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

# Final Environmental Assessment
# and
# Finding of No Significant Impact

# 3LPE Coating Special Permit

## Special Permit Information:

| | |
|---|---|
| **Docket Number:** | PHMSA-2017-0046 |
| **Requested By:** | Alaska Gasline Development Corporation |
| **Operator ID#:** | 40015 |
| **Original Date Requested:** | April 14, 2017 |
| **Issuance Date:** | September 9, 2019 |
| **Effective Date:** | September 9, 2019 |
| **Code Section(s):** | 49 CFR 192.112(f)(1) |

# Three-layer Polyethylene Coating - Special Permit

# 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) 192.112(f)(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's Mainline pipeline to transport natural gas to a facility on Alaska's North Slope. The United States Department of Transportation's (US DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) does not have pipeline siting or construction approval authority, but PHMSA's Pipeline Safety Regulations impose certain safety requirements that will 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 at 49 CFR 190.341. This FEA references the AGDC's FERC Resource Reports to avoid duplication. The FEA accompanies AGDC's special permit request for the use of three-layer polyethylene (3LPE) coating. This information can also be found in Appendix D, *Environmental Information for Multi-Layer Coating Special Permit* of the Alaska LNG FERC Resource Report No. 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 construct a 42-inch pipeline as part of an integrated liquefied natural gas (LNG) project with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas. The FERC is the lead federal agency. Pursuant to 49 USC 60101, *et seq*, and 49 CFR Part 192, PHMSA has authority over natural gas pipeline design, construction, operation, and maintenance of natural gas pipelines to maintain safety. As noted above, PHMSA does not have pipeline siting authority or construction approval authority. Special permits can be granted under 49 CFR 190.341 for deviations from the regulatory requirements. PHMSA imposes conditions on the grant of special permits to assure safety and environmental protection in accordance with 49 CFR 190.341. PHMSA complies with the National Environmental Policy Act (NEPA) in deciding whether to issue the special permit.

The AGDC special permit will allow exemption from the requirements of 49 CFR 192.112(f)(1) in pipeline segments that are built to comply with the alternative maximum allowable operation pressure (MAOP) requirements of 49 CFR 192. This clause requires that "The pipe must be protected against external corrosion by a non-shielding coating."

The Alaska LNG Pipeline[1] will traverse the state of Alaska. Construction will require transport of line pipe significant distances to remote regions. Fusion bonded epoxy (FBE) coatings, which are in common use in the contiguous U.S. (Lower 48), are susceptible to damage during transportation and installation. As a result, the AGDC plans to utilize 3LPE coatings, which consist of an FBE layer, a copolymer adhesive layer, and a polyethylene outer layer. 3LPE coatings have increased resistance to damage during transportation and installation. A special permit allows the application of 3LPE coatings to reduce the number of coating repairs, and install a pipeline with fewer coating holidays and higher integrity. The special permit includes 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

The Alaska LNG Pipeline route from the proposed gas treatment plant (GTP) located at Prudhoe Bay to the LNG Plant site located on the Kenai Peninsula is shown in Figure 1. The Alaska LNG Pipeline will be a 42-inch-diameter natural gas pipeline, approximately 807 miles in length, extending from the 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 will be a buried pipeline except for short, aboveground special design segments, such as aerial water crossings and aboveground fault crossings.

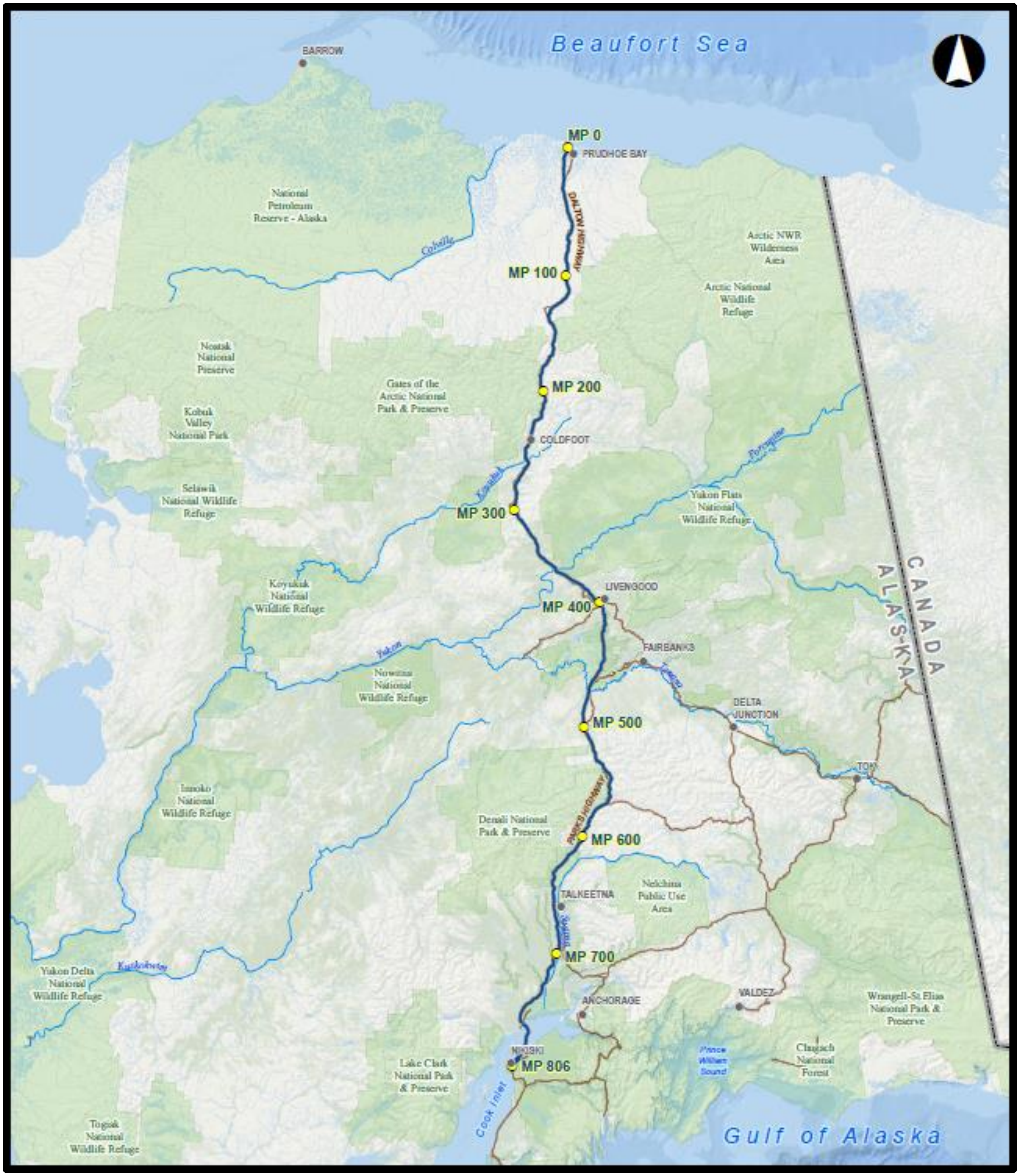


**Figure 1: Alaska LNG Pipeline Route Map**

As presented in Table 1.3.2-1 of FERC Resource Report No. 1, *General Project Description*, (inserted below), the Alaska LNG Pipeline will 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 an 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.

**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** |

The Alaska LNG Pipeline will include several types of aboveground pipeline facilities. The design includes eight (8) compressor stations, four (4) meter stations, multiple pig launching/receiving stations, multiple Alaska LNG Pipeline 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 No. 1 (inserted below).

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

| Station | Type | Location (Pipeline MilePost) |
|---|---|---|
| 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 No.1, *General Project Description*, (inserted below) summarizes collocation of the Alaska LNG Pipeline route that are within 500 feet of highways, major roads, TAPS, other pipeline ROWs, utilities, and railroads. The Alaska LNG Pipeline crosses TAPS 12 times, the TAPS Fuel Gas Line 5 times, and has four railroad crossings. A study was conducted to evaluate the potential effects on TAPS from the thermal radiation field produced in the highly unlikely scenario of an ignited rupture of the Mainline pipeline. The conclusion of the TAPS thermal radiation study was that, for distances between the two pipelines greater than 175 feet, there is no significant impact on TAPS integrity from the thermal radiation effects. This study confirmed the validity of the 200 feet separation distance that was used as routing criterion based on a previous preliminary assessment. For infrastructure such as bridges, the Housing and Urban Development (HUD) has developed an "acceptable separation distance of a proposed HUD-assisted project from a hazard" where the "projects shall be located so that the allowable thermal radiation flux level at the building shall not exceed 10,000 BTU/ft$^2$/hr".[2] The same thermal radiation flux is used to define a "thermal exclusion zone" in 49 CFR 193.2057, which references NFPA 59A (2001), 2.2.3.2(a)(4). This flux was used to determine which Alaska Department of Transportation and Public Facility bridges require additional considerations (crack arrest requirements) for a separation distance of 500 feet.

Design of the road and railroad crossings will be validated for applicability of the minimum wall thickness requirements for service loads on crossings in accordance with American Petroleum Institute (API) Recommended Practice (RP) 1102, using the appropriate design factor for the design class location, and comply with 49 CFR 192.111. The minimum depth of cover will be four 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 which requires a minimum of three feet at drainage ditches of public roads and railroads). Site-specific designs for major highway and railroad crossings are provided in Appendix H of the FERC Resource Report No. 1, *General Project Description*. Additional details on roads, railroads, pipelines, utilities, and power lines crossings can be found in FERC Resource Report No. 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 |

[2] Title 24 CFR 51.203 Safety standards, which can be accessed at http://www.ecfr.gov/cgi-bin/text-idx?SID=2e55921ee92291a1e8d0661a9e4df5b9&mc=true&node=pt24.1.51&rgn=div5#se24.1.51_1203

| | | |
| --- | --- | --- |
| 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 (i.e., the design factor in Class 1 Locations will be 0.60).

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 Alaska LNG Pipeline as defined under 49 CFR 192.903. Details of HCA locations can be found in FERC Resource Report No. 11, Section 11.7.

In addition, the pipeline route segments addressed in the special permit for Strain Based Design ([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 associated special permit conditions if the special permit for Strain Based Design is granted by PHMSA.

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 will be 50 feet plus the diameter of the pipeline (i.e., 53.5 feet). Greater details on construction ROW can be found in FERC Resource Report No. 1, *General Project Description*. The Alaska LNG Pipeline will 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 FERC Resource Report No. 8, *Land Use, Recreation and Aesthetics*).

The Alaska LNG Pipeline corridor spans nine ecoregions including the Beaufort Coastal Plain, Brooks Foothills, Brooks Range, Kobuk Ridges and Valleys, Ray Mountains, Yukon-Tanana Uplands, Tanana-Kuskokwim Lowlands, 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 No.3, *Fish, Wildlife and Vegetation Resources*.

A detailed description of the Alaska LNG Pipeline ROW is included in Section 1.3.2.1 of FERC Resource Report No. 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 No. 1, *General Project Description*. Baseline environmental conditions and the analysis of environmental effects resulting from construction and operation of the Alaska LNG Pipeline are addressed in the individual FERC Resource Reports which can be accessed by entering the FERC Docket Number "CP17-178" at https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14562356 and then opening the Accession Number of the FERC filing for that Resource Report. Direct links to the Accession File for each Resource Report are given below:

- Resource Report No. 1 (General Project Description) 20170417-5337. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561634
- Resource Report No. 2 (Water Use and Quality) 20170417-5341. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561641
- Resource Report No. 3 (Fish, Wildlife and Vegetation) 20170417-5351. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561657

- Resource Report No. 4 (Cultural Resources) 20170417-5336. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561631
- Resource Report No. 5 (Socioeconomics) 20170417-5338. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635
- Resource Report No. 6 (Geological Resources) 201704167-5338. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635
- Resource Report No. 7 (Soils) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report No. 8 (Land Use, Recreation and Aesthetics) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report No. 9 (Air and Noise Quality) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645
- Resource Report No. 10 (Alternatives) 20170417-5340 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561638
- Resource Report No. 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 be installed with coatings and cathodic protection (CP) systems to prevent external corrosion. This two-fold approach to protecting the pipeline from external corrosion is required by 49 CFR Part 192, Subpart I "Requirements for Corrosion Control." Coatings isolate the underlying pipe steel from groundwater and oxygen that could cause corrosion if they were to contact the pipe. In the case there is a coating damage that exposes bare steel, CP current suppresses the corrosion reaction at the location of the coating holiday. With an increased number of coating holidays for FBE due to transportation and installation damage and repairs and in-service degradation of the coating system, a larger cathodic protection current is required. To generate a larger current, larger cathodic protection systems with more power and more anode ground beds may be required to provide protection against corrosion.

49 CFR 192.112, which describes additional design requirements for steel pipe using alternative MAOP, states "the pipe must be protected against external corrosion by a non-shielding coating."

Although the regulations do not provide a definition of what is required to demonstrate a coating is "non-shielding," PHMSA has interpreted this requirement to necessitate the use of FBE coatings (i.e., single or dual layer FBE coatings).[3] AGDC plans to utilize alternative MAOP in most Class 1 locations of the Alaska LNG Pipeline. AGDC plans to utilize 3LPE coatings for the Alaska LNG Pipeline, except in locations where the pipeline is aboveground and where the pipeline is installed by trenchless installation methods, which will utilize FBE with an abrasion resistant overcoat. Since 3LPE coatings may shield CP current from reaching the exterior of the pipe wall surface, AGDC is seeking relief from the requirement in 49 CFR 192.112(f)(1) to use a "non-shielding" coating.

It is understood the requirement to utilize a "non-shielding" coating has been included in the regulations in response to historical pipeline integrity issues that have resulted from the use of tape wrap (including polyethylene), coal tar enamel and asphalt coatings that performed poorly in service. Failures of these historically applied coating systems have occurred in a manner that has allowed groundwater and oxygen to reach the steel surface, but blocked the flow of cathodic protection current (i.e., caused CP shielding). Failure of these coating systems has been associated with external corrosion and stress corrosion cracking (SCC). The 3LPE coating system is a modern coating system with over 20 years of world-wide field experience that has not been associated with the occurrence of similar issues. Although there has been limited use of this system in the U.S., three-layer polyolefin (3LPO) coatings, a category of coatings that includes 3LPE, are the most commonly utilized coating systems in the world and have an overall track record of good performance (see Attachment D – 3LPE Coating Technical Support document, Section 7), although specific data is limited.

There are several challenges a coating system in Alaska must be able to overcome, including resistance to damage, (from transport, UV degradation, and backfill), minimizing the potential for interference between cathodic protection systems given the proximity to TAPS, and minimizing the number of CP ground beds, given the remoteness of Alaska. While FBE coatings are often

[3] PHMSA Enforcement Guidance – Alternative MAOP, FAQs: FAQ 34 and 35 (2016). http://primis.phmsa.dot.gov/maop/faqs.htm.

selected for pipelines in the Lower 48 due to their lower cost and acceptable performance when good transportation infrastructure is available, 3LPE coatings have significant advantages over FBE for application in Alaska. Construction of the Alaska LNG Pipeline will require transporting pipe significant distances from the coating facilities by ship, railroad and/or truck. The limited transportation infrastructure within Alaska means that significant distances of trucking over unpaved roads and the unpaved pipeline right of way will be required. Although pipe handling procedures, as described in the special permit conditions, will be employed to minimize risk of damage to the pipe, the coated pipe will need to be handled many times between when the coating is applied in a coating plant and when the pipe is installed in the trench. The inclusion of a polyethylene outer layer in 3LPE coatings should provide increased resistance to damage of the coating during transportation and handling compared to FBE only, if the same detail to handling of the pipe is maintained in the AGDC procedures.[4, 5, 6, 7]

## III. Alternatives

An applicant requesting a special permit from PHMSA has the option of building a pipeline which will not require PHMSA to issue a special permit. This will require the design, construction, and operation of a pipeline in compliance with 49 CFR Part 192, and will not involve the use of 3LPE coatings in conjunction with alternative MAOP or strain based design (SBD). 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 will not require issuance of a special permit. The action alternative

[4] IPC04-0572 Field Trial of Coating Systems for Arctic Pipelines - Robert Worthingham, Matt Cetiner, Meera Kothari, TransCanada Pipelines, Proceedings of IPC 2004, International Pipeline Conference, October 4 - 8, 2004, Calgary, Alberta, Canada.

[5] IPC2008-64472 - Further Large-Scale Implementation of Advanced Pipeline Technologies - Joe Zhou, David Taylor and David Hodgkinson, TransCanada Pipelines Limited, Proceedings of IPC 2008, 7th International Pipeline Conference, September 29-October 3, 2008, Calgary, Alberta, Canada.

[6] Engineering Failure Analysis, Vol 5, No 2, pp. 99-104, 1997, Using the Direct Current Voltage Gradient Technology as a Quality Control Tool During Construction of New Pipelines – Zweni Masilela ¬ and Joe Pereira, Advance Engineering and Testing Services, CSIR.

[7] Pipeline Integrity Assessment: Effect of construction practices in external coating and its evaluation. Joan Soldevila. PROCAINSA, S.A. Major, 40 – 08221 Terrassa (Spain).

reflects Alaska LNG's use of 3LPE for which a special permit with conditions will be issued. The two alternatives are described below.

a. **No Action Alternative** – Construct the pipeline using FBE coatings where alternative MAOP or SBD apply.

This alternative will involve the use of FBE coatings recognized by PHMSA as "non-shielding." The FBE coatings could be single or dual layer FBE. Dual layer FBE includes an abrasion resistant overlay (ARO) as the outer layer.

Because single layer FBE coatings are more brittle than 3LPE coatings, an increased amount of damage to the coatings will occur during transportation if not properly handled. In addition, single layer FBE coatings are more susceptible to damage during installation and service particularly due to contact with rocks during laying, burial, and operation of the pipeline.

Dual layer FBE coatings have been formulated to provide greater impact and abrasion resistance than single layer FBE, but are not as resistant to damage as 3LPE. Both FBE and 3LPE coated pipe can be damaged if procedures are not developed and implemented during construction to control transportation and installation damage. At least one manufacturer does not recommend the use of dual layer FBE for field bending[8]. Cracking of dual layer FBE has also been reported during field bending in cold conditions in the Lower 48[9], and the lower temperatures in Alaska may increase the frequency of cracking. Therefore, the suitability of dual layer FBE products for application in arctic conditions needs to be confirmed to determine if this is a viable alternative. Dual layer FBE are planned to be used in trenchless installations, but this application does not require field bending of pipe.

The 3LPE coating is a more durable coating than FBE for transportation of coated pipe over non-paved roads and pipe installation in frozen soils. As a result of increased susceptibility to

[8] Dual Layer FBE Product Data Sheet, http://www.brederoshaw.com/non_html/pds/BrederoShaw_PDS_DLFBE.pdf..

[9] A. Kehr, M. Dabiri, R. Hislop, "Dual-layer Fusion-bonded Epoxy (FBE) Coatings Protect Pipelines", http://alankehr-anti-corrosion.com/Technical%20Papers/Dual-layer%20fusion-bonded%20epoxy%20(FBE)%20coatings%20protect%20pipelines.pdf.

damage due to the Arctic environment, FBE coatings may have lower initial coating integrity; and could degrade more rapidly in service than 3LPE coatings, thus requiring a greater cathodic protection current.[10] The use of FBE is not preferred for the following reasons:

- It will require a larger cathodic protection system capable of delivering a higher current. Such a system will require increased power consumption and may require larger and more closely spaced anode ground beds thereby increasing the Alaska LNG Pipeline's footprint;
- The higher current demand required from the CP system will increase the risk of interference of the Project's CP system with other systems, including the system protecting the existing TAPS pipeline;
- The lower coating integrity of an FBE system is expected to increase the risk of external corrosion in service, requiring an increased number of repairs in service to maintain pipeline safety; and
- The greater susceptibility to damage during transportation will require a greater number of coating repairs to be performed during construction.

b. **Action Alternative** – Construct and operate the pipeline using 3LPE coating in compliance with the special permit conditions, which generally require:[11]

- Line Pipe Coating Requirements:
  i. Develop a coating procedure that meets specific industry standard;
  ii. Inspections to confirm adequate coating thickness of each layer and that application complied with above-described procedure; and
  iii. Use of high voltage holiday detector.
- Field Joint Coatings:
  i. Coating content;
  ii. Pipe preparation and coating application, including thickness; and
  iii. Coating holiday detection in accordance with industry standard.
- Integrity Management for Cracking

[10] ISO 15589-1:2015, Petroleum, petrochemical and natural gas industries – Cathodic protection of pipeline systems – Part 1: On-land pipelines, Table 2 – Typical design coating breakdown factors, column $\Delta f$.

[11] The special permit contains the full list of special permit conditions. This list is summarized, and the special permit is controlling.

i. Electromagnetic acoustic transducer (EMAT) ILI tool 14 years after startup and every seven (7) years thereafter;

ii. Assess for cracking during excavations and direct assessment using certain tools; and

iii. Fracture mechanics analysis must be performed to evaluate cracking indications.

- Interference Current Control:

  i. Perform interference surveys each calendar year;

  ii. Address currents from interferences sources like pipelines, electric transmission lines, etc. within 12 months; and

  iii. Perform engineering analysis of actions to address interferences every seven (7) years.

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

The special permit allows the use of 3LPE coatings in pipeline segments subject to the requirements of 49 CFR 192.112: alternative MAOP and SBD segments.

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

49 CFR 192.112(f), which states the pipe must be protected against external corrosion by a “non-shielding” coating.

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.*

Except for the design of the coating system itself, the only change to the pipeline design under the special permit will be to the cathodic protection system. Under both the Proposed alternative and the No Action alternative, the cathodic protection system will be designed to deliver sufficient current to prevent corrosion of the pipe steel at locations where coating damage exposes the bare steel of the pipeline (“holidays”). However, the No Action alternative will require an increased current capability due to the greater number of holidays in the as-built condition and more rapid coating degradation. To obtain this higher current capacity, the size and number of anode ground beds will need to be increased. In some cases, this may require additional power generation facilities in remote locations.

The approach to operation and maintenance of the pipeline is expected to be similar under the SP and the No Action alternative. Similar approaches to monitor coating condition and cathodic protection system performance will be utilized, and similar inspections for corrosion damage will be performed. Since a greater number of coating holidays and more rapid coating degradation are expected under the No Action alternative, it should be anticipated that, over the life of the pipeline, a greater number of repairs will need to be performed for the No Action alternative with the commensurate increase in ground disturbance along the pipeline route.

a) *What mill applied and field joint coatings systems are being proposed for use?*

3LPE is proposed as the mill applied coating system for the majority of the pipeline. 3LPE consists of a FBE layer (8-10 mils), a copolymer adhesive layer (6 mils) and a polyethylene outer layer (47 – 118 mils). For more details, see the special permit conditions. The polyethylene outer layer is commonly applied by extrusion, but one available system uses a powder applied outer layer. This is the only coating system that is subject to the special permit.

For a trenchless pipeline installation, the use of FBE with ARO is planned due to its superior lubricity which results in less coating damage in this application.

Liquid applied epoxy or epoxy-urethane field joint coating system are preferred. FBE field joint coatings may also be considered. To provide for good bonding to the 3LPE coating, there will be an FBE ‘tail’, with the outer polyethylene layer removed, at the end of each pipe joint. Prior to coating the field joint, the exposed FBE tail will be prepared to remove non-adhering coating. The area will be preheated to remove moisture. The polyethylene immediately adjacent to the field joint will be cleaned by solvent wipe, roughened as needed to increase surface adhesion. The liquid epoxy/urethane coating will be applied in accordance with approved procedures. The field joint coating system will chemically bond to the FBE tail. Small repairs can be heated using a hot melt adhesive if the FBE base coat is intact. Pipe with damaged FBE coating will be repaired following a similar procedure to the application of liquid epoxy or epoxy-urethane field joint coating. The liquid repair will overlap with the intact parent coating.

b) *How do these proposed coating systems different from those used historically to coat pipelines, to include FBE?*

Numerous coating types have been used to coat pipelines historically including coal tar enamel, asphalt enamel, adhesive backed polyethylene tapes and dual layer polyethylene (PE), FBE and 3LPO coatings, a class of coatings that includes 3LPE. However, issues with the long-term performance of other systems have led to FBE and 3LPE being the predominant systems that are currently selected for new pipeline systems.

The first layer of the 3LPE is similar to an FBE coating. The FBE layer in a 3LPE system can be somewhat thinner (8-10 mils minimum dry film thickness for the Alaska LNG Project) than a standalone FBE system (typically 12-20 mils minimum dry film thickness) because the outer layers of the 3LPE system provide protection to the inner FBE layer. The 3LPE system includes a copolymer adhesive layer and an outer PE layer in addition to the FBE layer. The PE outer layer is designed to provide increased impact and damage resistance, while the copolymer adhesive ensures good bonding between the FBE and PE.

The field joint coating systems, described above, are the same systems that will be considered if FBE was to be used as the coating system. Figure 2 shows a summary of recent coating system installations worldwide.

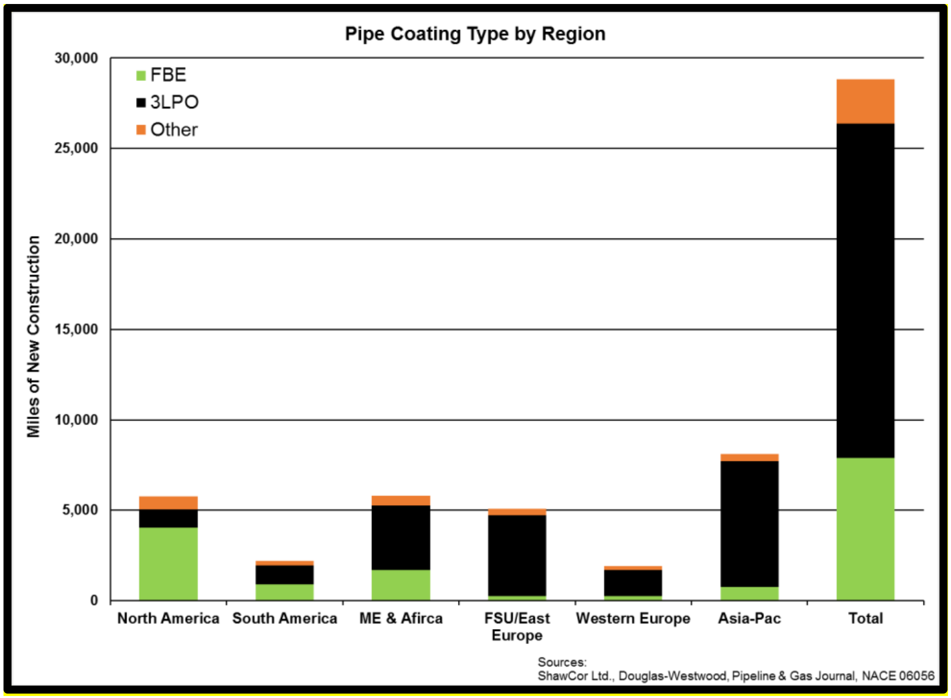


**Figure 2: Global Coatings Market Share by Region (Buchanan, 2013 reproduced from Attachment D, Section 7)**

c) *What are the pros and cons for a 3LPE system in Alaska?*

The pros and cons for a 3LPE system in Alaska as compared to FBE are included in Table 1, where green is a "pro," red is a "con," and orange is "neutral."

d) *Does CP work with 3LPE Coatings?*

The outer layers (i.e. polyethylene) of the 3LPE coating are electrically insulating; electrically insulating pipeline wraps and tapes have prevented or shielded CP from reaching the pipe metal in areas of coating disbondment, and resulting SCC has caused major pipeline failures. For these reasons, the practice in the U.S. has been to apply FBE coatings to ensure CP can reach areas of coating disbondment. PHMSA is not aware of any data that demonstrate the effectiveness of CP with 3LPE coatings. However, increased inspection for cracks is anticipated to detect any resulting SCC before it can threaten pipeline integrity.

See Attachment D – 3LPE Coating Technical Support document, Section 2 for more information on CP and its effectiveness under various disbondment scenarios.

e) *Are over the line CP testing techniques (direct current voltage gradient (DCVG), close inspection survey (CIS), etc.) effective in finding coating damage with 3LPE coatings? Is there anything different with 3LPE coatings that would impair the resultant over the line data? What will these techniques find, and miss with 3LPE (e.g. disbondment vs. break in coating)?*

The same over the pipeline inspection techniques [Close Interval Survey (CIS), Direct Current Voltage Gradient (DCVG) and Alternating Current Voltage Gradient (ACVG)] utilized for FBE are equally effective with 3LPE and will be implemented in compliance with the requirements of 49 CFR 192.620 in areas where alternative MAOP and SBD are utilized, at a minimum. For any coating system, over the line inspection, CP with periodic monitoring and remediation, coupled with in-line-inspection are the most effective ways to inspect, monitor, and remediate for coating integrity and corrosion. See Attachment D, Section 6 for further discussion of the utility of over-the-line surveillance techniques with 3LPE coated pipelines.

f) *What In-Line Inspection technology will be used to detect SCC?*

EMAT in-line inspection tool will be run to inspect for SCC. Additional details on Integrity management for SCC can be found in the special permit conditions.

**Table 1. Pros and Cons of FBE and 3LPE for application in Alaska**

| Characteristic | Fusion Bonded Epoxy (FBE) | Three Layer Polyethylene (3LPE) |
|---|---|---|
| Damage Resistance | Susceptible to damage from transport/backfill and UV degradation | High resistance to damage from transport/backfill and UV degradation |
| Long term integrity | Higher rate of coating degradation; higher reliance on cathodic protection for integrity | Long-term coating integrity (lower rate of coating degradation); low reliance on supplementary cathodic protection for integrity |
| CP System | High current requirement; special design considerations required to avoid imposing/experiencing stray current corrosion. | Low current requirement; low risk of imposing/experiencing stray current corrosion |
| | Additional ground beds will be required at sites without power. Larger footprint, increased emissions | Ground beds located at compressor stations |
| Most common failure modes | Cracking, perforations, blisters; not prone to delamination if properly applied | Perforations; not prone to delamination if properly applied. |
| Potential for shielding CP | Low; FBE is generally conductive when moisture is present in soil | Not established; 3LPE is insulating, but has worked effectively with CP systems in a limited data set. Worst case delamination scenario results in limited localized corrosion detectable by regular ILI-MFL inspection. |
| Experience | Good (extensive use worldwide) | Good (extensive use worldwide), little in United States. |
| Potential for SCC | None | May shield CP, which can lead to SCC. |
| Coating Repairs | Repairs in and around the trench during construction will be necessary (increased safety exposure) | Excellent mechanical damage resistance; few coating repairs anticipated |
| Coating Cost | Relatively inexpensive | About double the cost of FBE |
| Field Joint Coatings | Liquid epoxy/urethane system | Liquid epoxy/urethane system |
| Aboveground Assessment | Can detect coating damage that poses risk of corrosion | Can detect coating damage that poses risk of corrosion |

**Notes: Green** = Pro; **Orange** = Neutral; **Red** =

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 use of 3LPE coatings (see table below) include the entire onshore portion of the Alaska LNG Pipeline in Class 1 locations.

| **Table 2: Special Permit Segments** | |
|---|---|
| **Milepost (MP)** | |
| **Start (MP)** | **End (MP)** |
| 0.00 | 535.99 |
| 536.49 | 766.00 |
| 793.00 | 798.65 |
| 801.27 | 803.78 |
| 806.25 | 806.57 |

## 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.*

The following consideration of the potential impacts of small and large pipelines leaks/ruptures to the environment/human health apply equally to the Proposed Action and primary No Action alternatives, given both alternatives are buried pipelines.

i. Any discussion of leak or rupture consequence must be put into the context of its probability. It is highly unlikely a leak or rupture will occur in the Alaska LNG mainline for the following reasons:

a) Remoteness of the pipeline route: more than 99 percent of the Alaska LNG Pipeline route is in Class 1 location (801.0 miles of 806.6 miles). A study was performed in 2000 for the Pipeline Research Council International, Inc. wherein PHMSA incident data for 1985 through mid-1997 was reviewed.[12] Results of the review indicated the frequency of incidents is significantly less for pipelines in

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

Class 1 locations than in Class 2, 3 or 4. Specifically, the number of incidents per 1,000 mile-years in Class 1 Locations was 0.15 as compared with 0.24 and 0.65 for Class 2 and Class 3 and 4 Locations, respectively. When considering the reported cause of the incident, the cause with the most significant difference in incident rate was Damage by Outside Force. In fact, this cause was really the only difference between Class 1 and Class 2 Locations.

b) Resilience to third party mechanical damage: there is very low risk of mechanical damage given the remoteness of the pipeline and the high thickness of the pipeline. Fracture mechanics calculations have shown the pipe is very resistant to fracture, capable of withstanding a through wall thickness puncture of greater than 4 inches in length without rupturing for Class 1 locations of the pipeline designed with AMAOP, and even longer lengths for the SBD segments and higher-Class locations. Through wall thickness punctures of 4 inches or less will result in a leak. The pipe will be designed to prevent a propagating fracture from occurring in the unlikely event there was a rupture.

c) Very low probability of internal corrosion damage: The Alaska LNG Pipeline will be transporting a dry, liquefied natural gas (LNG) specification gas, thereby minimizing the probability of internal corrosion. To confirm the integrity of the pipeline, the inline inspection program will comply with the robust requirements of 49 CFR 192.620 and the special permit conditions. External corrosion will be minimized and mitigated by using a high integrity coating and a cathodic protection system.

d) Compliance with alternative MAOP requirements: the entire Alaska LNG Pipeline will be operated and maintained per applicable requirements in 49 CFR 192.620 with the exception of coating requirements. Additionally, more than 615 miles of the total Alaska LNG Pipeline length will be designed, constructed, operated and maintained to comply with applicable requirements in 49 CFR 192.112 and 192.328.

ii. A small leak from a buried 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 would permeate through the backfill material (soil) before dissipating into the air. Small gas pipeline leaks may result in some impacts to, or loss of, surrounding vegetation. This localized browning of vegetation can facilitate identification of small underground leaks.

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

iv. For a fire resulting from a rupture; the damage due to the fire would depend on the extent of the combustible materials in the vicinity, (infrastructure, vegetation), and local environmental conditions, (e.g., rain, snow cover, etc.).

b. *Submit an explanation of* ***<u>delta/difference</u>*** *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 multi-layer coating mitigation measures.*

The anticipated differences in effects for individual resources between the No Action alternative and the Proposed Action alternative are discussed below. The differences are negligible. References are made to FERC Resource Reports, where applicable, for further detailed information and analysis of impacted resources. The basis for the FERC Resource Reports is the Proposed Action alternative; however, the associated environmental impact analysis is also applicable to the No Action alternative, given both alternatives are based on buried design and installation, and both follow an identical route. In general, less long-term data is available for pipelines with 3LPE coatings than pipelines with FBE coatings. Therefore, it is possible 3LPE may not provide identical protection against external corrosion [and cracking], which could increase the risk or rates of external corrosion development. However, Alaska LNG maintains the 3LPE coating will be the most resistant to damage from shipping and handling over the long and potentially rough transport distances. Considering lesser data availability related to external corrosion caused by coating holidays with 3LPE coating, PHMSA will impose special permit conditions for Alaska LNG to implement.

1. Human Health and Safety

As discussed above, the probability of a pipeline leak or rupture is considered low due to several factors, largely independent of the coating system selected. While 3LPE coating has been in use for a shorter time than FBE, particularly in the U.S. and, therefore, has less long-term data available, it has been in use for more than 20 years and, based on information available, no leaks or ruptures due to external corrosion have been reported. Any possible increase in risk associated with the development of SCC is mitigated through use of the additional cracking protocol, including in line inspections and direct assessments requirements.

2. Air Quality

There will 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. Increased power generation will be required for the No Action alternative given its larger CP system, although this is not likely to significantly increase overall emissions. Operations and Maintenance activities to maintain the pipeline for the No Action and Proposed Action alternatives would require similar equipment and personnel.

Detailed descriptions of air emissions, including greenhouse gas emissions, from pipeline construction and operations are contained in FERC Resource Report No. 9, *Air and Noise Quality*.

3. Aesthetics

There will be no difference in visual effects between the No Action and Proposed Action alternatives. Visual effects from both will be limited to the ROW clearance, which would be less obvious with winter snow cover.

Analysis of potential impacts to aesthetics, and associated mitigations, from a buried pipeline are considered in FERC Resource Report No. 8, *Land Use, Recreation and Aesthetics*.

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

There will be no difference in impacts to vegetation, wetlands and wildlife between the between the No Action and Proposed Action alternatives. Both alternatives will be below ground, and follow the same route.

FERC Resource Report No. 3, *Fish, Wildlife and Vegetation,* contains descriptions of vegetation and wildlife resources, and potential impacts associated with the Alaska LNG Pipeline route. FERC Resource Report No. 2, *Water Use and Quality,* contains a detailed analysis of wetlands affected by the Alaska LNG Pipeline route, and mitigation of impacts.

5. Resilience and Adaptation

The potential effects of a changing climate on Alaska LNG Pipeline design and operation are not expected to differ between the No Action and Proposed Action alternatives. Project design criteria incorporated consideration of a range of variable site conditions that could occur based upon historic information and future conditions. Mitigations are integrated into the design where appropriate or required for facility integrity and safe operations. Opportunities for resilience and adaptation to potential weather effects have been considered in the design of the Alaska LNG Pipeline. For example, geothermal modeling will be used to assess potential changes in ground temperatures that could be caused by longer-term geothermal impacts of pipeline construction, operations and changes in climate. Other resilience and adaptation design considerations for the Alaska LNG Pipeline are addressed in FERC Resource Report No. 1, *General Project Description*.

FERC Resource Report No. 9, *Air and Noise Quality* discusses greenhouse gas emissions from the Project.

6. Cultural Resources

There will be no difference in the effect on Cultural Resources between the No Action and Proposed Action alternatives. Construction activities have the potential to affect cultural resources. Ground-clearing activities under both cases will be similar. The FERC is conducting the Section 106 consultation process with stakeholders; that process will lead to the development of an agreement that will address identification and management of known cultural resources as well as those that are inadvertently discovered during project implementation. The cultural resource requirements will apply to both the No Action and Proposed Action alternatives to mitigate effects on these resources. FERC Resource Report No. 6, *Cultural Resources*, addresses cultural resources affected by the Project, and associated mitigations.

7. Environmental Justice

Since both pipeline designs will be sited in the same footprint, there will be no difference in effects on environmental justice resulting from construction or operation of the pipeline between the No Action and Proposed Action alternatives.

8. Geology, Soils and Mineral Resources

There will be no difference in the effect on Geology, Soils and Mineral Resources between the No Action and Proposed Action Alternatives. Construction activities 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 using erosion and sediment control measures, including, where appropriate:

- The use of winter construction in areas of inundated and frozen ground conditions where practicable;

- Use of settlement basins, silt fences, and other Best Management Practices (BMP) for storm water control;
- Use of engineered flow diversions and slope breakers to control water flow on slopes and around water courses; and
- Installation of trench breakers to address storm and groundwater flow through the trench backfill or during construction.

Operations and maintenance activities along the pipeline right-of-way to meet 49 CFR Part 192 will be similar for the two alternatives. Operation and maintenance excavations will be conducted as authorized under the applicable ROW authorization. ROWs will be issued by one or both of the Bureau of Land Management and Alaska Department of Natural Resources as the land management agencies responsible for lands along the pipeline route. All excavations and other applicable activities will be permitted through the appropriate Federal and State agencies for both alternatives. Both alternatives will have similar impacts on soil resources.

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 contained in FERC Resource Report No. 7, *Soils*.

9. Indian Trust Assets

No Indian Trust Assets or Native allotments are located within the pipeline route.

10. Land Use, Subsistence, and Recreation

There will be no difference in the effect on Land Use, Subsistence, and Recreation between the No Action and Proposed Action alternatives. During construction, land use in the form of subsistence activities and recreation for both alternatives could be altered in the immediate vicinity of activities. The pipeline's remote location combined with the relatively small width of the ROW will generally limit the extent of displacement by users to the active construction zones.

After construction, the ROW will 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 No. 8, *Land Use, Recreation and Aesthetics*, considers potential effects to land use and recreation activities. FERC Resource Report No. 5, *Socioeconomics*, considers potential impacts to subsistence.

11. Noise

There will be no difference in Noise Impacts between the No Action and Proposed Action alternatives. Impacts will 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 will primarily result from operation of compressor and heater stations, and periodic ROW maintenance and inspection activities. Compression requirements are the same for both alternatives, so there is no change to the number of compressor and heater stations and the associated noise profile.

A detailed discussion of noise impacts associated with pipeline construction and operation is provided in FERC Resource Report No. 9, *Air and Noise Quality*.

12. Water Resources

There will be no difference in impacts to water resources between the No Action and the Proposed Action alternatives. For both alternatives, stabilization techniques, including gravel blankets, riprap, gabions, or geosynthetics as appropriate for the location, will be used to stabilize the channel bed and stream banks at stream crossings. The majority of rivers and streams along the pipeline route will 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 calculations to avoid the potential for scour. Methods for each watercourse crossing are the same for both alternatives.

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 No. 2, *Water Use and Quality*.

With the special permit conditions in place, PHMSA believes the Proposed Action alternative will result in the same protection against external corrosion and cracking as the No Action alternative. Therefore, PHMSA does not anticipate any change in risk to the above resources could be caused by a pipeline failure resulting from external corrosion or stress corrosion cracking.

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 of the code.

   The successful use of either FBE with ARO coating or 3LPE coating systems requires that coating application, inspection and quality assurance procedures lead to a high-quality coating with good adhesion of the coating to the pipe. Similarly, field joint coatings will be liquid epoxy or epoxy-urethane material and compatible with the coating system and the quality of the field joint coating must be ensured (See Attachment D, Section 5).

   The function of a coating system is to protect the pipeline from corrosion. The effect of coating type on susceptibility to corrosion and stress corrosion cracking was also considered.

   Coating damage will be repaired in a manner similar to the field joint application procedure. The damage area will be cleaned. The exposed FBE will be prepared to remove non-adhering coating. The area will be preheated to remove moisture. The polyethylene immediately adjacent to the damage will be cleaned by solvent wipe and roughened as needed to increase surface adhesion. The liquid epoxy or epoxy-urethane coating will be applied in accordance with approved procedures.

ii. What are the safety and environmental risks from usage of 3LPE that need to be protected against?

The safety and environmental risks associated with the Proposed Action will result from a change to the risk of a leak or rupture and the subsequent release of gas and possible explosion or fire. The risk of leak or rupture can be affected by coating performance because external corrosion and stress corrosion cracking are failure mechanisms that require failure of the coating. To ensure this benefit is achieved, compliance with the special permit conditions, including ensuring coating application procedures are qualified and adequate quality control is applied and a crack detection protocol is in place, is necessary.

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.*

i. The special permit conditions were designed to ensure best practices and application, testing and quality control for plant applied and field joint coating are applied.

The conditions were designed to reduce the risk of SCC. Although there is no history that indicates pipelines coated with 3LPE are susceptible to SCC, EMAT in-line inspection is required by the conditions to ensure this threat will be detected before it will lead to leak or rupture of the pipeline. The use of the above measures helps to ensure that no significant environmental impact will result from the use of 3LPE. It is anticipated that the higher initial coating integrity and reduced rate of coating degradation with the use of 3LPE will lead to an overall improvement in pipeline safety and reduce potential environmental impact.

ii. Figure 3 shows historical information of 3LPO coating systems installed by ShawCor Ltd., which indicate long term installations of the systems as well as a significant increase in installation of three-layer systems in the past 10 years.

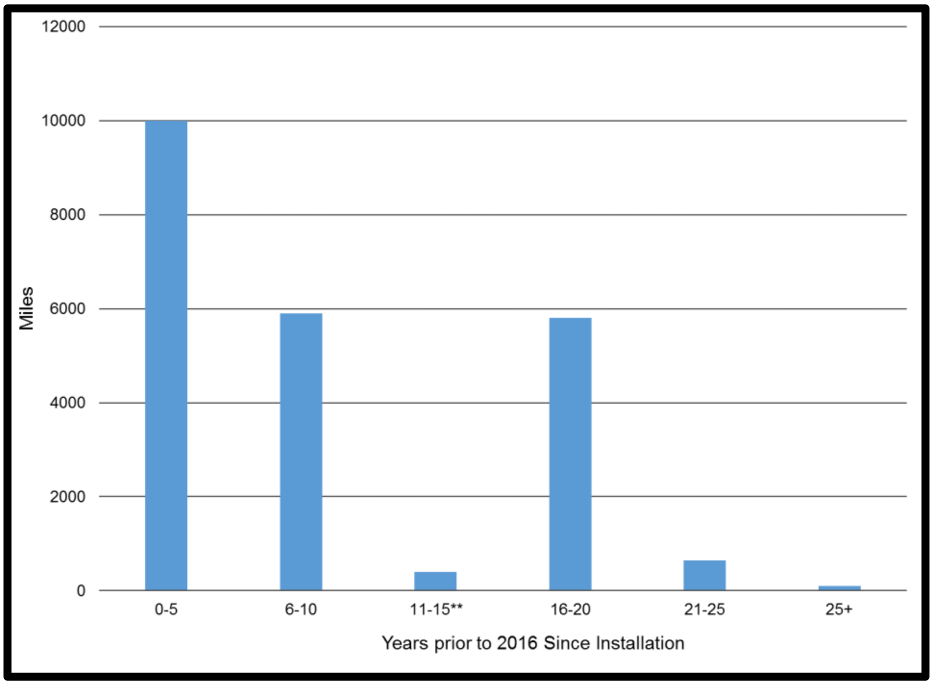


**Figure 3: Three-layer polyolefin pipeline coating length applied by ShawCor Ltd (reproduced from Attachment D, Section 7).**

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

PHMSA believes use of 3LPE along with implementation of the special permit conditions will not increase the risk of a pipeline leak or rupture through the use of a coating that is more resistant to mechanical and installation damage. Coating type has no effect on the consequences of a leak or rupture. Under either the Proposed Action or the No Action alternative, the consequences of a pipeline failure will 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.*

Implementation of the special permit conditions will positively impact pipeline longevity and reliability by reducing coating degradation, monitoring threats, and the implementation of remediation measures for 3LPE coating degradation and other related pipeline integrity threats.

PHMSA believes the approach for integrity management and maintenance of the pipeline is similar for the Proposed Action and No Action alternatives. However, the special permit conditions require additional inspection, and testing during the coating application, and more robust in-line inspection and assessment requirements during Operation and Maintenance for the Proposed Action alternative.

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

Several layers of protection are utilized to prevent pipeline failures due to corrosion:

i. The coating system prevents external corrosion by acting as a barrier between ground water, oxygen, and the steel pipe.

ii. The cathodic protection system prevents corrosion at any breaks in the coating.

iii. In-line inspection detects wall loss and cracking type defects allowing repair before failure.

The use of 3LPE and compliance with the special permit conditions are expected to positively impact the effectiveness of the first two items above. Reduced coating damage and slower coating degradation are expected to lead to fewer coating defects. The higher integrity of the 3LPE coatings are expected to lead to reduced current demand on the cathodic protection system and reduced risk of interference with neighboring structures. Thus, the special permit is expected to improve human safety by reducing the overall likelihood of failure and the potential for injury from the resulting release of gas.

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

Special permit status will not change land use planning processes, given that the Proposed Action and No Action alternatives will both be premised a belowground basis. The ROW authorization requirements, and other land use planning notification processes will be the same with or without a special permit.

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

The "No Action alternative" may require a small increase in size and number of anode ground beds to accommodate the possible higher CP current requirements of an FBE coating pipeline due to anticipated higher total current demand based on the difference in coating breakdown factors. Implementation of the special permit will not affect any other pipeline facilities, public infrastructure, or environmentally sensitive areas.

j. *What scenario would be required for CP shielding leading to corrosion or SCC to occur? How likely are these scenarios?*

In the event that the coating disbondments occur, it is possible that the 3LPE coatings could shield uncoated pipe from CP, which could lead to SCC over time. For this reason, AGDC will be required to run an EMAT tool, which exceeds current regulatory requirements. See Attachment D, Section 3 for a discussion of shielding and Section 4 for a discussion of SCC scenarios.

k. *Based on industry experience, 1) has SCC occurred with 3LPO coatings and what 2) mitigation and 3) detection techniques will be employed?*

1) Industry experience has not identified any instances of SCC with 3LPO coatings. See Attachment D, Section 9 for a summarized record of the Applicant's discussions with various pipeline operators. In addition, DNV GL was contracted to perform a search of global literature and pipeline operator data and did not identify any instances of SCC with 3LPE coatings.

2) Mitigation: Stringent quality assurance and quality control (QA/QC) measures will be employed during 3LPE coating application. The surface will be prepared by abrasive grit blasting, which imparts a compressive stress on the surface of the metal that is recognized to provide resistance to SCC. See Attachment D, Section 5 for more information on the QA/QC of 3LPE coatings.

3) Detection: EMAT and high resolution magnetic flux leakage (HR-MFL) in line inspection tools will be utilized to detect SCC and general corrosion.[13]

l. *What survey techniques will be used during Operations?*

The same survey techniques will be used during the construction and maintenance of 3LPE as with any other coating system:

- DCVG and CIS as part of commissioning the cathodic protection system as well as ongoing surveillance.
- ILI baseline upon commissioning and ongoing inspection in accordance with 49 CFR Part 192, Subpart O. The ILI tool results must address ILI tool tolerances. Fracture mechanics analysis must be performed to evaluate cracking indications reported by ILI or direct examinations. All cracking exceeding 40% of the pipe wall thickness or with a failure pressure ratio (FPR) below the criteria in 49 CFR 192.620(d)(11) must be remediated. The special permit conditions have the crack evaluation details.

m. *What is the threat from interference initiated corrosion (e.g. Alternating Current (AC) interference, Direct Current (DC) interference, stray current, telluric) and how do we plan to monitor and mitigate it?*

Electrical interference assessment, monitoring and mitigation are key aspects of pipeline and cathodic protection design, and will be addressed during the detailed engineering stages, in accordance with the special permit conditions and applicable requirements in 49

[13] Although the utilization of a high resolution magnetic flux leakage (HR-MFL) in-line inspection (ILI) tool is not a proposed condition of this special permit application, PHMSA will require the use of this tool in the special permit for the use of strain based design (SBD) on the Alaska LNG Pipeline.

CFR Part 192. Each type of interference (stray current, AC interference, and telluric) will be evaluated and, where necessary, electrical interference mitigation systems will be designed and installed. These actions are expected to confirm the functionality and adequacy of CP, which is critical for pipeline integrity by preventing corrosion in areas of coating disbondment.

Alaska LNG will implement a monitoring program and remediation plan in accordance with 49 CFR Part 192, Subpart I and the special permit conditions.

**AC Interference**

AC interference can occur where pipelines are in close proximity to AC electric power transmission system lines; particularly where pipelines are approximately parallel to power lines. AC interference can occur during steady-state operation of power lines and during fault conditions on power lines.

The electrical interference monitoring program and remediation plan will mitigate AC interference by identifying exposures, identifying changes in power line operating conditions that could cause or increase interference, and providing for mitigation to reduce interference to acceptable levels. Mitigation can include installation of AC interference mitigation grounding cells and parallel ribbons, potential gradient control mats and DC decoupling devices.

**DC Interference**

DC interference can be caused by several sources, such as foreign IC CP systems, DC electric power transmission systems, DC traction power systems and welding operations. Some sources of DC interference are considered to be steady-state sources (such as foreign IC CP systems), and some are considered to be stray sources (such as DC electric power transmission systems, DC traction power systems and welding operations).

The electrical interference monitoring program and remediation plan will facilitate mitigation of DC interference by identifying interference, by identifying the sources of interference, and by providing for mitigation to reduce interference to acceptable levels. Mitigation can include careful selection of sites for IC CP systems, collaborated adjustment of native and foreign IC CP systems, installation of bonds with interfering DC sources, installation of galvanic anode current drains, and dielectric shielding (use of robust coatings in areas of anticipated or known interference exposures).

**Telluric Current Interference**

Telluric current interference is electrical interference that results from the interaction of a pipeline with the earth's magnetic field and solar radiation passing around the earth. The interaction creates electric fields in and around a pipeline which result in DC voltages and current flow on the pipeline. Fluctuations in DC voltages and current flow caused by telluric activity are very low frequency electrical phenomena.

Telluric current interference does not normally cause significant corrosion damage on pipelines, but it can under certain conditions and/or over long periods of time. Pipe-to-soil potential data collected during annual CP surveys will be used to monitor for telluric current interference. When these pipe-to-soil potential measurements are made, telluric current interference will readily be detected if it causes fluctuations in pipe-to-soil potential measurements.

As a minimum telluric current interference will be mitigated in a manner that will achieve pipe-to-soil potentials in compliance with 49 CFR Part 192 Subpart I. Mitigation can include installation of galvanic anode current drains and installation of automatic potential control IC CP system rectifiers at exposure locations.

Locations and types of CP test stations to be installed for operational monitoring of CP and electrical interference will be determined during the detailed design phase of engineering for the Project. Determination of test station requirements will be performed following pipeline industry standards and regulatory requirements for special permit pipelines. As a minimum for special permit segments of the pipeline, test stations will be installed as follows:

- At least once every mile;
- At crossings of buried foreign metallic structures; and

- On each side of major waterbody crossings.

Coupons will generally be installed at each test station, except at locations where coupons will not function as intended (e.g. in permafrost). Coupons are used to determine the amount of voltage gradient (IR drop) in the soil when the CP systems are energized (or connected, in the case of sacrificial anodes). Use of coupons for this purpose is common practice for complex or hybrid CP systems where it is difficult to effectively obtain IR-free potential measurements by cycling the entire CP system on/off at the same time.

Remote monitoring will be installed to provide real time CP operating outputs. The specific products and frequency of installation of these systems will be determined in future Project engineering phases.

## V. Consultation and Coordination

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

**PHMSA:**

Amelia Samaras (Senior Attorney), Joshua Johnson (Engineer); Steve Nanney (Engineer)

**Alaska Gasline Development Corporation:**

Frank Richards (Senior Vice President)

**Alaska LNG LLC:**

Rick Noecker (PHMSA Filing Coordinator), Alyssa Samson (Materials Engineer), Mario Macia (Pipeline Technology Lead), Norm Scott (ERL Advisor)

**Michael Baker International:**

Keith Meyer (Senior Pipeline Advisor), Paul Carson (Corporate Pipeline 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 landowner's/land managers potentially impacted:

Cook Inlet Region, Inc.
Ben Mohr
Sr. Director, Land and Resources
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(907) 263-5140

Bureau of Land Management
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BLM Alaska State Office
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Alaska Department of Natural Resources
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Alaska Department of Transportation & Public Facilities
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Don Striker
Superintendent
Denali National Park and Preserve
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Denali Park, AK 99755-0009
(907) 683-9532

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

Active stakeholder engagement has occurred throughout Alaska and federal, state and local agency engagement is ongoing. In 2015 and 2016, one-on-one as well as multiagency engagement meetings were held to cover pipeline design construction and routing. Additionally, there have been over 20 engagement meetings between the Applicant and PHMSA. The coatings systems described herein were a topic of discussion at multiple meetings, and there have been responses to several requests for additional information on coatings systems that were made by PHMSA. Additionally, an overview of this special permit was provided at a joint meeting with PHMSA and FERC on April 19, 2016.

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 Section 1.9 and Appendix D of Resource Report 1 of the FERC Resource Reports.

## VI. Response to Public Comments Placed on Docket PHMSA-2017-0046

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-2017-0046, Usage of 3LPE Coating; PHMSA-2017-0044, Usage of Strain Based

Design; PHMSA-2017-0045, Alternative Mainline Block Valve Spacing; 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 all comments received through July 29, 2019, being reviewed and considered. PHMSA received a public comment concerning usage of fossil fuels, the building of the Alaska LNG Pipeline, and the building of a liquefied 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.

## VII. 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 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 will be achieved if the pipeline were designed, constructed, operated, and maintained in full compliance with 49 CFR Part 192.

## VIII. Bibliography

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

See footnotes.

## IX. Conditions: Example of what special permit conditions address

a. *Plant-applied coating system qualification and testing: What will be done to ensure the long-term integrity of the coating and the disbondment failures will not occur?*

To ensure the integrity benefits of 3LPE coatings are achieved, the conditions require best practices be applied to the qualification of the coating system. The qualification will require each plant used for the application of coatings be qualified separately. The qualified coating procedure and qualification testing must reflect the industry best practices that are included in ISO 21809-1[14], a global standard for 3LPO coatings. Periodic testing during coating application (production testing) confirms the properties achieved during qualification continue to be achieved.

The coating application procedure will be in accordance with requirements of ISO 21809-1, and will include details on the following:

a) Incoming inspection of pipes and pipe tracking.

b) Data sheets for coating materials and abrasive blasting materials.

c) Certification, receipt, handling and storage of materials for coating and abrasive blasting.

d) Cleaning procedure for application equipment.

e) Preparation of the steel surface including monitoring of environmental parameters, methods and tools for inspection, grinding of pipe surface defects and testing of surface preparation.

f) Coating application, including tools/equipment for control of process parameters essential for the quality of the coating.

g) Methods and tools/equipment for inspection and testing of the applied coating.

h) Repairs of coating defects and any associated inspection and testing.

i) Preparation of coating cutback areas.

j) Marking and traceability.

Qualification and production testing required by ISO 21809-1 includes:

- Inspection of surface preparation;
- Minimum epoxy thickness;

[14] ISO 21809-1 (2011) Petroleum and natural gas industries - External coatings for buried or submerged pipelines used in pipeline transportation systems Part 1: Polyolefin coatings (3-layer PE and 3- layer PP)

- Minimum adhesive thickness;
- Degree of cure;
- Continuity (holiday detection);
- Total thickness of coating;
- Impact resistance;
- Peel strength;
- Indentation;
- Elongation at break;
- Cathodic disbondment;
- Hot water immersion test; and
- Flexibility.

b. *Field Joint coating system qualification and testing: What will be done to ensure the long-term integrity of the field joint coating?*

Field joint coating systems are used to coat girth welds made in the field and the adjacent pipe ends. Ensuring the success of the coating system requires the field joint coating system achieve high integrity and the field joint coating system is compatible with the plant-applied system. The conditions require the qualification of the field joint coating procedure that will be used.

The conditions require that the field joint coating application procedure describe the following:

- Method for surface preparation and required surface profile;
- Method for heating the pipe and monitoring temperature;
- Nominal steel temperature for application of field joint coating and permitted range;
- Manufacturer and brand name of product;
- Method and equipment for application of coating;
- Minimum dry film thickness; and
- Method for holiday detection and repair.

The required field joint coating qualification tests include:

- Impact resistance testing;
- Hot-water soak/adhesion testing;
- Penetration resistance testing; and
- Cathodic disbondment testing.

In addition, the conditions require verification of the coating thickness on each field joint and holiday detection for each field joint.

c. *Inspection and qualification of inspectors: What will be done to ensure the qualifications of inspectors?*

The conditions require that coating and field joint coating operations are monitored by certified coating inspectors.

d. *What measures will be employed to detect SCC, if it were to occur?*

There have been pipeline integrity issues due to stress corrosion cracking resulting from the use of tape wrap, coal tar enamel, and asphalt coatings. Failures of these coatings have occurred in a manner that has allowed ground water and oxygen to reach the pipe steel surface, but blocked CP current (i.e., caused “CP shielding”). The 3LPE coating system is a modern coating system that has not been associated with the occurrence of similar issues. However, there is limited experience with 3LPE service times greater than 20 years. The conditions contain provisions that ensure the threat of SCC will be assessed throughout the life of the pipeline to ensure if long-term (i.e., 20+ years) use of these coatings leads to increased susceptibility to SCC, the threat will be identified and managed before it leads to leaks or ruptures of the pipeline.

The special permit conditions require periodic in-line inspection with a crack detection tool to identify whether SCC is an integrity threat to the Alaska LNG pipeline. Electromagnetic Acoustic Transducer (EMAT) is the crack detection tool required by the special permit conditions.

Because SCC can take at least 10 years to form, it should also be understood that by the time Project pipelines reach an age at which SCC could begin to develop, significant additional industry experience will be available with longer term use of 3LPE coatings. As a result, there will be a substantial global experience base available to identify whether 3LPE coated pipelines are susceptible to SCC and this additional knowledge will be available to further inform assessments of the risk of SCC.

*e. How will interference currents control be addressed?*

An induced AC or DC monitoring program and remediation plan to protect the pipeline from corrosion caused by stray or interference currents must be in place within 1 year of the pipe in these segments being installed in the ditch (including backfill).

Within 12 months of the results of the interference engineering analysis, any AC interference causing AC current discharge greater than 50 amperes per meter squared of surface area must be remediated. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference that results in CP levels that do not meet the requirements of 49 CFR Part 192, Subpart I, must be remediated within 12 months of this evaluation.

**Completed by PHMSA in Washington, DC on:** September 9, 2019