APPENDIX E.1 THREE-LAYER POLYETHYLENE COATING, MAINLINE BLOCK VALVE AND CRACK ARRESTOR SPACING PERMIT CONDITIONS

Three Layer Polyethylene Coating (3LPE) Coating

Special Permit Conditions

The ***Three Layer Polyethylene Coating (3LPE) Conditions*** are presented under the following titles:

- Overview
- Three Layer Polyethylene Coating
- Reporting and Certification
- Nomenclature
- Limitations

Overview:

1) **Purpose and Need:** The **ALASKA LNG PROJECT** and PHMSA agree that certain Conditions are necessary for the safe design, construction and operation of the pipeline extending from the Prudhoe Bay Unit to the LNG Plant located on the Kenai Peninsula, otherwise known as the ***Mainline***. **ALASKA LNG PROJECT** may propose changes to these ***3LPE Conditions (Conditions)***, review dates or timing to PHMSA for "no objection." Any proposed changes to the ***Conditions*** by the **ALASKA LNG PROJECT** must maintain equivalent/acceptable levels of safety. PHMSA will determine whether substantive changes to the ***Conditions*** require a modification or public notice of this special permit. PHMSA will provide the **ALASKA LNG PROJECT** with notice of its decision and an opportunity to respond to any proposed changes in accordance with 49 CFR § 190.341 and the Limitations section of this special permit. Any submittal timing, review timing, or completion timing in these ***Conditions*** can be modified by PHMSA upon request by the **ALASKA LNG PROJECT** and with a "no objection" from PHMSA[1] to the **ALASKA LNG PROJECT**.

[1] The **ALASKA LNG PROJECT** must submit any proposed changes to the ***Conditions*** to PHMSA Director,

2) **Applicable Regulations:** The ***Pipeline*** must be designed, constructed, operated and maintained in accordance with 49 CFR Part 192 including, but not limited to, those requirements that are stated as pertaining to alternative MAOP (§§ 192.112, 192.328, and 192.620), but with exception to the “non-shielding coating” requirements of § 192.112(f) as described herein and other exceptions as granted by other Special Permits. In addition to Part 192 conformance, the ***Pipeline*** must also be designed, constructed, operated and maintained in accordance with these ***Conditions***. In the event of a conflict between these ***Conditions*** and the applicable requirements under 49 CFR Part 192, the ***Conditions*** shall control.

3) **Maximum Allowable Operating Pressure (MAOP): The ALASKA LNG PROJECT** must operate the 42-inch diameter **ALASKA LNG PROJECT** Prudhoe Bay to Nikiski pipeline (the **ALASKA LNG PROJECT** ***Mainline Pipeline***) at or below a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The ***Mainline*** can be designed for operation up to 80% of specified minimum yield strength (SMYS), allowing for pressure build-up and overpressure protection in accordance with 49 CFR §§ 192.605(b)(5) and 192.201(a)(2).

Three Layer Polyethylene Coating:

4) **Plant-Applied Coating System and Coating Applicator Qualification**
   a) Before production starts, the coating application procedure shall be prepared in writing and qualified by the applicator in the factory that will be used for the Project’s production order on pipe of the same diameter and wall thickness. The procedure as a minimum, shall address the requirements of Section 9 from ISO 21809-1.
   b) The required qualification tests and acceptance criteria shall be in accordance with ISO 21809-1

Western Region or PHMSA project designee for review and “no objection” prior to usage.

5) **Plant-Applied Coating Specification Requirements**

   a) All coating operations shall be carried out according to the qualified coating application procedure.
   b) Prior to coating application, a suitable anchor pattern will be established on the metal surface by blasting.
   c) Visual inspection of the pipe surface shall be performed prior to coating application. All visible imperfections such as slivers shall be removed by grinding. If the area of grinding exceeds 10 cm^2 per meter of pipe length, the pipe shall be reblasted.
   d) Salt contamination on the pipe surface before coating application shall not exceed 20 mg/m^2 as measured per ISO 8502-6.
   e) The coating application temperature shall be continuously monitored throughout production.
   f) The dry film thickness of the fusion bonded epoxy layer shall be a minimum of 10 mils for 3LPE systems utilizing an extruded polyethylene outer layer and a minimum of 8 mils for 3LPE systems utilizing a spray applied polyethylene outer layer.
   g) The dry film thickness of the copolymer adhesive layer shall be a minimum of 6 mils.
   h) The polyethylene outer layer shall have a minimum average dry film thickness of 118 mils for extruded polyethylene and a minimum average dry film thickness of 47 mils for spray applied polyethylene.
   i) After application of the coating, holiday detection shall be performed using a high voltage holiday detector at 25 kV.

6) **Coating Application Quality Control Testing**

   a) Inspection and testing per Section 11 of ISO 21809-1 shall be performed for quality control during coating application.

7) **Field Joint Coatings**

   a) The field joint coating shall consist of liquid applied epoxy, liquid applied urethane or fusion bonded epoxy. Heat shrink sleeves or tape wrap coatings are not permitted for field joints.

b) Before production starts, the field joint coating application procedure shall be prepared in writing and qualified. At a minimum, the coating application procedure shall describe the following:

   i) Method for surface preparation and required surface profile
   ii) Method for heating the pipe and monitoring temperature
   iii) Nominal steel temperature for application of field joint coating and permitted range.
   iv) Manufacturer and brand name of product
   v) Method and equipment for application of coating
   vi) Minimum dry film thickness
   vii) Method for holiday detection and repair

c) The required qualification tests will include:

   i) Impact resistance testing
   ii) Hot-water soak/adhesion testing
   iii) Penetration resistance testing
   iv) Cathodic disbondment testing

d) Prior to coating, the pipe surface shall be prepared by abrasive blasting and visually inspected. Any surface imperfections (e.g., slivers, scabs, etc.) shall be removed by grinding.

e) Dry film thickness measurements shall be carried out on each field joint. The minimum dry film thickness shall be at least 20 mils.

f) After application of the field joint coating, holiday detection shall be performed using a high voltage holiday detector operating at 5 kV per mm of specified minimum coating thickness up to a maximum of 25 kV.

8) **Inspection Requirements**

a) A coating inspector shall monitor application of coatings at the coating facility and during field joint coating to ensure compliance with specifications.

b) Coating inspectors shall, at a minimum, have a valid NACE Certified Coating Inspector - Level 1 certificate, or equivalent certification.

9) **Integrity Management for Stress Corrosion Cracking (SCC)**

a) An Electromagnetic Acoustic Transducer (EMAT) in-line inspection tool must be run not later than fourteen (14) years[2] after Pipeline Start-Up and once every seven (7) years thereafter. An alternate EMAT ILI schedule can be proposed to PHMSA Director or Project Designee for "no objection".

b) Magnetic Particle Inspection will be performed to assess the pipeline for SCC in areas of disbonded coating found at Direct Assessment dig sites, ILI tool verification dig sites and any other digs performed due to the presence of corrosion.

Reporting and Certification:

10) **Reporting:** Within twelve (12) months following Pipeline Start-Up and annually[3] thereafter, the **ALASKA LNG PROJECT** must report the following to the PHMSA Director or Project Designee with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division[4].

a) In the first annual report, the **ALASKA LNG PROJECT** must describe the economic benefits of these ***Conditions***. Subsequent reports must indicate any changes to this initial assessment;

b) In the first annual report, fully describe how the public benefits from energy availability. Subsequent reports must indicate any changes to this initial assessment;

[2] ASME B31.8S (2004) Section A3.3 recognizes "age ≥ 10 years" as a criteria for the possibility of SCC to exist and there are no known instances of SCC occurring with 3LPE coated pipe that has been in service for <20 years, therefore the suggested initial inspection at 14 years.

[3] Annual reports and other reports submitted to PHMSA Director or Project Designee must be provided in accordance with 49 CFR Part 192 regulations.

[4] Upon notice to the **ALASKA LNG PROJECT**, PHMSA may update reporting contacts for Condition 10.

c) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within an potential impact radius (PIR) as defined in 49 CFR § 192.903;

d) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year;

e) Any reportable incident or any leak reported on the DOT Annual Report;

f) All repairs that occurred during the previous year;

g) Any on-going damage prevention, corrosion, and corrosion preventative initiatives and a discussion of the success of the initiatives;

11) **Certification:** A senior executive officer, vice president or higher, of the **ALASKA LNG PROJECT** must certify in writing that the Mainline of the **ALASKA LNG PROJECT** Pipeline meet these ***Conditions.*** The **ALASKA LNG PROJECT** must send this certification with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the PHMSA Director, Western Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within three (3) months of placing the pipeline into natural gas service.

Nomenclature:

12) **Nomenclature:** Defines technical terms used for throughout these conditions.

a) Pipeline Start-Up: An interval during which the pipeline system begins operations, and throughput (product flow through the pipeline) is ramped to its commercial capacity

Proprietary Data:

13) **Proprietary Data:** Proprietary Data may be submitted by the **ALASKA LNG PROJECT** to PHMSA Director or Project Designee on a confidential basis. This data would be labeled "Confidential Business Information" and will be afforded the protection of 49 CFR 7.23.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether the **ALASKA LNG PROJECT** has complied with the specified conditions of this special permit.
2) Failure to submit the certifications required by Condition 11 within the time frames specified may result in revocation of this special permit.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1). As provided in 49 U.S.C. § 60122, PHMSA may also issue an enforcement action for failure to comply with this special permit.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify the **ALASKA LNG PROJECT** in writing of the proposed action and provide the **ALASKA LNG PROJECT** an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective. Otherwise, in accordance with 49 CFR § 190.341(h)(2)(i), the **ALASKA LNG PROJECT** may provide a written response showing why the proposed action should not be taken within 30 days of the notice.
5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).
6) The **ALASKA LNG PROJECT** may seek reconsideration of a decision made pursuant to 49 CFR § 190.341(h) by submitting a petition to the Associate Administrator of Pipeline Safety in accordance with § 190.341(i). The Associate Administrator's decision made pursuant to 49 CFR § 190.341(i) constitutes final administrative action. All final administrative actions are subject to juridical review under 49 U.S.C. § 60119.
7) If the owner(s) of the **ALASKA LNG PROJECT** sells, merges, transfers, or otherwise disposes of the assets addressed in these Conditions, the **ALASKA LNG PROJECT** must

provide PHMSA with written notice of the transfer within 30 days after the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

APPENDIX E.2 MAINLINE BLOCK VALVE SPACING SPECIAL PERMIT CONDITIONS

Appendix E

Main Line Block Valve Spacing Special Permit CONDITIONS

Main Line Block Valve (MLBV) Spacing
Special Permit Conditions

The ***Main Line Block Valve (MLBV) Spacing Conditions*** are presented under the following titles:

- Overview
- MLBV Spacing
- Reporting and Certification
- Nomenclature
- Limitations

Overview:

1) **Purpose and Need:** The **ALASKA LNG PROJECT** and PHMSA agree that certain MLBV Conditions are necessary for the safe design, construction and operation of the pipeline extending from the Prudhoe Bay Unit to the LNG Plant located on the Kenai Peninsula, otherwise known as the ***Mainline***. **ALASKA LNG PROJECT** may propose changes to these ***MLBV Spacing Conditions (Conditions)***, review dates or timing to PHMSA for "no objection." Any proposed changes to the ***Conditions*** by the **ALASKA LNG PROJECT** must maintain equivalent/acceptable levels of safety. PHMSA will determine whether substantive changes to the ***Conditions*** require a modification or public notice of this special permit. PHMSA will provide the **ALASKA LNG PROJECT** with notice of its decision and an opportunity to respond to any proposed changes in accordance with 49 CFR § 190.341 and the Limitations section of this special permit. Any submittal timing, review timing, or completion timing in these ***Conditions*** can be modified by PHMSA upon request by the **ALASKA LNG PROJECT** and with a "no objection" from PHMSA[1] to the **ALASKA LNG PROJECT**.

[1] The **ALASKA LNG PROJECT** must submit any proposed changes to the ***Conditions*** to PHMSA Director, Western Region or PHMSA project designee for review and "no objection" prior to usage.

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Main Line Block Valve Spacing Special Permit CONDITIONS

2) **Applicable Regulations:** The ***Pipeline*** must be designed, constructed, operated and maintained in accordance with 49 CFR Part 192 including, but not limited to, those requirements that are stated as pertaining to alternative MAOP (§§ 192.112, 192.328, and 192.620), but with exception of the valve spacing requirement §192.179(4) as described herein, and other exceptions as granted by other Special Permits. In addition to Part 192 conformance, the ***Pipeline*** must also be designed, constructed, operated and maintained in accordance with these ***Conditions.*** In the event of a conflict between these ***Conditions*** and the applicable requirements under 49 CFR Part 192, the ***Conditions*** shall control.

3) **Maximum Allowable Operating Pressure (MAOP): The ALASKA LNG PROJECT** must operate the 42-inch diameter **ALASKA LNG PROJECT** Prudhoe Bay to Nikiski pipeline (the **ALASKA LNG PROJECT** ***Mainline Pipeline***) at or below a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The ***Mainline*** can be designed for operation up to 80% of specified minimum yield strength (SMYS), allowing for pressure build-up and overpressure protection in accordance with 49 CFR §§ 192.605(b)(5) and 192.201(a)(2).

MLBV Spacing:

4) **Spacing:**
   a) In Class 1 locations north of Fairbanks, each point on the pipeline must be within 27.5 miles of a sectionalizing block valve. In Class 1 locations south of Fairbanks, each point on the pipeline must be within 15.0 miles of a sectionalizing block valve.
   b) Sectionalizing block valves must be placed as close as reasonably possible to the start and end Mile Posts in Class 2, 3 and Class 4 locations, but not exceed the spacing requirements of §192.179.
   c) In High Consequence Areas (c.f. §192.905) in Class 1 and 2 locations, sectionalizing block valves spacing must comply with the requirements of §192.179, or utilize pipe compliant with the requirements of §192.112(a) and (b)(1) and (2) (i.e. capable of intrinsic arrest with concomitant increase in critical flaw length), or crack arrestors spaced every eight pipe lengths must be installed from the start to end Mile Posts of the HCA.

Main Line Block Valve Spacing Special Permit CONDITIONS

d) The **ALASKA LNG PROJECT** must perform an assessment, per ASME B31.8-2014 Section 846.1.1, that considers the following factors.

i) The amount of gas released due to repair and maintenance blowdowns, leaks, or ruptures

ii) The time to blow down an isolated section

iii) The impact in the area of gas release (e.g. nuisance and any hazard resulting from prolonged blowdowns)

iv) Continuity of service

v) Operating and maintenance flexibility of the system

vi) Significant conditions that may adversely affect the operation and security of the line

5) **Valve Monitoring, Control and Closure:**

a) The **ALASKA LNG PROJECT** must procure and operate the valves such that closure is automatically initiated when one of the following conditions occurs[2]:

i) Pressure drops to 60% of Maximum Operating Pressure (MOP) of that particular ***Pipeline Segment***.

ii) Decrease in operating pressure in ten (10) minutes is greater than 8.75% (ΔPressure/10min > 8.75%)[3].

b) Both Remote Controlled Valves (RCV), and Automatic Shut-Off Valves (ASV) are permissible. RCVs will be installed at all powered and telecommunications-equipped locations: compressor, heater and metering locations.

c) Real time monitoring of the RCVs will be performed at the **ALASKA LNG PROJECT's** Pipeline Control Center.

6) **Valve Siting:** the valves will be sited per Table 1 below.

[2] These set points must be low enough to ensure that a pipeline rupture is detected, yet high enough to not adversely impact the pipeline's normal anticipated operation. During operation, **ALASKA LNG** may seek modification of the pressure rate drop set point based upon the results of rupture and hydraulics analyses.

[3] This set-point is based upon preliminary design information and will be reevaluated prior to valve procurement.

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Main Line Block Valve Spacing Special Permit CONDITIONS

Table 1: Valve Siting for Alaska LNG Pipeline[4]

MLBV #	MP	ΔMP	Location Description	Valve Type
1	0.00		Gas Treatment Plant Meter Station (south fence line)	RCV
2	36.74	36.74	Stand-alone MLBV -Potential Station	ASV
3	75.97	39.23	Compressor Station - Sagwon	RCV
4	112.04	36.07	Stand-alone MLBV -Potential Station	ASV
5	148.51	36.47	Compressor Station - Galbraith Lake	RCV
6	194.09	45.58	Stand-alone MLBV -Potential Station	ASV
7	240.10	46.01	Compressor Station - Coldfoot	RCV
8	286.05	45.95	Stand-alone MLBV -Potential Station	ASV
9	332.64	46.59	Compressor Station - Ray River	RCV
10	377.95	45.31	Stand-alone MLBV -Potential Station	ASV
11	421.56	43.61	Compressor Station - Minto	RCV
12	444.90	23.34	Stand-alone MLBV	ASV
13	467.10	22.20	Stand-alone MLBV -Potential Station	ASV
14	492.96	25.86	Stand-alone MLBV	ASV
15	517.62	24.66	Compressor Station - Healy	RCV
16	534.79	17.17	Upstream of Class 3 Location at Glitter Gulch	ASV
17	538.79	4.00	Downstream of Class 3 Location	ASV
18	546.50	7.71	Stand-alone MLBV -Potential Station	ASV
19	572.23	25.73	Stand-alone MLBV	ASV
20	597.35	25.12	Compressor Station - Honolulu Creek	RCV
21	625.83	28.48	Stand-alone MLBV	ASV
22	648.16	22.33	Stand-alone MLBV -Potential Station	ASV
23	675.24	27.08	Compressor Station - Rabideux Creek	ASV
24	703.67	28.43	Stand-alone MLBV - Potential Deshka River Station	RCV
25	725.93	22.26	Stand-alone MLBV	ASV
26	749.11	23.18	Heater Station - Theodore River	RCV
27	766.01	16.90	Upstream of Cook Inlet Crossing	ASV
28	793.34	27.33	Downstream of Cook Inlet Crossing	ASV
29	799.85	6.51	Stand-alone MLBV (Potential Class 2 Location)	ASV
30	806.57	6.72	Kenai LNG Meter Station (north fence line)	RCV

[4] MLBV siting is based upon the latest route revision C2 and may be subject to change with future route alternatives. The final siting will follow the requirements and limitations of these Special Permit Conditions.

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Main Line Block Valve Spacing Special Permit CONDITIONS

Reporting and Certification:

7) **Reporting:** Within twelve (12) months following Pipeline Start-Up and annually[5] thereafter, the **ALASKA LNG PROJECT** must report the following to the PHMSA Director or Project Designee with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division[6].

   a) In the first annual report, the **ALASKA LNG PROJECT** must describe the economic benefits of these ***Conditions***. Subsequent reports must indicate any changes to this initial assessment;
   b) In the first annual report, fully describe how the public benefits from energy availability. Subsequent reports must indicate any changes to this initial assessment;
   c) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within an potential impact radius (PIR) as defined in 49 CFR § 192.903;
   d) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year;
   e) Any reportable incident or any leak reported on the DOT Annual Report;
   f) All repairs that occurred during the previous year;
   g) Any on-going damage prevention, corrosion, and corrosion preventative initiatives and a discussion of the success of the initiatives;

8) **Certification:** A senior executive officer, vice president or higher, of the **ALASKA LNG PROJECT** must certify in writing that the Mainline of the **ALASKA LNG PROJECT** Pipeline meet these ***Conditions.*** The **ALASKA LNG PROJECT** must send this certification with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the PHMSA Director, Western Region; Director,

[5] Annual reports and other reports submitted to PHMSA Director or Project Designee must be provided in accordance with 49 CFR Part 192 regulations.

[6] Upon notice to the **ALASKA LNG PROJECT**, PHMSA may update reporting contacts for Condition 7.

PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within three (3) months of placing the pipeline into natural gas service.

Nomenclature:

9) **Nomenclature:** Defines technical terms used for throughout these conditions.
   a) Real Time Monitoring: the continuous relay of relevant pipeline process information from SCADA systems associated with certain pipeline equipment and facilities via a telecommunications system. The relay of information is conducted in a manner than minimizes the time for this transfer to occur. The information collected is passed to a location where systems and/or persons can review, process and/or store it as needed
   b) Pipeline Start-Up: An interval during which the pipeline system begins operations, and throughput (product flow through the pipeline) is ramped to its commercial capacity

10) **Proprietary Data:** Proprietary Data may be submitted by the **ALASKA LNG PROJECT** to PHMSA on a confidential basis. This data would be labeled "Confidential Business Information" and will be afforded the protection of 49 CFR 7.23.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether the **ALASKA LNG PROJECT** has complied with the specified conditions of this special permit.
2) Failure to submit the certifications required by Condition 8 within the time frames specified may result in revocation of this special permit.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1). As provided in 49 U.S.C. § 60122, PHMSA may also issue an enforcement action for failure to comply with this special permit.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify the **ALASKA LNG PROJECT** in writing of the proposed action and provide the **ALASKA LNG PROJECT** an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if

necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective. Otherwise, in accordance with 49 CFR § 190.341(h)(2)(i), the **ALASKA LNG PROJECT** may provide a written response showing why the proposed action should not be taken within 30 days of the notice.

5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).
6) The **ALASKA LNG PROJECT** may seek reconsideration of a decision made pursuant to 49 CFR § 190.341(h) by submitting a petition to the Associate Administrator of Pipeline Safety in accordance with § 190.341(i). The Associate Administrator's decision made pursuant to 49 CFR § 190.341(i) constitutes final administrative action. All final administrative actions are subject to juridical review under 49 U.S.C. § 60119.
7) If the owner(s) of the **ALASKA LNG PROJECT** sells, merges, transfers, or otherwise disposes of the assets addressed in these Conditions, the **ALASKA LNG PROJECT** must provide PHMSA with written notice of the transfer within 30 days after the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

APPENDIX E.3 CRACK ARRESTOR SPACING SPECIAL PERMIT CONDITIONS

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Crack Arrestor Spacing Special Permit CONDITIONS

Crack Arrestor (CA) Spacing
Special Permit Conditions

The ***Crack Arrestor (CA) Spacing Conditions*** are presented under the following titles:

- Overview
- CA Spacing
- Reporting and Certification
- Nomenclature
- Limitations

Overview:

1) **Purpose and Need:** The **ALASKA LNG PROJECT** and PHMSA agree that certain MLBV and CA Conditions are necessary for the safe design, construction and operation of the pipeline extending from the Prudhoe Bay Unit to the LNG Plant located on the Kenai Peninsula, otherwise known as the ***Mainline***. **ALASKA LNG PROJECT** may propose changes to these ***Crack Arrestor Spacing Conditions (Conditions)***, review dates or timing to PHMSA for "no objection." Any proposed changes to the ***Conditions*** by the **ALASKA LNG PROJECT** must maintain equivalent/acceptable levels of safety. PHMSA will determine whether substantive changes to the ***Conditions*** require a modification or public notice of this special permit. PHMSA will provide the **ALASKA LNG PROJECT** with notice of its decision and an opportunity to respond to any proposed changes in accordance with 49 CFR § 190.341 and the Limitations section of this special permit. Any submittal timing, review timing, or completion timing in these ***Conditions*** can be modified by PHMSA upon request by the **ALASKA LNG PROJECT** and with a "no objection" from PHMSA[1] to the **ALASKA LNG PROJECT**.

[1] The **ALASKA LNG PROJECT** must submit any proposed changes to the ***Conditions*** to PHMSA Director, Western Region or PHMSA project designee for review and "no objection" prior to usage.

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Crack Arrestor Spacing Special Permit CONDITIONS

2) **Applicable Regulations:** The ***Pipeline*** must be designed, constructed, operated and maintained in accordance with 49 CFR Part 192 including, but not limited to, those requirements that are stated as pertaining to alternative MAOP (§§ 192.112, 192.328, and 192.620), but with exception the crack arrestor spacing requirements of §192.112(b)(2)(iii) in §192.112(b)(3), and other exceptions as granted by other Special Permits. In addition to Part 192 conformance, the ***Pipeline*** must also be designed, constructed, operated and maintained in accordance with these ***Conditions*.** In the event of a conflict between these ***Conditions*** and the applicable requirements under 49 CFR Part 192, the ***Conditions*** shall control.

3) **Maximum Allowable Operating Pressure (MAOP): The ALASKA LNG PROJECT** must operate the 42-inch diameter **ALASKA LNG PROJECT** Prudhoe Bay to Nikiski pipeline (the **ALASKA LNG PROJECT** ***Mainline Pipeline***) at or below a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The ***Mainline*** can be designed for operation up to 80% of specified minimum yield strength (SMYS), allowing for pressure build-up and overpressure protection in accordance with 49 CFR §§ 192.605(b)(5) and 192.201(a)(2).

CA Spacing:

4) **Fracture Control Plan:** Alaska LNG will produce a Fracture Control Plan (FCP) that details the Project's compliance with the requirements in 49 CFR § 192.112(b), with the exception of the crack arrestor spacing requirements in § 192.112(b)(3). As part of the FCP, to ensure a robust design and reduce the probability of fracture initiation, material requirements for pipe body and seam welds will be specified to achieve a large through-wall critical flaw length. This critical length will generally be selected as a high proportion (80-90%) of its maximum achievable threshold with a minimum requirement of 4 inches.

5) **Intrinsic arrest:** Certain pipeline segments will be designed to comply with the Fracture Control Requirements in 49 CFR § 192.112 without the use of crack arrestors. These include:
   a) Strain Based Design Segments, as defined in the SBD Special Permit

b) Mainline segments within a distance of the bridge structure defined by a maximum thermal radiation flux[2] of 10,000 BTU/hr/ft^2 for the bridges listed below:
   i) Dietrich River (1337)[3]
   ii) Nenana River at Moody (1143)
   iii) Nenana River at Windy (1243)
   iv) Iceworm Gulch (1146)
   v) Antler Creek (1141)

6) **<u>Crack Arrestor Design and Materials Testing</u>:** The materials testing and crack arrestor design and testing shall meet the following requirements:
   a) Material destructive testing will be carried out to demonstrate compliance with the Fracture Control requirements in 49 CFR § 192.112(b)(iv).
   b) Composite crack arrestors or heavy walled pipe (integral arrestor) will be used to ensure at least 99 percent probability of fracture arrest in one arrestor when the requirements of 49 CFR § 192.112(b)(1) and (2) cannot be met. Full scale crack arrestor testing will be performed to verify the design/material of the arrestor. This testing will be performed using the combination of operating pressure, design factor, and pipe grade that has the highest driving force for fracture propagation.

7) **<u>Crack Arrestor Spacing</u>:** Crack arrestor spacing is subject to the following requirements and limitations.
   a) In Class 1 locations, the spacing of crack arrestors or pipe that meets the requirements of 49 CFR § 192.112(b)(1) and (2) may extend up to one half mile (2,640 feet). This length is inclusive of the eight (8) joint spacing requirement in 49 CFR § 192.112(b)(2)(iii).
   b) Alaska LNG TAPS Crossing: comply with CFR 192 where the Alaska LNG pipeline crosses TAPS, or TAPS Fuel Gas Line, at the following distances on either side of the crossings:

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[2] Title 24 CFR §51.203 "Safety standards" utilizes 10,000 BTU/hr/ft^2 as the "Acceptable Separation Distance" between a fire and wooden buildings. This thermal radiation flux can be increased if a study is performed that demonstrates no impact on functionality of the bridge, and received "no objection" from PHMSA.
[3] Bridge numbers from "Alaska 2013 Bridge Inventory Report": http://www.dot.alaska.gov/stwddes/desbridge/assets/pdf/2013bridgeinventory.pdf

i) TAPS in an above ground mode: 200 feet

ii) TAPS in a below ground mode: 40 feet

iii) TAPS Fuel Gas Line in a below ground mode: 40 feet

c) Dwellings

i) Comply with CFR 192 requirements in Class Locations 2, 3, and 4

ii) Comply with CFR 192 requirements in an High Consequence Area (HCA)

Reporting and Certification:

8) **Reporting:** Within twelve (12) months following Pipeline Start-Up and annually[4] thereafter, the **ALASKA LNG PROJECT** must report the following to the PHMSA Director or Project Designee with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division[5].

a) In the first annual report, the **ALASKA LNG PROJECT** must describe the economic benefits of these ***Conditions***. Subsequent reports must indicate any changes to this initial assessment;

b) In the first annual report, fully describe how the public benefits from energy availability. Subsequent reports must indicate any changes to this initial assessment;

c) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within an potential impact radius (PIR) as defined in 49 CFR § 192.903;

d) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year;

e) Any reportable incident or any leak reported on the DOT Annual Report;

f) All repairs that occurred during the previous year;

g) Any on-going damage prevention, corrosion, and corrosion preventative initiatives and a discussion of the success of the initiatives;

[4] Annual reports and other reports submitted to PHMSA Director or Project Designee must be provided in accordance with 49 CFR Part 192 regulations.

[5] Upon notice to the **ALASKA LNG PROJECT**, PHMSA may update reporting contacts for Condition 8.

9) **Certification:** A senior executive officer, vice president or higher, of the **ALASKA LNG PROJECT** must certify in writing that the Mainline of the **ALASKA LNG PROJECT** Pipeline meet these ***Conditions.*** The **ALASKA LNG PROJECT** must send this certification with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the PHMSA Director, Western Region; Director, PHMSA Standards and Rulemaking Division; and Director, PHMSA Engineering and Research Division within three (3) months of placing the pipeline into natural gas service.

Nomenclature:

10) **Nomenclature:** Defines technical terms used for throughout these conditions.
    a) Pipeline Start-Up: An interval during which the pipeline system begins operations, and throughput (product flow through the pipeline) is ramped to its commercial capacity

Proprietary Data:

11) **Proprietary Data:** Proprietary Data may be submitted by the **ALASKA LNG PROJECT** to PHMSA on a confidential basis. This data would be labeled "Confidential Business Information" and will be afforded the protection of 49 CFR 7.23.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether the **ALASKA LNG PROJECT** has complied with the specified conditions of this special permit.
2) Failure to submit the certifications required by Condition 9 within the time frames specified may result in revocation of this special permit.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1). As provided in 49 U.S.C. § 60122, PHMSA may also issue an enforcement action for failure to comply with this special permit.

Appendix E

Crack Arrestor Spacing Special Permit CONDITIONS

4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify the **ALASKA LNG PROJECT** in writing of the proposed action and provide the **ALASKA LNG PROJECT** an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective. Otherwise, in accordance with 49 CFR § 190.341(h)(2)(i), the **ALASKA LNG PROJECT** may provide a written response showing why the proposed action should not be taken within 30 days of the notice.
5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).
6) The **ALASKA LNG PROJECT** may seek reconsideration of a decision made pursuant to 49 CFR § 190.341(h) by submitting a petition to the Associate Administrator of Pipeline Safety in accordance with § 190.341(i). The Associate Administrator's decision made pursuant to 49 CFR § 190.341(i) constitutes final administrative action. All final administrative actions are subject to juridical review under 49 U.S.C. § 60119.
7) If the owner(s) of the **ALASKA LNG PROJECT** sells, merges, transfers, or otherwise disposes of the assets addressed in these Conditions, the **ALASKA LNG PROJECT** must provide PHMSA with written notice of the transfer within 30 days after the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).