Segment Strain Demand Monitoring*.

c. *What will be the timing of inspections and remediation procedures, if not developed, when will procedures be developed?*

i. Inspections will be conducted utilizing a geospatial pipeline mapping ILI tool and a high-resolution deformation tool. Per the SBD Conditions, the tool must be run not later than the end of pipeline start-up and once each calendar year, but not to exceed intervals of fifteen (15) months per ILI tool runs. Alternatively, after the first three (3) tool runs, the timing of future tool runs may be determined by comparing the rate of increase of in site-specific strain demand with the remaining margin between site-specific strain demand and site-specific strain demand limit. Alternatively, a different ILI schedule can be proposed for review by an independent third-party engineering expert and PHMSA. AGDC may implement the alternate schedule if no objection to the proposed alternate schedule is received from PHMSA.

ii. The SBD Conditions require remediation once a strain demand condition of greater than or equal to 75% of the strain demand limit is discovered. This equates to a safety factor of 2.22 (the specified safety factor of 1.667 divided by the 75% limit when remediation is required) on tensile strain capacity and 1.47 (1.10/0.75) to 1.67 (1.25/0.75) on compressive strain capacity. See Section VIII(b)(1)(c) for more information on safety factors. See "Table 3" below, which is excerpted from SBD Special Permit Condition 17 Monitoring and Determination of Pipeline Strain Demand.

iii. Remediation procedures will be developed during final design and before Pipeline Start-up.

Table 3: Pipeline Segment Strain Demand Monitoring

Strain Demand Magnitude that Triggers Action		**Action Required**
Level	***Strain Demand***	
1	Greater than 0.5% longitudinal strain and less than 75% of strain demand limit.	Monitor.
2	Equal to or greater than 75% of strain demand limit and less than 90% of strain demand limit.	Monitor. Develop site specific strain growth rate and corresponding remediation plan to ensure strain demand limit is not reached during Operational Life. The remediation plan must be implemented within one (1) year of the date of discovery, or prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.
3	Equal to or greater than 90% of strain demand limit/	Report to PHMSA Regional Director within 5 days of discovery. Develop remediation plan and submit to PHMSA within 30 days of discovery. The remediation plan is to be implemented within one (1) year of the date of discovery, or 90 days prior to the date when the strain demand limit is expected to be exceeded, whichever is sooner.

d. *Has a temperature study been conducted on maximum operational temperatures and permafrost effects, if so findings? What criteria will be used to determine whether or how long it is safe to operate the pipeline if chillers are inoperable?*

The route temperature envelope (minimum to maximum gas pipeline discharge temperatures) has been developed using pipeline hydraulic analytical techniques that incorporate the effect of the subsurface condition along the route. Temperature effects beneath the pipeline are evaluated throughout the design life to determine the effects on permafrost utilizing hydraulics and soil thermal models. Pipeline strain calculations take maximum and minimum operating temperatures into account when determining strain demand along the pipeline, doing so utilizing the results of the extensive geotechnical investigations. The intent of the SBD approach to pipeline design is to account for potential thaw settlement and frost heave areas all along the route.

Potential upset conditions during the operational life, such as inoperable chillers or coolers, are examined using these same analytical techniques. The criteria for determination of the permissible duration of an upset condition are the same as used to determine the acceptability of long-term effects – i.e., the pipeline strain in strain based design segments conform to the special permit conditions. Pipeline strain criteria is the same for both upset conditions and long-term effects of pipeline operation. Typically, strain accumulation is a long-term effect due to geothermal conditions, so long-term operations are the primary driver in understanding segments that require strain-based design.

e. *How will maximum temperature compressor station temperatures be maintained to ensure permafrost melt will not affect pipe buoyancy and add additional stresses to the pipe?*

The intent of the SBD approach for pipeline design is to account for potential thaw settlement and any ditch displacement in permafrost areas. In continuous permafrost areas, the pipeline is designed to operate below freezing, utilizing gas to gas exchangers and aerial coolers at the compressor stations to ensure the discharge gas remains below the specified outlet temperature. The temperature of the natural gas will further decrease with distance from the compressor station due to the Joule-Thomson effect.[5]

f. *How will the pipeline be chilled between installation and first gas to prevent permafrost degradation?*

The pipeline will not be chilled between installation and first gas. The intent of the SBD approach to pipeline design is to account for potential thaw settlement in permafrost areas during this period in the design life assessment. Frost heave would not be expected during the dormant period since the heat sink of the chilled pipeline is not realized until startup.

6. **Integrity Management** – Assessment timing for baseline assessments and re-assessments taking into account usage of SBD and MAOP.

[5] The Joule-Thomson effect is the change in temperature of a fluid upon expansion (i.e., pressure decrease) in a steady flow process involving no heat transfer nor work (i.e., at constant enthalpy).

a. *How will the engineering evaluations for anomaly assessment be validated and applied during integrity assessments for tensile strain based design?*

O&M procedures will be developed based on results of the material testing program, as well as available PHMSA research on the effects of anomaly wall loss under combined pipeline loadings used to evaluate anomalies during engineering evaluations. Special Permit Condition 16 requires AGDC to have O&M procedures required by 49 CFR Part 192 and the procedures must technically consider all operating parameters that have an effect on the pipeline strain design including anomaly assessments with wall loss over 20% of pipe wall thickness. The procedure will be supplied to PHMSA in an O&M Plan for review prior to the start of pipeline Operations as outlined in the SBD Special Permit.

b. *What design factors will be used for maximum longitudinal strain loads, before remediation?*

The SBD Conditions require remediation once a strain demand condition of greater than or equal to 75% of the strain demand limit is discovered. This equates to a safety factor of 2.22 (the specified safety factor of 1.667 divided by the 75% limit when remediation is required) on tensile strain capacity and 1.47 (1.10/0.75) to 1.67 (1.25/0.75) on compressive strain capacity. See Section VII(b)(C) for more information on safety factors.

c. *What are integrity assessment timing intervals for tensile strain based design assessments?*

Integrity assessments associated with SBD will be conducted utilizing a geospatial pipeline mapping ILI tool. Per the SBD Special Permit Condition 17, the tool must be run not later than the end of Pipeline Start-Up and once each calendar year, not to exceed fifteen (15) months per each ILI assessment. Alternatively, AGDC can propose a strain demand monitoring approach in the SBD Plan, Element III, that takes into account as-built site-specific information, for review and "no objection" by PHMSA. After start-up, the justification for any alternative interval must be provided to PHMSA Director, Western Region, or PHMSA project designee, for review and AGDC must receive a "no objection" from PHMSA prior to extending Mapping ILI tool run interval.

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